2015 Rate Design Application

June 25, 2015/June 26, 2015

Workshop Nos. 11a and 11b

Large General Service (LGS)

Medium General Service (MGS)

Small General Service (SGS)

Rate Structures

BC Hydro Summary and

Consideration of Participant Feedback

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This memo documents stakeholder feedback and BC Hydro's consideration of this input as concerning BC Hydro's June 25, 2015 Workshop 11a and June 26, 2015 Workshop 11b, which addressed:

- BC Hydro's General Service (**GS**) customer segmentation analysis (Workshop 11a);
- BC Hydro's preferred SGS rate structure and an alternative level of SGS basic charge customer-related cost recovery (Workshop 11a);
- BC Hydro's preferred MGS energy rate structure, alternative MGS demand charge structures and an alternative level of demand-related cost recovery (Workshop 11a);
- Alternative LGS energy rate structures and alternative LGS demand charge structures (Workshop 11b);
- GS Minimum Monthly Charges (referred to as '**Demand Ratchet**') and Transformer Ownership Discount (**TOD**) (Workshop 11b); and
- GS voluntary rate options, including voluntary Time of Use (**TOU**) rates, interruptible rates and optional demand charges to be assessed as part of RDA Module 2 (Workshop 11b).

Workshops 11a and 11b were held in Vancouver, B.C. with customers also being provided an opportunity to listen into the discussions remotely through a webinar. Copies of Workshops 11a and 11b presentation slides can be found on the BC Hydro website at www.bchydro.com/2015RDA.

Customer input was received at Workshops 11a and 11b as well as through feedback forms and written comments submitted during a subsequent 30-day comment period, which began with the posting of draft Workshop 11b summary notes on July 13, 2015.

BC Hydro also references Workshop 12 analysis and stakeholder comments in a number of places in this memo. Workshop 12 was held on July 30, 2015, at which among other things BC Hydro identified its overall Bonbright rate criteria prioritization (refer to section 2 of the memo), its preferred rate structure for the LGS rate class and its preferred level of LGS demand charge recovery of demand-related costs (discussed in section 5 of the memo).

The memo is structured as follows:

- Section 1 addresses comments concerning alternative GS customer segmentation methodologies and BC Hydro's conclusion based on its analysis that the Status Quo (**SQ**) GS segmentation between the SGS, MGS and LGS rate classes remains appropriate for the purpose of Module 1 RDA GS rate design. BC Hydro commits to examining as a RDA Module 2 topic a potential rate class of large LGS customers (referred to as **XLGS** with demand greater than 2,000 kilowatts (**kW**)) as part of its assessment of a potential rate similar to Rate Schedule (**RS**) 1823 (**LGS TSR-Like Rate**) for such a class;
- Section 2 describes BC Hydro's overall Bonbright rate criteria prioritization in response to British Columbia Utility Commission (**BCUC** or **Commission**) staff requests that BC Hydro do so in the context of its preferred SGS, MGS and LGS rates;
- Section 3 addresses comments concerning the SGS basic charge and the level of customer-related cost recovery through this charge;
- Section 4 addresses comments concerning three MGS demand charge structure alternatives, which are: **MGS SQ Demand Charge** (Three-step Inclining Block); **MGS Flat Demand Charge** (single MGS charge); and **MGS Two-step Inclining Block** (zero Tier 1 charge and MGS Tier 2 charge). BC Hydro identifies that its preferred alternative is the MGS Flat Demand Charge.

Section 4 also reviews comments concerning the appropriate level of demand-related cost recovery through MGS demand charges and identifies BC Hydro's preference to increase the demand charge from its current level that recovers approximately 15 per cent of demand-related costs to approximately 35 per cent of demand-related costs;

- Section 5 addresses comments concerning four LGS energy rate alternatives and three LGS demand charge alternatives:
  - The LGS energy rate alternatives are: SQ LGS energy rate (**SQ LGS Energy Rate**); a modified SQ LGS rate aimed at simplifying the LGS energy rate while retaining the baseline (**SQ LGS Simplified Energy Rate**); flattening the LGS energy rate with no baseline (**LGS Flat Energy Rate**); and segmenting the existing LGS rate class to create a new XLGS rate class with the ability to define and adjust baselines annually through a LGS TSR-Like Rate.
  - The LGS demand charge structure alternatives are **SQ** (Three-step Inclining Block); **LGS Flat Demand Charge** (single LGS charge); and **LGS Two-step Inclining Block** (zero Tier 1 charge and LGS Tier 2 charge).

Section 5 identifies BC Hydro's preferred energy and demand alternatives, which are easy to understand LGS Flat Energy Rate with LGS Flat Demand Charge.

Section 5 reviews comments received on the existing provisions and administrative rules associated with the SQ Part 2 baseline structure.
BC Hydro's consideration is that the SQ LGS Simplified Energy Rate is probably too complicated for many customers to understand and therefore its acceptance is unlikely to improve much beyond the relatively low level of understanding of the status quo design.

Section 5 also addresses comments concerning the appropriate level of demand cost recovery through LGS demand charges and identifies BC Hydro's preference to increase demand charges to a level that recovers approximately 65 per cent of demand-related costs, which would make it consistent with demand-related cost recovery percentage through the RS 1823 demand charge;

- Section 6 reviews BC Hydro's assessment of the recommended transition strategies for implementation of its preferred MGS and LGS rate designs. Based on its analysis BC Hydro identifies that on balance no phase-in period is required for either class of customers.
- Section 7 reviews comments concerning the MGS and LGS Demand Ratchets, which is applicable at 50 per cent of peak monthly demand registered in the most recent winter period (November to March); and
- Section 8 concludes by canvassing comments concerning BC Hydro's proposal to address potential GS rate options such as interruptible rates, optional demand charges and an efficiency rate credit during RDA Module 2. Section 8 also addresses further comments on optional TOU rates.

Participants to Workshop 11b raised issues for consideration of TOD and transformer rentals, which will be evaluated in conjunction with BC Hydro's Distribution extension policy as part of RDA Module 2.

Attachment 1 includes the Workshop 11a and 11b summary notes, which provide a more detailed description of issues (including questions and answers);

Attachment 2 contains the feedback forms received during the written comment period;

Attachment 3 contains a summary overview of Canadian default GS charges and optional rates and an expanded Canadian jurisdictional review of GS segmentation;

Attachment 4 contains BC Hydro's modelling results concerning a potential three year phase-in period for: (1) BC Hydro's preferred MGS rate (MGS Flat Energy

Rate, MGS Flat Demand Charge and a one-time increase in the MGS demand charge recovery of demand-related costs from about 15 per cent to 35 per cent); and (2) BC Hydro's preferred LGS rate (LGS Flat Energy Rate, LGS Flat Demand Charge and a one-time increase in the LGS demand charge recovery of demand-related costs from about 50 per cent to 65 per cent);

Attachment 5 is a reference for interpreting the sensitivity analysis outcomes presented in the corresponding tables in Section 1 and in Attachment 4.

For ease of reference, BC Hydro sets out in Table 1 its energy Long-Run Marginal Cost (**LRMC**)-range for F2016 to F2019, adjusted for distribution loss and inflation.[1]

Table 1: BC Hydro Energy LRMC Range

Fiscal Year	Lower End of Energy LRMC Range	Upper End of Energy LRMC Range
F2013	8.5 cents/kWh	10.0 cents/kWh
F2013 (*Distribution loss 6%)*	*9.01 cents/kWh*	*10.60 cents/kWh*
F2014	9.03 cents/kWh	10.62 cents/kWh
F2015	9.17 cents/kWh	10.79 cents/kWh
F2016	9.36 cents/kWh	11.01 cents/kWh
F2017	9.46 cents/kWh	11.13 cents/kWh
F2018	9.65 cents/kWh	11.35 cents/kWh
F2019	9.84 cents/kWh	11.58 cents/kWh

1 Section 9.2.12 of BC Hydro's 2013 Integrated Resource Plan (**IRP**) sets out the energy LRMC range of $85 per megawatt hour (/**MWh**) to $100/MWh ($F2013); copy available at https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html. For rate making purposes BC Hydro factors in Distribution losses and uses a 2 per cent inflation assumption for F2016-F2019.

1 Rate Class Segmentation

In the Workshop 8a/8b consideration memo, BC Hydro reviewed the cost of service (**COS**) analysis completed to date, consisting of individual customer sampling (referred to as **Method 1**). The results of Method 1 were inconclusive.[2] There is no difference in dollars per kilowatt hour (**$/kWh**) energy costs between GS customers and there is no pattern to suggest a breakpoint between different customer size on the basis of dollars per kilowatt (**$/kW**) differences in 4-coincident peak (**4CP**)-related costs or distribution non-coincident customer peak (**NCP**)-related costs. BC Hydro reviewed the results of Method 1 at Workshop 11a.

BC Hydro committed to undertake additional COS analysis to assess the existing LGS/MGS 150 kW breakpoint[3] and for purposes of potentially creating a new XLGS rate class. This additional COS analysis consisted of customers clustered by size (referred to as **Method 2**) and was reviewed at Workshop 12. BC Hydro highlighted at Workshop 12 that the results of Method 2 did not support a change to the existing MGS/LGS breakpoint approved by BCUC Order G-110-10 as part of the 2009 Large General Service Negotiated Settlement Agreement (**NSA**).

BC Hydro sought feedback on the two COS segmentation methodologies:

- *Method 1* sampled 1,000 customers from each of the SGS, MGS and LGS classes and pooled and re-allocated assigned F2016 costs pro rata by individual customer kWh, 4CP demand and NCP demand.

  The results of Method 1 are not conclusive in that NCP allocation varies depending on coincidence within the three rate classes. Coincidence is better correlated with cost than customer size. Transformer cost may vary with size but cost impact is small.

[2] Section 1.2 of the Workshop 8a/8b consideration memo; https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-06-19-bch-rda-wksp-8a-8b-gsrs.pdf.

[3] The additional energy basis of 550,000 kWh for segmenting between LGS and MGS arose from the 2009 LGS Application NSA; see sections 3 and 4 of Appendix B to BCUC Order No. G-110-10; http://www.bcuc.com/Documents/Orders/2010/DOC_25763_G-110-10_%20BCH-Large%20General%20Service%20Rate_Reasons-NSA.pdf

- *Method 2* pooled and re-allocated assigned F2016 costs pro rata to clusters of pre-assigned segments of customers, whereby customers were grouped by size as opposed to evaluated individually.

  The results of Method 2, as presented at RDA Workshop 12, suggest that coincidence is somewhat correlated with customer size and that as coincidence factor decreases, costs decrease on a $/kW basis.

1.1 Participant Comments

Commercial Energy Consumers Association of British Columbia (**CEC**) remarks that cost allocation to customers appears not to be well accomplished with the existing methodology, but that there appears to be no evidentiary basis to improve upon the SQ. CEC concludes that SQ segmentation of GS rate classes should be maintained.

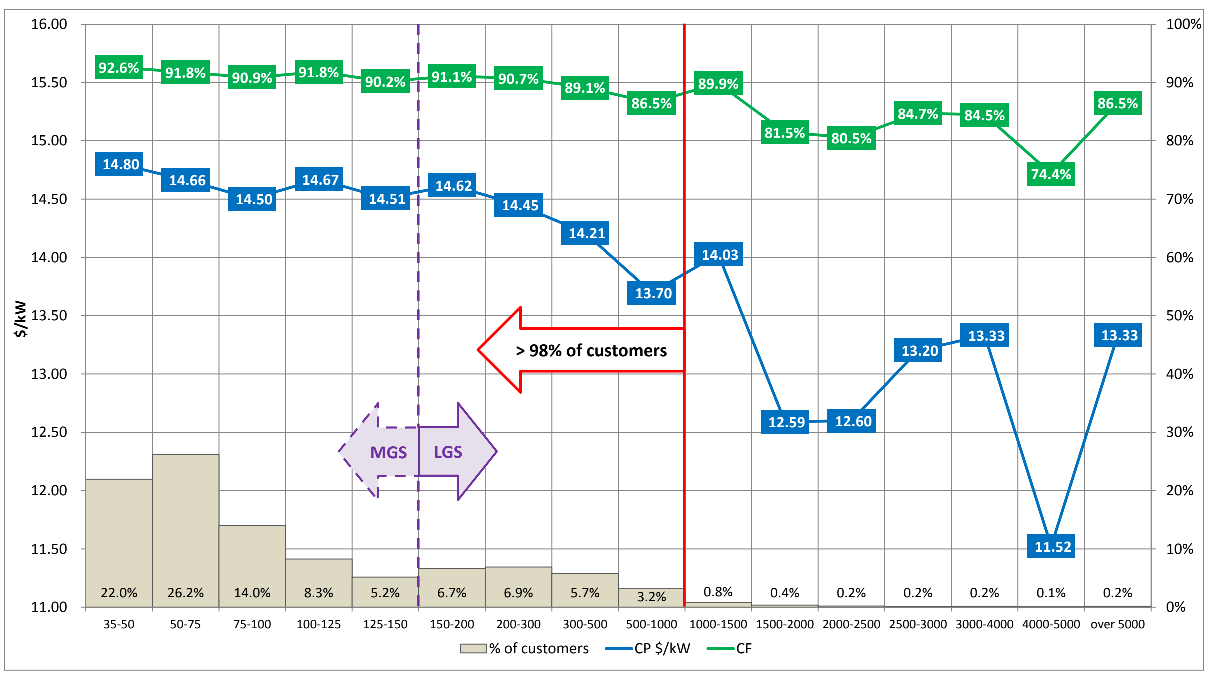
British Columbia Old Age Pensioners' Organization *et al* (**BCOAPO**) suggests that to ensure a fair recovery of costs between customers within a class, it would be ideal if all customers in the class generally had: 1) a similar ratio between their billing demand and their contribution to the class's 4CP and NCP values, and 2) similar load factors in recognition of the fact that not all demand and energy-related costs are recovered respectively through demand and energy charges. BCOAPO is not suggesting that these parameters should be used to classify individual customers, as it agrees that more understandable factors such as size or service voltage should be used for this purpose. BCOAPO is interested in understanding how these various factors vary by customer size and to learn whether there are any obvious break points to suggest points at which classes should be segmented.

Canadian Office and Professional Employees Union Local 378 (**COPE 378**) states that the finding of coincidence correlating better with cost than customer size would not appear to support the existing MGS/LGS segmentation. COPE 378 requests analysis and implications of eliminating the existing MGS/LGS split and/or replacing it with a very large LGS category. COPE 378 questions whether public entitites such as municipalities, universities, school boards and hospitals (referred to as the **MUSH** sector) are being fairly treated, especially those with a large number of sites. COPE 378 suggests an analysis of each customer's own account costs under the GS rates and asks whether there is a COS or other justification for creating a 'multiple account' MUSH sector rate class.

1.2 BC Hydro Consideration

As suggested by BCOAPO, BC Hydro explored the load characteristics of its SGS, MGS and LGS customers in an attempt to find "obvious break points". BC Hydro described in Workshop 12 that the clearest relationship that can be observed is between size and coincidence factor, with costs declining with the size of a customers' peak coincident demand. However, even with this trend, it is difficult to pinpoint a clear breakpoint where the trend changes. Refer to Figure 1, as presented at Workshop 12.[4]

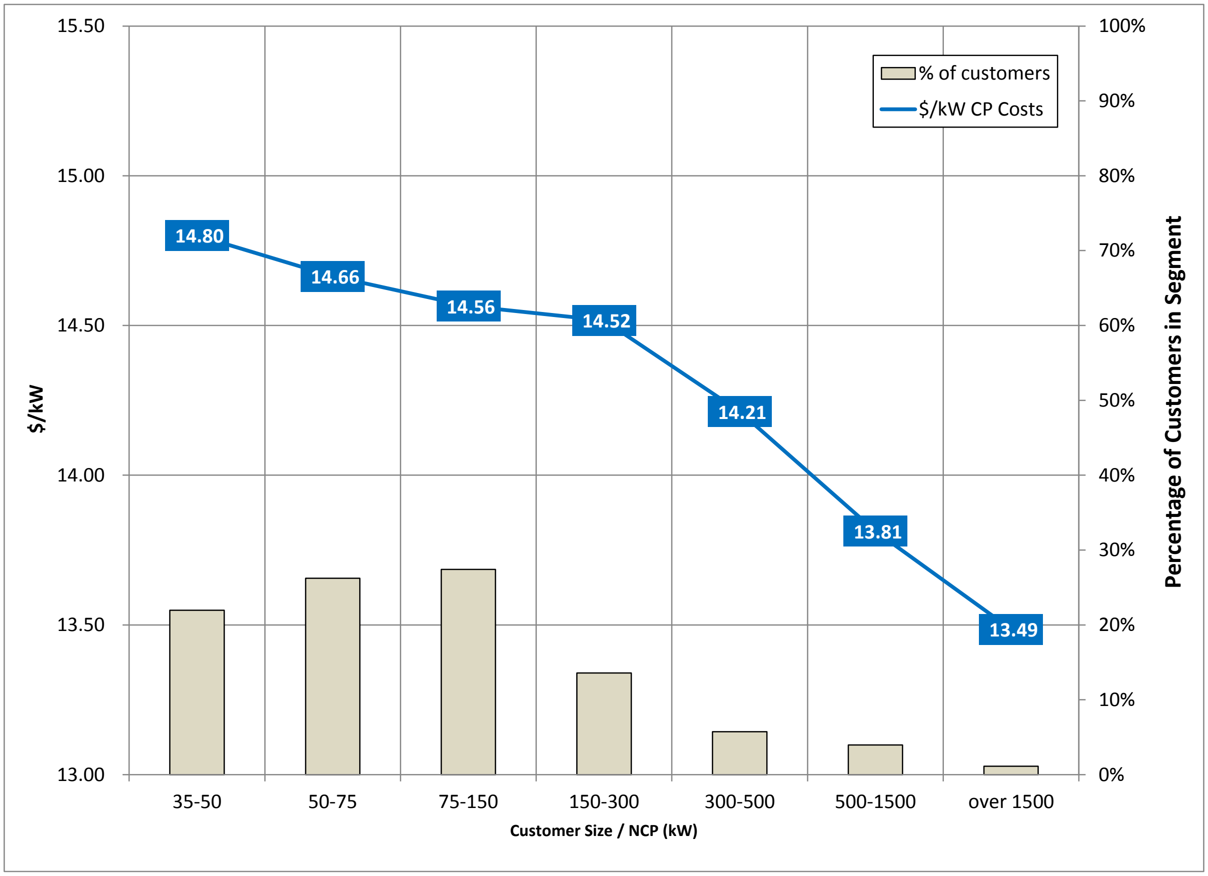
Figure 1: 4 Coincident Peak Costs



4 Workshop 12 presentation slide deck, slide 36; https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/01_2015-07-30-wksp-12-pres.pdf.

As can be seen in Figure 1, as segment size decreases the costs assigned are very sensitive to the coincidence factor (the green line) of the customers within the segment. Coincidence factor is calculated as the relationship between the segment's contribution to system coincident peak compared to their non-coincident peak. Other than the 1000-1500 kW segment, all segments to the right of the red line in Figure 1 have fewer than 100 customers as compared to an average of 2,000 customers for segments to the left of the red line. The average number of customers in the segments greater than 2000 kW is 33 (a total of 166 customers are in the segments greater than 2000 kW). The behaviour of a small number of customers can have a large impact since they account for a relatively large proportion of the segment. For example, if a few customers in the smaller segments have an annual peak that is not coincident with the system peak, the segment is consequently assigned less costs associated with Generation and Transmission Demand costs. The same variability would be observed if the lower ranges of customers were segmented to such an extent that the number of customers was similarly small. For this reason, the smaller segments of larger sized customers have been aggregated in Figure 2 to reduce the variability of the results.

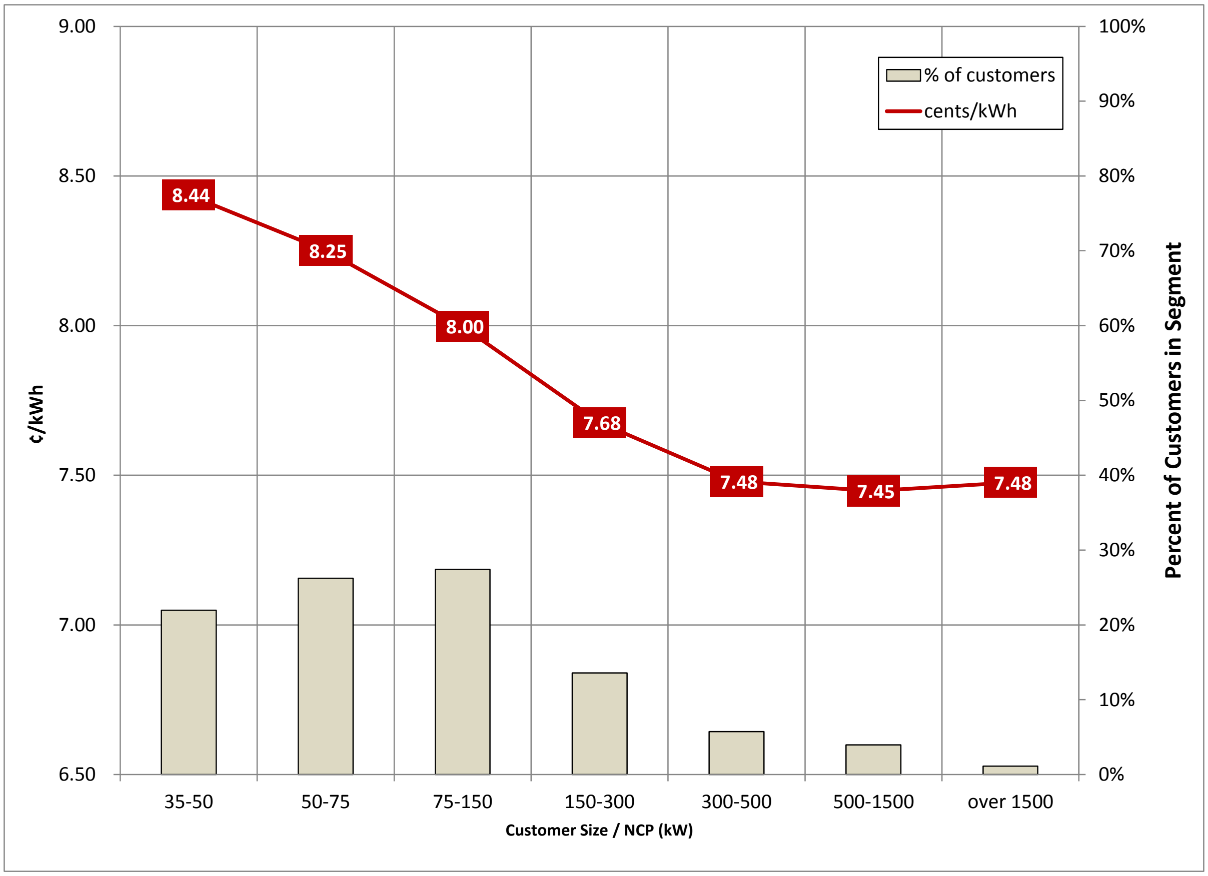
Figure 2: 4 Coincident Peak Costs – Aggregated Segments



In Figure 3 below, BC Hydro supplements the analysis presented at Workshops 8a/8b and 12 with a graph comparable to one BC Hydro's consultant Energy + Environmental Economics prepared as part of the 2009 LGS Application's segmentation analysis[5] showing full COS (energy, demand and customer costs) allocated to the same segments but on a cents per kWh basis. This method incorporates the load factor of customers in each segment and supports the conclusion from Figure 2 that there is no reason to deviate from the 150 kW breakpoint.

5 See Figure J-1 on page 9 of Appendix J of BC Hydro's 2009 LGS Application; http://www.bcuc.com/ApplicationView.aspx?ApplicationId=251.

Figure 3: Cents per kWh Cost by Segment



BC Hydro concludes through Method 2 that there is no compelling evidence to change the current 150 kW MGS/LGS breakpoint, and that there is a need to undertake further analysis regarding a potential XLGS rate class. BC Hydro also notes that no participant other than COPE 378 has suggested that the LGS and MGS rate classes should be merged at this time; refer to BC Hydro's assessment below.

Potential XLGS Rate Class

While there is jurisdictional support for a potential XLGS rate class (refer to Table 3 in Attachment 3 of this memo, BC Hydro has not yet modelled the impact of creating a new separate XLGS class of customers. BC Hydro will undertake additional engagement with Association of Major Power Consumers of British Columbia (**AMPC**) and individual customers for purposes of RDA Module 2. BC Hydro sees no point in creating a separate XLGS class at this time given that the conservation and other potential benefits, and administrative burdens, associated with a LGS TSR-Like Rate have not yet been thoroughly assessed. The potential for a LGS TSR-Like Rate and the associated segmentation of a XLGS class will be assessed through RDA Module 2.

Re-Merging LGS and MGS Rate Classes

BC Hydro is opposed to re-merging the LGS and MGS rate classes at this time. BC Hydro considers it premature to re-merge the MGS and LGS rate classes given the possibility of different rate structures for these two respective classes through the Commission's Module 1 decision, and the potential for a XLGS rate class as part of Module 2.

No LGS or MGS customer favours re-merging the two classes at this time, and several such customers oppose it; refer to the comments of Loblaws Companies Limited and TransLink, both of which have LGS and MGS accounts, in section 1.1 of the Workshop 8a/8b consideration memo. AMPC, which represents some LGS customers, does not contest the existing MGS/LGS breakpoint. BC Hydro also notes CEC's comments in favour of the status quo MGS/LGS breakpoint. Given forecast revenue neutrality for the LGS and MGS rates, and the recent amendment to section 9 of Direction No. 7[6] prohibiting the Commission from setting rates for BC Hydro for F2017-F2019 for the purpose of changing the R/C ratio of a class of customers (**Rate Rebalancing Amendment**), there are no cost implications for other rate classes if BC Hydro maintains the existing LGS/MGS breakpoint, and accordingly BC Hydro gives more weight to the views of LGS and MGS customers and associations representing such customers on this subject.

Regarding COPE 378's request for analysis of re-merging the existing MGS and LGS rate classes, BC Hydro undertook bill impact analysis consisting of comparing the SQ F2016 LGS and MGS rates to a F2017 combined LGS-MGS rate as follows:

6 B.C. Reg. 140/2015, discussed at Workshop 12.

- The F2017 combined rate is based on BC Hydro's preferred flat energy rate, flat demand charge and demand charge cost recovery of 35 per cent for MGS and 65 per cent and demand charge cost recovery for LGS; and
- The pricing elements of the combined LGS-MGS rate are as follows: Demand charge: $9.24/kW; Energy rate: 6.08 cents/kWh; Basic charge: $0.2347/day (same as F2016 status quo MGS and LGS rates).

Eliminating the existing MGS/LGS split would lead to significant bill impacts for LGS customers. Figures 4 and 5 below illustrate the bill impacts to MGS and LGS customers respectively:

- MGS customers: Other than the extremely low load factor, low consumption customers, all other MGS customers have a bill impact less than the RRA rate increase, or a much lower bill than otherwise. About 4,000 MGS accounts (~20 per cent of MGS accounts) have F2017 bill impacts of 10 per cent or greater.

Figure 4: Re-Merged MGS Bill Impacts[7]

Consumption kWh

Load Factor	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	82.9%	87.2%	37.7%	26.0%	20.8%	11.9%	4.3%	1.6%	-0.4%	-1.9%	-3.0%	-3.9%	-4.7%	-5.3%	-5.8%	-6.3%	-6.7%
20%	23.8%	24.9%	25.2%	11.8%	5.8%	2.4%	0.6%	2.6%	4.1%	4.5%	2.6%	1.0%	-0.2%	-1.2%	-2.1%	-2.8%	-3.5%
30%	4.1%	4.1%	4.1%	4.1%	-1.7%	-5.1%	-7.0%	-5.0%	-3.4%	-2.1%	-1.1%	-0.2%	0.5%	1.2%	0.3%	-0.6%	-1.4%
40%	-5.7%	-6.2%	-6.4%	-6.4%	-6.5%	-9.6%	-11.5%	-9.4%	-7.8%	-6.5%	-5.5%	-4.6%	-3.9%	-3.2%	-2.7%	-2.2%	-1.7%
50%	-11.6%	-12.5%	-12.7%	-12.8%	-12.8%	-12.8%	-14.4%	-12.4%	-10.8%	-9.5%	-8.4%	-7.5%	-6.8%	-6.1%	-5.6%	-5.1%	-4.6%
60%	-15.6%	-16.6%	-16.9%	-17.0%	-17.0%	-17.1%	-16.8%	-14.5%	-12.9%	-11.6%	-10.5%	-9.6%	-8.9%	-8.2%	-7.6%	-7.1%	-6.7%
70%	-18.4%	-19.6%	-19.9%	-20.0%	-20.1%	-20.1%	-19.8%	-16.3%	-14.4%	-13.1%	-12.1%	-11.2%	-10.4%	-9.8%	-9.2%	-8.7%	-8.3%
80%	-20.5%	-21.8%	-22.2%	-22.3%	-22.3%	-22.4%	-22.1%	-18.6%	-15.8%	-14.4%	-13.3%	-12.4%	-11.6%	-11.0%	-10.4%	-9.9%	-9.5%
90%	-22.1%	-23.5%	-23.9%	-24.0%	-24.1%	-24.1%	-23.9%	-20.5%	-17.8%	-15.5%	-14.3%	-13.4%	-12.6%	-12.0%	-11.4%	-10.9%	-10.4%

- LGS - Most customers sees a substantial increase in their bills. About 1,400 LGS accounts (~20 per cent of LGS accounts) have F2017 bill impacts of 10 per cent or greater.

7 Please refer to Attachment 5 of this memo for a reference to interpreting this form of bill impact table.

Figure 5: Re-Merged MGS Bill Impacts

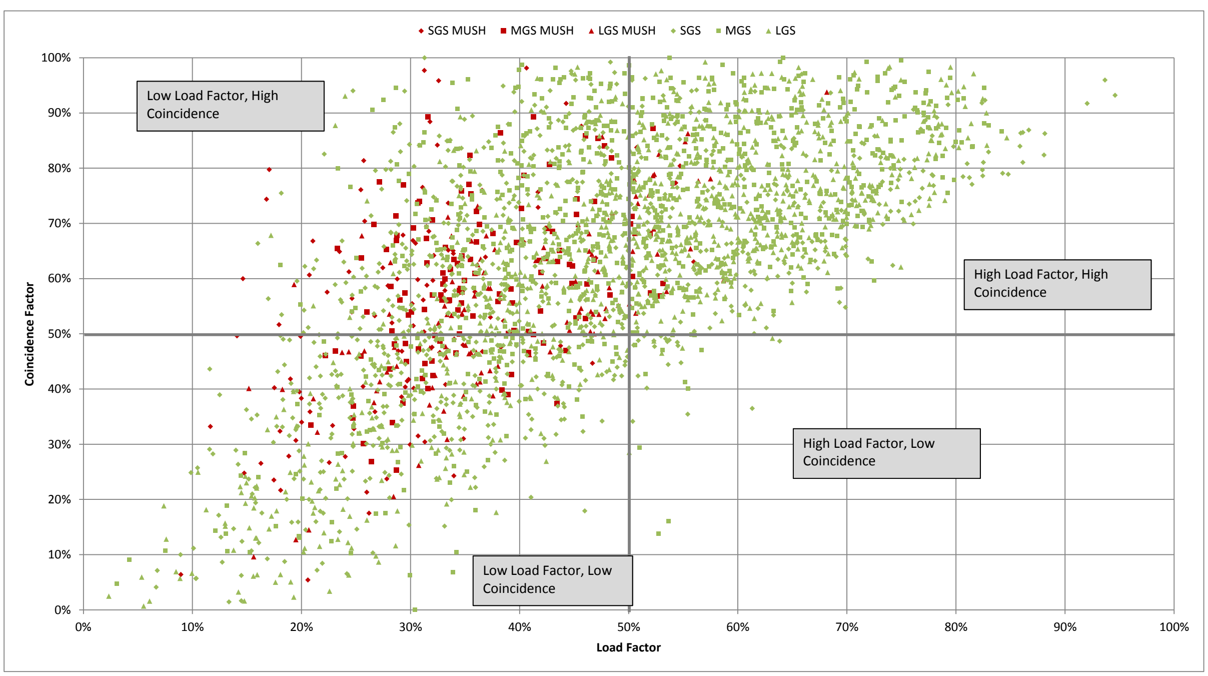
Consumption kWh

Load Factor	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	-0.3%	-2.3%	-3.0%	-3.3%	-3.5%	-3.7%	-3.8%	-3.8%	-3.9%	-3.9%	-4.0%	-4.0%	-4.0%	-4.0%	-4.1%	-4.1%	-4.1%
20%	-1.9%	3.7%	2.6%	2.1%	1.7%	1.5%	1.4%	1.2%	1.1%	1.1%	1.0%	1.0%	0.9%	0.9%	0.9%	0.8%	0.8%
30%	-9.6%	7.8%	6.3%	5.6%	5.2%	4.9%	4.7%	4.6%	4.5%	4.4%	4.3%	4.2%	4.2%	4.1%	4.1%	4.1%	4.0%
40%	-14.1%	4.0%	9.0%	8.2%	7.7%	7.3%	7.1%	6.9%	6.8%	6.7%	6.6%	6.5%	6.5%	6.4%	6.4%	6.3%	6.3%
50%	-17.1%	1.1%	9.2%	10.1%	9.5%	9.2%	8.9%	8.7%	8.6%	8.4%	8.3%	8.3%	8.2%	8.1%	8.1%	8.0%	8.0%
60%	-19.2%	-0.9%	7.2%	11.5%	11.0%	10.6%	10.3%	10.1%	9.9%	9.8%	9.7%	9.6%	9.5%	9.5%	9.4%	9.3%	9.3%
70%	-21.3%	-2.4%	5.8%	10.4%	12.1%	11.7%	11.4%	11.2%	11.0%	10.9%	10.7%	10.6%	10.6%	10.5%	10.4%	10.4%	10.4%
80%	-23.6%	-3.6%	4.6%	9.3%	12.3%	12.6%	12.3%	12.0%	11.9%	11.7%	11.6%	11.5%	11.4%	11.4%	11.3%	11.3%	11.2%
90%	-25.3%	-4.5%	3.7%	8.4%	11.4%	13.3%	13.0%	12.8%	12.6%	12.5%	12.3%	12.2%	12.2%	12.1%	12.0%	12.0%	11.9%

Potential MUSH Sector Segmentation

To respond to COPE 378's request with respect to the MUSH sector, BC Hydro compared a sample of 353 MUSH customers to a sample of 3,000 GS customers. Figure 6 below shows the MUSH sample data used for BC Hydro's analysis as filtered to examine public entities (North American Industry Classification System codes: Educational Services, Health Services, Municipal Pumping, Public Hospital, Public School, and University/College).

Figure 6: Relationship of Load Factor and Coincidence Factor for Sample Subset of Public Entities compared to Sample



As compared to the entire sample of 3,000 GS customers, the public entities tend to have similar levels for coincidence factor, which drives demand cost allocation, but a lower load factor. Given the comparison, BC Hydro concludes there is not a cost basis to segment the MUSH sector.

In addition, there is no Canadian electric utility jurisdictional support for creating a separate MUSH rate class. Based on the COS Canadian jurisdiction survey discussed at Workshops 2 and 4, there is no Canadian electric utility that separates the MUSH sector for COS or rate class purposes. At Workshop 2 participants generally agreed that for COS purposes, BC Hydro should focus on utilities operating in a similar market structure with similar features (e.g., winter peaking and/or hydro-based). None of the following utilities have a MUSH rate class: FortisBC; SaskPower; Manitoba Hydro; Hydro Quebec; New Brunswick Power; and Nova Scotia Power.

Yukon Energy has separate rates for municipal and federal/territorial governments, but they are typically equivalent to or higher than the corresponding non-government GS rates.[8]

[8] https://www.yukonenergy.ca/customer-centre/commercial-wholesale/rate-schedules/.

2 BC Hydro's Rate Design Priorities

In response to the request of Commission staff that BC Hydro set out its rate design priorities (particularly with respect to the SGS, MGS and LGS rates), BC Hydro confirmed at Workshop 12 that overall for the purpose of the 2015 RDA, it prioritizes the three Bonbright rate design criteria as set out in the table below.

Table 2: Three BC Hydro Prioritized Rate Design Criteria

Rate Design Criteria	Description
Customer understanding and acceptance / Practical and cost-effective to administer	Rates should be clear, transparent and cost-effective to implement. Bill impacts are part of customer acceptance; Both the maximum and customer bill impact are assessed (per cent, including the 10 per cent bill impact test). BC Hydro considers jurisdictional assessment as part of the Bonbright customer understanding and acceptance criterion
Stable rates for customers	Overall, minimize unexpected changes that can be seriously adverse to existing customers: If existing rates are understandable and generally accepted, and continue to be useful, they should not be replaced with new rates; For those rates that do not meet the customer understanding and acceptance criterion and/or are no longer useful, replace or amend the rate so that the rate is simple, understandable with an anticipated high degree of acceptance
Fair apportionment of cost among customers	BC Hydro uses the fairness criterion tied to designing rates based on embedded cost of service. The goal is partially constrained by the Rate Rebalancing Amendment, which prevents the Commission from setting rates for the purposes of changing the R/C ratio for a class of customers.

2.1 Participant Comments

Three participants submitted Workshop 12 written comments concerning BC Hydro's prioritization of the Bonbright rate criteria:[9]

- Commission staff ask whether BC Hydro should have different rate priorities for the different rate classes, and give an example involving the LGS and MGS rate classes: if the demand response of these customers is low, does this suggest that **LRMC**-based rate pricing should be given a lower priority?;
- British Columbia Sustainable Energy Association and Sierra Club B.C. (**BCSEA**) comments that while it believed that the Bonbright efficiency criterion is important, it is evident that complex LGS and MGS rates are not achieving the energy savings results predicted at the time of the 2009 LGS Application, and accordingly BCSEA supports moving toward simplified LGS and MGS flat energy rate structures to improve customer understanding of the rates;
- AMPC agrees with BC Hydro's prioritization, arguing that BC Hydro gave excessive weight to the efficiency criterion without balancing the other seven Bonbright criteria, offering the 2009 LGS Application as but one example. AMPC suggests that of the three criteria prioritized by BC Hydro, fairness should be accorded the most weight.

2.2 BC Hydro Consideration

BC Hydro is prioritizing the Bonbright customer acceptance and understanding, rate stability and fairness criteria over the efficiency criterion for purposes of the 2015 RDA Module 1:

- A number of elements, including a change to the regulatory regime relating to self-sufficiency[10] and a lower load forecast, have reduced forecasted energy and capacity need; and

[9] These written comments are posted at the BC Hydro website at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/stakeholdercomments.pdf.

- BC Hydro proposed and after Commission approval implemented a number of new rate designs between 2005 and 2013, including the default Transmission Service stepped rate (RS 1823), the Residential Inclining Block (**RIB**) rate, and the MGS and LGS two part energy rates. These rate initiatives responded to B.C. Government policy imperatives contained in the 2002 and 2007 Energy Plans to among other things explore the use of rates to assist with achieving aggressive conservation goals. In light of the reduced forecasted energy and capacity need, and the various evaluations of these rate initiatives, this is an apt time to take stock, and consolidate or simplify where appropriate (in BC Hydro's view, this applies to RS 1823 and the RIB rate) and amend where appropriate (this is the case for the MGS and LGS two part energy rates).

BC Hydro will outline further reasons for this prioritization in the 2015 RDA.

3 SGS Basic Charge

For the reasons articulated in section 2.2 of the Workshop 8a/8b consideration memo and as discussed during Workshops 11a and 12, BC Hydro identified that the SQ SGS Flat Energy Rate is its preferred rate structure for the SGS class. There is no basis to depart from this rate structure and no viable alternative rate structures have been identified.

Following the suggestion of Commission staff BC Hydro modelled and sought participant feedback on increasing the SGS basic charge to a level comparable to RIB rate basic charge fixed cost recovery, from the current 33 per cent level to 45 per cent. BC Hydro noted that increasing the SGS basic charge improves

[10] The Electricity Self-Sufficiency Regulation, B.C. Reg. 315/2010, as amended by Order in Council No. 036 (B.C. Reg. 16/2012), requires BC Hydro to achieve self-sufficiency by 2016 and each year after that, assuming its Heritage hydroelectric resources are capable of producing no more than what they can produce under "average water conditions"; copy at https://www.canlii.org/en/bc/laws/regu/bc-reg-315-2010/latest/bc-reg-315-2010.html. Until the 2012 amendments, the Electricity Self-Sufficiency Regulation required BC Hydro to plan for self-sufficiency based on an assessment of what the Heritage hydroelectric resources are capable of generating under the most adverse sequence of stream flows between October 1940 and September 2000, known as 'critical water conditions'. The 2012 change in planning from critical water to average water conditions increases the combined reliance on the Heritage hydroelectric system non-firm energy back by market reliance in F2017 by about 4,100 GWh per year, thus reducing the need for new energy resources.

fairness because the 45 per cent of fixed cost recovery moves closer to full fixed cost recovery. BC Hydro also highlighted that the resulting SGS energy rate remains within BC Hydro's energy LRMC range and without substantial bill impacts.

3.1 Participant Comments

Commission staff note that the increase in the basic charge to 45 per cent recovery has very low bill impacts and only small reductions in the energy rate. Commission staff request that BC Hydro further explain its rate design priorities as between stable recovery of costs versus price signals to encourage conservation. Commission staff question that if the MGS demand charge cost recovery is to remain below 35 per cent, should the SGS basic charge be increased from 35 per cent to 45 per cent? Commission staff inquired as to what the "seams" implications may be between BC Hydro's preferred level of MGS demand charge cost recovery versus SGS basic charge cost recovery.

CEC, AMPC and the First Nations Energy & Mining Council (**FNEMC**) agree that the SGS basic charge should be increased to better match allocated costs. AMPC suggests that less emphasis should be placed on the level of the energy rate relative to BC Hydro's energy LRMC, given the uncertainty of LRMC evaluation and its variation over time. As discussed in section 5.1 below, AMPC emphasizes that the energy LRMC, as a planning concept that changes as markets, technology and legislation changes, is not known with the precision suggested in setting rate design limits.

BCOAPO questions the relevance of comparing the RIB rate and SGS basic charges given BC Hydro's indication that these charges to each class recover both demand and customer-related fixed costs. BCOAPO suggests that the relevant measure of comparability should be only the percent of customer costs recovered via the basic charge for each customer class. BCOAPO comments that another relevant consideration, which would support increasing the SGS basic charge recovery, is the fact that escalation by inflation (e.g., 2 per cent per year) of the

F2016 LRMC upper bound of 11.10 cents/kWh would result in the SQ SGS energy rate exceeding the upper end of the energy LRMC range by F2018.

BCSEA states that it is not clear what the benefits of increasing the SGS basic charge would be, noting that increasing the level of the basic charge to 45 per cent cost recovery would slightly reduce the energy rate and have a corresponding slight reduction in natural conservation (at -0.5% elasticity BC Hydro uses for general rate increase-related price responsiveness).

COPE 378 does not think it is advisable to increase the SGS basic charge because of its impact on the energy rate, which, although relatively small, is directionally counter to energy conservation. In the alternative, COPE 378 suggests that if consistency with the rates to the Residential class is required, BC Hydro should consider lowering the Residential basic charge to be comparable to the SQ SGS basic charge fixed cost recovery.

3.2 BC Hydro Consideration

BC Hydro's preference is to increase the level of the SGS basic charge to about 45 per cent of allocated customer-related cost recovery; this improves fairness in matching cost recovery with cost causation while maintaining a SGS flat energy rate that provides both a simple and an efficient price signal that is both reflective of and within BC Hydro's energy LRMC range. As shown in the Workshop 11a materials, the bill impacts of this change are not unreasonable to the majority of customers on both a percentage and absolute basis. BC Hydro's preferred SGS rate for F2017 would consist of the pricing elements (as compared to the SGS status quo rate) as follows in the table below:

Table 3: Alternative SGS Pricing - BC Hydro Preferred and Status Quo (F2017)

Pricing Element	BC Hydro Preferred (Increase Basic Charge)	Status Quo
Energy rate (cents/kWh)	11.01	11.16
Basic charge ($/day)	0.3200	0.2347

BC Hydro will bring these two options forward in the 2015 RDA.

In response to feedback from BCOAPO, BC Hydro confirms that its prior references in 2015 RDA engagement materials to SGS basic charge and RIB rate basic charge *fixed cost* recovery should properly refer instead to *customer-related* cost recovery. All referred-to percentages and modelling results are correct in reference to customer-related cost recovery; the SGS and RIB basic charges do not recover any demand-related costs. Demand-related costs are recovered through the respective SGS flat energy rate and RIB rate Step 1 and Step 2 energy rates.

BC Hydro agrees with BCOAPO that customer-related costs are the relevant measure of comparability as between Residential and SGS basic charges. The level of the SGS basic charge is appropriately compared to the level of the RIB rate basic charge, not the MGS demand charge; basic charges recover customer-related costs while demand charges recovery demand-related costs.

At Workshop 12, BC Hydro presented the F2016 COS study cost allocation between the seven existing rate classes[11] and this is reproduced as Table 4 below as it informs RIB rate and SGS rate basic charge cost recovery of customer costs. As can be seen in Table 4, Residential and SGS customer cost allocation are similar, as are energy and demand cost allocations.

[11] Slide 18 of the Workshop 12 presentation slide deck; https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/01_2015-07-30-wksp-12-pres.pdf.

Table 4: F2016 Cost of Service Study Cost Classification

Rate Class	Energy (%)	Demand (%)	Customer (%)
Residential	35	52	13
SGS	38	50	12
MGS	43	52	5
LGS	50	49	1
Transmission	65	35	0
Irrigation	42	45	13
Street Lighting	30	47	23

BC Hydro concludes the RIB rate basic charge customer-related cost recovery level is the appropriate reference. BC Hydro has not been able to determine the small general service basic charge cost recovery of other surveyed Canadian electric utilities.

Regarding the 'seam' between SGS and MGS, which concerns the difference in bills between customers at the segmentation breakpoint (in this case, the 35 kW SGS/MGS breakpoint), BC Hydro highlighted in the summary notes to Workshop 11a (Attachment 1 to this memo) that a transition from the SQ SGS energy rate to MGS rates at the seam would result in lower bills under all MGS alternatives; however, the degree to which the MGS bill is lower differs between alternatives. BC Hydro reports these results in more detail in section 4.2 below.

BC Hydro is of the view that review of the design of the SGS SQ rate is an opportunity to more fairly balance the recovery of fixed versus variable costs. There are no trade-offs between increasing the basic charge to 45 per cent customer–related cost recovery and leaving the basic charge cost recovery at its present 33 per cent: While increasing the amount of revenue collection through fixed charges will improve revenue stability, the effect in this case will be small; the predicted bill impacts of the increase to the basic charge are low; and the flat energy rate remains priced within BC Hydro's energy LRMC range. The basic charge is a relatively high percentage of the total bill for only a very small percentage of SGS customers.

Concerning COPE 378's suggestion that the SGS basic charge recovery of customer costs should remain at about 33 per cent and the RIB rate basic charge recovery of customer costs should be lowered from 45 per cent to 35 per cent, BC Hydro does not agree that its proposal to increase the basic charge to 45 per cent customer–related cost recovery is directionally counter to energy conservation. There will be an imperceptible effect on natural conservation using the -0.05 default elasticity assumption discussed above. COPE 378 has consistently prioritized the Bonbright efficiency criterion above all other criteria in its RDA workshop comments, and BC Hydro does not agree with this prioritization for purposes of 2015 RDA Module 1 for the reasons discussed at Workshop 12 and summarized in section 2 above.

BC Hydro used the RIB rate basic charge cost recovery as a guide for the reasons noted above. BC Hydro notes its jurisdictional assessment of residential Canadian electric utility residential rate basic charge cost recovery presented at Workshop 9a,[12] which range between a low of 22 per cent (SaskPower) and a high of 100 per cent (New Brunswick Power). The current RIB rate basic charge recovery of 45 per cent is in the range of Canadian electric utility residential rate basic charge cost recovery but at the lower end of the range; reducing RIB rate basic charge recovery of customer costs from 45 per cent to 33 per cent would leave BC Hydro with the second lowest residential basic charge cost recovery of the eight Canadian electric utilities surveyed (SaskPower, Manitoba Hydro, Hydro Quebec, Nova Scotia Power, Newfoundland Power, new Brunswick Power, ATCO Electric Yukon, FortisBC).

[12] Slide 28 of the Workshop 9a presentation; https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-04-24-bch-apr-28-wksp-pres.pdf.

4 MGS Demand Charges

At Workshop 11a BC Hydro sought participant feedback on three alternative MGS demand charge structures: 1) MGS SQ Demand Charge, 2) MGS Flat Demand Charge, and 3) MGS Two-step Inclining Block Demand Charge. BC Hydro modelled the bill impacts of (2) and (3) assuming the preferred MGS Flat Energy rate.

In response to stakeholder comment, BC Hydro also presented the modelling results of, and sought further feedback on, increasing the MGS demand charge recovery of demand-related costs from about 15 per cent to 35 per cent, assuming the MGS Flat Demand Charge and the MGS Flat Energy Rate.

BC Hydro reviewed and sought feedback on two high-level transition strategies for moving to a MGS Flat Energy Rate and MGS Flat Demand Charge: 1) a three year phase-in, and 2) a 10 per cent bill impact cap. A summary of participant comments on MGS transition strategies and BC Hydro's consideration of transition strategies on its preferred designs for both MGS and LGS rates are reported in Section 6 of this memo.

4.1 Participant Comments

4.1.1 MGS Demand Charge Structure

Commission staff summarize that BC Hydro identified that the MGS Flat Demand Charge reflects cost causation better than an inclining block structure and has the benefit of simplicity. Commission staff remark that if the MGS Flat Demand Charge alternative best meets rate design objectives, the major remaining issues are: (a) the ways to phase it in or otherwise deal with the customer bill impacts, and (b) reconciliation of a zero demand charge for the SGS rate class and a full flat demand charge for a small MGS customer.

CEC comments that the MGS SQ Demand Charge does not adequately and appropriately allocate costs to customers and that a two-step inclining block demand charge would have similar problems. CEC remarks that the MGS Flat Demand Charge may have less problems than other alternatives.

AMPC strongly prefer the MGS Flat Demand Charge and MGS Flat Energy Rate for simplicity, ease of understanding, bill stability (as customer usage changes) and comparability to rates of other utilities. AMPC notes that the principle of efficient use is still met; simple flat energy and demand charges encourage efficiency by setting a price on both demand and energy that encourages energy conservation and more efficient use of existing and future infrastructure.

BCOAPO does not have a strong preference, but considers that the MGS Flat Demand Charge and MGS Flat Energy Rate appear to be the most appropriate as compared to the SQ, which is poorly understood and does not appear to be achieving the efficiency and conservation objectives for which it was intended. BCSEA and COPE 378 have similar views. BCOAPO notes that inclining demand charges in other jurisdictions are frequently accompanied by declining energy rates, which tend to have an offsetting effect on the total bill. BCOAPO suggests that the need for an inclining demand charge is questionable if BC Hydro moves to a flat energy rate for the MGS class.

FNEMC is alone in supporting the MGS Two-step Inclining Block Demand Charge (with the MGS Flat Energy Rate). FNEMC notes that while the MGS Two-step Inclining Block Demand Charge is not substantially different than the MGS SQ Demand Charge, it considers the bill impacts of the MGS Two-step Inclining Block Demand Charge to be more favourable in comparison to the MGS Flat Demand Charge. FNEMC supports tiered demand charges to encourage conservation behaviour.

4.1.2 MGS Demand Charge Cost Recovery

Commission staff note that an increase in the MGS demand charge to 35 per cent demand cost recovery “moves the energy charge out of the LRMC range”. Commission staff thus question what the rate design priority is for BC Hydro – cost recovery stability or LRMC energy pricing – and whether the objective of keeping the energy charge in the LRMC range has less importance. Commission staff also inquire into the tax deductibility of a commercial customer's electricity bills and whether this may: 1) have a major impact on commercial customers' attitudes to energy price conservation compared to Demand Side Management (**DSM**) incentives, or 2) reduce the already very low MGS class elasticity of demand to energy pricing to such a low level that even LRMC energy pricing will have a minimal impact on commercial customer conservation.

CEC states that increased demand charge cost recovery might somewhat improve appropriate cost allocation to customers. CEC is of the view that choosing a level of demand charge based on the relationship of energy charge to LRMC is likely an inappropriate logic for cost allocation decisions.

AMPC agrees that the MGS demand charge should be increased as it does not adequately capture the full demand cost, and states that this is as much an efficiency consideration as the level of energy cost recovery (for expansion of AMPC's comments in this regard, please refer to Section 5.1.1 below regarding LGS rate structures). FNEMC supports increasing the MGS demand cost recovery to be closer to full fixed cost recovery and more consistent with the two other rate classes with demand charges – LGS and Transmission Service.

BCOAPO agrees with BC Hydro's view that the correct level of demand charge cost recovery cannot be targeted in isolation, commenting that in addition to fairness and customer understanding and acceptance considerations there are also efficiency considerations associated with the extent to which the resulting energy charge aligns with the energy LRMC range. BCOAPO notes that increasing MGS demand charge cost recovery appears to move the energy charge further below LRMC and with consequent greater bill impacts. Thus, BOAPO states that on balance there appears to be little merit in increasing demand charge cost recovery at this time. BCSEA is also inclined to favour leaving the demand cost recovery rate at the current level of about 15 per cent of demand costs on the basis that the energy rate would remain

relatively higher and so provide a stronger signal for energy conservation.
COPE 378 also does not see merit to an increase in the per cent of demand costs recovered in the demand charge due to the lower flat energy rate that results relative to LRMC and as long as the demand charge is not based on system coincident peak.

4.2 BC Hydro Consideration

4.2.1 MGS Demand Charge Structure

For the reasons summarized in its Workshop 8a/8b consideration memo and as discussed during RDA Workshops 11a and 12, BC Hydro identified that its preferred energy rate structure for the MGS rate class is the MGS Flat Energy Rate, and that the SQ MGS Energy Rate would be advanced in the 2015 RDA for comparison purposes (as will the MGS SQ Demand Charge). There was a general consensus that the MGS Flat Demand Charge is superior to the MGS SQ Demand Charge and the MGS Two-step Inclining Block Demand Charge. Accordingly, BC Hydro will not advance the MGS Two-step Inclining Block Demand Charge for the 2015 RDA. Given that there was no general consensus among participants with respect to the MGS demand charge cost recovery, BC Hydro will bring forward the MGS Flat Demand Charge under both demand charge cost recovery scenarios (SQ 15 per cent and preferred 35 per cent).

Thus the MGS rate alternatives brought forward into the 2015 RDA are as follows in the table below.

Table 5: Alternative MGS Pricing – SQ, BC Hydro Preferred and Demand Cost Recovery Sensitivity (F2017)

Pricing Element	**Status Quo** For Comparison Only	**BC Hydro Preferred** (35% demand-related cost recovery)	**Sensitivity** on BC Hydro Preferred (SQ demand-related cost recovery ~15%)
Energy rate (cents/kWh)	Part 1, Tier (**T**) 1: .... 10.33 Part 1, T2: .... 7.21 Part 2: 10.10	8.54	9.35
Demand charge ($/kW)	T1:............................... 0.00 T2:............................... 5.72 T3:.............................. 10.97	4.76	2.14
Basic charge ($/day)	0.2347	0.2347	0.2347

BC Hydro's preferred demand charge structure for the MGS rate class is the MGS Flat Demand Charge. A flat demand charge:

- Simplifies the rate structure and will improve customer understanding and acceptance. Customer acceptance will also be improved in that the MGS Flat Demand Charge generally offsets the bill impacts associated with BC Hydro's preferred MGS Flat Energy Rate (and to a greater extent than the MGS Two-step Inclining Block) as highlighted at Workshop 11a;
- Aligns with the rate design practice of other Canadian electric utilities surveyed for GS rate purposes that have a flat demand charge; the MGS SQ Demand Charge with its three tiers is unique to BC Hydro;
- Improves fairness between customers within the MGS class in two ways. First, a flat demand charge design is better aligned with overall costs of service; the cost to serve a GS customer's peak demand is generally flat on a $/kW basis. Second, increasing the demand charge recovery of demand-related costs is also more reflective of BC Hydro's demand costs because more demand-related costs are recovered. This latter point is expanded upon below in section 4.2.2.

In response to Commission staff, BC Hydro considers there to be only a minor seams issue between the SGS and MGS rate classes in respect a move from SGS rates (assuming BC Hydro's preferred increase to SGS basic charge customer-related cost recovery) to MGS rates (assuming BC Hydro's preferred MGS Flat Energy Rate and MGS Flat Demand Charge, including an increase to demand charge cost recovery to 35 per cent). The impact at the seam affects mainly a small segment of customers with very low load factors of less than about 25 per cent. A MGS Flat Energy Rate and MGS Flat Demand Charge are expected to mitigate bill impacts at the SGS/MGS seam to the greatest extent in comparison to the alternatives:

- Transitioning from SQ SGS to SQ MGS rates would result in a 8 per cent lower bill at the seam;
- Transitioning from BC Hydro's preferred SGS rate to the preferred MGS Flat Energy Rate and MGS Flat Demand Charge would result in a 3 per cent to 12 per cent lower bill at the seam, for low to high load factor customers, respectively. The impacts are driven by both the different energy rate and a demand charge now applicable to monthly demand less than 35 kW; and
- Transitioning from BC Hydro's preferred SGS to the MGS Two-step Inclining Block Demand Charge and MGS Flat Energy Rate would result in a 16 per cent lower bill at the seam. This is driven solely by the different energy charge.

In response to Commission staff requests that BC Hydro reconcile a zero demand charge for the SGS rate class and a full flat demand charge for a small MGS customer, BC Hydro's proposed rates for the SGS and MGS rate classes are relatively commonplace. BC Hydro's jurisdictional review in Attachment 3 reveals that there is no demand charge to small general service customers for low levels of demand (e.g., <50kVa, <50kW, <20kW). BC Hydro observes that its SGS class is comparable to most utilities in Canada in not charging for demand.

4.2.2 MGS Demand Charge Cost Recovery

BC Hydro prefers to increase the level of demand cost recovery through the MGS demand charge from the current approximate 15 per cent level to 35 per cent as this better aligns with the Bonbright fairness and customer understanding and acceptance (bill impacts) criteria:

- An increase in the amount of demand costs recovered through demand charges improves fairness as between customers within the class by improving the alignment of charges with cost causation;
- The specific effect of the increase in the level of demand cost recovery is to more evenly offset and distributes 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. BC Hydro demonstrated through its Workshop 11a presentation materials that under SQ demand cost recovery, in terms of bill impacts, the weight of the benefit from a move to its preferred MGS rate structures would tend toward low load factor and low consumption customers while the weight of the burden would tend toward high load factor and high consumption customers. Workshop participants questioned whether this outcome would be fair and acceptable given that high load factor customers make more efficient use of BC Hydro’s system.

In response to CEC, BC Hydro notes that the 35 per cent level was arrived at by targeting an increase in demand cost recovery that (under forecast revenue neutrality) would result in the MGS Flat Energy Rate generally reflective of the energy LRMC range. BC Hydro agrees with the perspective of AMPC, as reviewed with respect to LGS in section 5.1.1 of this memo, in expressing caution that the LRMC be relied upon with a false precision when setting rate design limits. In prior BC Hydro and FortisBC rate design-related decisions, the Commission has commented that the LRMC for new supply is the appropriate referent for an efficient price signal. Generally speaking, BC Hydro regards the MGS Flat Energy rate to still be reflective of LRMC even though the energy rate drops below the lower bound of LRMC when the level of demand-related costs recovered through demand charges is increased to 35 per cent. In BC Hydro's view, there is no single "correct" level of demand charge cost recovery. Nor can demand charge cost recovery be targeted in isolation from other factors; the proposed 35 per cent level best balances the competing Bonbright criteria.

In response to COPE 378, BC Hydro notes that MGS (and LGS) demand charges recover embedded costs and are not intended to be charged only in the system coincident peak period, as defined by 4CP; rather, the demand charge is charged across all 12 months of the year. BC Hydro's demand charges are not specifically designed to signal avoided Generation demand, Transmission and/or Distribution demand costs; they are intended to recover demand related costs. In this regard BC Hydro's proposed MGS demand charge is consistent with all other surveyed Canadian electric utilities with one exception. Only Newfoundland Power has a seasonal demand charge (with higher rates in the four winter months. BC Hydro also notes the existence of the MGS (and LGS) monthly minimum charge (Demand Ratchet) which is defined as follows:

> *50% of the highest maximum Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding eleven Billing Periods. For the purpose of this provision an on-peak period commenced on 1 November in any year and terminates on 31 March of the following year.*

The Demand Ratchet is discussed in section 7 of this memo.

In response to Commission staff on its questions regarding tax deductibility, BC Hydro has not heard from customers or through its customer accounts group that tax deductibility reduces interest in DSM. BC Hydro has not estimated the impact of tax deductibility on customer price elasticity. This would require a level of precision that BC Hydro does not have concerning behavioural response to prices. Given the immediate effect of prices on customer response versus the lagged effect of taxes, the effect of tax deductibility on price elasticity could be minimal. Price elasticity is discussed in respect of LGS in section 5.2 below.

5 LGS Energy Rate and Demand Charge Structures

In the Workshop 8a/8b consideration memo BC Hydro detailed four LGS energy rate structure alternatives and three LGS demand charge alternatives to carry forward for engagement:

Energy Rate Structure Alternatives

1. SQ LGS Energy Rate
2. SQ LGS Simplified Energy Rate
3. LGS Flat Energy Rate
4. LGS TSR-like Energy Rate

Demand Charge Structure Alternatives

1. SQ Three-step Inclining Block demand charge
2. LGS Flat demand charge
3. LGS Two-step Inclining Block demand charge

BC Hydro did not identify a preferred LGS rate design, and at Workshop 11b it further reviewed the performance of these alternatives against the Bonbright rate design criteria. BC Hydro sought participant feedback on which of the alternatives were preferred and why.

The question in respect of the SQ LGS Simplified Energy Rate is whether there are changes to the design or mechanisms to the SQ baseline rate structure that would yield material improvement in customer understanding and acceptance and/or conservation behaviour. In its Workshop 8a/8b consideration memo and at Workshop 11b BC Hydro set out its assessment of the various LGS rate provisions that accompany the baseline structure (set out below) and sought participant feedback on its findings:

- Flatten Part 1 Energy Rate;
- *Price Limit Band* (**PLB**); not all of the difference between a Historical Baseline (**HBL**) and monthly billed consumption is charged at the Part 2 energy rate. PLBs limit a customers' exposure to the Part 2 energy rate within a range of 80 per cent of the HBL to 120 per cent of the HBL. Put another way, only a maximum of 20 per cent of HBL is subject to the part 2 energy rate; monthly energy consumption outside the range would be charge the applicable Part 1 energy rate;
- *Anomaly rule*, allowing up to four historic baselines to be adjusted per year. When the lowest consumption month used in baseline calculation is less than 50 per cent of the second lowest month, the lowest month is excluded from baseline calculation;
- *Formulaic growth rule* (**FGR**), allowing baselines to be based on the most recent two years of consumption history in the year (Y2) following a year (YI) in which energy consumption exceeded the previous year's (YO) energy consumption by at least i) 30 per cent or ii) 4,000,000 kWh;
- *Prospective growth adjustment (Tariff Supplement (**TS**) 82)*, allowing LGS customers that anticipate significant, permanent increases in energy consumption to apply to BC Hydro to seek an increase in their baselines on a prospective basis. "Permanent" means arising from a significant capital investment in plant and "Significant" means increases in energy consumption totaling at least 30%, or 4,000,000 kWh;
- *Application for exemption*, allowing customers to apply to the BCUC for an exemption from 2-part rate on the basis that they are electricity re-sellers under regulated tariffs with conservation rates for their end-use customers; and

- *New accounts pricing*, specifying that for new accounts the last 15 per cent of energy consumed in a monthly billing period will be charged at the Part 2 LRMC Energy Rate rather than at the Part 1 Energy rate until a baseline level of consumption is established one year hence.

BC Hydro also set out considerations for a LGS TSR-Like Rate, as suggested by Viterra and AMPC, as a potential rate design for very high consumption LGS customers (XLGS). BC Hydro's consideration of this alternative was carried forward for review and stakeholder feedback alongside the LGS Flat Energy Rate alternative, which would be applicable to the remaining majority of LGS customers.

At Workshop 12, BC Hydro set out that its leading option for the default LGS rate structure is the LGS Flat Energy Rate (no baseline) and the LGS Flat Demand Charge. BC Hydro noted its corresponding commitment to explore the merits of a LGS TSR-Like Rate through RDA Module 2. In response to the suggestion of AMPC, at Workshop 12 BC Hydro presented the results of an increase in LGS demand charge cost recovery from about 50 per cent to 65 per cent of demand-related costs, a level that is consistent with RS 1823 demand charge recovery of demand-related costs.

5.1 Participant Comments

Based on the comments received and given BC Hydro's analysis, BC Hydro organized its summary of feedback and consideration of LGS rate design into separate discussions of 1) SQ versus Flat Alternatives, Energy and Demand, 2) SQ LGS Simplified Energy Rate, including a review of feedback received on possible modifications to the provisions of the SQ structure, and 3) LGS TSR-Like Rate.

5.1.1 SQ versus Flat Alternatives, Energy and Demand; Demand Charge Cost Recovery

Commission staff note that based on customers' feedback and BC Hydro's experience, the SQ energy and demand structures are complicated for almost all except a few LGS customers, and this complication creates room for complaints, gaming, and/or the lack of ability to respond to the price signals. Commission staff remark that if the only benefit realized is negligible conservation, then the SQ may be considered to have failed to achieve the aggregate of the various rate design objectives. Commission staff suggest that the discussion of the LGS Flat Energy Rate would benefit from a prioritizing of BC Hydro's rate design objectives and how this rate structure achieves the objectives. In particular, Commission staff question how important rate simplicity and customer understanding are compared to sending a LRMC price signal.

CEC and AMPC prefer both the LGS Flat Energy rate and LGS Flat Demand Charge. CEC remarks that the SQ LGS Energy Rate is unnecessary and that the LGS Flat Energy Rate would likely provide the best opportunity for appropriate cost allocation and the best platform going forward to allow consideration of other approaches to improve conservation and efficiency, such as through CEC's optional Efficiency Rate Credit concept. As it expressed with respect to alternative MGS demand structures, CEC expects that the Flat LGS Demand Charge may be more appropriate for cost allocation than a three-step or two-step inclining block.

AMPC strongly prefers for the majority of LGS customers the LGS Flat Energy Rate and the LGS Flat Demand Charge, with a LGS TSR-Like Rate (two tier energy rate) for XLGS. AMPC notes that the LGS Flat Energy Rate and the LGS Flat Demand Charge should be adopted for most LGS customers for the same reasons it is recommended for MGS customers; that is, for simplicity, ease of understanding, bill stability and comparability to rates of other utilities.

In addition to its Workshop 11a/11b written comments, in a letter dated July 27, 2015 (found at Attachment 2 to this memo), AMPC recommends increasing the LGS rate demand charge cost recovery to a proportion consistent with Transmission customers taking service under RS 1823, which will reduce the bill impacts associated with the LGS Flat Energy Rate and the LGS Flat Demand Charge; AMPC calls this a fair, pragmatic and stable outcome. AMPC adds that the effect also would be to send a better efficiency and conservation signal by mitigating a disincentive to low load factor customers to make more efficient use of existing infrastructure. AMPC remarks that high load factor customers respond to higher demand charges by using existing facilities more efficiently and reduce the need for future (marginal) facilities.

AMPC submits that the LGS Flat Energy Rate well below the lower end of the energy LRMC (as would result under the LGS Flat Energy Rate alternative) is not a significant detraction for the following reasons:

1. The LGS class is currently showing no significant conservation response – even at the higher SQ LGS Energy Rate second tier energy rate;
2. Customers respond to the total bill rather than individual components such as energy;
3. LRMC is not simply a variable cost that directly translates to an energy rate. LRMC involves significant fixed costs. LGS demand charges are also too low; and
4. LRMC is a planning concept that changes as markets, technology and legislation changes, and is not known with the precision suggested in setting rate design limits.

Whistler Blackcomb, a LGS customer, supports the LGS Flat Energy Rate because it would simplify business forecasting, noting also that cost increases are enough of an incentive for conservation. Whistler Blackcomb prefers the LGS Flat Demand Charge, commenting that there is no need for two or three tiers. It uses one single cost per kW for forecasting, which it believes is sufficient to signal demand costs.

Thrifty Foods, also a LGS customer, supports the SQ LGS Energy Rate. Thrifty Foods comments that the SQ LGS Energy Rate allowed it to include credits under the Part 2 energy rate in its business plans when considering energy conservation projects, which has often made the difference in whether to proceed by reducing payback periods by 25 per cent or more. Thrifty Foods is concerned that removal of the Part 2 credit will reduce the anticipated savings of its energy conservation investments. Thrifty Foods questions whether customer growth has masked conservation savings under the SQ LGS Energy Rate.[13]

BCSEA supports the LGS Flat Energy Rate as the means to simplify the SQ LGS Energy Rate and it is inclined to support the LGS Flat Demand Charge as better reflecting cost causality. BCSEA highlights that BC Hydro's evaluation reports on the SQ LGS Energy Rate establish that it does not achieve its primary purpose of inducing DSM, and accordingly, there is no justification for retaining it. BCSEA also remarks that the SQ LGS Energy Rate is more costly to administer and less transparent and comprehensible to ratepayers. BCSEA encourages BC Hydro to take advantage of any change in the LGS rate to promote customer awareness of DSM.

BCOAPO does not see a basis for an inclining demand charge and it supports the LGS Flat Energy Rate if it is not possible otherwise that simplification could materially improve customer acceptance and understanding of the SQ LGS Energy Rate. BCOAPO describes two critical concerns regarding the SQ LGS Energy Rate: 1) it is not achieving the desired nor anticipated conservation results, and 2) the rate is difficult to understand such that customers cannot readily predict their bills or budget. BCOAPO notes further that lack of conservation effect is, in itself, largely attributable to the complexity and lack of understanding of the current rate design. In BCOAPO's view, it is a basic requirement that customers be able to understand the rate structure being used to bill them and how its application will impact their bills

[13] Please refer to Section 4.1 of BC Hydro's Workshop 8a/8b Consideration memo for a summary of feedback on LGS energy rate alternatives from LGS customers that did not provide feedback on Workshop 11a or 11b:

- TransLink does not favour any LGS alternative that would retain a baseline-based rate structure;
- Panorama Mountain Village Inc. and Toby Creek Utility prefer the LGS Flat Energy Rate;
- Vancouver Aquarium, Ivanhoe Cambridge and Peterson Commercial Property Management would retain the SQ LGS Energy rate with consideration of modifications to the baseline-related provisions; and
- In separate customer review sessions, 14 of 22 customers with key account managers favour the LGS Flat Energy Rate, with three preferring the SQ LGS Energy Rate and three favouring the SQ LGS Simplified Energy Rate.

(regardless of whether or not it results in a conservation effect). Thus, BCOAPO regards the SQ LGS Energy Rate structure as unsustainable.

COPE 378 sees merit in the LGS Flat Energy Rate and the LGS Flat Demand Charge subject to consideration of other approaches to cost allocation and recovery. COPE 378 suggests combining a flat energy rate with lower demand charge cost recovery, especially if demand charges are not based on system coincident peak. COPE 378 suggest that other measures such as seasonal or Low Load Hour discounts or customer credits could provide appropriate incentives to conserve while maintaining revenue neutrality.

FNEMC does not have any preferred LGS energy rate or demand charge at this time.

5.1.2 SQ LGS Simplified Energy Rate and Baseline Rate Provisions

Commission staff ponder what the rate design objective is of a declining block for Part 1 energy rate since most customers quickly consume beyond the 14,800 kWh/month and mainly see Tier 2 of the Part 1 rate. Thus, Commission staff question if the SQ LGS Simplified Energy Rate would address the real problems of the SQ LGS Energy Rate other than nominal simplification.

AMPC remarks that changes to the provisions other than elimination of the baseline will only make matters worse. For example, AMPC notes that the concept of a PLB for the LGS rate class is too complex and that none of the administratively burdensome procedures such as the FGR or anomaly rules are necessary if the LGS rate is simplified so as to remove the baseline structure for the majority of LGS customers.

Whistler Blackcomb would favour flattening Part 1 rates, but notes that the impact would not be significant for LGS accounts. Thrifty Foods suggests that the SQ LGS Energy Rate could be improved by flattening Part 1 of the Tier 1 energy rate, given that the Part 1 Tier 1 energy rate is insignificant and adds complexity to the bill.

Thrifty Foods would also support eliminating the 85/15 new account rule, which it considers punitive.

CEC suggests that modifying the baseline provisions under SQ LGS Simplified Energy Rate would only add complication to the SQ LGS Energy Rate.

BCOAPO comments that flattening the Part 1 energy rate under the SQ LGS Simplified Energy Rate would only be acceptable if it was considered as part of an overall package of changes aimed at improving customer acceptance and understanding of the rate design. If it is not the case that the alternative would be understandable then BCOAPO is of the view that there is little point in pursing it further.

BCSEA is not convinced that flattening the Part 1 LGS energy rate while retaining a Part 2 rate would increase conservation or simplify the rate structure enough to overcome the complexity problem associated with the SQ LGS Energy Rate. BCSEA is also not convinced that changing the baseline determination (e.g., from monthly to annual, or from three-year to one- or five-year rolling average) or the PLBs would improve the conservation results or achieve the necessary simplification of a flat rate structure. BCSEA highlights that the LGS Flat Energy Rate eliminates the need for the administrative rules of the SQ LGS Energy Rate.

Although FNEMC has not established its preferred LGS rate design it generally supports flattening the Part 1 energy rate as the consumption threshold of 14,800 kWh/month is not material to most LGS customers and more customers would be better off than worse off. Should BC Hydro maintain the baseline structure, FNEMC supports that the various provisions be modified or removed based upon the analysis presented by BC Hydro and customer feedback.

A summary of specific feedback received on the provisions of the SQ LGS Energy Rate follows.

Baseline determination

Commission staff note that one customer at the workshop claimed that a 5-year rolling average baseline could pose a problem for estimating investment returns and that if this limitation is true, then there may be additional disadvantages to 5- year baselines rather than positive benefits. Commission staff comment that similarly, the 1-year baseline may result in business instability and thus the best approach would be to maintain the 3-year average unless it can be demonstrated that there is material improvement of rate design objectives from alternatives compared to the 3-year methodology.

CEC states that maintaining a 3-year rolling average ensures that the inadequate economic price signal is maintained making it undesirable as a rate structure while extending the baseline adjustment in the alternative could add other complications. CEC remarks that there is no point to maintaining the SQ LGS Energy Rate as it is not achieving a purpose, but if retained then options for changing the determination of baselines should be explored to support achieving the purpose.

Whistler Blackcomb states that if the baseline structure is to be maintained it would prefer annual baselines due to the winter fluctuations due to snowmaking, which would also facilitate more simple communication to senior leaders.

PLB

CEC expects that there are no changes to PLBs that would materially change the performance of the rate. Whistler Blackcomb considers that due to the size of LGS accounts, changing the PLB is unlikely to have an impact on bills; increases or decline in energy usage are unlikely to exceed 10 per cent.

FGR

Commission staff suggest that it is not clear that the FGR should be discarded. Commission staff ask whether it would make sense to keep the FGR when it is beneficial to a customer so as to not punish growth, but to not apply the FGR if other factors would otherwise result in higher bills with the FGR.

CEC comments that one of the problems with the SQ LGS Energy Rate is its inability to distinguish productive growth from inefficient growth and/or use. CEC states that if the SQ LGS Energy Rate is retained than the FGR provisions should also be retained given the evidence that 76 per cent of customers that qualified for the FGR benefitted from the its application. CEC considers that the 30 per cent threshold increase in energy consumption is too high.

Whistler Blackcomb states that the thresholds are too high to allow consideration of consumption increases due to growth. With the size of its accounts, “even a very large addition to infrastructure would not meet the thresholds and therefore would be subjected to conservation rate penalties.” Whistler Blackcomb states that if the baseline structure is to be maintained there would need to be more consideration to business growth. Whistler Blackcomb contemplates that this would further complicate the process and BC Hydro would be unlikely to come up with a solution for most businesses that would be feasible or fair; a flat rate would be a simpler way to assess costs of new infrastructure and expanded operations.

Anomaly Rule

Commission staff comment that the anomaly rule seems to be achieving its intended purpose of smoothing out anomalous months as defined in the negotiated settlement agreement that introduced this rule.

CEC states that the anomaly rule should be eliminated if the SQ LGS Energy Rate is retained to simplify the rate structure. CEC suggests that a move to annual assessment of baselines would moderate some of the reasons behind the implementation of the anomaly rule.

Prospective Growth Rule

Commission staff suggest that with so few customers meeting the threshold this rule could be discontinued. That said, Commission staff raise the possibility of modifying the rule so as to still help fast growing customers and only applying the rule when it is beneficial.

CEC comments that along with an FGR rule change to accommodate growth, the Prospective Growth Rule should have relaxed thresholds and criteria to protect productive growth from inappropriate impacts. Further, CEC suggests that implementation of the rule should be automated if the SQ LGS Energy Rate is retained to reduce BC Hydro's administrative costs.

Whistler Blackcomb comments that the concerns it expressed with respect to the formulaic growth rule are similarly applicable in respect of the Prospective Growth Rule.

New Account Rule

Commission staff highlight that the issue of whether customers should continue to be defined as an account is an outstanding issue for BC Hydro. Commission staff question what the benefit from the 85/15 new account rule is given the estimated low conservation savings and no evidence of gaming.

CEC comments that the prevalence of account changes and inappropriate bill impacts means that this provision should be adjusted to enable continuity on account transfers change and 100 per cent Part 1 pricing for new accounts with no continuity.

Whistler Blackcomb states that a flat rate would take care of this issue, noting that new accounts would be based on their consumption and demand usage. Presently, if a large project is planned that could be on an existing account, Whistler Blackcomb would strive to establish the project under a new account because of LGS.

5.1.3 LGS TSR-Like Rate

Commission staff inquire what the source is of the very small conservation savings from the SQ LGS Energy Rate; in particular, whether the limited savings come mainly from the largest customers who may be considered for a LGS TSR-Like Rate. Commission staff anticipate that if the savings were mainly from the largest customers it would add support for the a LGS TSR-Like Rate for customers with demand over a threshold of, for example, 1 or 2 megawatts, and justify a flattened energy and demand charge with modified or no baselines for the remaining customers. Commission Staff ask what BC Hydro's current estimate is of LGS and MGS energy price elasticity of demand based on the experience of the last few years. Commission staff suggest that if the largest LGS customers are more likely to respond to a LRMC type price for their marginal consumption, then a LGS TSR-Like Rate may be quite effective in promoting some conservation.

AMPC notes that XLGS customers are significantly larger than typical LGS customers, fewer in number and have more in common with the Transmission Service rate class. AMPC describes that the 25 kilovolt voltage level of service reflects an accident of geography rather than a significant difference in electrical characteristics, and these are customers that tend to own their own substations. AMPC is of the view that XLGS customers are large and sophisticated enough to better respond to the two tiered energy price signal, if they also have the flexibility of a Customer Baseline Load (**CBL**) rather than a rigid HBL determination as exists with the SQ LGS Energy Rate. A number of XLGS customers are also Transmission Service customers and sufficiently familiar with the tiered energy and CBL concept to effectively respond to the efficiency signals that have been refined through the RS 1823 CBL process for the last decade.

Whistler Blackcomb comments that for its LGS accounts, a simple flat rate structure would be sufficient.

BCOAPO highlights that the major drawback to the LGS Flat Energy Rate is that the resulting energy rate would be significantly below the LRMC, but notes that this issue would be addressed for at least some of the customers by a LGS TSR-Like Rate. BCOAPO suggest that a LGS TSR-Like Rate should be considered for high consumption LGS customers, provided application of such a rate design is administratively practical and forecast revenue neutral.

FNEMC is supportive of a LGS TSR-Like Rate that that would encourage conservation and customer DSM initiatives, and therefore would support BC Hydro investigating further and entering into customer discussions as well as undertaking further analysis.

COPE 378 believes that a LGS TSR-Like Rate is problematic because of the limited conservation incentive it provides for customers operating at or near 90 per cent of their CBL.

5.2 BC Hydro Consideration

5.2.1 Preferred LGS Energy Rate and Demand Charge Structures

At Workshop 12 BC Hydro identified that its leading options for the LGS rate class were the LGS Flat Energy Rate and LGS Flat Demand Charge structures. BC Hydro remarked it would not identify its preferred LGS rate until it reviewed participant feedback relating to Workshop 11b. BC Hydro now identifies the LGS Flat Energy rate and LGS Flat Demand Charge as its preferred LGS rate structures, which is generally supported by LGS customers and organizations representing such customers, and most other stakeholders. BC Hydro also prefers to increase the LGS demand charge recovery of demand-related costs from about 50 per cent to 65 per cent:

- The SQ LGS Energy Rate will be brought forward for comparison purposes. BC Hydro also notes that in contrast to the MGS rate where no identified MGS customers prefer the SQ MGS Energy Rate, there are LGS customers such as Thrifty Foods that prefer the SQ LGS Energy Rate to the LGS Flat Energy Rate. BC Hydro notes that consideration of the SQ LGS Energy Rate would not foreclose advancement of recommended changes to any particular provision, such as the current 85/15 new account rule. Potential changes to the SQ LGS Energy Rate-related rules will be identified in the 2015 RDA;

- There was a general consensus that the LGS Flat Demand Charge is superior to the LGS SQ Demand Charge and the LGS Two-Step Inclining Block Demand Charge. Accordingly, BC Hydro will not advance the LGS Two-Step Inclining Block Demand Charge for the 2015 RDA;
- There appears to be a general consensus among participants commenting on LGS demand charge cost recovery that it should be increased. AMPC strongly supports increasing the LGS demand charge recovery of demand-related costs. So too does BCSEA as part of its Workshop 12 comments on the basis that the increase will "blunt bill impacts of flattening the LGS energy charge". Neither BCOAPO nor COPE 378 commented on this topic in their Workshop 12 written materials. Nevertheless, BC Hydro will bring forward the LGS Flat Demand Charge under both demand charge cost recovery scenarios (SQ 50 per cent and preferred 65 per cent) given that this topic arose late in the RDA stakeholder engagement process.

Thus, the LGS rate alternatives brought forward into the 2015 RDA are as follows in the table below.

Table 6: Alternative LGS Pricing– SQ, Simplified SQ, BC Hydro Preferred and Demand Cost Recovery Sensitivity (F2017)

Pricing Element	**Status Quo** For Comparison Only	**Simplified SQ + Flat Demand** (SQ demand-related cost recovery ~50%)	**BC Hydro Preferred** (65% demand-related cost recovery)	**Sensitivity** on BC Hydro Preferred (SQ demand-related cost recovery: ~50%)
Energy rate (cents/kWh)	Part 1, T1: ....11.17 Part 1, T2: ....5.37 Part 2: 10.10	*Flat rate not modeled for F2017 but expected = ~5.98, subject to Part 2 adjustments* *Potential changes to the current LGS-related rules would be considered under this alternative*	5.37	5.98
Demand charge ($/kW)	T1:.....................0.00 T2:.....................5.72 T3:...................10.97	8.35	10.83	8.35
Basic charge ($/day)	0.2347	0.2347	0.2347	0.2347

Preferred LGS Flat Energy Rate

BC Hydro's preferred LGS Flat Energy Rate prioritizes customer understanding and acceptance by significantly simplifying the SQ LGS Energy Rate and aligning it with how other similarly situated Canadian electric utilities structure GS energy rates (predominantly flat energy rates).

The SQ LGS Energy Rate does not provide a clear and strong price signal for conservation. What is clear from the September 2014 LGS/MGS customer focus group sessions and related survey is that the design is overly complex and poorly understood. It has been evaluated through the *F2014 Evaluation of the Large and Medium Service Conservation Rates* report (**F2014 LGS and MGS Evaluation Report**) circulated to stakeholders prior to Workshops 8a/8b and the *Evaluation of* *the LGS and MGS Conservation Rates – Calendar Years 2011 and 2012* report (**2011-2012 LGS and MGS Evaluation Report**) posted to the RDA website[14] to have delivered lower than expected conservation savings with a declining confidence in the persistence of the savings, as shown in the table below:

Table 7: Cumulative Net Evaluated Conservation Savings: Gigawatt Hours per Year

Year	Level of Statistical Significance			
	80%	85%	90%	95%
Fiscal 2014	77	77	0	0
Calendar 2013	200	200	200	0
Calendar 2012	144	144	144	0

Focus group results[15] confirm that the complexity of the SQ LGS Energy Rate is a barrier to customer understanding of the price signal and customer ability to act upon it. As a result, as discussed at Workshop 11a, BC Hydro cannot count on and does not forecast any conservation savings from the SQ LGS Energy Rate on a planning basis for future years.

BC Hydro notes the participant concern that the resulting flat energy rate under its preferred alternative is below the lower end of the energy LRMC. BC Hydro acknowledges that in contrast with the MGS Flat Energy Rate, this is something that requires a trade-off between different design criteria. BC Hydro prioritizes the Bonbright customer understanding and acceptance and fairness criteria at this time above the economic efficiency criterion for the reasons set out in section 2 above. BC Hydro also notes two additional considerations: First, maintaining the SQ LGS Energy Rate would make improving the design and cost recovery of the LGS demand charge untenable in light of the isolated bill impacts of its preferred LGS Flat Demand Charge; Second, the sacrifice in perceived strength of the economic

14 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/lgs-nsa-resp-g-110-10-c16.PDF.

15 The LGS/MGS customer focus group report is found at Appendix F to the F2014 LGS and MGS Evaluation Report.

efficiency signal seems to be a relatively small loss, given the difficulty many customers had understanding the signal in the first place.

SQ LGS Simplified Energy Rate

BC Hydro considered a SQ LGS Simplified Energy Rate that would flatten Part 1 of the energy rate (with nominal effect given typical LGS customer consumption) while maintaining the baseline structure of Part 2 of the rate. This alternative would modify the original tariff provisions of the baseline structure in an attempt to improve the price signal and/or customer understanding and acceptance. The central issue is that the SQ LGS Energy Rate and related provisions attempt to strike a balance between sending an efficient price signal and addressing customers concerns with respect to growth and expected bill impacts. The result is that it would difficult to alter any one provision or group of provisions in an attempt to simplify the SQ LGS Energy Rate.

On the basis of BC Hydro's review and customer feedback, BC Hydro's conclusion is that the single change of simplifying the Part 1 energy rate that is embedded in the SQ LGS Simplified Energy Rate is not likely to substantially improve customer understanding and acceptance nor improve the status quo in terms of providing an efficient price signal:

- *Flatten Part 1 Rates* – The substantive issues associated with the complexity of and minimal conservation delivered under the LGS two-part rate is in large part unrelated to the declining energy rate structure of Part 1. Most LGS customers consume much beyond the monthly 14,800 kWh threshold between the Tier 1 and Tier 2 rates of Part 1; flattening these rates would result only in nominal simplification and would not be expected to materially improve customer understanding and acceptance of the overall energy rates, including the Part 2 energy rate.
- *Modify the PLB* – Lowering the PLB could mitigate customer concerns that the rate is a barrier to growing customers, but would diminish the strength of the

price signal. Conversely, due to a relatively low frequency in customer exceedance of the PLB, increasing the PLB (or removing it altogether while keeping the Part 2 energy rate) would not be expected to materially impact conservation, but would further exacerbate customer concerns that the rate is a barrier to business expansion. BC Hydro concludes that short of eliminating the PLB altogether, there are no feasible changes to the PLB that would improve customer understanding and acceptance of the SQ LGS Energy rate.

- *Modify baseline determination* – BC Hydro considered the possibility of annual versus monthly determination of HBLs. As described in the 2009 LGS Application, the monthly concept was regarded as achieving a balance, conveying an efficient price signal with more frequent reinforcement compared to a stepped rate using an annual CBL.
- *Modify FGR* – The intent of the FGR is to minimize exposure of consumption to LRMC through a higher baseline for customers who experience atypical one-time growth in annual consumption. BC Hydro reviewed its FGR and concludes that it is not entirely functioning as intended. As reviewed in the Workshop 8a/8b consideration memo: 1) few customers were able to reach the "significant growth" thresholds to trigger the rule; 2) some customers' baselines became lower after an adjustment under the rule; and 3) customers that continued to have significant growth in year four actually paid more under the higher baselines as the 20 per cent PLB was larger with higher baselines. In BC Hydro's view, the challenges to be faced in revising the FGR would be not unlike the challenges in designing the rule initially: how to design a relatively simple formulaic method to offset significant growth situations while maintaining balance with the Bonbright efficiency (price signal) objective.
- *Modify prospective growth applications (TS 82)* – Very few customers have applied under TS 82 due to the high qualification thresholds; 17 customers have been on TS 82 since it was first introduced in March 2012 and 4 customers did not meet the threshold after 12 months and were removed from

TS 82. BC Hydro determined that customers with lower consumption might meet the threshold but won't necessarily benefit from the modified pricing structure. BC Hydro questions whether revisiting this rule would result in material benefit to customer understanding and acceptance of the basic SQ design.

- *Modify new account rule* – As reviewed at Workshop 11b, BC Hydro will propose modifying the new account rule by applying 100% Part 1 rates for new accounts for one year.

Preferred LGS Flat Demand charge and Cost Recovery

- BC Hydro's preferred demand charge structure for the LGS rate class is the LGS Flat Demand Charge; and
- BC Hydro's preference is to increase the level of demand charge recovery of demand-related costs from the current approximate 50 per cent level to about 65 per cent.

A flat demand charge for the LGS class improves fairness by aligning cost recovery with the pattern of cost causation to serve LGS customers. As noted above in respect of MGS in section 4.2, the cost to serve a GS customer's peak demand is generally flat on a $/kW basis and a flat $/kW demand charge for LGS customers is consistent with this observation. A flat demand charge also simplifies the rate structure and will improve customer understanding and acceptance. As BC Hydro reviewed in Workshop 11b and 12, a flat demand charge generally offsets bill impacts associated with BC Hydro's preferred LGS Flat Energy Rate (and to a greater extent than a two-step inclining block structure). As compared to the SQ LGS Demand Charge, the LGS Flat Demand Charge will also better reflect the rate design practice of other utilities, which either have flat or two step demand charges.

AMPC requested that BC Hydro consider and model an increase in the LGS demand charge recovery of demand-related costs; AMPC's July 27, 2015 letter on this topic is included in Attachment 2 to this memo. As noted above, at Workshop 12 BC Hydro presented the results of an increase in LGS demand charge cost recovery from about 50 per cent to 65 per cent of demand costs, a level consistent with RS 1823 demand cost recovery. An increase in demand cost recovery will improve fairness in cost causation. BC Hydro's analysis highlights that the increase in demand cost recovery to 65 per cent will further offset and generally level the bill impacts to a reasonable level among LGS customers across size and load factor. This is the same effect as described above in respect of BC Hydro's preferred increase to MGS demand charge cost recovery. BC Hydro agrees with AMPC that this is a fair, pragmatic and stable outcome.

5.2.2 Response to Participant Comments

In response to Commission staff, BC Hydro believes that the complexity of the SQ LGS Energy Rate is most likely the primary reason that minimal conservation has been achieved. BC Hydro has not estimated the MGS or LGS energy price elasticity of demand based on its experience of the last few years with the 2-Part baseline-based rates:

- As described in Workshop 8a and in BC Hydro's Workshop 8a/8b consideration memo, BC Hydro employed a randomized control trial research design to estimate LGS customer response to the two-part baseline-based rates in both the F2014 LGS and MGS Evaluation Report and the 2011-2012 LGS and MGS Evaluation Report;
- The randomized control trial approach employed in the two evaluation reports is generally viewed as the most accurate method for estimating net impacts, and it is widely accepted in the natural and social sciences as the gold standard of research designs.[16] However, the requirement to create a randomized control trial creates a practical barrier to the use of this research design in many cases. This is the case in most rate and pricing interventions, and for this reason

[16] National Renewable Energy Laboratory, U.S. Department of Energy, *Estimating Net Saving: Common Practice* September 2014, pages 14 & 15; http://www.nrel.gov/docs/fy14osti/62678.pdf.

elasticity-based methods are the most common rate impact evaluation method used in the DSM evaluation industry;

- The only estimate of the overall commercial customer price elasticity is -0.1 (consisting of rate structure induced conservation and natural conservation) based on the jurisdictional assessment set out in BC Hydro's 2008 Long-Term Acquisition Plan.

The F2014 LGS and MGS Evaluation Report did not detect a statistically significant response to the introduction of the SQ LGS Energy Rate under separate regression modelling of a sample of 12 industrial key account LGS customers with dedicated energy managers on staff. BC Hydro's expectation was that these customers might be particularly responsive to the LGS rate because they both consume considerable amounts of electricity and have staff dedicated to energy management.

In response to CEC and COPE 378, and as BC Hydro set out in its Workshop 8a/8b consideration memo, BC Hydro is in the process of moving forward items related to developing efficiency ratings, measures or credits. This work is being informed by BC Hydro's Electricity Conservation and Efficiency Advisory Committee. Work in this area will help establish the efficacy and level of credibility in efficiency ratings and standards as well as the potential infrastructure required to implement them in practice.[17] These steps must occur before considering whether an Efficiency Rate Credit can be designed in concept. BC Hydro has committed to considering CEC's Efficiency Rate Credit as part of RDA Module 2.

BC Hydro notes that optional demand charges will be reviewed as part of RDA Module 2. BC Hydro refers to its jurisdictional assessment in Attachment 5 of its Workshop 8a/8b consideration memo that it is unaware of any Canadian jurisdiction that has implemented time-varying demand charges other than Newfoundland Power.

[17] The Workshop 11b slide deck at slide 61 sets out a number of building blocks to be established before developing a credit potentially linked to efficiency ratings or measures.

In response to Thrifty Foods, BC Hydro notes that it used a randomized control trial research design to estimate the conservation savings of the MGS and LGS SQ energy rates. This approach accounts for and does not mask the impact of customer growth on conservation savings estimation.

6 MGS and LGS Transition Strategies

At RDA Workshop 11a BC Hydro considered two high-level transition strategies for moving to a MGS Flat Energy Rate and MGS Flat Demand Charge, assuming SQ demand charge cost recovery of about 15 per cent of demand costs:

1. A three-year phase-in, which limits maximum bill impacts to below 10 per cent for most customers except MGS small consumption, low load factor customers, and
2. A 10 per cent bill impact cap, which would lengthen the phase-in period to over 15 years.

BC Hydro highlighted that it questioned the practicality of such a long phase-in period under option (2), which would frustrate rate stability. BC Hydro sought feedback on which of the two high-level strategies is preferred and why.

At RDA Workshop 12, BC Hydro commented that it would assess alternative transition strategies for its preferred LGS rate design when confirmed. BC Hydro commented that the phase-in may not be beneficial, as the offsetting effects of the increase in demand cost recovery, flattening of the demand charge, and flattening of the energy charge already helps mitigate bill impacts.

6.1 Participant Comments

Overall, participants generally favour a defined period of transition over a 10 per cent bill impact cap with uncertain term. AMPC, BCSEA and FNEMC prefer a three year phase-in compared to a potentially long transition, with reasons cited including: ease of administration, rate stability, and improved customer understanding and acceptance. FNEMC suggests that since small consumption, low load factor customers may be the most adversely affected by the three-year phase-in, BC Hydro could consider some measure of rate relief for hardship on a case-by-case basis. CEC notes generally that a phase-in approach over a defined number of years would enable a balance between fairer cost allocation and impact transition fairness. Whistler Blackcomb suggests that that a 10 per cent bill impact would be preferred for simplicity.

Commission staff raise questions of whether the analysis of bill impacts and transition strategies should exclude impacts to, for example, the lowest and highest 5 percent of load factor customers so that the rate design is not limited by the customers at the extremes. Commission staff question that if a 10 per cent bill impact transition would take too long to implement, should BC Hydro consider an extended implementation period of perhaps 5 to 7 years so that implementation is still complete before the next rate design? Similarly, BCOAPO views 15 years as being too long a period for transition, suggesting that a period slightly greater than three years could be considered.

6.2 BC Hydro Consideration

Rate design phase-in is typically implemented to soften the effect of implementation where adverse bill impacts would be imposed on specific customer segments (such as the largest 25 per cent of customers).

Subsequent to Workshop 12, BC Hydro assessed the need for phase-in periods for its preferred MGS and LGS rate structures and demand charge recovery of demand-related costs. BC Hydro understands that the bill impact test has in the past been used to slow down the transition to rates that would improve future economic efficiency. 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. In this case, 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.

Please refer to Attachment 4 for a summary of BC Hydro's analysis, which demonstrates that:

- A three year phase-in period for BC Hydro's preferred MGS rate may have minor mitigation of bill impacts but the trade-off is a complex transition that will not give MGS customers certainty; and
- A phase-in period for the preferred LGS rate is not an effective bill impact mitigation strategy. With a three year transition, BC Hydro estimates that about 3,200 accounts (just under half of all LGS accounts) will experience bill impacts of 10 per cent or greater; the impacted customers are 'typical' customers as well as low consumption, low load factor customers.

As a result, in the 2015 RDA BC Hydro will propose one-step transitions for both the preferred MGS rate and the preferred LGS rate on April 1, 2017.

MGS Preferred Design: Flat Energy Rate & Flat Demand Charge (35 per cent demand cost recovery)

BC Hydro will not propose a phase-in to its preferred MGS rate design.

Following Workshop 11a, BC Hydro updated its analysis of MGS phase-in to incorporate its preferred increase in demand charge cost recovery to 35 per cent of demand costs. The only phase-in method that offers any softening of bill impacts is a three-year phase-in, although the impacts are marginal compared to not implementing any phase-in at all. Furthermore, a three-year phase-in delays the demand revenue recovery adjustment by three years. BC Hydro's simulations indicate that under the 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 load factors of less than 10 per cent.

Correspondingly, the absolute dollar impacts to these customers are expected to be small. Refer to Attachment 4 to this memo.

The three-year phase-in method is highly complex and the amount of softening of bill impacts is not substantive, with the key trade-off being a substantial decline in customer understanding and bill predictability. Therefore, BC Hydro questions whether phase-in would be worthwhile. For the majority of MGS customers the phase-in will delay the offsetting effect of the flat energy rate, flat demand charge and increasing demand cost recovery; the opposite of what a phase-in is intended to accomplish.

LGS Preferred Rate Design: Flat Energy Rate & Flat Demand Charge (65 per cent demand cost recovery)

BC Hydro will not propose a phase-in to its preferred LGS rate design.

Following Workshop 12, BC Hydro analyzed the implementation of a phase-in to its preferred LGS rate structures and demand charge cost recovery. BC Hydro's simulations show that any form of phase-in is not advantageous to the LGS rate class in managing the bill impacts of either "typical" customers (in terms of load factor and annual consumption (around the medians of each of these measures)), or of large customers with high annual consumption.

The effects of combining the changes in energy and demand charges alone offset and soften the bill impacts to any set of LGS customers. A phase-in to the preferred LGS rate structures would delay the offsetting benefits of its three elements, and result in the opposite effect of what a phase-in is intended to accomplish. That is, for most LGS customers a phase-in performs worse than no-phase-in. The key reason is because the phase-in delays the benefits of the rate design changes (rather than stretching out adverse impacts).

7 Minimum Charges (Demand Ratchet)

The minimum monthly charge for the MGS and LGS rates is based on 50 per cent of peak monthly demand registered in the most recent winter period (November to March). This demand ratchet ensures that customers with low consumption in a particular billing period because of inconsistent demand or with low consumption in non-winter billing periods due to seasonal usage pay a share of BC Hydro's fixed costs to maintain its infrastructure related to serving peak demand.

7.1 Participant Comments

Commission staff state that more information is necessary to determine if the current minimum charges are appropriate, suggesting that BC Hydro could survey some high winter/low summer consumption customer bills to determine if their contributions to infrastructure and peak supply commitments are appropriate, or if the ratchet should be increased to the 75 per cent RS 1823 level.

AMPC also believes that there is insufficient information provided on the impact, distribution, or effectiveness of various ratchet mechanisms, percentage levels or waiver arrangements to provide any constructive feedback at this time. CEC believes that the demand ratchet is an unnecessary complication that could be appropriately handled in demand charge allocation approaches.

Whistler Blackcomb does not support an increase in ratchet charges; it is far busier in winter than in summer and thus incurs these charges, in its words "penalties". Whistler Blackcomb comments that ratchet charges can be a disincentive for conservation in the summer months if viewed as having been paid for anyway.

BCOAPO and FNEMC support increasing the demand ratchet to be consistent with the Transmission Service rate class. BCOAPO comments on the important issue of fairness involved, highlighting that given that cost causality is determined based on peak demand, customers whose billing demands are materially lower in the off-peak months (relative to the peak months) are likely not paying their "fair" share of costs. Further, BCOAPO believes there should be consistency of treatment across rate classes. BCOAPO sees merit to including a review of the GS demand ratchet in Module 2.

BCSEA agrees with the concept of having a minimum charge to ensure that all customers pay a fair share of costs for system capacity, but seeks more information of the effects of this rate before commenting further. COPE 378 generally supports recovering more of the revenue requirements through efficient flat energy and demand rates, which would suggest further reducing or eliminating the minimum charges.

7.2 BC Hydro Consideration

BC Hydro will not propose eliminating the MGS and LGS demand ratchets in the RDA. BC Hydro believes that the demand ratchet is an important rate mechanism for applying minimum billing to a customer for recovery of the fixed costs of serving peak demand. Almost all jurisdictions surveyed have a form of minimum monthly charge; refer to Attachment 3.

The demand ratchet was reduced from 75 per cent to 50 per cent in April 1980; BC Hydro is researching the rationale for this and will report its findings in the 2015 RDA itself if available at the time of the filing.

In response to AMPC, BCUC staff and BCSEA requests for more information concerning the MGS and LGS demand ratchet, BC Hydro offers the following.

To put the MGS and LGS demand ratchets in context, Table 8 below provides summary information on MGS and LGS demand ratchet charges in F2015 (F2013 and F2014 data are comparable). Table 8 highlights that the number of MGS and LGS customers incurring demand ratchet charges is relatively few in comparison to the total number of customers in each class. Correspondingly, the amount of MGS and LGS demand ratchet revenue is also relatively low in comparison to total MGS and LGS class revenue.

Table 8: Summary of F2015 demand ratchet charges, MGS and LGS

F15 Demand Ratchet Charge	MGS	LGS
Total Customers Incurring Demand Ratchet	211	213
% of Total Customers of Class	~ 1%	~ 3%
Total Demand Ratchet Revenue	$122,744	$1,794,043
% of Total Revenue (F2015)	~ 0.04%	~ 0.2%

Table 9 below provides a frequency distribution of total MGS and LGS demand ratchet charges in F2013 through F2015. This data highlights that relatively low annual demand ratchet charges are more frequent than relatively high annual demand ratchet charges across the entire range of annual demand ratchet charges in the period.

Table 9: Frequency distribution of total MGS and LGS demand ratchet charges, F2013-F2015

MGS Annual Ratchet Charge F2013-F2015			LGS Annual Ratchet Charges F2013-F2015		
Amount (Bin)	**Frequency**	**Percent**	**Amount (Bin)**	**Frequency**	**Percent**
$100	163	23.3%	$1,000	196	30%
$200	150	21.4%	$2,000	130	20%
$300	92	13.1%	$3,000	76	12%
$400	73	10.4%	$4,000	55	8%
$500	40	5.7%	$5,000	36	5%
$600	30	4.3%	$6,000	23	3%
$700	34	4.9%	$7,000	18	3%
$800	19	2.7%	$8,000	17	3%
$900	20	2.9%	$9,000	10	2%
$1,000	20	2.9%	$10,000	5	1%
$2,000	41	5.8%	$20,000	45	7%
$3,000	8	1.1%	$30,000	17	3%
$4,000	3	0.4%	$40,000	11	2%
$5,000	4	0.6%	$50,000	3	0%
$6,000	1	0.1%	$60,000	2	0%
$7,000	1	0.1%	$70,000	2	0%
$8,000	0	0.0%	$80,000	1	0%
$9,000	0	0.0%	$90,000	1	0%
$10,000	0	0.0%	$100,000	3	0%
More:	2	0.3%	More:	7	1%
Total:	**701**	**100%**	**Total:**	**658**	**100%**

Tables 10 and 11 below report by site type the total MGS and LGS customers that have incurred the demand ratchet charge between F2013 and F2015, their average annual ratchet charge and their average annual demand charges as a percentage of annual total bills. This information highlights that demand ratchet charges are dispersed broadly across the MGS and LGS customer classes by type of customer. This information also highlights that annual demand ratchet charges tend to be relatively low in absolute and percentage terms, on average.

Table 10: MGS average annual ratchet charges and average % of total bills by site type, F2013-F2015

Site Type	Total Customers F2013-F2015	Average Annual Ratchet Charge	Average % of Total Bill
Agriculture	42	$505	11%
Apartment Common	4	$223	15%
Chemical - Other	5	$494	21%
Educational Services	1	$750	24%
Food Retail	3	$303	6%
Hotels	6	$180	4%
Industrial - Food & Beverages	18	$326	14%
Industrial - Heavy Manufacturing	29	$438	10%
Industrial - Light Manufacturing	43	$423	10%
Industrial - Other	28	$276	7%
Municipal Pumping	72	$520	8%
Non-Buildings	22	$189	6%
Non-Food Retail	26	$481	20%
Offices	141	$352	11%
Other Commercial	139	$543	5%
Public School	27	$419	3%
Restaurant	6	$257	17%
Transportation	23	$1,899	18%
University/College	5	$223	7%
Warehouses	16	$369	30%
Wood - Lumber	17	$519	12%
Wood - Other	17	$294	18%
Wood - Panel	2	$1,668	73%
Temporary Meter	9	$50	11%
Total:	**701**	**$480**	**10%**

Table 11: LGS average annual ratchet charges and average % of total bills by site type, F2013-F2015

Site Type	Total Customers F2013-F2015	Average Annual Ratchet Charge	Average % of Total Bill
Agriculture	52	$8,447	11%
Apartment Common	1	$2,160	2%
Chemical - Other	3	$1,965	13%
Educational Services	1	$4,349	8%
Food Retail	3	$5,586	26%
Hotels	3	$2,678	7%
Industrial - Food & Beverages	17	$4,225	7%
Industrial - Heavy Manufacturing	53	$9,567	14%
Industrial - Light Manufacturing	68	$9,197	33%
Industrial - Other	28	$4,461	7%
Irrigation	1	$21	0%
Municipal Pumping	79	$3,524	9%
Non-Buildings	22	$4,305	9%
Non-Food Retail	14	$3,692	21%
Nursing Home	1	$356	1%
Offices	66	$1,983	9%
Other Commercial	111	$13,941	10%
Public Hospital	1	$217	1%
Public School	44	$1,593	4%
Restaurant	1	$450	31%
Transportation	11	$7,678	11%
Warehouses	17	$1,709	16%
Wood - Lumber	31	$7,847	13%
Wood - Other	24	$4,875	9%
Wood - Panel	2	$15,186	32%
Temporary Meter	4	$3,443	18%
Total:	**658**	**$6,835**	**13%**

Table 12 provides a simple estimation of the annual bill impacts to customers that have incurred the demand ratchet charge between F2013 and F2015 as resulting from a 50 per cent increase in demand ratchet charges; that is, had the GS demand ratchet been 75 per cent of peak monthly demand in F2013 through F2015, as opposed to 50 per cent. Median bill impacts to MGS and LGS customers that have incurred demand ratchet charges are estimated to be 2 per cent and 3 per cent, respectively. Bill impacts in the 90th percentile for MGS and LGS customers that have incurred demand ratchet charges are estimated to be 13 per cent.

To estimate the impact of an increase in the demand ratchet to customers that have not incurred a demand ratchet charge, Table 13 provides a corresponding estimation of the annual bill impacts reported in Table 12, but assuming those customers had not incurred demand ratchets previously in the period F2013-F2015. Table 13 illustrates that the result for customers that currently do not incur a demand ratchet charge is a predicted three- to four-fold increase in estimated bill impacts compared to customers that have incurred the demand ratchet charge.

Table 12: Illustrative annual bill impact from 50% increase in demand ratchet charge to customers that incurred demand ratchet F2013-F2015

Percentile	MGS Annual Bill Impact	LGS Annual Bill Impact
10th	0.4%	0.8%
20th	0.7%	1.2%
30th	1.0%	1.6%
40th	1.4%	2.3%
Median	2.0%	3.0%
60th	2.8%	3.7%
70th	4.2%	5.4%
80th	7.4%	7.6%
90th	13.3%	12.9%

Table 13: Illustrative annual bill impact from 50% increase in demand ratchet charge if customers had not incurred demand ratchet F2013-F2015

Percentile	MGS Annual Bill Impact	LGS Annual Bill Impact
10th	1.2%	2.2%
20th	2.0%	3.5%
30th	3.0%	4.7%
40th	4.3%	6.7%
Median	6.1%	8.7%
60th	8.8%	11.2%
70th	13.7%	16.4%
80th	25.5%	24.8%
90th	51.7%	42.3%

BC Hydro observes that the current level of the MGS and LGS demand ratchet charge is not a significant issue in terms of its overall impact on total BC Hydro MGS and LGS revenue, but the charges are a major component of some customer bills. Tables 12 and 13 illustrate that some customers would face very large bill impacts if the level of the demand ratchet was increased. Customers that incur demand ratchets and the level of their charges cannot be readily generalized on the basis of site type.

BC Hydro recognizes that an increase in the level of the MGS and LGS demand ratchets would improve fairness in customer contribution to the infrastructure costs that BC Hydro incurs to serve the peak demand of its GS customers, as per the purpose of the demand ratchet. Furthermore, an increase in the level of the demand ratchet to 75 per cent of peak monthly demand would provide consistent rate treatment between BC Hydro's MGS and LGS classes and RS 1823 customers.

However, given that the level of the demand ratchet charge is not a major issue, at this time BC Hydro prefers to maintain the level of the MGS and LGS demand ratchets at the existing level of 50 per cent of peak monthly demand.

8 Voluntary Rate Options for GS Customers

As discussed at Workshops 11 and 12, BC Hydro will use 2015 RDA Module 1 to set the default GS rate structures; it is imperative that the issues with the default rates for LGS and MGS customers be addressed before optional rates for GS customers are pursued.

At Workshop 11b BC Hydro advanced that it has no plan to proceed developing voluntary Time of Use (**TOU**) Rates at this time for reasons set out in section 6.1 of the Workshop 8a/8b consideration memo. BC Hydro proposed to assess a number of potential voluntary rate options such as interruptible rates for GS customers, demand charge options and the CEC's efficiency rate credit concept as part of RDA Module 2, after default GS rates are determined. BC Hydro sought participant feedback on the options noted above and if there are any other GS rate options BC Hydro should consider.

8.1 Participant Comments

Commission staff highlight BC Hydro's claim that a large differential of 3 to 4 times the differential between Heavy Load Hour and Light Load Hour pricing is necessary to induce customers to join a voluntary TOU rate and request BC Hydro to validate this in support of its decision not to proceed with a voluntary TOU rate at this time. Commission staff also remark that interruptible rate options are likely to be of interest to some customers and to BC Hydro. Commission staff suggest that issues such as metering, entry and exit fees and the amount of interruption should be clarified so that serious customer interest could then be assessed. Commission staff state that a pilot program to introduce such new rate structures has been successful in the past.

AMPC agrees with BC Hydro's proposed approach in respect of GS rate options.

CEC and FNEMC suggest that as a matter of fairness freshet rate considerations should be reviewed under GS options as well.

BCOAPO and BCSEA agree with BC Hydro’s proposal not to proceed with the development of an optional TOU rate at this time, citing that there appears to be no cost justification for any material differential in peak/off-peak rates and the considerable opportunity for free-riders. BCSEA and BCOAPO have reservations about the suggested optional rates for GS customers, with BCOAPO noting that the details will need to be given careful consideration to ensure that they do not have a negative impact on other customers. BCSEA and BCOAPO are content to await consideration of these options in RDA Module 2, although BCOAPO seeks to ensure that there is sufficient time and resources available to comprehensively assess all other issues also identified for review as part of RDA Module 2. BCSEA supports an efficiency rate credit concept, subject to further development and understanding of its details and implications.

COPE 378 recognizes that a mandatory TOU rate (which by its nature would be a default rate) is currently prohibited by B.C. Government policy but it is of the view that BC Hydro should be modelling such a TOU rate and seasonal rates and discounts to present to stakeholders, the BCUC and the B.C. Government for consideration. COPE 378 states that absent such a model it is difficult for parties to appreciate whether these types of rate structures might be in the public interest.

Whistler Blackcomb supports exploration of the GS optional rates and would seek to understand the impacts of the options on its business.

8.2 BC Hydro Consideration

BC Hydro appreciates the feedback to date and notes broad agreement to consider GS rate options during RDA Module 2.

In response to Commission staff, BC Hydro points to a few sources to support its claim that a differential between peak and off-peak prices of between 3 and 4 to 1 is necessary to induce a response to a TOU rate:

1. As per the summary provided in the Workshop 5 consideration memo concerning RS 1825 (the current voluntary TOU rate for Transmission Service customers), BC Hydro set out that it understood from the work its consultant Energy + Environmental Economics (**E3**) that the Canadian and U.S. jurisdictions it sampled in 2010 had average commercial TOU ratios of peak to off-peak of 3;
2. In 2010, the Ontario Energy Board commissioned The Brattle Group to study about 50 TOU rates across North America and elsewhere, and reported that the average ratio is about 4 to 1.[18] The Brattle Group noted that, in comparison, the Ontario Regulated Price Plan TOU price ratio is 1.9 to 1, a magnitude that will provide modest incentives for load shifting and bill savings opportunities for some customers. It also commented that the Ontario ratio is similar in magnitude to that of a TOU rate offered by Puget Sound Energy in 2001, which encountered significant customer acceptance challenges;
3. As per the summary provided in the RDA Workshop 8a/8b consideration memo, BC Hydro considered its 2000 to 2001 voluntary TOU LGS pilot.[19] The peak to off-peak price differentials under this pilot were between 2 and 3 to 1. On an aggregate basis, there was an estimated small reduction in winter peak usage (1.3 per cent) and an increase in usage in winter non-peak usage (1.5 per cent);
4. BC Hydro notes the Industrial Electricity Policy Review (**IEPR**) task force's questioning of how an industrial TOU in B.C. with its small differential between on-peak and off-peak pricing could lead to significant peak shaving.[20]

[18] A. Faruquai *et al*, "Assessing Ontario's regulated Price Plan: A White Paper", page 3; copy available at http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0364/Report-Assessing%20Ontarios%20Regulated%20Price%20Plan.pdf.

[19] Implemented pursuant to BCUC Order No. G-117-99; http://www.bcuc.com/Documents/Orders/Orders99_2/G4_Orders/G117_99BCH.pdf.

[20] IEPR Task Force, "Industrial Time of Use (TOU) Rates"; http://www.empr.gov.bc.ca/EPD/Documents/Task%20Force%20Issue%20Paper%20-%20Time%20of%20Use%20Rates%20FINAL.pdf.

BC Hydro has no plans to model mandatory default TOU rates given B.C. Government policy. Furthermore, no GS customer has indicated a desire for a mandatory default TOU rate. BC Hydro also has no plans to model a voluntary TOU rate for GS customers or Residential customers at this time. BC Hydro notes COPE 378's opposition to a voluntary Residential TOU as provided in its feedback concerning Workshop 3:

> A voluntary program encourages self-selection, creating a situation where free riders (those who would otherwise be incented to conserve or those few who have the ability to shape their use beyond the ability of the majority of ratepayers to take advantage of the lowest rate) will be receiving a subsidy from the majority of ratepayers who cannot modify their usage and who do not have the time to determine how best to shape their usage patterns.

COPE 378 noted that a voluntary TOU does not incent energy conservation and is likely to result in minimal capacity savings.

BC Hydro agrees with COPE 378's concerns over the self-selection effects that are present with a voluntary TOU rate, and in particular that if 'structural winners' with favorable load shapes choose a voluntary TOU rate, there would be a cost shift to other customers. Again, if this shift in costs is driven by a TOU rate with larger TOU rate differentials than are currently justified by TOU period costs, then the rate promotes neither an increase in equitable cost allocation nor an increase in economic efficiency.

Consideration of a GS freshet rate in RDA Module 2 would be premature in advance of the contemplated two year freshet pilot for RS 1823 customers. At the conclusion of the pilot, BC Hydro will reassess which types of customers should be eligible for a freshet rate if the freshet rate becomes a permanent offering.

2015 Rate Design Application

June 25, 2015/June 26, 2015

Workshop Nos. 11a and 11b

Large General Service (LGS)

Medium General Service (MGS)

Small General Service (SGS)

Rate Structures

BC Hydro Summary and

Consideration of Participant Feedback

Attachment 1

Summary Notes

Draft

BC Hydro Rate Design Workshop

SUMMARY 25 JUNE 2015 9 AM TO 11.45 AM BCUC Hearing Room
1125 Howe Street, Vancouver

TYPE OF MEETING	RDA Workshop 11A
FACILITATOR	Anne Wilson, BCH
PARTICIPANTS	Association of Major Power Consumers of British Columbia (AMPC); British Columbia Old Age Pensioners Organization (BCOAPO), BC Sustainable Energy Association and Sierra Club of Canada BC Chapter (BCSEA), BCUC staff, Canadian Office and Professional Employees Union Local 378 (COPE 378), Clean Energy BC/Weimer Consulting Inc., CLEAResult, Commercial Energy Consumers Association of British Columbia (CEC), First Nations Energy & Mining Council/Linda Dong Associates (FNEMC), FortisBC Inc. (Fortis), TransLink
BC HYDRO ATTENDEES	Gordon Doyle, Rob Gorter, Paulus Mau, Dani Ryan, Anne Wilson, Craig Godsoe, Jeff Christian (Lawson Lundell)
AGENDA	1. Welcome & Introductions 2. Overview of GS Rates, Stakeholder Engagement to Date and Issues Identified 3. GS Segmentation 4. SGS 5. MGS – Preferred Energy Rate and Demand Charge Structure Alternatives 6. MGS – Demand Charge Cost Recovery 7. MGS – Transition Options

MEETING MINUTES		
ABBREVIATIONS	BCH ...... BC Hydro BCUC......BC Utilities Commission COS........Cost of Service CP...........Coincident Peak DSM ...... Demand Side Management E3............Energy + Environmental Economics, Inc. GS...........General Service GWh.......Gigawatt hour IPP........ Independent Power Producer kW..........Kilowatt	kWh........Kilowatt hour LGS.........Large General Service LTAP.......Long-Term Acquisition Plan MGS.......Medium General Service NCP........Non-Coincident Peak R/C..........Revenue to Cost ratio RDA........Rate Design Application RIB........Residential Inclining Block rate SGS........Small General Service SQ..........Status Quo

1. Welcome and Introductions

Anne Wilson opened the meeting by reviewing the agenda set out in slide 2 of the Workshop 11A slide deck.

2. Presentation: GS Rate Overview

Gordon Doyle stated that BCH now has a preferred SGS rate structure, which is the SQ flat energy rate, and a preferred MGS energy rate structure, which is a flat energy rate with no baseline.

Gord described the purpose of Workshop 11A, which is to solicit feedback on: (1) what additional GS rate class segmentation analysis should be conducted; (2) whether BCH should increase the SGS basic charge cost recovery; (3) what should the preferred MGS demand charge structure be; (4) whether BCH should increase the MGS demand charge cost recovery; and (5) what should the preferred MGS transition option be.

Gord also reviewed stakeholder engagement on GS rates to date, including BCH's GS jurisdictional assessment results and issues identified with the SQ MGS and LGS rates.

	FEEDBACK	RESPONSE
1.	**BCOAPO**	The basis of the LGS and MGS forecasted conservation savings is a commercial customer elasticity assumption of -

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	What is the basis of the LGS and MGS forecasted conservation savings shown on slide 8?	0.1 for rate structure conservation. The -0.1 elasticity assumption results from a jurisdictional and literature survey done by E3 as part of the BCH 2008 LTAP review. E3 focused on winter peaking jurisdictions, including Ontario, Illinois, Wisconsin and New York.[1]
2.	**BCOAPO** In BCH's view, were the original commercial customer elasticity assumptions flawed or is the lack of LGS and MGS customer response to the SQ two-part baseline rates due to customers not understanding the price signals and therefore being unable to react?	As discussed at Workshop 8A, one common theory behind LRMC-priced rate structures is that awareness leads to understanding and understanding results in a conservation response. If awareness is low, as was found for the LGS and MGS rates, then understanding and conservation actions are also expected to be low.[2]
3.	**BCUC staff** -0.1 is a fairly low elasticity of demand; we may be spending too much time trying to get the price signal right for the diverse LGS and MGS rate classes instead of addressing what rate structure would work best for these classes.	

3. Presentation: GS Segmentation

Dani Ryan described the two main GS segmentation issues raised by stakeholders as part of Workshop 8A/8B: (1) segment the existing LGS rate class to create a new class of larger LGS customers (referred to as **XLGS**); and (2) possible re-merging of MGS and LGS rate classes. Dani discussed analysis BCH has done to date (jurisdictional assessment and COS analysis 'Method 1') and the additional analysis BCH is undertaking and targeting to discuss at the 30 July 2015 RDA wrap-up workshop (COS analysis 'Method 2', which is clustering analysis).

Dani emphasized that to date, BCH is finding that no matter how the GS could be segmented, its heterogeneity would remain; there is no obvious breakpoint for segmenting the GS rate class beyond the current segmentation into SGS, MGS and LGS rate classes.

	FEEDBACK	RESPONSE
1.	**AMPC** On slide 13, BCH states that metering is one basis for the existing SGS rate class demarcation at 35 kW. AMPC would like an update on whether there is now increased metering capability.	There is increased metering capability. However, at Workshop 8A BCH described how about 45% of SGS customers have residential-type meters and these meters do not have Measurement Canada approved demand functions.[3] Thus while demand can be calculated using interval data it cannot be used for billing. BCH's jurisdictional assessment revealed that Canadian electric utilities surveyed have small GS classes which do not have demand charges, and that the current SGS 35 kW breakpoint is within the range of other Canadian electric utility breakpoints used for smaller GS (10 kW to 75 kW). Refer to slide 15.

[1] The four non-residential studies E3 viewed as most comparable to B.C. report short-run elasticities of between 0.0 and -0.142, with three of the four studies reporting short-run elasticities below -0.1. Refer to the Direct Testimony of Dr. Ren Orans, 2008 LTAP Appendix E, pages 19 and 20 of 28; http://www.bcuc.com/Documents/Proceedings/2008/DOC_18928_B-1-1_APPENDICES.pdf.

[2] Refer to the Workshop 8A/8B Consideration Memo, Attachment 1, page 3 of 29; http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-06-19-bch-rda-wksp-8a-8b-gsrs.pdf.

[3] Per the Electricity and Gas Inspection Regulations, SOR/86-131; copy available at http://laws-lois.justice.gc.ca/eng/regulations/SOR-86-131/.

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BC Hydro Rate Design Workshop

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2.	**AMPC** AMPC agrees with BCH's comment that it is general utility practice to have a small GS rate class with no demand charge.	
3.	**AMPC** AMPC notes the prevalence of very large GS classes on slide 15 e.g., Toronto Hydro 5,000 kW breakpoint; Epcor 5,000 kW breakpoint. What is the number of BCH LGS accounts at 5,000 kW?	This information is set out at page 44 of the Workshop 8A/8B Consideration Memo: 5,000 kW: 37 accounts; 2,000 kW: 172 accounts; 1,000 kW – 437 accounts. BCH is still investigating the COS basis for the creation of a XLGS rate class say above a 2,000 kW breakpoint. BCH will also explore whether E3's other factors for segmentation - customer understanding and practicality of tariff administration – support different breakpoints, for example for a XLGS class.
4.	**BCOAPO** On slides 17 and 18, the issue that the analysis seems to miss is that the MGS and LGS customers are not billed using Energy/NCP/4CP – rather they are billed strictly on energy and their individual monthly NCP. The other issue missed in the analysis is that the amount of dollars allocated to each class using energy is not equivalent to the dollars collected from customers through energy rates. The implications of the first point are: • Ideally one would want to group in the same rate class customers whose ratio of Billing Demand is similar to 4CP; • Similarly one would want to group in the same rates class customers whose ratio of billing demand to NCP are similar. The implications of the second point are: • Ideally one would want to group into the same rate class customers that have the same load factor (measured using NCP); • Similarly one would want to look at grouping customer into the same rate class that have similar load factors measured using 4 CP. Based on these observations it would be interesting to see how each of the three ratios vary across individual customers when "plotted" against customer size (i.e. peak) in order to see if there are any obvious break points.	Slides 17 and 18 are looking at segmentation from a cost perspective alone, which E3 did in 2009. BCOAPO seems to be asking BCH to relate the costs to the revenue. It is not apparent to BCH why one would calculate a load factor using 4 CP. The standard load factor calculation is already based on the customer's peak demand or NCP. • The relationship between a customer's Billing Demand and 4CP would be similar to the relationship between load factor and coincidence factor. It is not clear how this could be used for rate class segmentation. • The ratio of billing demand to NCP would be similar to load factor and there is no cost basis for grouping customers this way. • Load factor does not drive costs and should not be used as the basis for rate class segmentation. • While coincidence factor may predict cost causation, it is not a practical way of segmenting customers.
5.	**FortisBC** Has BCH done a statistical cluster analysis?	Not yet; as set out in the Workshop 8A/8B Consideration Memo, BCH will be doing a cluster analysis as part of Method 2 and anticipates being able to discuss the results with stakeholders at the 30 July 2015 workshop.

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BC Hydro Rate Design Workshop

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6.	**BCSEA** Is the Method 2 cluster analysis a COS method?	Yes.
7.	**BCSEA** Given the importance of coincidence factor, can coincidence factor be used as a basis for GS segmentation?	Coincidence factor is variable; there is no GS subset that is entirely coincident with system peak. E3 stated as part of its 2009 GS segmentation analysis that customer accounts should be segmented using readily observable variables that can be easily understood, together with other factors such as customer understanding and practicality of tariff administration. BCH is not aware of any Canadian jurisdiction that uses coincidence factor to segment GS customers. BCH does not think that coincidence factor (or load factor) meets these requirements; instead, BCH agrees with E3 that BCH should continue to use kW demand intervals as the basis for GS class segmentation.
8.	**CLEAResult** The finding that load factor does not relate too strongly to cost is incredible. BCH may be able to do more rate innovation if coincident factor is really the main cost driver.	Load factor is the relationship of average use (measured in kWh) to peak use (measured in kW). A customer's load factor is only related to cost to the extent that their peak use occurs coincidently with other customers' peak use, which is better expressed as coincidence factor. Load factor is more predictive of revenue impacts, especially when cost recovery is shifted between energy charges and demand charges.
9.	**CEC** There appears to be a relationship between low load factor and low coincidence factor on slide 20. Could this group be segmented?	If we just examine low load factor customers, some of these will have high coincidence. BCH has concerns with using load factor to segment GS customers as this concept is not readily understood by customers and changes with the addition of equipment, for example. In BCH's view, using load factor to segment does not meet either the customer understanding or practicality of tariff administration tests. Instead, as will be described in Workshop 11B, BCH will review a demand charge option for low load factor, low coincidence customers (referred to as the Manitoba Hydro Limited Use of Billing Demand option).

4. Presentation: SGS Rate

Rob Gorter set out the reasons why BCH's preferred SGS rate is the SQ SGS flat energy rate with a basic charge and no demand charge. Rob also discussed the results of increasing the SGS basic charge fixed cost recovery from about 35% to about 45%, which is the level of the RIB basic charge fixed cost recovery.

	FEEDBACK	RESPONSE
1.	**CEC** The draft F2016 COS shows that BCH is over-recovering from the SGS rate class. Would rate-rebalancing cause BCH to reconsider the SGS rate structure?	BCH does not see possible rate-rebalancing causing BCH to consider a different SGS rate structure. An inclining block rate is not viable for this heterogeneous class and a two part baseline rate such as the SQ MGS rate is not appropriate for this class regardless of rate rebalancing.

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2.	**COPE 378** What is the LRMC range for comparison to the SGS energy charge? How confident is BCH in the energy LRMC range?	This information is set out at page 7 of the Workshop 8A/8B Consideration Memo. For F2016, the energy LRMC range is 9.36 cents/kWh (lower end) and 11.01 cents/kWh (upper end). As shown on slide 24, the SGS energy charge in F2016 is 10.73 cents/kWh, which is within the energy LRMC range. The energy LRMC range results from the approved 2013 Integrated Resource Plan, which found that the two resources types required to fill the energy gap over the next ten years is DSM and IPP contract renewals, and this resulted in a range of 8.5 cents/KWh to 10.0 cent/kWh (F2013).
3.	**BCOAPO** Did increasing the SGS basic charge result from stakeholder feedback?	Yes, as did the level of possible SGS basic charge increase to 45% fixed cost recovery.
4.	**BCOAPO** What does BCH mean by 'fixed costs'? Can BCH provide what % of customer costs are recovered by the SQ RIB basic charge and the SQ SGS basic charge?	On slide 27, fixed costs are demand- and customer-related costs. Both the SQ RIB basic charge and SQ SGS basic charge recover all customer costs and a portion of demand costs, with most demand costs being recovered through the respective energy charges.
5.	**BCSEA** What is the effect on energy conservation if BCH were to increase the SGS basic charge fixed cost recovery to 45%?	As shown on slide 26, the resulting reduction in the SGS energy charge is very small – in F2017 from 11.16 cents/kWh to 11.01 cents/kWh. Applying the -0.05 elasticity assumption BCH has for natural conservation through rate increases, there may be a very small increase in energy consumption.
6.	**BCUC staff** Any resulting increase in energy consumption would be so small as to be negligible.	
7.	**BCOAPO** BCH concludes that increasing the SGS basic charge fixed cost recovery to 45% would not result in 'substantial' bill impacts. How does BCH define substantial given the bill impact is over 10% for the first two percentile consumption categories on slide 26?	BCH continues to use the 10% bill impact test as an 'amber signal' rather than a stop or go constraint. This is particularly the case where, as in this case, the absolute dollar value of the increases is small.
8.	**CEC** CEC agrees that absolute dollar value is an important part of the 10% bill impact test.	

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9.	**BCOAPO** It would be useful to know how many SGS customers fall into each of the percentile consumption categories on slide 26.	The distribution on slide 26 illustrates bill impacts of the single account at each specified percentile, as opposed to the impact of a group of accounts in blocks of 10%. For example, the result for the 10th percentile shows the bill for the single account that represents the 10th percentile of consumption of accounts in the F2014 sample used for the analysis. The forecasted number of SGS accounts, which this distribution will apply to, for illustrative purposes are below.

Forecast year	Forecast number of accounts	10 percent of forecasted accounts
F17	181,698	18,170
F18	183,727	18,373
F19	185,817	18,582

5. Presentation: MGS Demand Charge Structure Alternatives

Paulus Mau reiterated that BCH's preferred energy rate structure is a flat energy rate with no baseline. The MGS Flat Energy Rate would be very close to the lower end of the energy LRMC range, with an energy charge of 8.98 cents/kWh in F2016 as compared to the lower end of the energy LRMC of 9.36 cents/kWh ($F2016).

Paulus identified and reviewed the BCH Bonbright assessment of three demand charge structure alternatives: the three step SQ Demand Charge; the Flat Demand Charge; and the Two Step Demand Charge, which retains the current zero Tier 1 and flattens Tier 2 and Tier 3 into a single Tier 2.

	FEEDBACK	RESPONSE
1.	**BCUC staff** It appears that the Two Step Demand Charge would be better from a SGS/MGS seams perspective; this is something BCH should consider.	***Revised Response*** A transition from the Status Quo SGS energy rate to MGS at the seam (35 kW) would result in lower bills under all MGS alternatives; however, the degree to which the bill is lower differs between alternatives. • Under status quo rates, transitioning from SGS to MGS would result in a 8% lower bill at the seam. Comparatively: • Transitioning from SGS to the MGS alternative with Flat Demand Charge, Flat Energy charge would result in a 3% to 12% lower bill at the seam, for low to high load factor customers, respectively. The impacts are driven by both the different energy charges and a demand charge at T1. • Transitioning from SGS to the MGS alternative with Two Step Demand Charge, Flat Energy charge would result in a 16% lower bill at the seam. This is driven by the different energy charge.

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2.	**BCUC staff** Why does BCH not have a preference for the Two Step Demand?	BCH has no identified preferred demand charge structure at this time and is soliciting feed-back. Both a Flat Demand Charge and a Two Step Demand Charge are used by other Canadian electric utilities. BCH is concerned that the Two Step Demand Charge does not have the same offset of bill impacts as the Flat Demand Charge for high load factor customers. In addition, a Flat Demand Charge better reflects costs which are flat.
3.	**BCUC staff** We see bill impacts as more of a transition issue and not a rate design issue.	BCH does not agree. Bill impacts have consistently been treated in rate design as a Bonbright customer understanding and acceptance rate design issue.
4.	**COPE 378** How are MGS customers charged for demand?	MGS customers are billed each month for the highest monthly peak. Individual MGS customer peaks may or may not be coincident with the system peak.
5.	**CEC** Is the demand charge monthly due to monthly billing?	The demand charge is expressed as $/kW/month and is billed monthly. The monthly demand reading is a reasonable proxy (and understandable for customers) for assigning customers their contribution of costs.
6.	**COPE 378** BCH should explore different demand charge approaches that better reflect contribution to coincident peak.	In Workshop 11B BCH will discuss a demand option like that of RS 1852 type demand charge with HLH concept which some have described as a Time of Use-like effect. In addition, BCH will be exploring demand ratchets.
7.	**AMPC** We caution that demand is not as simple as looking at a single coincident peak.	Agreed.
8.	**TransLink** Regarding slide 36, can BCH estimate the bill impacts for individual MGS customers?	At the May 2015 sessions described at page 4 of the Workshop 8A/8B Consideration Memo, BCH offered to estimate LGS and MGS customer bills for the SQ rates and alternatives using a simplified forecasting tool (the 'bill estimator'). BCH has used the bill estimator for TransLink accounts.
9.	**BCSEA** Does BCH have the absolute dollar impacts for illustrative bill impacts of both the Flat Demand and two Step Demand alternatives? Is it possible to produce graphs comparing cost causality and bill impacts? We ask because we want to know if the customers with bill impacts are those that drive demand costs.	Yes. This can be easily computed by applying the F2017 illustrative bills under status quo to the illustrative percentage variances of the alternative for each load-factor/annual consumption combination. The illustrative bills under status quo are located on slide 18 in the RDA Workshop 11 Appendix posted to the RDA website. No. The cost of service models and the rates models come from different and independent datasets, each drawn for their respective purposes. Note that costs are not simply driven by load factors and consumption of customer bills, but also by the coincidence factors. Since it is not practical to price rates using coincidence factors or load factors, there will naturally be some disparity between the annual allocators used to assign costs and the effectiveness of monthly customer bill determinants at revenue recovery.

10.	**COPE 378** Does BCH have an analysis with the number of customers impacted?	Yes; refer to the RDA Workshop 11 Appendix posted to the RDA website where the distribution is set out.
11.	**FNEMC** Is it possible to identify those low load factor customers that are worse off under the Flat Demand and Two Step Demand charge alternatives?	The impacted low load factor customers are very heterogeneous and include pumps, schools etc. Refer to the final slide of the RDA Workshop 11 Appendix posted to the RDA website, which has the SQ for each box for estimating bill impacts for these and other customers.
12.	**BCSEA** The very high load factor customers at the lower right hand side on slide 46 look like a separate population. Would segmenting these customers offer a potential solution?	Yes; many of these customers are migrating to the LGS rate class. No. BCH rejects segmenting GS customers on the basis of load factor for the reasons discussed earlier [Refer to Part 3, BCH responses to Q.7 and Q.9]. There is no logical end point to an exercise of creating rate classes or sub-classes for the purpose of mitigating bill impacts arising from rate restructuring. Each adversely affected member of a rate class would have the same basis for a further division of the class, potentially ultimately leading to a rate class for every customer. E3 found as part of its 2009 segmentation analysis that five GS classes were the most BCH could administer.
13.	**CEC** Does BCH agree that high load factor customers use the BCH system more efficiently?	Yes.
14.	**BCUC staff** Is it fair to summarize the two demand charge alternatives as follows: (1) the two alternatives are viewed by BCH about equally; (2) the Flat Demand Charge is better at bill impact offsetting; and (3) the Two Step Demand Charge may be better from a SGS/MGS seams perspective?	Not necessarily. Please see the response to Q.1, Section 5 above.

6. Presentation: Increasing Demand Charge Cost Recovery

Paulus Mau discussed how stakeholders suggested that BCH investigate increasing the MGS demand cost recovery of demand-related costs from the current 15%, and the results of increasing cost recovery to 35% using the MGS Flat Energy Rate with the Flat Demand alternative for illustration. Increasing the MGS demand charge cost recovery reduces bill impacts on MGS high load factor customers.

	FEEDBACK	RESPONSE
1.	**BCOAPO** What is the basis for the LRMC pricing of the SQ MGS two part rate?	The F2006 Call for Tenders, inflated.[4] F2016 MGS two-part baseline energy rate pricing is set out at page 25 of the Workshop 8A/8B Consideration Memo – the Part 2 LRMC based energy rate is 9.90 cents/kWh.

[4] For a summary of LRMC application to BCH rate structures, refer to slide 13 of the 'Introduction and Context' slide deck for Workshop 1; http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/rate-design-application-workshop-presentation-may8-2014.pdf.

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2.	**BCSEA** We are concerned with the impact on the resulting MGS Flat Energy Rate if MGS demand fixed cost recovery is increased to 35% as shown on slide 48; the impact is more significant than increasing the SGS basic charge fixed cost recovery to 45%.	Agreed that there could be an increase in consumption. There is a trade-off between the Bonbright efficiency criterion and the customer understanding and acceptance and fairness criteria. BCH is concerned with the impact of the MGS Flat Energy Rate on MGS high load factor customers, and one mitigation measure is to increase the demand charge fixed cost recovery, which also aligns with the fairness criterion (fair apportionment of costs among customers).
3.	**BCUC staff** Will BCH model increasing cost recovery to 35% using the MGS Flat Energy Rate with the Two Step Demand alternative? Would BCH expect that increasing cost recovery to 35% using the MGS Flat Energy Rate with the Two Step Demand alternative would also soften the bill impacts on MGS high load factor customers?	Yes. BCH may be able to present these modelling results at the 30 July 2015 wrap-up workshop and/or the Workshop 11A/11B Consideration Memo. Yes.

7. Presentation: Two Potential MGS Phase-in Options

Paulus Mau introduced two high-level MGS phase-in options: (1) a 3-year period; and (2) using a 10% bill impact cap. BCH prefers the 3 year phase-in approach for the reasons set out in slide 54.

	FEEDBACK	RESPONSE
1.	**AMPC** What happens to revenues if the 10% bill impact cap is used? Is there lost revenue?	All designs are revenue neutral to the status quo rate. That is, all alternatives are priced to recover the same revenue as the status quo for each of the years simulated, including years during the phase-in period. That is, the rates will incrementally flatten so that the most adversely impacted customer will have a maximum bill impact of 10%, while remaining revenue neutral to the status quo.
2.	**BCOAPO** On slide 57, how many customers have bill impacts over 10%? What is the maximum bill impact under the 3 year phase in option?	For F2017, BCH forecasts about 55 accounts with bill impacts greater than 10%. The customer with the highest bill Impact, calculated as the per cent bill difference between F2016 and F2017, is 31% ($150) The maximum bill impact customer, calculated as the 3-year cumulative per cent bill difference between F2016 and F2019, has a bill impact of 93% ($456).
3.	**FNEMC** For smaller MGS customers, what is the absolute bill impact under the 3 year phase in option?	Please refer to slide 18 of the RDA Workshop 11 Appendix posted to the RDA website, which has the SQ for each box for comparison; this allows readers to do their own calculations. For the most adverse customer with the highest bill impacts on a percentage basis, see response to BCOAPO above.
4.	**BCSEA** Does BCH have any customer input as to whether a quicker – say 1 year – phase-in period is preferred?	Phase-in requests have come from customers whenever a rate structure is changed. The 3 year period is consistent with 2007 RDA and 2009 LGS Application proposals.
5.	**BCOAPO** Has BCH investigated a 'middle ground' between the 3-year period phase-in and the 15+ years required under the 10% bill impact cap option?	Not to date. The 3-year period was chosen on the basis of the 2007 RDA and 2009 LGS Application proposals.

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6.	**BCUC staff** Bill impacts alone should not drive rate design. Here we have about 350 customers, out of a total of about 17,000 for the MGS rate class, with 10% bill impacts.	
7.	**COPE 378** If BCH pursues the MGS Flat Energy Rate, to what extent would it simply reverse the bill impacts arising from the 2009 LGS Negotiated Settlement?	The impacts are not comparable. There would be no reversing of effects if BCH pursues the MGS Flat Energy rate, as the energy rates were not flat prior to 2009 but rather were a declining block structure. Rate shaping of the Part-1 energy charges toward a flat rate was part of the 2009 LGS Negotiated Settlement, subject to a maximum bill impact of 5% above the class average rate change. The 2009 LGS Negotiated Settlement resulted in a transition focused on introducing the two part energy rate with a baseline to the MGS class. Changes to the demand rate structure were not part of the 2009 LGS application.
8.	*Closing Comments*	

Anne Wilson thanked everyone for making the time to participate in the workshop and reminded participants that Workshop 11B addressing LGS rate issues would be held tomorrow, 26 June 2015. Meeting adjourned at 11.45 am.

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TYPE OF MEETING	RDA Workshop 11B
FACILITATOR	Anne Wilson, BCH
PARTICIPANTS	Association of Major Power Consumers of British Columbia (AMPC); British Columbia Old Age Pensioners Organization (BCOAPO), BC Sustainable Energy Association and Sierra Club of Canada BC Chapter (BCSEA), BCUC staff, Canadian Office and Professional Employees Union Local 378 (COPE 378), Chemtrade, CLEAResult, Commercial Energy Consumers Association of British Columbia (CEC), First Nations Energy & Mining Council/Linda Dong Associates (FNEMC), FortisBC Inc. (Fortis), Ivanhoe Cambridge, Thrifty Foods, TransLink, Vancouver Aquarium, Viterra, West Fraser
BC HYDRO ATTENDEES	Shiau-Ching Chou, Allan Chung, Gordon Doyle, Rob Gorter, Paulus Mau, Anne Wilson, Bryan Hobkirk, Craig Godsoe, Jeff Christian (Lawson Lundell)
AGENDA	1. Welcome & Introductions 2. LGS Energy Rate Alternatives 3. LGS Demand Charge Alternatives 4. GS Voluntary Rate Options 5. Other GS Rate Issues – Demand Ratchet and TOD

MEETING MINUTES

ABBREVIATIONS	BCH …… BC Hydro BCUC……BC Utilities Commission CBL……..Customer Baseline Load COS……..Cost of Service CP……….Coincident Peak DSM …… Demand Side Management EC&E……BCH Electricity Conservation & Efficiency Committee FGR…….Formulaic Growth Rule GS………..General Service GWh…….Gigawatt hour HBL……..Historic Baseline HLH…….High Load Hours IPP………Independent Power Producer kW……….Kilowatt	kWh……..Kilowatt hour LGS………Large General Service LLH……..Light Load Hours LRMC…..Long-Run Marginal Cost MGS…….Medium General Service PLB…….Price Limit Bands RDA……..Rate Design Application RS………Rate Schedule SQ……….Status Quo TOD…….Transformer Ownership Discount TRC……..Total Resource Cost TS………Tariff Supplement TOU…….Time of Use rate UCA…….Utilities Commission Act

1. *Welcome and Introductions*

Anne Wilson opened the meeting by reviewing the agenda set out in slide 2 of the Workshop 11B slide deck.

Gordon Doyle stated that BCH does not yet have a preferred alternative for either the LGS energy rate or the LGS demand charge. Gord described the purpose of Workshop 11B, which is to solicit feedback on: (1) what should the preferred LGS energy rate be; (2) what should the preferred LGS demand charge be; (3) BCH's position that GS voluntary rate options form part of RDA Module 2, and the potential options BCH has identified to date; and (4) BCH's proposals for the review timing of the LGS/MGS demand ratchets and the TOD.

2. *Presentation: LGS Energy Rate Alternatives*

Rob Gorter and **Paulus Mau** reviewed the BCH Bonbright assessment of the four LGS energy rate alternatives:(1) SQ LGS Energy Rate; (2) SQ LGS Simplified Energy Rate; (3) LGS Flat Energy Rate; and (4) a TSR-Like Rate for a new class of larger LGS customers (referred to as **XLGS**), which both BCH and AMPC would consider in the context of the LGS Flat Energy Rate alternative for the remainder of the LGS rate class.

Shiau-Ching Chou discussed a number of LGS rate provisions that could be modified or eliminated as part of the SQ LGS Simplified Energy Rate.

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Allan Chung outlined BCH's thinking to date regarding a TSR-Like Rate for a new XLGS rate class.

	FEEDBACK	RESPONSE
1.	**BCSEA** While not advocating for this rate structure, is BCH constrained from examining a declining block energy rate for LGS?	BCH is not constrained, and did examine and then screened out a LGS declining block energy rate on the basis that it is inferior to the four LGS energy rate alternatives, particularly concerning the Bonbright efficiency criterion.
2.	**FortisBC** Is the 800 GWh/year energy conservation forecast number rate structure specific?	Yes; this forecasted number does not include natural conservation.
3.	**COPE 378** The general problem BCH is grappling with is the diversity of the LGS rate class. If there is consensus that the LGS Flat Energy Rate does not perform worse than the SQ LGS Energy Rate on conservation, and BCH is forecasting zero conservation from the LGS Flat Energy Rate, why not pursue the LGS Flat Energy Rate?	
4.	**CEC** We are not sure the main problem is class diversity; there are elements of the SQ LGS Energy Rate that are problematic for conservation such as the three year rolling HBL average. Nonetheless, it seems to make sense to pursue the LGS Flat Energy Rate and then review voluntary rate options that may increase conservation and/or address economic cycle issues, etc.	
5.	**AMPC** AMPC's concern with SQ LGS Simplified Energy Rate and the LGS Flat Energy Rate is the bill impacts on LGS high load factor customers. Yesterday BCH acknowledged that high load factor customers use the BCH system more efficiently. What are BCH's proposals to mitigate these bill impacts?	BCH is exploring demand charge structure alternatives that among other things have the effect of offsetting some of the high load factor customer bill impacts. This is the subject of the next presentation at today's workshop. Another possibility is to increase the LGS demand charge demand cost-related recovery, which is currently about 50%. BCH has not modelled different levels of LGS demand charge cost recovery as the current cost recovery is not unreasonable when compared to the Transmission Service RS 1823 demand charge cost recovery of about 65%. BCH is open to feedback on why the LGS demand charge demand cost-related recovery should be increased, and to what level.
6.	**COPE 378** As a follow-up to AMPC's comment, COPE 378 thinks it would be a mistake to impose a hard constraint such as 'no adverse bill impacts to high load factor customers'. COPE 378 thinks the main inefficiency is coming from the level of the energy charge for big GS customers, and not the LGS demand charge level.	

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7.	**Vancouver Aquarium** The SQ LGS Energy Rate is flawed – it penalizes businesses that are in growth phase. The SQ LGS Energy Rate cost Vancouver Aquarium $80,000 triggered by an efficiency-related project but we also received $200,000 in DSM program incentives for the project. The SQ LGS Energy Rate PLBs do not incent conservation. BCH should flatten the LGS energy rate and look to its DSM programs, which can be better targeted to individual businesses.	The SQ LGS rate was designed to influence decision making to support the efficient use of energy through a price signal that reflects BC Hydro's marginal cost of energy. As a result customers who grow relative to their baseline will see higher bills and those that decrease consumption relative to their baseline will see lower bills. Rates designed to encourage conservation can impact growing customers due to higher energy charges for increased consumption.
8.	**CLEAResult** What is the cost of conservation versus DSM programs? The avoided cost of supply is market.	The avoided cost of supply is not market as a result of section 6 of the *Clean Energy Act*, which requires BCH to be self-sufficient. The avoided cost of supply is thus B.C.-based resources. BCH uses the avoided cost of supply in the TRC test for DSM programs as described in the California Standard Practice Manual[1] to screen DSM. The BCUC's determination of DSM cost-effectiveness for purposes of DSM expenditure schedules submitted under section 44.2 of the UCA is guided by the Demand-Side Measures Regulation, which among other things contains modifications to the TRC test – the Regulation provides for a deemed value of natural gas savings and a deemed non-energy benefit adder of 15 per cent.
9.	**Thrifty Foods** Thrifty Foods has benefitted from the SQ LGS Energy Rate; we think the SQ LGS Energy Rate reduced the payback period for some projects as we received credits. We are concerned that with the LGS Flat Energy Rate there will be no more credits.	
SQ LGS Simplified Energy Rate		
10.	**BCUC staff** Is the SQ LGS Simplified Energy Rate simply 'flogging a dead horse'? Does BCH anticipate that the SQ LGS Simplified Energy Rate can deliver more conservation?	The SQ LGS Simplified Energy Rate was brought forward in response to some LGS customer comments at Workshop 8B that it may be possible to simplify the SQ LGS Energy Rate and that BCH should review a number of the SQ LGS Energy Rate provisions such as TS 82, the prospective growth rule. Nonetheless, the complexity flows from the baseline and the SQ LGS Simplified Energy Rate retains the baseline. It also debatable whether flattening the LGS Part 1 energy rate will make for a clearer price signal.
11.	**BCSEA** We echo BCUC staff's comment; in the end, to the extent complexity is the reason for the SQ LGS Simplified Energy Rate poor conservation performance, SQ LGS Simplified Energy Rate is not likely to solve the problem.	

[1] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects (October 2001); available at California Energy Commission's website at www.energy.ca.gov.

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12.	**Viterra** The statement on slide 17 that moving to annual baselines may create cash flow problems at the end of the year for customers is a red herring. Business customers do annual budgeting and can plan out the cash flow fluctuation ahead of time.	BCH bases this statement from its experience with the 2005 Transmission Service Rate application, but recognizes that cash flow may not be an issue for all LGS customers. Customers who cannot cope with the bill fluctuation can set up the Equal Payment Plan (EPP).
13.	**BCOAPO** Could BCH make either TS 82 or the FGR optional for LGS customers, e.g., if there is a benefit, BCH would put the customer on the particular rule?	Customers' consumption fluctuates throughout the year. BCH will not know whether a customer would benefit from the provisions until the end of the special adjustment (1 year for FGR and three years for TS82).
14.	**TransLink** The 30% threshold is too high for the FGR and TS 82.	
15.	**Vancouver Aquarium** We echo TransLink's concern that the 30% threshold for TS 82 and the FGR is very difficult to meet.	
16.	**Ivanhoe Cambridge** Is the 30% increase in energy consumption over a one year period? If so, it cannot take into account projects that come in phases.	Yes, it is 30% increase in energy consumption over a one year period.
17.	**BCOAPO** Can BCH explain how higher baselines sometimes create higher bills?	When baselines are lower, the 20% price limit band (PLB) is smaller. Additional growth above the PLB is priced at the Part 1 rate. Higher baselines have larger 20% PLBs. Customers with significant growth are likely to have consumption exceeding baselines, even after their baselines are adjusted to be higher. With a larger 20% PLB, more kWhs are being priced at the higher LRMC rate, thus the bill is higher.
18.	**Thrifty Foods** While we are in favor of the SQ LGS Energy Rate, the new accounts 85/15 rate must be changed as it is unfair when there has been no change in operations. What was the reason for the 85/15 rate?	In its 2009 LGS Application, BCH originally proposed that new accounts would pay the Part 1 energy rate for billed consumption for the first 12 months of service with one exception: the last 10% of energy consumed in a monthly billing period would be charged at the Part 2 energy rate, the LRMC-based rate, rather than the Part 1 energy rate. The 2010 Negotiated Settlement Agreement resulted in the current 85/15 rate. There were two reasons for the 85/15 rate – to prevent gaming to obtain a more favorable baseline and to ensure that new accounts were exposed to some sort of LRMC price signal. BCH has heard that a number of LGS customers are concerned with the 85/15 rate for new accounts.
19.	**Ivanhoe Cambridge** We support the BCH proposal on slide 27 of applying 100% Part 1 energy rates to new accounts.	

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20.	**CEC** By Part 1 energy rates, BCH means both Tier 1 and Tier 2? We agree that the 85/15 new accounts rate is problematic.	Yes.
LGS Flat Energy Rate		
21.	**FortisBC** Would the LGS Flat Energy Rate address customer concerns that the SQ LGS Energy Rate 'penalizes' growth?	With the LGS Flat Energy Rate, there are no baseline-related rules, so a customer's consumption relative to their past consumption history is not a factor in determining the energy portion of the bills. All energy consumed will be charged at the same rate.
22.	**Chemtrade** Chemtrade has two chemical plants located in Prince George, B.C. Chemtrade takes service under the LGS rate for the smaller of the two plants. If the baseline is removed, LGS customers may do conservation projects that might not otherwise have done.	
23.	**BCUC staff** It would be helpful if BCH for purposes of the RDA obtained more feedback from LGS customers as to impact of baselines on conservation projects. The LGS Flat Energy Rate seems to look better than either of the SQ LGS Energy Rate or the SQ LGS Simplified Energy Rate. It also appears that the SQ LGS Simplified Energy Rate has many of the same problems as the SQ LGS Energy Rate with the baseline complexity still being there impeding conservation.	
24.	**COPE 378** While the conservation goals have not been met through the SQ LGS Energy Rate, this is not a reason to drop the energy rate to about half the lower end of the LRMC range through the LGS Flat Energy Rate.	The energy rate of 5.94 cents/kWh (F2017) resulting from the LGS Flat Energy Rate is based on revenue neutrality and keeping the demand charge at its current cost recovery. Note that the energy LRMC range is set out at page 7 of the Workshop 8A/8B Consideration Memo, including for F2017 (lower end – 9.54 cents/kWh; upper end – 11.23 cents/kWh).[2] BCH is not clear on what, if anything, COPE 378 is suggesting as an alternative. As set on slide 30, it is not possible to set the LGS Flat Energy Rate at the lower end of the LRMC range as BCH would need to credit customers for demand to maintain revenue neutrality.

[2] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-06-19-bch-rda-wksp-8a-8b-gsrs.pdf.

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25.	**AMPC** We question the origin of the energy LRMC range. We have seen quotes for gas-fired combined cycle gas turbines of about 5 c/kWh. There are differences of option as to whether gas-fired generation is on the margin.	As discussed yesterday, the energy LRMC range results from the approved 2013 Integrated Resource Plan, which found that the two resources types required to fill the energy gap over the next ten years are DSM and IPP contract renewals, and this resulted in a range of 8.5 cents/KWh to 10.0 cent/kWh (F2013). Gas-fired generation is not on the margin for BCH given the section 2 *Clean Energy Act*'s 90% clean or renewable generation energy objective.
TSR-Like Rate		
26.	**Viterra** Would BCH employ the concept of revenue neutrality for a XLGS rate class taking service under the TSR-Like Rate?	BC Hydro would review the application of revenue neutrality and bill neutrality to a XLGS rate class to ensure pricing principles are appropriate to the rate design.
27.	**BCOAPO** How does the number of accounts at a breakpoint of 2,000 kW compare to the RS 1823 number of about 140 accounts?	This information is set out at page 44 of the 8A/8B Consideration Memo for a number of peak demand breakpoints; a 2,000 kW breakpoint results in 172 LGS accounts.
28.	**CEC** Has BCH undertaken analysis of the 172 accounts using the 2,000 kW breakpoint?	***Revised Response*** The general sector classification of the 172 accounts is as follows in the table below: (see table below)
29.	**CLEAResult** Given that a TSR-Like Rate would have annual baselines, public institutions and municipal governments may have end of year cash flow problems.	

Sector	#	% of Total
Transportation	14	8%
Commercial	18	10%
Government & Institution	26	15%
Property	25	15%
Industrial	35	20%
Wood	41	24%
Other Resource	13	8%
Total	172	100%

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BC Hydro Rate Design Workshop

SUMMARY 26 JUNE 2015 9AM TO 2.30 P.M. BCUC Hearing Room 1125 Howe Street, Vancouver

30.	**COPE 378** A TSR-Like Rate may be a bad fit for public institutions. BCH should consider segmenting the LGS rate class and creating a new class of government and public institutions.	BCH does not see a cost of service basis for this kind of segmentation. Based on the jurisdictional analysis for GS segmentation discussed yesterday, BCH is not aware of Canadian electric utilities segmenting government and public institutions from the rest of the GS classes. However, Yukon Electric has separate GS rate schedules for the federal and territorial governments in its service area.[3]
31.	**BCOAPO** Regarding slide 33 and the potential conservation savings of about 200 GWh, what is the basis for the assumption of accounts consuming at 90%?	The assumption is based on RS 1823.
32.	**West Fraser** What is the LGS equivalent of the 2,020 GWh figure on slide 33? We do not see the cash flow issue as a con as noted on slide 34; it can be a pro to pay at the end of the year.	It is about 19% of total LGS class load. Noted. BCH's main concern with the TSR-Like Rate is the administrative burden as outlined on slide 34.
33.	**Viterra** We don't see the administrative issues as significant hurdle for the TSR-Like Rate, particularly if the TSR-Like Rate is extended to only 170 or so accounts.	
34.	**CEC** Importing the concept of the RS 1823 dead-band may result in a loss of the LRMC signal. This issue is more complex than shown on slide 33.	BCH has only begun exploring a TSR-Like Rate in responses to comments from AMPC and Viterra provided in respect of Workshop 8B.
35.	**COPE 378** The LGS Flat Energy Rate energy price is too low, and in our view, this is the only reason for examining a TSR-Like Rate. However, there are problems with RS 1823 – it seems easy to save at 10%. The administrative issues look significant. BCH should explore if there other ways to induce conservation for LGS while pursuing the LGS Flat Energy Rate.	

[3] https://www.yukonenergy.ca/customer-centre/commercial-wholesale/rate-schedules/.

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BC Hydro Rate Design Workshop

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36.	**AMPC** Consumption at or around 90% of CBL does not mean RS 1823 is not working or delivering conservation. AMPC proposed a TSR-Like Rate for large LGS customers with peak demand of 2,000 kW because: (1) it recognized that extending a TSR-Like Rate to all LGS accounts is not viable; (2) the 2,000 kW breakpoint limits the administrative issues – 170 accounts is comparable to the current RS 1823 140 or so accounts. In addition, many of the larger LGS customers are served by distribution due to 'accidents of geography' but are more akin to BCH Transmission Service customers. Finally, a TSR-Like Rate has the potential to incent conservation from those LGS customers most able to respond. Note also that AMPC proposed a TSR-Like Rate to work with the LGS Flat Energy Rate for the remainder of the current LGS class.	Agreed that the overall administrative burden falls if the TSR-Like Rate is coupled with the LGS Flat Energy Rate. BCH would be opposed to a TSR-Like Rate together with either the SQ LGS Energy Rate or the SQ LGS Simplified Energy Rate.
37.	**Viterra** Note that with the coming to an end of the persistence of DSM projects, the RS 1823 Tier 2 rate will come back into play as customers begin to consume above 90% of CBL.	Agreed that going forward, more Transmission Service customers are like to see the RS 1823 Tier 2 rate due to DSM persistence.
38.	**BCUC staff** We heard in Workshops 8A/8B and this workshop that some LGS customers have conserved under the SQ LGS Energy Rate, but that a larger portion has not. How many of the LGS customers who stated that they have conserved would migrate to a TSR-Like Rate and continue with conservation?	BCH will seek this feed-back.
39.	**BCUC staff** It appears a TSR-Like Rate could address the problem of bill impacts to high load factor customers associated with the LGS Flat Energy Rate.	This is not clear to BCH at the present time. For example, BCH has not yet examined the bill impacts for the remainder of the LGS rate class under a LGS Flat Energy Rate after segmenting and creating a XLGS class and implementing a TSR-Like Rate.

3. Presentation: LGS Demand Charge Alternatives

Rob Gorter and **Paulus Mau** reviewed the BCH Bonbright assessment of the three LGS demand charge alternatives: (1) SQ Demand Charge; (2) Flat Demand Charge; and (3) Two Step Demand Charge, which retains the current zero Tier 1 and flattens Tier 2 and Tier 3 into a single Tier 2.

	FEEDBACK	RESPONSE
1.	**BCUC staff** In terms of pursuing a Flat Demand Charge, many of the high load factor accounts in the lower right of slide 42 would migrate to a TSR-Like Rate and this could be a mitigation measure.	BCH has not modelled the level of demand charge cost recovery or other aspects of the TSR-Like Rate and so is not able to conclude what its effects are.

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2.	**CEC** Is it the Flat Demand Charge that is causing the high load factor customer bill impacts? CEC wishes to engage with BCH to explore if there are additional ways to mitigate the high load factor customer bill impacts.	No, it is the flattening of the SQ LGS Energy Rate Part 1 energy rates which causes the high load factor customer bill impacts; the Flat Demand Charge somewhat offsets these bill impacts.
3.	**COPE 378** Has BCH considered using HLH/LLH concepts for a LGS demand charge which would better reflect the marginal cost?	Yes; one demand charge option that is the subject of the next presentation at today's workshop is to charge customers for peak HLH only.
4.	**BCSEA** In BCH's view, which of the Flat Demand Charge and the Two Step Demand Charge better reflects cost causality?	The Flat Demand Charge. Refer to section 5.2 of the Workshop 8A/8B Consideration Memo for additional details.

4. Presentation: GS Voluntary Rate

Rob Gorter set out BCH's position that GS voluntary rate options should form part of Module 2, as BCH believes that the GS default rates need to be set first through Module 1 before customers can make decisions about voluntary rate options. Rob also outlined the four GS rate options BCH has considered to date in conjunction with CEC: (1) TOU rate; (2) interruptible rates; (3) Efficiency Rate Credit; and (4) three demand charge options.

	FEEDBACK	RESPONSE
1.	**COPE 378** Has BCH considered a default LGS rate which would have a significantly lower energy rate for LLH and a higher HLH rate?	In BCH's view, this option is essentially a mandatory TOU rate which is contrary to B.C. Government policy.
2.	**FNEMC** Would BCH open up the optional Transmission Service freshet pilot to GS customers if the pilot is deemed a success?	Yes, this is something BCH would consider.
3.	**BCUC staff** BCH should consider testing GS interruptible rate options through pilots to see what actual take-up is.	
4.	**CEC** We urge caution in using the pilot demonstration approach for interruptible rate options. GS customers will want some certainty for their investments. It appears that the interruptible rate options will require separate metering. GS customers will want to know what the probability is of interruption and for how long.	Not necessarily for option 3 on slide 58. The timing and length of interruptions and other necessary design parameters are considerations that BC Hydro would review in RDA Module 2 in consultation with customers and stakeholders.

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5.	**BCOAPO** Are the three interruptible rate options set out on slide 58 meant to address Transmission and/or Distribution constraints?	Yes with respect to Option 1; BCH is exploring a RS 1852-like option with CEC and to date has focused on Delta in the Lower Mainland as this is where GS greenhouse growers are located, which CEC advised are interested in interruptible rates. BCH does not see any Transmission constraints in the Delta area but is investigating if there are Distribution constraints. Option 3 is more likely aimed at Generation capacity resource displacement and so the credit could be based on the avoided cost of Generation capacity resources such as Revelstoke Unit 6 or gas-fired Simple Cycle Gas Turbines.
6.	**CEC** CEC proposes to explore the Efficiency Rate Credit concept as part of Module 2 but slide 61 shows a timeline out to 2020-2030. CEC would like a discussion on what can be done before arriving at an efficiency-based price signal; CEC raised this same issue at the May 2015 EC&E meeting and this slide has not changed.	Slide 61 shows that a considerable amount of work is needed for an efficiency price signal. BCH will continue liaising with CEC at EC&E regarding this, and is proposing to explore CEC's Efficiency Rate Credit as part of Module 2. As part of this, BCH wants to know what the advantage of a credit approach is as compared to DSM programs; in other words, the appropriate mechanism may not be a rate.
7.	**BCUC staff** We are interested in more information concerning Manitoba Hydro's Limited Use of Billing Demand option.	***Revised Response*** Set out below is a link to Manitoba Hydro's report to the Manitoba Public Utilities Board concerning its Limited Use of Billing Demand option for 2013/2014.[4] Note that a key aspect of the option is that it is for low load factor customers with low coincidence.
8.	**CEC** We encourage BCH to explore demand charge options beyond those listed on slide 62 as we have heard from greenhouse growers in particular they have concerns with the current MGS and LGS demand charge structure.	BCH will discuss with CEC what other options CEC is thinking of, and what the rationale for those options may be.
9.	**CLEAResult** Since 4 CP is such a large BCH cost item, has BCH explored seasonally-based demand charges?	BCH found through its jurisdictional assessment that other Canadian electric utilities typically have flat or two step demand charges for larger GS customers. Nevertheless, a seasonally-based demand charge is close to the demand ratchet BCH will be discussing as part of the next presentation at today's workshop.

5. Presentation: LGS/MGS Demand Ratchets and TOD

Rob Gorter outlined BCH's proposals for examining the MGS and LGS demand ratchets as part of Module 1 as they are integral part of these default rates, and for reviewing the TOD as part of Module 2 as it more closely relates to Distribution extension policy.

	FEEDBACK	RESPONSE
1.	**FNEMC** The amount of revenue collected through demand ratchets. What is the rationale for demand ratchets?	Demand ratchets ensure a minimum contribution from those customers with high winter peak consumption and little consumption the rest of the year.

4 https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/pdf/appendix_6_12.pdf.

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2.	**BCOAPO** Can the COS provide insight into the TOD?	The TOD represents the estimated capital cost of transformation that BC Hydro would incur if BC Hydro was responsible for providing transformation . The analysis of TOD is more of an avoided cost as opposed to embedded cost approach.
6.	***Closing Comments***	
Anne Wilson thanked everyone for making the time to participate in the workshop and reviewed the ways that feedback can be submitted to BC Hydro. The 30 day written comment period commences for both Workshop 11A and Workshop 11B with the posting of the Workshop 11B summary notes on July 13, 2015. Meeting adjourned at 2.30 PM.		

2015 Rate Design Application

June 25, 2015/June 26, 2015

Workshop Nos. 11a and 11b

Large General Service (LGS)

Medium General Service (MGS)

Small General Service (SGS)

Rate Structures

BC Hydro Summary and

Consideration of Participant Feedback

Attachment 2

Feedback Forms and Written Comments

Association of Major Power Customers of BC (AMPC)

Further Submissions re LGS Demand and Energy Charges

July 27, 2015

I. INTRODUCTION

1. In this submission, AMPC provides additional comments on BC Hydro's large general service (LGS) "flattened" rate alternatives.

2. AMPC supports a flattened, no baseline alternative ("Flat Part 1 Energy + Flat Demand, no baseline") provided that the proportion of demand and energy charges is revised to recover a substantially greater portion of demand related costs from demand charges. AMPC also supports the "TSR-like rate" proposed by BC Hydro on June 26, for loads greater than 2 MW. AMPC considers that option complementary, and not mutually exclusive, to this proposal.

3. AMPC's proposal is pragmatic and consistent with RS 1823. It would moderate the rate shock that BC Hydro's proposed alternatives would create for some industrial customers.

II. BACKGROUND

4. Direction 19 in the 2007 Rate Design Application (RDA) Decision directed BC Hydro to develop rates for existing LGS customers that would encourage conservation and not unduly harm or benefit its customers. BC Hydro entered into a Negotiated Settlement Agreement (NSA) in 2010 to meet these requirements, and established two part energy rates for LGS. BC Hydro's consultation materials explain BC Hydro's current view, that the LGS rates were complex, causing customers to have difficulty understanding them, and had only a limited impact on conservation.[1]

5. BC Hydro examined four "Bonbright" criteria as part of its analysis when it concluded its previous LGS rate approach was inadequate:

(i) economic efficiency, including a price signal that encouraged efficient use and discouraged inefficient use;

(ii) fairness, including fair apportionment among customers and avoiding undue discrimination;

[1] BC Hydro 2015 Rate Design Application Workshop 11A Presentation dated June 25, 2015, slide 8.

(iii) practicality, including customer understanding and acceptance; and

(iv) stability, including recovery of the revenue requirement, revenue stability and rate stability.[2]

6. In AMPC's view, the LGS rates established under the NSA did not follow the first and third criteria because they had only a limited conservation impact and were difficult to understand, by all but the most sophisticated customers.

7. In the current rate design process, two prominent BC Hydro alternatives include a flat energy charge of $0.0576/kWh and a flat demand charge of $8.07/kW (one with a baseline second calculation, and one without).[3] BC Hydro identified a number of benefits to a no baseline approach:[4]

(i) Customer understanding and acceptance because the approach is easier to understand and less complex.

(ii) Fairness through a better reflection of demand costs and a more equitable distribution of fixed costs among customers of different sizes.

(iii) Improved practicality through a significant reduction in time to manage bill adjustments and information technology time.

8. However, BC Hydro also identified drawbacks to such an approach:

(i) Some customers will experience large bill impacts.

(ii) One-time administrative costs to change billing procedures.

(iii) Economic efficiency effects that may reduce conservation and cause the marginal energy rate to be below the lower end of the long run marginal cost (LRMC) range.

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[2] BC Hydro 2015 Rate Design Application, Session 1: Existing Rate Structures Presentation dated January 21, 2015, slide 65.
[3] BC Hydro 2015 Rate Design Application, Session 2: Alternative Rate Structures dated February 11, 2015, slide 19.
[4] BC Hydro 2015 Rate Design Application, Session 2: Alternative Rate Structures dated February 11, 2015, slides 20-21.

III. PROPOSAL

9. AMPC generally supports BC Hydro's use of flattened energy and demand charges with no baseline. Such an approach is simpler, more transparent, easier to understand and more efficient than the status quo and the other alternative rate options. Demand charges should, in any event, always be single tier.

10. According to BC Hydro, LGS demand charge revenue only recovers about 50% of the demand charge related costs as determined by the Fully Allocated Cost of Service (FACOS) study. BC Hydro has not identified any principled basis for the current split in cost recovery through the energy charge and the demand charge, and relies on its historic usage of this ratio and the absence of participant objections to its use as its basis for the ratio's continued usage.[5]

11. BC Hydro's data demonstrates that maintaining the 50/50 split creates unfair distributional impacts across LGS customers depending on load factor and annual consumption.[6] Many of the lowest load factor customers see bill decreases between 7 and 9%, while the highest load factor customers see bill increases between 10 and 12%, despite there being no principled basis to limit demand cost recovery by demand charges to 50%. Low load factor customers whose use of facilities is relatively inefficient get a windfall relative to the status quo rate option, at the expense of high load factor customers, who use the infrastructure more efficiently.

12. AMPC disagrees with BC Hydro's choice of energy and demand charges, and earlier provided an illustrative industrial customer example with a reduced energy charge of $0.0521/kWh and an increased demand charge of $10.075/kW (see Appendix A). That structure better balances demand costs with demand rates and would reduce the negative impact of the proposed rates, as well as better meet the Bonbright standard of efficiency.[7]

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[5] BC Hydro 2015 Rate Design Application, BC Hydro Summary and Consideration of Participant Feedback dated January 21, pp. 50-51.

[6] BC Hydro 2015 Rate Design Application, Session 2: Alternative Rate Structures dated February 11, 2015, slide 64.

[7] AMPC also earlier proposed a tiered (two part) energy structure for either a "Super Class" of LGS customers with loads at or above 2MW, or that a new rate class be established for that characteristic. In either case, the rate would feature a Customer Base Line (CBL) that is set and adjusted on an annual basis similar to the CBL process currently used for RS 1823 customers. AMPC continues to support that option, in addition to this proposal. Doing so would preserve a dynamic energy conservation signal for the largest general service customers familiar with the TSR/CBL procedures and most able to understand and respond to the sophisticated energy conservation price signal, and who have the potential to make the greatest conservation impact.

13. Increasing the demand charge proportion of LGS rates better matches the demand related costs identified in the FACOS study. It is also directionally consistent with the Transmission Service Rate (TSR) customers' demand charge cost recovery of approximately 65%.[8]

14. AMPC's earlier illustrative $10.075/kW demand charge (Appendix A) would recover roughly 60% of demand related costs, and is consistent with the demand charges in other jurisdictions in Canada that BC Hydro has presented. It therefore fits within an appropriate range.[9] This is also the case if it is increased by about 10% further to recover ~65% of demand related costs, consistent with TSR demand cost recovery.

15. AMPC submits that increasing the demand charge proportion for the flattened/no baseline alternative better satisfies the four Bonbright criteria used by BC Hydro to evaluate the status quo LGS rate, identified earlier. By reducing bill impacts the approach is more fair, more pragmatic, and has no adverse effects on rate stability. For the reasons mentioned below, the revision would also send a better conservation signal, and hence better satisfy the economic efficiency criterion. .

16. A potential criticism of increasing the proportion of demand costs recovered by demand charges is that the energy price would decline (e.g., by approximately 10% in the illustrative example provided earlier in Appendix A), limiting the conservation signal that the energy rate would send. In response, AMPC notes that (i) BC Hydro's research shows that total bill impact drives behaviour, rather than bill components,[10] and (ii) a modest decline in the energy rate would have little effect on its conservation signal in any event.

17. To the extent that bill components influence behaviours, in AMPC's view demand charges also transmit an important efficiency and conservation signal. Benefitting low load factor users at the expense of high load factor users sends the wrong conservation signals to customers and reverses any incentive to shift from low load factor usage to high load factor usage, which over time increases the demand on the electric system as a whole to match peak demand requirements. This increases the need for new infrastructure, and reduces the use of infrastructure already in place.

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[8] BC Hydro Rate Design Workshop Summary Notes dated June 26, 2015, p. 2.
[9] BC Hydro 2015 Rate Design Application Workshops 11A and 11B, Appendix dated June 25-26, 2015, pp. 2-3.
[10] BC Hydro 2015 Rate Design Application, Session 1: Existing Rate Structures Presentation dated January 21, 2015, slide 48.

18. In the planning process, long-run marginal costs expressed as unit energy costs ($/MWh – presuming all the costs of development are variable) are frequently used to summarize the comparative costs of alternative sources in a highly simplified manner for ranking of new resource choices. In transferring this simplified unit energy cost concept to rate design, care must be taken to not lose sight of the reality that most of the marginal costs of supply are fixed costs and not variable costs. Demand charges are therefore an important price signal for efficiency. They reflect the high proportion of marginal (as well as embedded) costs that do not vary with hourly energy usage. High load factor customers responding to higher demand charges not only use existing facilities more efficiently, but also reduce the need for future (marginal) facilities. Marginal cost in rate design should not only focus on energy rates, and the significance of demand rates in providing efficiency signals should not be neglected.

19. In summary, the rate system for LGS customers should send well-accepted signals, and incentivize a shift from low load factor use to high load factor use. Under BC Hydro's proposed flattening options, this can only occur by varying the split in cost recovery between energy and demand charges.

IV. CONCLUSION

20. For the reasons above, AMPC suggests that BC Hydro revise its LGS rate demand charges to recover 65% of demand costs, to match the TSR proportion. This is directionally consistent with the earlier example of proposed energy and demand rates of $0.0521/kWh and $10.075/kW, respectively. AMPC's proposal is superior to the alternatives proposed to date by BC Hydro, having similar positive attributes but fewer negative attributes, and should be adopted in the forthcoming Rate Design Application.

APPENDIX A

BC Hydro has proposed a demand charge of $8.07 /kW and a commodity charge of $0.0576/kWh for its "Flat Part 1 Energy + Flat Demand, no baseline" option. AMPC suggests pricing the same scenario at a demand charge of $10.075/kW and a commodity charge of $0.0521/kWh.

Based on a sample calculation for a customer with a 2 MW demand, 30-day month, and 75% load factor (i.e., 1,080 MWh consumed):

- BC Hydro's proposed $8.07 /kW and $0.0576/kWh figures result in:
    - a cost increase of 2.59% for 75% load factor customers, relative to RS 1611; and
    - a cost decrease of 4.65% for 30% load factor customers, relative to RS 1611.

- Using AMPC's proposed $10.075/kW and $0.0521/kWh figures result in:
    - no cost increase compared to RS 1611 for 75% load factor customers; and
    - a cost decrease of 1.10% compared to RS 1611 for 30% load factor customers.

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2015 Rate Design Application (RDA) – General Service Rates Workshop 11, Sessions A (June 25, 2015) and B (June 26, 2015) Feedback Form

Name/Organization: AMPC

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Workshop 11A: Segmentation, SGS and MGS	
A. Cost of Service Analysis: Segmentation Methodology (Slides 17 to 21 of June 25, 2015 Workshop 11A Presentation). BC Hydro discussed two methods of segmentation: Method 1: BC Hydro took samples of 1,000 customers from each of SGS, MGS and LGS classes; F16 Forecast costs assigned to GS rate classes pooled and re-allocated pro rata by individual customer kWh, 4 Coincident Peak (CP) demand, and Non-Coincident Peak (NCP) demand. Results of method 1 not conclusive: • NCP allocation varies depending on coincidence within classes. • Coincidence is better correlated with cost than customer size. • Transformer cost may vary with size but cost impact is small. Method 2: Consider cost allocation based on pre-assigned segments of customers. Customers will be grouped by size as opposed to evaluated individually – to be reviewed at July 30, 2015 wrap-up workshop. **BC Hydro seeks stakeholder feedback on what other analysis of segmentation should be conducted. Please provide any comments in the column to the right.**	

<table>
<tr><th colspan="2">Workshop 11A: Segmentation, SGS and MGS</th></tr>
<tr><td>B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation)

BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%.

Results:
• Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery
• Resulting energy rate remains within the LRMC and without substantial bill impacts

BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.</td><td>The SGS basic charge should be increased to better match the allocated costs.

Less emphasis should be placed on LRMC reflecting uncertainty of LRMC evaluation, its variation over time, and its appropriateness as a purely variable charge.</td></tr>
</table>

**2015 Rate Design Application (RDA) –
General Service Rates Workshop 11, Sessions A (June 25, 2015)
and B (June 26, 2015) Feedback Form**

Workshop 11A: Segmentation, SGS and MGS

C. MGS Demand Charges 1. BC Hydro presented three alternatives for demand charges: i. Status Quo ii. Alternative A - flat demand charge + flat energy rate iii. Alternative B – two step demand charge + flat energy rate **BC Hydro seeks feedback on which of the three demand charge structure alternatives is preferred (with reasons). Please provide any comments in the column to the right.**	The flat demand charge and flat energy charge is strongly preferred for simplicity, ease of understanding, bill stability (as customer usage changes) and comparability to rates of other utilities.
2. Stakeholders requested BC Hydro model increased MGS demand charge cost recovery; BC Hydro modeled increasing the MGS demand cost recovery of flat demand from approximately 15% to 35% for Flat Energy Rate/Flat Demand Charge Alternative **BC Hydro seeks feedback on whether the MGS demand charge cost recovery should be increased, and if so to what level (with reasons). Please provide comments in the column to the right.**	The principle of efficient use is still met. Simple flat energy and demand charges encourage efficiency by setting a price on both demand and energy that encourages both energy conservation and more efficient use of existing and future infrastructure. The MGS demand charges should be increased as they do not adequately capture the full demand cost. This is as much an efficiency consideration as the level of energy cost recovery.
3. BC Hydro considered Transition Strategies for moving to a flat energy rate, and flat demand charge: • three-year phase–in • 10% bill impact Cap **BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.**	A three year phase-in is preferred. This is an easily administered and commonly adopted approach that meets the principles of rate stability and customer understanding/acceptance.

Workshop 11B: LGS Rate Structure	
A. Preferred LGS Rate Structure (Slides 9 to 54 of Workshop 11B Presentation) **BC Hydro is seeking stakeholder feedback on which of the four energy rate structure alternatives and the three demand charge structure alternatives are preferred, and why. Please provide any comments you have in the column to the right.** **Energy rate alternatives:** 1. Status Quo LGS Energy rate (retain baseline) 2. Simplify energy rate structure (retain baseline): A. Flatten Part 1 Energy Rate B. Consider modify Baseline Rate Provisions: i. Determination of baselines (monthly versus annual versus rolling average, etc.) ii. Price limit bands (PLBs) to address concerns that rates are 'punitive to growing customers', and/or to encourage further conservation iii. Growth rules to make less restrictive iv. New account rules 3. LGS Flat Energy Rate (remove baseline structure) 4. LGS Flat Energy Rate for majority of LGS customers and create TSR-like rate with individually administered baselines for segment of very large LGS customers **Demand Charge alternatives:** 1. Status quo inclining three-step demand charge 2. Flat demand charge 3. Two-step demand charge	A flat demand and flat energy rate for the majority of LGS customers with a TSR-like two tier energy rate for very large (greater than 2MW) "XLGS" customers is strongy preferred (Option 4). The flat demand and flat energy rate should be adopted for most LGS customers for the same reasons it is recommended for MGS customers. Consistent with its earlier separate submission, AMPC recommends increasing the demand charge cost recovery to a proportion consistent with the TSR rate class. XLGS customers are significantly larger than typical LGS customers, fewer in number, and have more in common with the TSR class. The 25KV voltage level of service reflects an accident of geography rather than a significant difference in electrical characteristics, and these are customers that tend to own their own substations. XLGS customers are large and sophisticated enough to better respond to the two tiered energy price signal, if they also have the flexibility of a CBL rather than a rigid HBL determination. Many XLGS customers are also TSR customers and sufficiently familiar with the tiered energy and CBL concept to effectively respond to the efficiency signals that have been refined through the TSR CBL process for the last decade.

Workshop 11B: LGS Rate Structure

B. Flatten Part 1 Energy Rate (Slide 16 of June 26, 2015 Workshop Presentation)

Flat Part 1 energy rate would be nominal simplification, as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers:

- More customers better off than worse off, higher consuming customers have more adverse bill impacts

BC Hydro is seeking feedback on this option to flatten Part Energy Rate. Please provide any comments in the column to the right.

Anything other than a simple flat demand and energy charge with no baseline is too complex to be effective for most of the LGS class – particularly those below 2MW. Those above 2MW are more efficiently and fairly served using a version of the TSR two tiered energy rate with CBL, rather than HBL determinations.

C. Baseline Rate Provisions

(i) Baseline determination (slide 17 of 26 June Workshop 11B presentation)

- BC Hydro considered baseline determination on annual basis versus monthly baseline calculation, and
- Considered determining one-year and five-year rolling average baselines, versus status quo determination of three–year rolling average monthly baselines

Annual baseline could create cash flow burden for many customers at year end. five-year rolling average baselines will further increase the complexity of the rate; one-year baselines could cause bill instability as unusual consumption months cannot be levelled in baselines.

If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right.

HBL was adopted for the GS class as it would have been administratively infeasible to implement the superior CBL approach as developed over many years for the TSR. There are so few XLGS customers that the more adaptive CBL approach becomes administratively feasible.

(ii) Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation)

PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/- 10%) and increasing the PBL (i.e. +/-30%)

BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback.

If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB shoud be modified and if so,how. Please explain your response in the column to the right.

The concept of PBL is too complex for the LGS rate class and creates bill instabilities. Changes other than elimination would only make matters worse.

<table>
<tr><th colspan="2">Workshop 11B: LGS Rate Structure</th></tr>
<tr><td>(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation)

The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh.

Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption.

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.</td><td>None of the administratively burdensome procedures such as FGR or anomaly rules are necessary if the LGS rate is simplified to remove the two tiered approach and this is reserved for XLGS customers above 2MW.</td></tr>
<tr><td>(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation)

In calculating HBLs, anomalously low consumption months from previous years are excluded:

• In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded
• Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule
• Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right</td><td></td></tr>
</table>

Workshop 11B: LGS Rate Structure

<table>
<tr>
<td>
(v) Growth Mitigation – Prospective Growth Rule (TS82) (Slides 24 to 25 of Workshop 11B Presentation)
Customers who anticipate ‘significant’, ‘permanent’ increases in energy consumption may apply to BC Hydro for modified pricing under TS 82 that may reduce their energy costs. Significant means a prospective first year annual increase in energy consumption totaling at least 30% or 4,000,000 kWh above the historical three-year average annual consumption. Permanent means arising from a significant capital investment.

Very few customers have applied due to high thresholds
Customers with lower consumption might meet the 30% threshold but may not benefit from the modified pricing structure
High administrative cost to BC Hydro

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Prospective Growth Rule and if so, what. Please explain your response in the column to the right
</td>
<td>Please see above comments on simplification of the LGS rate structure.</td>
</tr>
<tr>
<td>
(vi) New Accounts (85/15) (Slides 26 to 27 of Workshop 11B Presentation)

85/15 applies when a new account is set up in BC Hydro’s billing system, regardless of whether there were changes in customers’ operation
First 85% of energy consumed in a monthly billing period is charged at the Part 1 rate. Last 15% of energy consumed in a monthly billing period is charged Part 2 LRMC rate
Established to prevent customers from ‘gaming’ by opening new accounts to reset baselines

BC Hydro found no evidence of “gaming” in the LGS Three-Year Report. Customers raised concerns that 85/15 rate unfairly penalizes customers who have no change in operations during account ownership transfers.
If the baseline structure is maintained, BC Hydro would recommend applying 100% Part 1 rates for new accounts, and is seeking further stakeholder feedback. Please provide any comments in the column to the right.
</td>
<td>Please see above comments on simplification of the LGS rate structure.</td>
</tr>
</table>

Workshop 11B: LGS Rate Structure

<table>
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<td>

D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation)

Option: Flatten LGS Energy rate for all consumption levels

Pros:

- Eliminates all complexity from baseline component of status quo LGS energy rate
- Easier and more accurate customer forecasting
- Improved customer understanding
- Aligns with other Cdn. Jurisdictions

Cons:

- Energy rate is well below lower end of energy LRMC

Observations:

- Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b
- There are bill impacts from flattening Part 1 Energy rates; typical customers better off
- No change in conservation – zero forecast for planning purposes

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.

</td>
<td>

This is by far the preferred option, as long as an XLGS rate is created for those above 2MW of billing demand as discussed above. Please refer to AMPC's earlier separate submission.

An energy rate "well below the lower end of energy LRMC" is not a significant detraction for the following reasons:

1. The LGS class is currently showing no significant conservation response – even at the higher second tier energy rate.
2. Customers respond to the total bill rather than individual components such as energy.
3. LRMC is not simply a variable cost that directly translates to an energy rate. LRMC involves significant fixed costs. Demand charges on the LGS rate are also too low.
4. LRMC is a planning concept that changes as markets, technology, and legislation changes, and is not known with the precision suggested in setting rate design limits.

</td>
</tr>
</table>

<table>
<tr><th colspan="2">Workshop 11B: LGS Rate Structure</th></tr>
<tr>
<td>
E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation)
Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers
Rate may have following elements based on BC Hydro's existing TSR – RS 1823:

Available to large LGS accounts
Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate:
5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year
10.10 cents/kWh applied to all kWh above 90% of customer's CBL in each billing year
Initial annual CBL determined by historic baseline year(s)
Allowable adjustments for DSM, plant capacity increases and force majeure
Annual CBL approved each year by BCUC

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.
</td>
<td>This is AMPC's preferred option for reasons already stated above.</td>
</tr>
</table>

Workshop 11B: Optional Rates and Other Issues	
A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation) **1. Voluntary Time of Use Rates** • BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo **2. Interuptible Rates** • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **3. Efficiency Rate Credit concept** • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **4. Demand Charge Options** • BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined **BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.**	AMPC agrees with these proposals.

Workshop 11B: Optional Rates and Other Issues	
B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation) **1. Minimum Charges (Demand Ratchet)** Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March) Ratchet was reduced from 75% to 50% effective April 1, 1980 Based on F14 data: • MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%) • LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%) **BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.**	There is insufficient information provided on the impact, distribution, or effectiveness of various ratchet mechanisms, percentage levels or waiver arrangements to provide any constructive feedback at this time on this rate design issue.

<table>
<tr><th colspan="2">Workshop 11B: Optional Rates and Other Issues</th></tr>
<tr><td>2. Transformer Ownership Discount (TOD) and Transformer Rentals
• TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential
• Last review of $0.25 /month discount was completed in August 2004

BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right.</td><td>As these issues have been deferred to module two and little data or discussion has been presented so far, comment would be premature.

A thorough review of system extension and contribution policy for transmission and distribution (including ownership of lines and third party access) is critical to support rational and efficient economic development in BC. AMPC looks forward to engaging in this discussion and sharing our extension policy experience and ideas over the next few months.</td></tr>
<tr><td>F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision.

Design Considerations:
• At-home charging (Residential)
• Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power)
• Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California ‘super off-peak’ concept to encourage late night to early morning charging?
• Requirement of a separate meter?
• Interaction with RIB?
• Other?

BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.</td><td>EV charging would be an end-use rate that must be designed to recover its full cost of service, including the provision of any specific equipment such as higher capacity distribution facilities. There is ample time prior to module two of the RDA to discuss the precise form and desirability of an EV rate, as opposed to the RIB or a generic TOD rate and if it would have a significant effect on the rate of EV penetration. The desirability, impacts and costs of “electrification” in order to reduce 3rd party GHGs is itself an issue that deserves thorough discussion before the design of further end-use rates.</td></tr>
</table>

Additional Comments:

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:____Richard Stout____Date: _2015:08:17_______________________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

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Form available on Web: http://www.bchydro.com/about/planning_regulatory/regulatory.html

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BC hydro FOR GENERATIONS

2015 Rate Design Application (RDA) – General Service Rates Workshop 11, Sessions A (June 25, 2015) and B (June 26, 2015) Feedback Form

Name/Organization: BC Sustainable Energy Association and Sierra Club of BC – 29 July 2015

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Workshop 11A: Segmentation, SGS and MGS	
A. Cost of Service Analysis: Segmentation Methodology (Slides 17 to 21 of June 25, 2015 Workshop 11A Presentation). BC Hydro discussed two methods of segmentation: Method 1: BC Hydro took samples of 1,000 customers from each of SGS, MGS and LGS classes; F16 Forecast costs assigned to GS rate classes pooled and re-allocated pro rata by individual customer kWh, 4 Coincident Peak (CP) demand, and Non-Coincident Peak (NCP) demand. Results of method 1 not conclusive: • NCP allocation varies depending on coincidence within classes. • Coincidence is better correlated with cost than customer size. • Transformer cost may vary with size but cost impact is small. Method 2: Consider cost allocation based on pre-assigned segments of customers. Customers will be grouped by size as opposed to evaluated individually – to be reviewed at July 30, 2015 wrap-up workshop. **BC Hydro seeks stakeholder feedback on what other analysis of segmentation should be conducted. Please provide any comments in the column to the right.**	BCSEA-SCBC do not have any suggestions for segmentation methodologies that BCH should examine in addition to Method 1 and Method 2.

Workshop 11A: Segmentation, SGS and MGS	
B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation) BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%. Results: • Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery • Resulting energy rate remains within the LRMC and without substantial bill impacts **BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.**	Increasing the SGS basic charge to recover 45% (from 35%) of costs would slightly reduce the energy charge and have a corresponding slight reduction in natural conservation (at -0.5% elasticity). While this negative impact would be small, BCSEA-SCBC are not clear what the benefits of increasing the basic charge would be.

Workshop 11A: Segmentation, SGS and MGS	
C. MGS Demand Charges 1. BC Hydro presented three alternatives for demand charges: i. Status Quo ii. Alternative A - flat demand charge + flat energy rate iii. Alternative B – two step demand charge + flat energy rate **BC Hydro seeks feedback on which of the three demand charge structure alternatives is preferred (with reasons). Please provide any comments in the column to the right.** 2. Stakeholders requested BC Hydro model increased MGS demand charge cost recovery; BC Hydro modeled increasing the MGS demand cost recovery of flat demand from approximately 15% to 35% for Flat Energy Rate/Flat Demand Charge Alternative **BC Hydro seeks feedback on whether the MGS demand charge cost recovery should be increased, and if so to what level (with reasons). Please provide comments in the column to the right.** 3. BC Hydro considered Transition Strategies for moving to a flat energy rate, and flat demand charge: • three-year phase–in • 10% bill impact Cap **BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.**	1. Alternatives for MGS demand charge. BCSEA-SCBC are inclinded to favour Alternative A (flat demand charge) over Alternative B. 2. Whether to increase MGS demand charge cost recovery? BCSEA-SCBC are inclined to favour leaving the demand cost recovery rate at the current ~ 15%, on the ground that that would leave the energy rate relatively higher and so provide a stronger signal for energy conservation. 3. Transition Strategies. BCSEA-SCBC support a 3-year phase-in period, rather than a 10% bill impact cap, on the grounds that it would be clearer to customers and simpler to administer to have a short, fixed term transition, rather than a potentially long transition of uncertain term.

Workshop 11B: LGS Rate Structure

A. Preferred LGS Rate Structure (Slides 9 to 54 of Workshop 11B Presentation) **BC Hydro is seeking stakeholder feedback on which of the four energy rate structure alternatives and the three demand charge structure alternatives are preferred, and why. Please provide any comments you have in the column to the right.** **Energy rate alternatives:** 1. Status Quo LGS Energy rate (retain baseline) 2. Simplify energy rate structure (retain baseline): A. Flatten Part 1 Energy Rate B. Consider modify Baseline Rate Provisions: i. Determination of baselines (monthly versus annual versus rolling average, etc.) ii. Price limit bands (PLBs) to address concerns that rates are 'punitive to growing customers', and/or to encourage further conservation iii. Growth rules to make less restrictive iv. New account rules 3. LGS Flat Energy Rate (remove baseline structure) 4. LGS Flat Energy Rate for majority of LGS customers and create TSR-like rate with individually administered baselines for segment of very large LGS customers **Demand Charge alternatives:** 1. Status quo inclining three-step demand charge 2. Flat demand charge 3. Two-step demand charge	Energy rate alternatives. BCSEA-SCBC support simplifying the status quo LGS rate structure. They support a flat energy rate structure for the LGS class, with no baseline or Part 2 rate structure (Alternative 3). BC Hydro's report on the current LGS two-part rate structure establishes that it does not achieve its primary purpose of inducing DSM, and accordingly, there is no justification for retaining it. Meanwhile, it is more costly to administer and less transparent and comprehensible to ratepayers. BCSEA-SCBC encourage BC Hydro to take advantage of any change in the LGS rate to promote customer awareness of DSM. BCSEA-SCBC's position on a TSR-like (customer baseline) energy rate structure for a new very large general service class will depend on the details and further consideration. Demand charge alternatives. BCSEA-SCBC are inclined to support a flat demand charge (Alternative 2), as better reflecting cost causality.

Workshop 11B: LGS Rate Structure

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B. Flatten Part 1 Energy Rate (Slide 16 of June 26, 2015 Workshop Presentation)

Flat Part 1 energy rate would be nominal simplification, as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers:

- More customers better off than worse off, higher consuming customers have more adverse bill impacts

BC Hydro is seeking feedback on this option to flatten Part Energy Rate. Please provide any comments in the column to the right.

C. Baseline Rate Provisions

(i) Baseline determination (slide 17 of 26 June Workshop 11B presentation)

- BC Hydro considered baseline determination on annual basis versus monthly baseline calculation, and
- Considered determining one-year and five-year rolling average baselines, versus status quo determination of three–year rolling average monthly baselines

Annual baseline could create cash flow burden for many customers at year end. five-year rolling average baselines will further increase the complexity of the rate; one-year baselines could cause bill instability as unusual consumption months cannot be levelled in baselines.

If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right.

(ii) Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation)

PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/- 10%) and increasing the PBL (i.e. +/-30%)

BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback.

If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB shoud be modified and if so,how. Please explain your response in the column to the right.

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<td>

BCSEA-SCBC are not convinced that flattening the Part 1 LGS energy rate while retaining a Part 2 rate would increase conservation or simplify the rate structure enough to overcome the complexity problem. A flat energy rate for LGS would have the advantage of being easily understood.

Similarly, BCSEA-SCBC are not convinced that changing the baseline determination (e.g., from monthly to annual, or from three-year to one- or five-year rolling average) or the price band limit rules would improve the conservation results or achieve the necessary simplification of a flat rate structure.

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Workshop 11B: LGS Rate Structure	
(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation) The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh. Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption. **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.**	BCSEA-SCBC favour moving to a flat energy rate structure for the LGS class. This would eliminate formulaic growth rate adjustment.
(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation) In calculating HBLs, anomalously low consumption months from previous years are excluded: • In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded • Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule • Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right**	As stated above, BCSEA-SCBC favour moving to a flat energy rate structure for the LGS class, which would eliminate the growth mitigation anomaly rule.

Workshop 11B: LGS Rate Structure

(v) Growth Mitigation – Prospective Growth Rule (TS82) (Slides 24 to 25 of Workshop 11B Presentation) Customers who anticipate 'significant', 'permanent' increases in energy consumption may apply to BC Hydro for modified pricing under TS 82 that may reduce their energy costs. Significant means a prospective first year annual increase in energy consumption totaling at least 30% or 4,000,000 kWh above the historical three-year average annual consumption. Permanent means arising from a significant capital investment. • Very few customers have applied due to high thresholds • Customers with lower consumption might meet the 30% threshold but may not benefit from the modified pricing structure • High administrative cost to BC Hydro **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Prospective Growth Rule and if so, what. Please explain your response in the column to the right**	BCSEA-SCBC favour moving to a flat energy rate structure for the LGS class. This would eliminate the prospective growth rule.
(vi) New Accounts (85/15) (Slides 26 to 27 of Workshop 11B Presentation) • 85/15 applies when a new account is set up in BC Hydro's billing system, regardless of whether there were changes in customers' operation • First 85% of energy consumed in a monthly billing period is charged at the Part 1 rate. Last 15% of energy consumed in a monthly billing period is charged Part 2 LRMC rate • Established to prevent customers from 'gaming' by opening new accounts to reset baselines BC Hydro found no evidence of "gaming" in the LGS Three-Year Report. Customers raised concerns that 85/15 rate unfairly penalizes customers who have no change in operations during account ownership transfers. **If the baseline structure is maintained, BC Hydro would recommend applying 100% Part 1 rates for new accounts, and is seeking further stakeholder feedback. Please provide any comments in the column to the right.**	As stated above, BCSEA-SCBC favour moving to a flat energy rate structure for the LGS class, which would eliminate the need for special rules for new accounts.

<table>
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<tr><td>D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation)

Option: Flatten LGS Energy rate for all consumption levels

Pros:
• Eliminates all complexity from baseline component of status quo LGS energy rate
• Easier and more accurate customer forecasting
• Improved customer understanding
• Aligns with other Cdn. Jurisdictions

Cons:
• Energy rate is well below lower end of energy LRMC

Observations:
• Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b
• There are bill impacts from flattening Part 1 Energy rates; typical customers better off
• No change in conservation – zero forecast for planning purposes

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.</td><td>BCSEA-SCBC favour moving to a flat energy rate structure for the LGS class.</td></tr>
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<td>E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation)
Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers

Rate may have following elements based on BC Hydro's existing TSR – RS 1823:
• Available to large LGS accounts
• Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate:
• 5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year
• 10.10 cents/kWh applied to all kWh above 90% of customer's CBL in each billing year
• Initial annual CBL determined by historic baseline year(s)
• Allowable adjustments for DSM, plant capacity increases and force majeure
• Annual CBL approved each year by BCUC
BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.</td>
<td>BCSEA-SCBC reserve judgement on a TSR-like energy rate for large LGS customers, pending more detailed information and analysis of such a rate. In general, an inclining block rate similar to RS 1823 could induce conservation; however 'the devil is in the details,' particularly with respect to setting and amending customer baselines.</td>
</tr>
</table>

<table>
<tr><th colspan="2">Workshop 11B: Optional Rates and Other Issues</th></tr>
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A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation)

1. Voluntary Time of Use Rates
• BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo

2. Interuptible Rates
• BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined

3. Efficiency Rate Credit concept
• BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined

4. Demand Charge Options
• BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined

BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.
</td><td>
1. BCSEA-SCBC concur with BC Hydro's decision not to proceed with voluntary time of use rates for general service at this time. The basic problem with a voluntary TOU rate is that it would attract mainly 'free riders.'

2. BCSEA-SCBC are cautious about interruptible rates, but are content to await consideration in Module Two of the rate design application process.

3. BCSEA-SCBC are supportive of the efficiency rate credit concept, subject to further development and understanding of the details and implications. They are content to have this addressed in Module Two.

4. BCSEA-SCBC are content to have general service demand charge options addressed in Module Two.
</td></tr>
</table>

Workshop 11B: Optional Rates and Other Issues	
B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation) **1. Minimum Charges (Demand Ratchet)** Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March) Ratchet was reduced from 75% to 50% effective April 1, 1980 Based on F14 data: • MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%) • LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%) **BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.**	BCSEA-SCBC agree with the concept of having a minimum charge to ensure that all customers pay a fair share of costs for system capacity. They reserve judgement on the current rate, pending receipt of more information of the effects of this rate.

Workshop 11B: Optional Rates and Other Issues	
2. Transformer Ownership Discount (TOD) and Transformer Rentals • TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential • Last review of $0.25 /month discount was completed in August 2004 **BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right.** F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision. Design Considerations: • At-home charging (Residential) • Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power) • Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California 'super off-peak' concept to encourage late night to early morning charging? • Requirement of a separate meter? • Interaction with RIB? • Other? **BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.**	BCSEA-SCBC are content for the TOD to be reviewed in Module 2, along with the Distribution Extension Policy. BCSEA-SCBC agree with the issues proposed for considering an EV rate. In addition, of particular relevance will be the consideration of government's energy goals for reducing greenhouse gas emissions and its policies to encourage people to switch to EVs. Also, worth considering is the possible desire of building owners to charge for the use of EV charging facilities, based on energy provided or duration of the use of the charging service.

Additional Comments:

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:_____ ___________ Date: July 31, 2015

Thank you for your comments.

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BC hydro FOR GENERATIONS

2015 Rate Design Application (RDA) – General Service Rates Workshop 11, Sessions A (June 25, 2015) and B (June 26, 2015) Feedback Form

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<tr><td colspan="2">Workshop 11A: Segmentation, SGS and MGS</td></tr>
<tr><td>
A. Cost of Service Analysis: Segmentation Methodology (Slides 17 to 21 of June 25, 2015 Workshop 11A Presentation). BC Hydro discussed two methods of segmentation:

<u>Method 1:</u>

BC Hydro took samples of 1,000 customers from each of SGS, MGS and LGS classes;

F16 Forecast costs assigned to GS rate classes pooled and re-allocated pro rata by individual customer kWh, 4 Coincident Peak (CP) demand, and Non-Coincident Peak (NCP) demand. Results of method 1 not conclusive:

NCP allocation varies depending on coincidence within classes.
Coincidence is better correlated with cost than customer size.
Transformer cost may vary with size but cost impact is small.

<u>Method 2:</u>

Consider cost allocation based on pre-assigned segments of customers. Customers will be grouped by size as opposed to evaluated individually – to be reviewed at July 30, 2015 wrap-up workshop.

BC Hydro seeks stakeholder feedback on what other analysis of segmentation should be conducted. Please provide any comments in the column to the right.
</td><td>

If BCH billed all customers on the same basis as costs were allocated (e.g. customer, energy, 4CP and NCP) and the costs recovered using each of these billing parameters were equivalent to the costs allocated to each class, then customer segmentation would be less of an issue and would only need to focus on grouping customers that use the same types of facilities (e.g. transmission customers vs. primary distribution customers) and have similar cost characteristics. However, this is not the case. As a result, in order to try to ensure a fair recovery of costs between customers within a class, it would be ideal if all the customers in the class generally had:

A similar ratio between their billing demand (which is used to collect costs) and their contribution to the class's 4CP and NCP values (which are used to allocate costs to the class). Otherwise some customers will be paying more and some will be paying less than their fair share of demand costs.
Similar load factors in recognition of the fact that not all demand and energy-related costs (as identified and allocated using the cost of service) are recovered respectively through demand and energy charges.

This is the point that BCOAPO was attempting to explore through in the GSR Workshop (see Feedback Summary notes, p. 3, #4). It was not meant to suggest that these parameters would actually be used to classify individual customers – BCOAPO agrees that more understandable factors such as size or service voltage should be used for this purpose. Rather the suggestion was to look at how these various factors vary by customer size and see if there any obvious break points which would suggest points at which classes should be segmented.

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Workshop 11A: Segmentation, SGS and MGS	
B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation) BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%. Results: • Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery • Resulting energy rate remains within the LRMC and without substantial bill impacts BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.	• During the Workshop BC Hydro clarified that the 35% and 45% referred to the portion of demand and customer costs being recovered by the basic charges to SGS and Residential customers respectively. It is not clear to BCOAPO why this should be the relevant measure of comparability as opposed to looking at the percent of customer costs recovered via the basic charge for each customer class. • Another relevant consideration, which would support increasing the SGS basic charge recovery, is the fact that if one escalates the F16 LRMC upper boundary of 11.10 cents/kWh by inflation (e.g. 2%) by F18 the SQ energy rates will exceed the LRMC value.

<table>
<tr><th colspan="2">Workshop 11A: Segmentation, SGS and MGS</th></tr>
<tr>
<td>C. MGS Demand Charges

1. BC Hydro presented three alternatives for demand charges:
i. Status Quo
ii. Alternative A - flat demand charge + flat energy rate
iii. Alternative B – two step demand charge + flat energy rate

BC Hydro seeks feedback on which of the three demand charge structure alternatives is preferred (with reasons). Please provide any comments in the column to the right.

2. Stakeholders requested BC Hydro model increased MGS demand charge cost recovery;

BC Hydro modeled increasing the MGS demand cost recovery of flat demand from approximately 15% to 35% for Flat Energy Rate/Flat Demand Charge Alternative

BC Hydro seeks feedback on whether the MGS demand charge cost recovery should be increased, and if so to what level (with reasons). Please provide comments in the column to the right.

3. BC Hydro considered Transition Strategies for moving to a flat energy rate, and flat demand charge:
• three-year phase–in
• 10% bill impact Cap

BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.</td>
<td>1. <u>MGS Demand Charge Alternatives</u>
• BCOAPO does not have a strong preference, but Alternative A appears to be the most appropriate.
• As noted, the Status Quo approach is poorly understood and does not appear to be achieving the efficiency/conservation objectives for which it was intended. With respect to Alternative B, BCOAPO notes that inclining demand charges in other jurisdictions are frequently accompanied by declining energy rates, which tend to have an offsetting effect for the total bill. If BCH moves to a flat energy rate for the MGS class, the need for an inclining demand charge is questionable.

2. <u>MGS Demand Charge Cost Reovery</u>
• BCOAPO agrees with the point made in the presentation that the correct level of cost recovery cannot be targeted in isolation (Slide #33). As well as the cost causation and customer acceptance/ understanding considerations noted on Slide 32, there are also efficiency considerations (i.e. the extent to which the resulting energy charge aligns with LRMC). In this regard, increasing the demand charge cost recovery appears to move the energy charge further below LRMC. Increasing the demand charge cost recovery also appears to lead to greater bill impacts (in terms of maximum impacts – Slide 49 and Slide 40 vs. 51).
• Finally, if fixed costs include both demand and customer costs, we also question the use of “fixed costs” as the relevant reference for cost causation with respect to demand costs. On balance, there appears to be little merit in increasing demand charge cost recovery at this time.

3. <u>Transition</u>
• BCOAPO views 15 years as being too long a period for transition. Perhaps something slightly greater than 3 should be considered.</td>
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</table>

Workshop 11B: LGS Rate Structure	
A. Preferred LGS Rate Structure (Slides 9 to 54 of Workshop 11B Presentation) BC Hydro is seeking stakeholder feedback on which of the four energy rate structure alternatives and the three demand charge structure alternatives are preferred, and why. Please provide any comments you have in the column to the right. Energy rate alternatives: 1. Status Quo LGS Energy rate (retain baseline) 2. Simplify energy rate structure (retain baseline): A. Flatten Part 1 Energy Rate B. Consider modify Baseline Rate Provisions: i. Determination of baselines (monthly versus annual versus rolling average, etc.) ii. Price limit bands (PLBs) to address concerns that rates are 'punitive to growing customers', and/or to encourage further conservation iii. Growth rules to make less restrictive iv. New account rules 3. LGS Flat Energy Rate (remove baseline structure) 4. LGS Flat Energy Rate for majority of LGS customers and create TSR-like rate with individually administered baselines for segment of very large LGS customers Demand Charge alternatives: • Status quo inclining three-step demand charge • Flat demand charge • Two-step demand charge	• BCOAPO understands that there are two critical concerns regarding the Status Quo LGS rate design: i) it is not achieving the desired/anticipated conservation results, and ii) the rate is difficult to understand such that customers cannot readily predict their bills or budget (Slide #12, 15 & 29). Further, lack of conservation effect is, in itself, largely attributable to the complexity and lack of understanding of the current rate design. • In BCOAPO's view, it is a basic requirement that customers be able to understand the rate structure being used to bill them and how its application will impact their bills (regardless of whether or not it results in a conservation effect). As a result, it would appear to us that the SQ rate structure is unsustainable. Given this context, energy rate Alternative #2 is only acceptable if it truly leads to a rate design that customers are able to understand. It should not be pursued as the "preferred option" unless the associated proposal has been fully developed, canvassed with affected customers and, at a minimum, viewed to be workable. Note: All changes in rate design will have impacts (favourable to some customers and unfavourable to others). The first critical issue for considering an Alternative 2 rate design proposal is that it be understandable. If this is not the case, there seems to little point in pursing it further. • The major drawback to Alternative #3 is that the resulting energy rate would be significantly below LRMC. This issue would be addressed for at least some of the customers by Alternative 4 – which, as a result, is preferable to Alternative #3 – if administratively practical without significant additional costs. • With respect to demand charges, there does not appear to be any basis for an inclining demand charge.

Workshop 11B: LGS Rate Structure	
B. Flatten Part 1 Energy Rate (Slide 16 of June 26, 2015 Workshop Presentation) Flat Part 1 energy rate would be nominal simplification, as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers: • More customers better off than worse off, higher consuming customers have more adverse bill impacts BC Hydro is seeking feedback on this option to flatten Part Energy Rate. Please provide any comments in the column to the right.	• The flattening of the part 1 energy rate should only be considered as part of an overall package of changes aimed at improving the acceptability/understandability of the SQ rate design (i.e. energy rate alternative 2). There would seem to be little merit on changing just this aspect of the energy rate design.
C. Baseline Rate Provisions **(i)** Baseline determination (slide 17 of 26 June Workshop 11B presentation) • BC Hydro considered baseline determination on annual basis versus monthly baseline calculation, and • Considered determining one-year and five-year rolling average baselines, versus status quo determination of three–year rolling average monthly baselines Annual baseline could create cash flow burden for many customers at year end. five-year rolling average baselines will further increase the complexity of the rate; one-year baselines could cause bill instability as unusual consumption months cannot be levelled in baselines. If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right. **(ii)** Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation) PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/- 10%) and increasing the PBL (i.e. +/-30%) BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback. If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB shoud be modified and if so,how. Please explain your response in the column to the right.	• Since the key purpose of the suggested revisions is to improve the understanding (and therefore also the "conservation" performance) of the SQ rate design, BCOAPO does not have any specific views or suggestions to offer at this time and is interested (first) in seeing/considering the responses from the customers actually billed using the rate.

Workshop 11B: LGS Rate Structure	
(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation) The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh. Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption. If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.	
(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation) In calculating HBLs, anomalously low consumption months from previous years are excluded: • In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded • Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule • Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right	

<table>
<tr><th colspan="2">Workshop 11B: LGS Rate Structure</th></tr>
<tr><td>(v) Growth Mitigation – Prospective Growth Rule (TS82) (Slides 24 to 25 of Workshop 11B Presentation)

Customers who anticipate ‘significant’, ‘permanent’ increases in energy consumption may apply to BC Hydro for modified pricing under TS 82 that may reduce their energy costs. Significant means a prospective first year annual increase in energy consumption totaling at least 30% or 4,000,000 kWh above the historical three-year average annual consumption. Permanent means arising from a significant capital investment.

• Very few customers have applied due to high thresholds
• Customers with lower consumption might meet the 30% threshold but may not benefit from the modified pricing structure
• High administrative cost to BC Hydro

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Prospective Growth Rule and if so, what. Please explain your response in the column to the right</td><td></td></tr>
<tr><td>(vi) New Accounts (85/15) (Slides 26 to 27 of Workshop 11B Presentation)

• 85/15 applies when a new account is set up in BC Hydro’s billing system, regardless of whether there were changes in customers’ operation
• First 85% of energy consumed in a monthly billing period is charged at the Part 1 rate. Last 15% of energy consumed in a monthly billing period is charged Part 2 LRMC rate
• Established to prevent customers from ‘gaming’ by opening new accounts to reset baselines

BC Hydro found no evidence of “gaming” in the LGS Three-Year Report. Customers raised concerns that 85/15 rate unfairly penalizes customers who have no change in operations during account ownership transfers.

If the baseline structure is maintained, BC Hydro would recommend applying 100% Part 1 rates for new accounts, and is seeking further stakeholder feedback. Please provide any comments in the column to the right.</td><td></td></tr>
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Workshop 11B: LGS Rate Structure	
D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation) Option: Flatten LGS Energy rate for all consumption levels Pros: • Eliminates all complexity from baseline component of status quo LGS energy rate • Easier and more accurate customer forecasting • Improved customer understanding • Aligns with other Cdn. Jurisdictions Cons: • Energy rate is well below lower end of energy LRMC Observations: • Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b • There are bill impacts from flattening Part 1 Energy rates; typical customers better off • No change in conservation – zero forecast for planning purposes BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.	• In BCOAPO's view, this is the preferred alternative if an acceptable set of revisions to the current rate design (that would clearly improve both understandability and performance) cannot be identified.

Workshop 11B: LGS Rate Structure	
E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation) Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers Rate may have following elements based on BC Hydro's existing TSR – RS 1823: • Available to large LGS accounts • Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate: • 5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year • 10.10 cents/kWh applied to all kWh above 90% of customer's CBL in each billing year • Initial annual CBL determined by historic baseline year(s) • Allowable adjustments for DSM, plant capacity increases and force majeure • Annual CBL approved each year by BCUC BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.	• The TSR-Like energy rate appears to be well understood by the transmission customers it is currently applied to and working well (both in terms of performance and CBL setting). In BCOAPO's view a similar structure should be considered for high consumption LGS customers, provided application of such a rate design is administratively practical. The only concern BCOAPO would have with the introduction of such a rate design with respect to the definition "revenue neutrality" that would be used in setting the rate – which is similar to the previous concerns expressed by BCOAPO regarding the current definition of revenue neutrality used for the TSR. • Given the concerns expressed by institutional and municipal government customers, it may be useful to explore the merits/drawbacks of introducing such a rate on an optional basis. This may be more workable than trying to "define" a class/type of customer that would be exempt.

Workshop 11B: Optional Rates and Other Issues	
A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation) **1.** Voluntary Time of Use Rates • BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo **2.** Interuptible Rates • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **3.** Efficiency Rate Credit concept • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **4.** Demand Charge Options • BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.	• BCOAPO agrees with BC Hydro's proposal not to proceed with the development of an optional TOU rate at this time. There appears to be no cost justification for any material differential in peak/off-peak rates and considerable opportunity for free-riders (WorkShop8A/8B Consideration Memo, pg. 56). • BCOAPO has reservations about the other suggested optional rates for General Service customers. They need to be given careful consideration to ensure that they do not have a negative impact on other customers. • In the case of interruptible rates a number of possible approaches have been identified. However, each appears to be applicable to a different set of circumstances such that the terms and conditions would be an important part of the "rate". In the case of the "efficiency rate credit", it appears to BCOAPO that considerable work is still required to flesh out the details and, indeed, in this case the "devil is likely to be in the details". • BCOAPO views RDA Module 2 as a reasonable forum to consider the optional rates noted provided, given the other issues identified for Module 2, there is sufficient time and resources available to comprehensively assess these options as well.

<table>
<tr><th colspan="2">Workshop 11B: Optional Rates and Other Issues</th></tr>
<tr><td>B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation)

1. Minimum Charges (Demand Ratchet)

Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March)

Ratchet was reduced from 75% to 50% effective April 1, 1980

Based on F14 data:

• MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%)

• LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%)

BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.</td><td>• BCOAPO notes that there is an important issue of fairness involved. Given that cost causality is determined based on peak demand (e.g., 4CP and NCP), customers whose billing demands are materially lower in the off-peak months (relative to the peak months) are likely not paying their “fair” share of costs. There is also the matter of consistent treatment across customer classes and, in this context, it is noted that for BCH’s TSR customers, the ratchet is currently set at 75% as compared to 50% for LGS and MGS customers. Overall, BCOAPO sees merit to including a review of the MGS/LGS demand ratchet in Module 2.</td></tr>
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<tr><td>
2. Transformer Ownership Discount (TOD) and Transformer Rentals
• TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential
• Last review of $0.25 /month discount was completed in August 2004

BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right.

F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision.

Design Considerations:
• At-home charging (Residential)
• Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power)
• Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California ‘super off-peak’ concept to encourage late night to early morning charging?
• Requirement of a separate meter?
• Interaction with RIB?
• Other?

BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.
</td><td>
• While there is some linkage between the TOD and the Distribution Extension Policy in terms of avoided costs, BCOAPO also sees there being a linkage between the TOD and the Cost of Service Study. The rates charged to a customer class such as MGS or LGS includes an allocation of costs for transformers owned by BC Hydro attributable to those customers in the class that use BC Hydro owned transformers. Ideally, these costs should only be recovered from those customers using BC Hydro-owned transformers. One way to achieve this is to provide a credit (equivalent to estimated embedded cost of such transformers) to customers in the class that own their transformers and include the cost of such credits as part of the revenue requirement attributable to the class. As a result, BCOAPO sees merit in considering the TOD in this context as well and therefore in Module 2 – after the Cost of Service methodology has been reviewed and agreed upon.

• BCOAPO is not totally familiar with EV charging technology and therefore uncertain whether there may also be issues associated with capability of the standard service (i.e. amps, volts, etc.) provided for Residential customers to handle an EV charging station or whether, in some cases, service upgrades may be required. If this is the case, the treatment of the associated costs would also be a relevant issue.

• It appears there are a number of issues to sort out and consider in the design of future EV rates such that it may be premature to consider EV rates as part of Module 2 given the other issues also to be considered.
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Additional Comments:

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:_______________Sarah Khan__________ Date: _______08/13/15___________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

You can return completed feedback forms by:

Mail: BC Hydro, BC Hydro Regulatory Group – "Attention 2015 RDA", 16th Floor, 333 Dunsmuir St. Van. B.C. V6B-5R3

Fax number: 604-623-4407 – "Attention 2015 RDA"

Email: bchydroregulatorygroup@bchydro.com

Form available on Web: http://www.bchydro.com/about/planning_regulatory/regulatory.html

Any personal information you provide to BC Hydro on this form is collected and protected in accordance with the ***Freedom of Information and Protection of Privacy Act***. BC Hydro is collecting information with this for the purpose of the 2015 RDA in accordance with BC Hydro's mandate under the ***Hydro and Power Authority Act***, the BC Hydro Tariff, the ***Utilities Commission Act*** and related Regulations and Directions. If you have any questions about the collection or use of the personal information collected on this form please contact the BC Hydro Regulatory Group via email at: bchydroregulatorygroup@bchydro.com

2015 Rate Design Application (RDA) – General Service Rates Workshop 11, Sessions A (June 25, 2015) and B (June 26, 2015) Feedback Form

Name/Organization:	
	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Workshop 11A: Segmentation, SGS and MGS	
A. Cost of Service Analysis: Segmentation Methodology (Slides 17 to 21 of June 25, 2015 Workshop 11A Presentation). BC Hydro discussed two methods of segmentation: <u>Method 1:</u> BC Hydro took samples of 1,000 customers from each of SGS, MGS and LGS classes; F16 Forecast costs assigned to GS rate classes pooled and re-allocated pro rata by individual customer kWh, 4 Coincident Peak (CP) demand, and Non-Coincident Peak (NCP) demand. Results of method 1 not conclusive: • NCP allocation varies depending on coincidence within classes. • Coincidence is better correlated with cost than customer size. • Transformer cost may vary with size but cost impact is small. <u>Method 2:</u> Consider cost allocation based on pre-assigned segments of customers. Customers will be grouped by size as opposed to evaluated individually – to be reviewed at July 30, 2015 wrap-up workshop. BC Hydro seeks stakeholder feedback on what other analysis of segmentation should be conducted. Please provide any comments in the column to the right.	

Workshop 11A: Segmentation, SGS and MGS	
B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation) BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%. Results: • Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery • Resulting energy rate remains within the LRMC and without substantial bill impacts BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.	BC Hydro shows on slide 26 that the increase in basic charge to 45% has very low bill impacts and only small reductions in the energy charge. Is it reasonable to conclude that this implies that the fixed costs of BC Hydro are relatively small compared to its energy costs. It will be informative if BC Hydro further explained the cost relationship. Although movement to 45% provides comparability with the RIB basic charge recovery, BC Hydro should provide the context by further explaining its priorities within the rate design objectives such as the priority for stable cost recovery of fixed costs vs the priority for price signals to encourage conservation. If the MGS Demand charge cost recovery is to remain below 35% (15% currently), should the SGS Basic charge be increased from 35% to 45%? If so, would there be any 'seams' implications between the MGS Demand Charge and the SGS Basic charge?

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• three-year phase–in
• 10% bill impact Cap

BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.
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BC Hydro identifies that a flat demand charge reflects cost causation better than an inclining block structure, that it has the benefit of simplicity, and that it may induce some level of conservation compared to the complications of the existing rate. If the flat Demand charge best meets the rate design objectives of BC Hydro, the major remaining issues are: (a) the ways to phase it in or otherwise deal with the bill impacts for the bulk of the customers, and (b) how does BC Hydro reconcile the zero demand charge for the <35 kW SGS class and a full flat demand charge for, say a 40 kW MGS customer?

Slide 35 shows that the flat demand charge at the very low fixed cost recovery of 15% is also very low but the increase to 35% moves the energy charge out of the LRMC range. Which is the rate design priority for BC Hydro – cost recovery stability or LRMC energy pricing? If BC Hydro now believes, based on its evaluation reports, that energy pricing has only minimal impact on commercial customer conservation, does it mean that the objective of keeping the energy charge in the LRMC range has less importance? Does the tax deductability of a commercial customer's electricity bills have a major impact on commercial customers' attitudes to energy price conservation compared to DSM incentives? Does tax deductibility reduce the already very low elasticity of demand to energy pricing to such a low level that even LRMC energy pricing will have a minimal impact on commercial customer conservation?

In considering bill impacts and transition strategies, should BC Hydro's analysis exclude impacts to, perhaps, the lowest and highest 5 percent of load factor customers so that the rate design is not limited by the customers at the extreme ends ? If the 10% bill impact transition will take too long to implement, should BC Hydro consider an extended implementation period of perhaps 5-7 years so that implementation is still complete before the next rate design?
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Workshop 11B: LGS Rate Structure	
A. Preferred LGS Rate Structure (Slides 9 to 54 of Workshop 11B Presentation) BC Hydro is seeking stakeholder feedback on which of the four energy rate structure alternatives and the three demand charge structure alternatives are preferred, and why. Please provide any comments you have in the column to the right. Energy rate alternatives: 1. Status Quo LGS Energy rate (retain baseline) 2. Simplify energy rate structure (retain baseline): A. Flatten Part 1 Energy Rate B. Consider modify Baseline Rate Provisions: i. Determination of baselines (monthly versus annual versus rolling average, etc.) ii. Price limit bands (PLBs) to address concerns that rates are 'punitive to growing customers', and/or to encourage further conservation iii. Growth rules to make less restrictive iv. New account rules 3. LGS Flat Energy Rate (remove baseline structure) 4. LGS Flat Energy Rate for majority of LGS customers and create TSR-like rate with individually administered baselines for segment of very large LGS customers Demand Charge alternatives: 1. Status quo inclining three-step demand charge 2. Flat demand charge 3. Two-step demand charge	BC Hydro has identified only a very small conservation achievement from the existing LGS rate structure. Does BC Hydro have the source of those savings? Are those limited savings coming mainly from the largest customers who may be considered for a TSR like rate? If so it would add support for the a TSR-like rate for customers with demand over a threshold of, for example, 1 or 2 MW. Then a flattened energy and demand charge with modified or no baselines for the remaining customers might be justified. From customers' feedback and from BC Hydro's implementation, the status quo energy and demand structure is complicated (i.e., 3-part pricing, baselines, PLBs, rules for growth and new accounts) for almost all except a few LGS customers and the complication creates room for complaints, gaming, or simply the lack of ability to respond to the price signals. If the only benefit that has been realized is negligible conservation, then the status quo may be considered to have failed to achieve the aggregate of the various rate design objectives.

Workshop 11B: LGS Rate Structure

B. Flatten Part 1 Energy Rate (Slide 16 of June 26, 2015 Workshop Presentation) Flat Part 1 energy rate would be nominal simplification, as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers: • More customers better off than worse off, higher consuming customers have more adverse bill impacts BC Hydro is seeking feedback on this option to flatten Part Energy Rate. Please provide any comments in the column to the right. C. Baseline Rate Provisions **(i)** Baseline determination (slide 17 of 26 June Workshop 11B presentation) • BC Hydro considered baseline determination on annual basis versus monthly baseline calculation, and • Considered determining one-year and five-year rolling average baselines, versus status quo determination of three–year rolling average monthly baselines Annual baseline could create cash flow burden for many customers at year end. five-year rolling average baselines will further increase the complexity of the rate; one-year baselines could cause bill instability as unusual consumption months cannot be levelled in baselines. If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right. **(ii)** Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation) PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/- 10%) and increasing the PBL (i.e. +/-30%) BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback. If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB shoud be modified and if so,how. Please explain your response in the column to the right.	What is the rate design objective of a declining block for Part 1 rate? Since most customers consume the 14,800 KWh/month quickly, are most MGS customers consuming at Tier 2 of the Part 1 rate? Does the simplified energy rate address the real problems of the status quo rate other than nominal simplification Feedback on moving monthly baseline to annual baseline: One customer at the workshop claimed that a 5-year rolling average baseline could pose a problem for estimating investment returns. If this limitation is true, then there may be additional disadvantages to 5- year baselines rather than positive benefits. Similarly, the 1 year baseline may result in business instability. Perhaps the best approach would be to maintain the 3-year average unless it can be demonstrated that there is material improvement of rate design objectives from alternatives compared to the 3-year methodology. Price Band Limit No Comment.

Workshop 11B: LGS Rate Structure	
(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation) The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh. Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption. If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.	Although BC Hydro believes that the FGR is not working as intended, it is also not clear that it should be discarded. Would it make sense to keep the FGR when it is beneficial to a customer so as to not punish growth and not apply the FGR if other factors resulted in higher bills with FGR? In cases where the year 1 consumption was significantly higher than year 2 consumption BC Hydro could consider that it would not apply the FGR since this might be considered more of a market fluctuation than a rapid growth scenario.
(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation) In calculating HBLs, anomalously low consumption months from previous years are excluded: • In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded • Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule • Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right	The anomaly rule seems to be achieving its intended purpose of smoothing out anomalous months as defined in the negotiated settlement agreement that introduced this rule.

<table>
<tr><th colspan="2">Workshop 11B: LGS Rate Structure</th></tr>
<tr><td>(v) Growth Mitigation – Prospective Growth Rule (TS82) (Slides 24 to 25 of Workshop 11B Presentation)

Customers who anticipate ‘significant’, ‘permanent’ increases in energy consumption may apply to BC Hydro for modified pricing under TS 82 that may reduce their energy costs. Significant means a prospective first year annual increase in energy consumption totaling at least 30% or 4,000,000 kWh above the historical three-year average annual consumption. Permanent means arising from a significant capital investment.

• Very few customers have applied due to high thresholds
• Customers with lower consumption might meet the 30% threshold but may not benefit from the modified pricing structure
• High administrative cost to BC Hydro

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Prospective Growth Rule and if so, what. Please explain your response in the column to the right</td><td>The purpose of this option is to take account of large, permanent growth impacts and 30% seemed, at the time when the rate was designed, a reasonable level to set the ‘signficant’ threshold.

With so few customers meeting the threshold, perhaps this rule could be discontinued although this Prospective Growth Rule would still help fast growing customers. Has BC Hydro considered what would be an acceptable number of customers to apply under this rule? Should the rule be modified accordingly?

Similar to Commission staff comments under FGR on page 7, can the rule apply only when it is beneficial?</td></tr>
<tr><td>(vi) New Accounts (85/15) (Slides 26 to 27 of Workshop 11B Presentation)

• 85/15 applies when a new account is set up in BC Hydro’s billing system, regardless of whether there were changes in customers’ operation
• First 85% of energy consumed in a monthly billing period is charged at the Part 1 rate. Last 15% of energy consumed in a monthly billing period is charged Part 2 LRMC rate
• Established to prevent customers from ‘gaming’ by opening new accounts to reset baselines

BC Hydro found no evidence of “gaming” in the LGS Three-Year Report. Customers raised concerns that 85/15 rate unfairly penalizes customers who have no change in operations during account ownership transfers.

If the baseline structure is maintained, BC Hydro would recommend applying 100% Part 1 rates for new accounts, and is seeking further stakeholder feedback. Please provide any comments in the column to the right.</td><td>The issue of whether customers should continue to be defined as an account seems to be an outstanding issue for BC Hydro.

New Accounts is a transition mechanism until a baseline is established. Since BC Hydro has not estimated any significant conservation savings from the LRMC energy pricing, and no evidence of gaming has been found, is there any benefit from the 85/15 rule compared to the proposed 100% Part 1 rates?</td></tr>
</table>

<table>
<tr><th colspan="2">Workshop 11B: LGS Rate Structure</th></tr>
<tr><td>D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation)

Option: Flatten LGS Energy rate for all consumption levels

Pros:
• Eliminates all complexity from baseline component of status quo LGS energy rate
• Easier and more accurate customer forecasting
• Improved customer understanding
• Aligns with other Cdn. Jurisdictions

Cons:
• Energy rate is well below lower end of energy LRMC

Observations:
• Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b
• There are bill impacts from flattening Part 1 Energy rates; typical customers better off
• No change in conservation – zero forecast for planning purposes

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.</td><td>The discussion of this rate option would benefit from a prioritizing of BC Hydro’s rate design objectives and how this rate structure achieves the objectives. For example, is sending an LRMC price signal important if BC hydro does not expect any significant conservation from that higher rate?

How important is rate simplicity and customer understanding compared to sending a price signal related to a commodity that has such low price elasticity? What is BC Hydro’s current estimate of LGS and MGS energy price elasticity of demand based on the experience of the last few years?</td></tr>
</table>

<table>
<tr><th colspan="2">Workshop 11B: LGS Rate Structure</th></tr>
<tr><td>E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation)

Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers

Rate may have following elements based on BC Hydro’s existing TSR – RS 1823:

• Available to large LGS accounts
• Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate:
• 5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year
• 10.10 cents/kWh applied to all kWh above 90% of customer’s CBL in each billing year
• Initial annual CBL determined by historic baseline year(s)
• Allowable adjustments for DSM, plant capacity increases and force majeure
• Annual CBL approved each year by BCUC

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.</td>
<td>If these largest customers are more likely to respond to a LRMC type price for their marginal consumption, then the proposed new rate may be quite effective in promoting some conservation.

This may also be appropriate if the baselines for remaining LGS customers are to be terminated in favour of a flat rate.</td></tr>
</table>

Workshop 11B: Optional Rates and Other Issues	
A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation) 1. Voluntary Time of Use Rates • BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo 2. Interuptible Rates • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined 3. Efficiency Rate Credit concept • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined 4. Demand Charge Options • BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.	BC Hydro claims that a large differential of 3 to 4 times the differential between HLH and LLH pricing is necessary to induce customers to join a voluntary TOU rate. It would be helpful if BC Hydro could validate this assertion in support of its decision not to proceed with a voluntary TOU rate. The interruptible options shown on slide 58 are likely to be of interest to some customers and to BC Hydro. Issues such as metering, entry and exit fees and the amount of interruption should be clarified so that serious customer interest could then be assessed. The potential for a pilot program was discussed and this method of introduction of new rate structures has been successful in the past.

Workshop 11B: Optional Rates and Other Issues	
B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation) 1. Minimum Charges (Demand Ratchet) Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March) Ratchet was reduced from 75% to 50% effective April 1, 1980 Based on F14 data: • MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%) • LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%) BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.	The purpose of the minimum charges is to ensure that customers make an appropriate contribution for the infrastructure required to serve them on peak. More information is necessary to determine if the current minimum charges are appropriate. Perhaps BC Hydro should survey some of the high winter/low summer consumption customers' bills to determine if their contributions to infrastructure and peak supply commitments are appropriate, or if the ratchet should be increased to the 75% TSR level.

Workshop 11B: Optional Rates and Other Issues	
2. Transformer Ownership Discount (TOD) and Transformer Rentals • TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential • Last review of $0.25 /month discount was completed in August 2004 BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right. F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision. Design Considerations: • At-home charging (Residential) • Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power) • Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California 'super off-peak' concept to encourage late night to early morning charging? • Requirement of a separate meter? • Interaction with RIB? • Other? BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.	No comment.

Additional Comments:

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:______________________________ Date: ____________________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

You can return completed feedback forms by:

Mail: BC Hydro, BC Hydro Regulatory Group – "Attention 2015 RDA", 16th Floor, 333 Dunsmuir St. Van. B.C. V6B-5R3

Fax number: 604-623-4407 – "Attention 2015 RDA"

Email: bchydroregulatorygroup@bchydro.com

Form available on Web: http://www.bchydro.com/about/planning_regulatory/regulatory.html

Any personal information you provide to BC Hydro on this form is collected and protected in accordance with the ***Freedom of Information and Protection of Privacy Act***. BC Hydro is collecting information with this for the purpose of the 2015 RDA in accordance with BC Hydro's mandate under the ***Hydro and Power Authority Act***, the BC Hydro Tariff, the ***Utilities Commission Act*** and related Regulations and Directions. If you have any questions about the collection or use of the personal information collected on this form please contact the BC Hydro Regulatory Group via email at: bchydroregulatorygroup@bchydro.com

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BC hydro
FOR GENERATIONS

2015 Rate Design Application (RDA) – General Service Rates Workshop 11, Sessions A (June 25, 2015) and B (June 26, 2015) Feedback Form

Name/Organization:

Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).

A. Cost of Service Analysis: Segmentation Methodology (Slides 17 to 21 of June 25, 2015 Workshop 11A Presentation). BC Hydro discussed two methods of segmentation:

Method 1:

BC Hydro took samples of 1,000 customers from each of SGS, MGS and LGS classes;

F16 Forecast costs assigned to GS rate classes pooled and re-allocated pro rata by individual customer kWh, 4 Coincident Peak (CP) demand, and Non-Coincident Peak (NCP) demand. Results of method 1 not conclusive:

- NCP allocation varies depending on coincidence within classes.
- Coincidence is better correlated with cost than customer size.
- Transformer cost may vary with size but cost impact is small.

Method 2:

Consider cost allocation based on pre-assigned segments of customers. Customers will be grouped by size as opposed to evaluated individually – to be reviewed at July 30, 2015 wrap-up workshop.

BC Hydro seeks stakeholder feedback on what other analysis of segmentation should be conducted. Please provide any comments in the column to the right.

The costs of service analysis presented at the workshop and, in particular, the finding that coincidence better correlates with cost than size, would not appear to support the existing MGS/LGS segmentation. COPE suggests some analysis be done on the merits and implications of eliminating the existing MGS/LGS split or replacing it with a very large LGS category.

As a separate matter, the Union suggests there should be some analysis of whether public entities are being fairly treated within the general sector, especially those with a large number of sites, each with its own account costs under the general rate service and whether there is cost of service or other justification for creating a 'multiple account' public entity rate class.

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General Service Rates Workshop 11, Sessions A (June 25, 2015)
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B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation) BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%. Results: • Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery • Resulting energy rate remains within the LRMC and without substantial bill impacts **BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.**	***The union does not think it advisable to increase the SGS basic charge because of its impact on the energy rate. Though the impact is relatively small, it is directionally counter to energy conservation goals. If consistency between the residential and SGS basic charge is required, we would recommend considering lowering the % cost recovery in the residential sector, as opposed to increasing it in the general sector.***

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General Service Rates Workshop 11, Sessions A (June 25, 2015)
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Workshop 11A: Segmentation, SGS and MGS	
C. MGS Demand Charges 1. BC Hydro presented three alternatives for demand charges: i. Status Quo ii. Alternative A - flat demand charge + flat energy rate iii. Alternative B – two step demand charge + flat energy rate **BC Hydro seeks feedback on which of the three demand charge structure alternatives is preferred (with reasons). Please provide any comments in the column to the right.**	
2. Stakeholders requested BC Hydro model increased MGS demand charge cost recovery; BC Hydro modeled increasing the MGS demand cost recovery of flat demand from approximately 15% to 35% for Flat Energy Rate/Flat Demand Charge Alternative **BC Hydro seeks feedback on whether the MGS demand charge cost recovery should be increased, and if so to what level (with reasons). Please provide comments in the column to the right.**	***COPE sees merit in pursuing a flat demand and energy charge. The union doesn't support moving to a higher demand cost recovery to the extent that causes the flat energy rate to fall farther from the LRMC and as long as that demand rate is not based on system coincident peak.***
3. BC Hydro considered Transition Strategies for moving to a flat energy rate, and flat demand charge: • three-year phase–in • 10% bill impact Cap **BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.**	

2015 Rate Design Application (RDA) –
General Service Rates Workshop 11, Sessions A (June 25, 2015)
and B (June 26, 2015) Feedback Form

Workshop 11B: LGS Rate Structure

A. Preferred LGS Rate Structure (Slides 9 to 54 of Workshop 11B Presentation) **BC Hydro is seeking stakeholder feedback on which of the four energy rate structure alternatives and the three demand charge structure alternatives are preferred, and why. Please provide any comments you have in the column to the right.** **Energy rate alternatives:** 1. Status Quo LGS Energy rate (retain baseline) 2. Simplify energy rate structure (retain baseline): A. Flatten Part 1 Energy Rate B. Consider modify Baseline Rate Provisions: i. Determination of baselines (monthly versus annual versus rolling average, etc.) ii. Price limit bands (PLBs) to address concerns that rates are 'punitive to growing customers', and/or to encourage further conservation iii. Growth rules to make less restrictive iv. New account rules 3. LGS Flat Energy Rate (remove baseline structure) 4. LGS Flat Energy Rate for majority of LGS customers and create TSR-like rate with individually administered baselines for segment of very large LGS customers **Demand Charge alternatives:** 1. Status quo inclining three-step demand charge 2. Flat demand charge 3. Two-step demand charge	***In general, COPE sees merit in pursuing a flat demand and energy rate. However the union would be concerned with a rate that is well below the LRMC. We suggest a flat energy rate be combined with lower demand charge cost recovery, especially if the demand charge is not based on system coincident peak, and other measures such as seasonal or LLH discounts or customer credits in order to provide an appropriate incentive to conserve while maintaining revenue neutrality.***

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B. Flatten Part 1 Energy Rate (Slide 16 of June 26. 2015 Workshop Presentation) Flat Part 1 energy rate would be nominal simplification, as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers: • More customers better off than worse off, higher consuming customers have more adverse bill impacts **BC Hydro is seeking feedback on this option to flatten Part Energy Rate. Please provide any comments in the column to the right.**	***As stated above, COPE supports movement to a flat rate as opposed to baseline PLB, growth mitigation or other adjustments to the existing tiered rate.***
C. Baseline Rate Provisions (i) Baseline determination (slide 17 of 26 June Workshop 11B presentation) • BC Hydro considered baseline determination on annual basis versus monthly baseline calculation, and • Considered determining one-year and five-year rolling average baselines, versus status quo determination of three–year rolling average monthly baselines Annual baseline could create cash flow burden for many customers at year end. five-year rolling average baselines will further increase the complexity of the rate; one-year baselines could cause bill instability as unusual consumption months cannot be levelled in baselines. **If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right.** (ii) Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation) PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/-10%) and increasing the PBL (i.e. +/-30%) BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback. **If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB should be modified and if so, how. Please explain your response in the column to the right.**	

2015 Rate Design Application (RDA) –
General Service Rates Workshop 11, Sessions A (June 25, 2015)
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(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation)

The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh.

Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption.

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifications to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.

(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation)

In calculating HBLs, anomalously low consumption months from previous years are excluded:

- In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded
- Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule
- Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifications to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right

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(v) Growth Mitigation – Prospective Growth Rule (TS82) (Slides 24 to 25 of Workshop 11B Presentation)

Customers who anticipate 'significant', 'permanent' increases in energy consumption may apply to BC Hydro for modified pricing under TS 82 that may reduce their energy costs. Significant means a prospective first year annual increase in energy consumption totaling at least 30% or 4,000,000 kWh above the historical three-year average annual consumption. Permanent means arising from a significant capital investment.

- Very few customers have applied due to high thresholds
- Customers with lower consumption might meet the 30% threshold but may not benefit from the modified pricing structure
- High administrative cost to BC Hydro

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifications to or removal of the Prospective Growth Rule and if so, what. Please explain your response in the column to the right

(vi) New Accounts (85/15) (Slides 26 to 27 of Workshop 11B Presentation)

- 85/15 applies when a new account is set up in BC Hydro's billing system, regardless of whether there were changes in customers' operation
- First 85% of energy consumed in a monthly billing period is charged at the Part 1 rate. Last 15% of energy consumed in a monthly billing period is charged Part 2 LRMC rate
- Established to prevent customers from 'gaming' by opening new accounts to reset baselines

BC Hydro found no evidence of "gaming" in the LGS Three-Year Report. Customers raised concerns that 85/15 rate unfairly penalizes customers who have no change in operations during account ownership transfers.

If the baseline structure is maintained, BC Hydro would recommend applying 100% Part 1 rates for new accounts, and is seeking further stakeholder feedback. Please provide any comments in the column to the right.

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and B (June 26, 2015) Feedback Form

Workshop 11B: LGS Rate Structure

D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation)

Option: Flatten LGS Energy rate for all consumption levels

Pros:

- Eliminates all complexity from baseline component of status quo LGS energy rate
- Easier and more accurate customer forecasting
- Improved customer understanding
- Aligns with other Cdn. Jurisdictions

Cons:

- Energy rate is well below lower end of energy LRMC

Observations:

- Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b
- There are bill impacts from flattening Part 1 Energy rates; typical customers better off
- No change in conservation – zero forecast for planning purposes

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.

COPE supports a flat LGS energy rate combined with measures as discussed above provided it is done in such a way that it brings the rate closer to or within the LRMC range

(COPE)

<table>
<tr><th colspan="2">Workshop 11B: LGS Rate Structure</th></tr>
<tr><td>E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation)
Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers

Rate may have following elements based on BC Hydro's existing TSR – RS 1823:
• Available to large LGS accounts
• Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate:
• 5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year
• 10.10 cents/kWh applied to all kWh above 90% of customer's CBL in each billing year
• Initial annual CBL determined by historic baseline year(s)
• Allowable adjustments for DSM, plant capacity increases and force majeure
• Annual CBL approved each year by BCUC
BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.</td><td>COPE believes a TSR rate is problematic because of the limited conservation incentive it provides for customers operating at or near 90% of their CBL.</td></tr>
</table>

Workshop 11B: Optional Rates and Other Issues

A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation)

1. Voluntary Time of Use Rates

- BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo

2. Interruptible Rates

- BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined

3. Efficiency Rate Credit concept

- BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined

4. Demand Charge Options

- BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined

BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.

COPE recognizes that a TOU rate is currently prohibited by government but we think BC Hydro should be modelling TOU and seasonal rate and discounts to present to stakeholders, the BCUC, and government for their consideration. Absent such a model, it is difficult for parties to appreciate whether these types of rate structures might be in the public interest.

2015 Rate Design Application (RDA) –
General Service Rates Workshop 11, Sessions A (June 25, 2015)
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Workshop 11B: Optional Rates and Other Issues	
B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation) **1. Minimum Charges (Demand Ratchet)** Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March) Ratchet was reduced from 75% to 50% effective April 1, 1980 Based on F14 data: • MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%) • LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%) **BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.**	***COPE is generally supportive of recovering more of the revenue requirements through efficient flat energy and demand rates. That would suggest further reducing or eliminating the minimum charges.***

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2015 Rate Design Application (RDA) –
General Service Rates Workshop 11, Sessions A (June 25, 2015)
and B (June 26, 2015) Feedback Form

Workshop 11B: Optional Rates and Other Issues	
2. Transformer Ownership Discount (TOD) and Transformer Rentals • TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential • Last review of $0.25 /month discount was completed in August 2004 **BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right.** F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision. Design Considerations: • At-home charging (Residential) • Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power) • Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California 'super off-peak' concept to encourage late night to early morning charging? • Requirement of a separate meter? • Interaction with RIB? • Other? **BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.**	

Additional Comments:

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<tr><td>A. Cost of Service Analysis: Segmentation Methodology (Slides 17 to 21 of June 25, 2015 Workshop 11A Presentation). BC Hydro discussed two methods of segmentation:

<u>Method 1:</u>

BC Hydro took samples of 1,000 customers from each of SGS, MGS and LGS classes;

F16 Forecast costs assigned to GS rate classes pooled and re-allocated pro rata by individual customer kWh, 4 Coincident Peak (CP) demand, and Non-Coincident Peak (NCP) demand. Results of method 1 not conclusive:

• NCP allocation varies depending on coincidence within classes.
• Coincidence is better correlated with cost than customer size.
• Transformer cost may vary with size but cost impact is small.

<u>Method 2:</u>

Consider cost allocation based on pre-assigned segments of customers. Customers will be grouped by size as opposed to evaluated individually – to be reviewed at July 30, 2015 wrap-up workshop.

BC Hydro seeks stakeholder feedback on what other analysis of segmentation should be conducted. Please provide any comments in the column to the right.</td><td>The evidence provided by BC Hydro shows that cost allocation to customers is not particularly well accomplished with the existing methodology. The CEC does not see from the evidence any particularly useful segmentation methodology that would change this and concludes upon analysis that segmentation is best left as is for the general service rates.</td></tr>
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Workshop 11A: Segmentation, SGS and MGS	
B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation) BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%. Results: • Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery • Resulting energy rate remains within the LRMC and without substantial bill impacts **BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.**	The CEC expects that evidence supporting an increased basic charge would improve cost allocation to customers. The CEC has proposed examining some alternative methodologies and was asked to note those in an email to BC Hydro which the CEC did. BC Hydro advised that it would arrange a meeting to discuss these approaches but has not to date done so.

Workshop 11A: Segmentation, SGS and MGS	
C. MGS Demand Charges 1. BC Hydro presented three alternatives for demand charges: i. Status Quo ii. Alternative A - flat demand charge + flat energy rate iii. Alternative B – two step demand charge + flat energy rate **BC Hydro seeks feedback on which of the three demand charge structure alternatives is preferred (with reasons). Please provide any comments in the column to the right.**	The CEC expects that the Status Quo 3 step inclining block does not adequately and appropriately allocate costs to customers and that a 2 step demand would similarly have problems. The flat rate may have less problems than other alternatives but still would be a poor methodology.
2. Stakeholders requested BC Hydro model increased MGS demand charge cost recovery; BC Hydro modeled increasing the MGS demand cost recovery of flat demand from approximately 15% to 35% for Flat Energy Rate/Flat Demand Charge Alternative **BC Hydro seeks feedback on whether the MGS demand charge cost recovery should be increased, and if so to what level (with reasons). Please provide comments in the column to the right.**	The CEC expects that the evidence would show that increased demand charges might somewhat improve appropriate cost allocation to customers.
3. BC Hydro considered Transition Strategies for moving to a flat energy rate, and flat demand charge: • three-year phase–in • 10% bill impact Cap **BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.**	The CEC expects that a phase-in approach over a particular number of years would enable a balance between fairer cost allocation and impact transition fairness. The CEC is awaiting a meeting with BC Hydro to discuss alternatives it has proposed which may do a better job of cost allocation to customers. Choosing a level of demand charge based on the relationship of energy charge to LRMC is likely an inappropriate logic for cost allocation decisions.

Workshop 11B: LGS Rate Structure

A. Preferred LGS Rate Structure (Slides 9 to 54 of Workshop 11B Presentation) **BC Hydro is seeking stakeholder feedback on which of the four energy rate structure alternatives and the three demand charge structure alternatives are preferred, and why. Please provide any comments you have in the column to the right.** **Energy rate alternatives:** 1. Status Quo LGS Energy rate (retain baseline) 2. Simplify energy rate structure (retain baseline): A. Flatten Part 1 Energy Rate B. Consider modify Baseline Rate Provisions: i. Determination of baselines (monthly versus annual versus rolling average, etc.) ii. Price limit bands (PLBs) to address concerns that rates are 'punitive to growing customers', and/or to encourage further conservation iii. Growth rules to make less restrictive iv. New account rules 3. LGS Flat Energy Rate (remove baseline structure) 4. LGS Flat Energy Rate for majority of LGS customers and create TSR-like rate with individually administered baselines for segment of very large LGS customers **Demand Charge alternatives:** 1. Status quo inclining three-step demand charge 2. Flat demand charge 3. Two-step demand charge	The CEC expects that Status Quo baseline approach is unnecessary and conservation and efficiency may be better addressed through an alternative 'credit' mechanism. Modifying the baseline provision based on the evidence BC Hydro presented seems only to add complication. A base flat energy rate would appear to have the best opportunity to provide appropriate cost allocation. Administered baselines are costly and may not improve cost allocation to a degree which would justify the process. The CEC expects that a flat demand charge may be more appropriate for cost allocation than 3 or 2 step approaches. The CEC is awaiting a meeting with BC Hydro to discuss alternative approaches it raised during the process.

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B. Flatten Part 1 Energy Rate (Slide 16 of June 26, 2015 Workshop Presentation)

Flat Part 1 energy rate would be nominal simplification, as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers:

- More customers better off than worse off, higher consuming customers have more adverse bill impacts

BC Hydro is seeking feedback on this option to flatten Part Energy Rate. Please provide any comments in the column to the right.

</td><td>The CEC expects that a flattened energy rate would provide better cost allocation if combined with alternative approaches to demand charges.</td></tr>
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C. Baseline Rate Provisions

(i) Baseline determination (slide 17 of 26 June Workshop 11B presentation)

- BC Hydro considered baseline determination on annual basis versus monthly baseline calculation, and
- Considered determining one-year and five-year rolling average baselines, versus status quo determination of three–year rolling average monthly baselines

Annual baseline could create cash flow burden for many customers at year end. five-year rolling average baselines will further increase the complexity of the rate; one-year baselines could cause bill instability as unusual consumption months cannot be levelled in baselines.

If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right.

</td><td>Maintaining a 3 year rolling average ensures that the inadequate economic price signal is maintained making it undesirable as a rate structure. Extending the baseline adjustment period provides a better economic signal but adds other complications. There is no point to maintaining the SQ as it is not achieving a purpose so if retained then options for extension would need to be tried to determine if they would achieve the purpose.</td></tr>
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(ii) Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation)

PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/- 10%) and increasing the PBL (i.e. +/-30%)

BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback.

If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB shoud be modified and if so,how. Please explain your response in the column to the right.

</td><td>The CEC expects that there are no changes to price band limits that would materially change performance of the rate. If the structure is retained it should enable annual assessment as the monthly approach is too complex.</td></tr>
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Workshop 11B: LGS Rate Structure	
(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation) The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh. Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption. **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.**	One of the problems with the rate structure is its inability to distinguish productive growth from inefficient growth and/or use. Still if the rate is retained and 76% benefit form FGR provisons they should be retained and extended to others via lower thresholds. The 30% bar has proven too high.
(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation) In calculating HBLs, anomalously low consumption months from previous years are excluded: • In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded • Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule • Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right**	The CEC expects that the anomaly rule should be eliminated if the rate is retained in order to simplify the rate structure. A move to annual assessment of baseline would moderate some of the reasons behind the implementation of the anomaly rule.

Workshop 11B: LGS Rate Structure

(v) Growth Mitigation – Prospective Growth Rule (TS82) (Slides 24 to 25 of Workshop 11B Presentation) Customers who anticipate 'significant', 'permanent' increases in energy consumption may apply to BC Hydro for modified pricing under TS 82 that may reduce their energy costs. Significant means a prospective first year annual increase in energy consumption totaling at least 30% or 4,000,000 kWh above the historical three-year average annual consumption. Permanent means arising from a significant capital investment. • Very few customers have applied due to high thresholds • Customers with lower consumption might meet the 30% threshold but may not benefit from the modified pricing structure • High administrative cost to BC Hydro **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Prospective Growth Rule and if so, what. Please explain your response in the column to the right**	Along with FGR rule change to accommodate growth the PGR (TS82) should have relaxed thresholds and criteria to protect productive growth from inappropriate impacts. The implementation of this should be automated if the rate is retained in order to reduce BC Hydro's administrative costs.
(vi) New Accounts (85/15) (Slides 26 to 27 of Workshop 11B Presentation) • 85/15 applies when a new account is set up in BC Hydro's billing system, regardless of whether there were changes in customers' operation • First 85% of energy consumed in a monthly billing period is charged at the Part 1 rate. Last 15% of energy consumed in a monthly billing period is charged Part 2 LRMC rate • Established to prevent customers from 'gaming' by opening new accounts to reset baselines BC Hydro found no evidence of "gaming" in the LGS Three-Year Report. Customers raised concerns that 85/15 rate unfairly penalizes customers who have no change in operations during account ownership transfers. **If the baseline structure is maintained, BC Hydro would recommend applying 100% Part 1 rates for new accounts, and is seeking further stakeholder feedback. Please provide any comments in the column to the right.**	The prevalence of account changes and inappropriate bill impacts means that this provision should be adjusted to enable continuity on transfer change and 100% Part 1 for new accounts with no continuity. This can be controlled at the point of account set up by qualifying the reason for the new account.

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D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation)
Option: Flatten LGS Energy rate for all consumption levels
Pros:

Eliminates all complexity from baseline component of status quo LGS energy rate
Easier and more accurate customer forecasting
Improved customer understanding
Aligns with other Cdn. Jurisdictions

Cons:

Energy rate is well below lower end of energy LRMC

Observations:

Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b
There are bill impacts from flattening Part 1 Energy rates; typical customers better off
No change in conservation – zero forecast for planning purposes

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.
</td><td>The CEC expects that the flat energy rate will provide the best platform going forward and that other approaches to providing appropriate price signals will be the more productive approach to getting an optimal fit with Bonbright criteria.</td></tr>
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E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation)
Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers

Rate may have following elements based on BC Hydro's existing TSR – RS 1823:
• Available to large LGS accounts
• Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate:
• 5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year
• 10.10 cents/kWh applied to all kWh above 90% of customer's CBL in each billing year
• Initial annual CBL determined by historic baseline year(s)
• Allowable adjustments for DSM, plant capacity increases and force majeure
• Annual CBL approved each year by BCUC
BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.

</td><td>The CEC would suggest that if BC Hydro is going to pursue this it be an option and that it be considered in Module 2. There are some consequences of this approach that could be inappropriate for some customers and the costs of the process are likely not justified.</td></tr>
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A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation)
1. Voluntary Time of Use Rates
• BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo
2. Interuptible Rates
• BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined
3. Efficiency Rate Credit concept
• BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined
4. Demand Charge Options
• BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined
BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.
</td><td>The CEC expects that GS options 2,3 & 4 will be appropriate and useful and expects to fully participate in their development. The CEC has suggested that as a matter of fairness freshet rate considerations should be available for GS options as well.</td></tr>
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<tr><th colspan="2">Workshop 11B: Optional Rates and Other Issues</th></tr>
<tr><td>B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation)
1. Minimum Charges (Demand Ratchet)
Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March)
Ratchet was reduced from 75% to 50% effective April 1, 1980
Based on F14 data:
• MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%)
• LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%)
BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.</td><td>The CEC expects that the demand ratchet is an unnecessary complication which may be appropriately handled in demand charge allocation approaches.</td></tr>
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2. Transformer Ownership Discount (TOD) and Transformer Rentals

- TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential
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BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right.

F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision.

Design Considerations:

- At-home charging (Residential)
- Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power)
- Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California ‘super off-peak’ concept to encourage late night to early morning charging?
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- Other?

BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.

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The CEC will likely support reviewing extension policy as part of Module 2 and would likely be satisfied to review TOD and TR at athat time.

The CEC will likely support reviewing EV policy and rate design in Module 2. The use of EV is likely very small currently and not likely to change significantly over a year or so. Therefore EV policy and rates can appropriately be considered in Module 2. All of the considerations noted warrant attention at that time.

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Additional Comments:

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Workshop 11A: Segmentation, SGS and MGS	
B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation) BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%. Results: • Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery • Resulting energy rate remains within the LRMC and without substantial bill impacts **BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.**	*FNEMC supports increasing the SGS basic charge to be comparable to the RIB rate Basic Charge cost recovery and therefore closer to full fixed cost recovery without substational bill impacts.*

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1. BC Hydro presented three alternatives for demand charges:
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ii. Alternative A - flat demand charge + flat energy rate
iii. Alternative B – two step demand charge + flat energy rate

BC Hydro seeks feedback on which of the three demand charge structure alternatives is preferred (with reasons). Please provide any comments in the column to the right.
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BC Hydro modeled increasing the MGS demand cost recovery of flat demand from approximately 15% to 35% for Flat Energy Rate/Flat Demand Charge Alternative

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BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.
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<u>MGS Demand Charges</u>

FNEMC supports Alternative B (two step demand charge + flat energy rate). Given the evaluation results, the status quo energy rate structure, is poorly understood and does not provide a clear price signal for conservation. The two step demand charge is not substantially different than the SQ since few MGS customers have demand charges at T3; however, the bill impact analysis of the two step demand in comparison to the flat demand charge indicates that more customers would be better off. In addition, FNEMC supports tiered demand charges to encourage conservation behaviour.

<u>MGS Demand Charge Cost Recovery</u>

FNEMC supports increasing the MGS demand cost recovery to be closer to full fixed cost recovery and more consistent with other customer rate classes.

<u>Transition Strategies</u>

FNEMC supports the 3-year phase-in Transition Strategy rather than the 10% bill impact Cap phase-in since the estimated transition time is over 15 years. Since small consumption, low load factor customers may be the most affected by the 3-year phase-in, suggest BC Hydro offer some measure of rate relief for hardship on a case-by-case basis.
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CapWorkshop 11B: LGS Rate Structure	
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If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right.

(ii) Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation)

PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/- 10%) and increasing the PBL (i.e. +/-30%)

BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback.

If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB shoud be modified and if so,how. Please explain your response in the column to the right.

Flatten Part 1 Energy Rate

FNEMC supports flattening the Part 1 Energy Rate for the reasons BC Hydro has identified, specifically:

- *Nominal simplification as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers*
- *More customers are better off than worse off*

Baseline Rate Provisions

FNEMC has no comment on Baseline Rate Provisions.

<table>
<tr><th colspan="2">Workshop 11B: LGS Rate Structure</th></tr>
<tr><td>
(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation)
The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh.
Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption.
If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.
</td><td>Should BC Hydro maintain the baseline structure, FNEMC supports that the FGR provision be modified or removed based upon the analysis presented from BC Hydro and customer feedback.</td></tr>
<tr><td>
(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation)
In calculating HBLs, anomalously low consumption months from previous years are excluded:

In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded
Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule
Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills

If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right
</td><td>Should BC Hydro maintain the baseline structure, FNEMC supports that the Anomaly Rule be modified or removed based upon the analysis presented from BC Hydro.</td></tr>
</table>

Workshop 11B: LGS Rate Structure

(v) Growth Mitigation – Prospective Growth Rule (TS82) (Slides 24 to 25 of Workshop 11B Presentation) Customers who anticipate 'significant', 'permanent' increases in energy consumption may apply to BC Hydro for modified pricing under TS 82 that may reduce their energy costs. Significant means a prospective first year annual increase in energy consumption totaling at least 30% or 4,000,000 kWh above the historical three-year average annual consumption. Permanent means arising from a significant capital investment. • Very few customers have applied due to high thresholds • Customers with lower consumption might meet the 30% threshold but may not benefit from the modified pricing structure • High administrative cost to BC Hydro **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Prospective Growth Rule and if so, what. Please explain your response in the column to the right**	*Should BC Hydro maintain the baseline structure, FNEMC supports that the Prospective Growth Rule (TS82) be modified or removed based upon the analysis presented from BC Hydro and customer feedback.*
(vi) New Accounts (85/15) (Slides 26 to 27 of Workshop 11B Presentation) • 85/15 applies when a new account is set up in BC Hydro's billing system, regardless of whether there were changes in customers' operation • First 85% of energy consumed in a monthly billing period is charged at the Part 1 rate. Last 15% of energy consumed in a monthly billing period is charged Part 2 LRMC rate • Established to prevent customers from 'gaming' by opening new accounts to reset baselines BC Hydro found no evidence of "gaming" in the LGS Three-Year Report. Customers raised concerns that 85/15 rate unfairly penalizes customers who have no change in operations during account ownership transfers. **If the baseline structure is maintained, BC Hydro would recommend applying 100% Part 1 rates for new accounts, and is seeking further stakeholder feedback. Please provide any comments in the column to the right.**	*Should BC Hydro maintain the baseline structure, FNEMC supports that the New Accounts (85/15) be modified or removed based upon the analysis presented from BC Hydro and customer feedback.*

Workshop 11B: LGS Rate Structure	
D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation) **Option: Flatten LGS Energy rate for all consumption levels** Pros: • Eliminates all complexity from baseline component of status quo LGS energy rate • Easier and more accurate customer forecasting • Improved customer understanding • Aligns with other Cdn. Jurisdictions Cons: • Energy rate is well below lower end of energy LRMC Observations: • Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b • There are bill impacts from flattening Part 1 Energy rates; typical customers better off • No change in conservation – zero forecast for planning purposes **BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.**	*FNEMC does not have any preferred LGS energy rate at this time.*

Workshop 11B: LGS Rate Structure

<table>
<tr>
<td>
E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation)
Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers

Rate may have following elements based on BC Hydro’s existing TSR – RS 1823:
• Available to large LGS accounts
• Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate:
• 5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year
• 10.10 cents/kWh applied to all kWh above 90% of customer’s CBL in each billing year
• Initial annual CBL determined by historic baseline year(s)
• Allowable adjustments for DSM, plant capacity increases and force majeure
• Annual CBL approved each year by BCUC
BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.
</td>
<td>
FNEMC is supportive of a “TSR-like” energy rate that that would encourage conservation and customer DSM initiatives and therefore would support BC Hydro investigating further and entering into customer discussions as well as undertaking further analysis.
</td>
</tr>
</table>

Workshop 11B: Optional Rates and Other Issues	
A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation) **1. Voluntary Time of Use Rates** • BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo **2. Interuptible Rates** • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **3. Efficiency Rate Credit concept** • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **4. Demand Charge Options** • BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined **BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.**	*In addition to the General Service Optional Rates BC Hydro presented, FNEMC suggests BC Hydro also consider Freshet Energy Sales depending upon the experience of the TSR pilot program.*

<table>
<tr><th colspan="2">Workshop 11B: Optional Rates and Other Issues</th></tr>
<tr><td>B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation)
1. Minimum Charges (Demand Ratchet)
Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March)
Ratchet was reduced from 75% to 50% effective April 1, 1980
Based on F14 data:
• MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%)
• LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%)
BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.</td><td>FNEMC supports BC Hydro making adjustments to the Demand Ratchet such that consistency is maintained between the rate classes.</td></tr>
</table>

<table>
<tr><th colspan="2">Workshop 11B: Optional Rates and Other Issues</th></tr>
<tr><td>
2. Transformer Ownership Discount (TOD) and Transformer Rentals
• TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential
• Last review of $0.25 /month discount was completed in August 2004

BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right.

F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision.

Design Considerations:
• At-home charging (Residential)
• Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power)
• Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California 'super off-peak' concept to encourage late night to early morning charging?
• Requirement of a separate meter?
• Interaction with RIB?
• Other?

BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.
</td><td>
FNEMC supports the evaluation of TOD in conjunction with Distribution Extension Policy as part of the RDA Module 2. However, there is concern as to the extent and diversity of issues that are being addressed as part of Module 2 and maybe BC Hydro might consider a Module 3 or alternate process.

FNEMC supports BC Hydro developing an EV Rate to improve sustainability in BC's transportation sector.
</td></tr>
</table>

Additional Comments:

FNEMC submits these comments to BC Hydro on a without prejudice basis.

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:____________________ Date: ____________________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

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2015 Rate Design Application (RDA) – General Service Rates Workshop 11, Sessions A (June 25, 2015) and B (June 26, 2015) Feedback Form

<table>
<tr><td colspan="2">Name/Organization:</td></tr>
<tr><td></td><td>Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).</td></tr>
<tr><td colspan="2">Workshop 11A: Segmentation, SGS and MGS</td></tr>
<tr><td>A. Cost of Service Analysis: Segmentation Methodology (Slides 17 to 21 of June 25, 2015 Workshop 11A Presentation). BC Hydro discussed two methods of segmentation:

<u>Method 1:</u>

BC Hydro took samples of 1,000 customers from each of SGS, MGS and LGS classes;

F16 Forecast costs assigned to GS rate classes pooled and re-allocated pro rata by individual customer kWh, 4 Coincident Peak (CP) demand, and Non-Coincident Peak (NCP) demand. Results of method 1 not conclusive:

≠ NCP allocation varies depending on coincidence within classes.
≠ Coincidence is better correlated with cost than customer size.
≠ Transformer cost may vary with size but cost impact is small.

<u>Method 2:</u>

Consider cost allocation based on pre-assigned segments of customers. Customers will be grouped by size as opposed to evaluated individually – to be reviewed at July 30, 2015 wrap-up workshop.

BC Hydro seeks stakeholder feedback on what other analysis of segmentation should be conducted. Please provide any comments in the column to the right.</td><td>While the coincidence factor is better correlated with demand cost than customer size, customer service size is better correlated with service capital cost and OMA cost.</td></tr>
</table>

Workshop 11A: Segmentation, SGS and MGS	
B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation) BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%. Results: ≠ Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery ≠ Resulting energy rate remains within the LRMC and without substantial bill impacts **BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.**	**The SGS basic charge should be the same as the Residential Basic Charge for single phase, 240VAC services that are not greater than 200A. Above 200A an extra demand charge should apply.**

Workshop 11A: Segmentation, SGS and MGS	
C. MGS Demand Charges 1. BC Hydro presented three alternatives for demand charges: i. Status Quo ii. Alternative A - flat demand charge + flat energy rate iii. Alternative B – two step demand charge + flat energy rate **BC Hydro seeks feedback on which of the three demand charge structure alternatives is preferred (with reasons). Please provide any comments in the column to the right.** 2. Stakeholders requested BC Hydro model increased MGS demand charge cost recovery; BC Hydro modeled increasing the MGS demand cost recovery of flat demand from approximately 15% to 35% for Flat Energy Rate/Flat Demand Charge Alternative **BC Hydro seeks feedback on whether the MGS demand charge cost recovery should be increased, and if so to what level (with reasons). Please provide comments in the column to the right.** 3. BC Hydro considered Transition Strategies for moving to a flat energy rate, and flat demand charge: ≠ three-year phase–in ≠ 10% bill impact Cap **BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.**	**I support the flat demand and energy over a 3 year phase-in. The PF should be maintained above 0.95. The increase in the demand charge should be sufficient to fully recover the costs.**

Workshop 11B: LGS Rate Structure	
A. Preferred LGS Rate Structure (Slides 9 to 54 of Workshop 11B Presentation) **BC Hydro is seeking stakeholder feedback on which of the four energy rate structure alternatives and the three demand charge structure alternatives are preferred, and why. Please provide any comments you have in the column to the right.** **Energy rate alternatives:** 1. Status Quo LGS Energy rate (retain baseline) 2. Simplify energy rate structure (retain baseline): A. Flatten Part 1 Energy Rate B. Consider modify Baseline Rate Provisions: i. Determination of baselines (monthly versus annual versus rolling average, etc.) ii. Price limit bands (PLBs) to address concerns that rates are 'punitive to growing customers', and/or to encourage further conservation iii. Growth rules to make less restrictive iv. New account rules 3. LGS Flat Energy Rate (remove baseline structure) 4. LGS Flat Energy Rate for majority of LGS customers and create TSR-like rate with individually administered baselines for segment of very large LGS customers **Demand Charge alternatives:** 1. Status quo inclining three-step demand charge 2. Flat demand charge 3. Two-step demand charge	**For the majority of LGS customers, I support a LGS Flat Energy Rate and a flat demand charge based on the maximum annual demand with the caveat that the PF be maintained above 0.95.** **For the very large LGS customers, I support the creation of a TSR-like rate with or without baselines and with the caveat that the PF be maintained above 0.95.**

2015 Rate Design Application (RDA) –
General Service Rates Workshop 11, Sessions A (June 25, 2015)
and B (June 26, 2015) Feedback Form

Workshop 11B: LGS Rate Structure

B. Flatten Part 1 Energy Rate (Slide 16 of June 26, 2015 Workshop Presentation)

Flat Part 1 energy rate would be nominal simplification, as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers:

≠ More customers better off than worse off, higher consuming customers have more adverse bill impacts

BC Hydro is seeking feedback on this option to flatten Part Energy Rate. Please provide any comments in the column to the right.

Flatten the energy rate for customers who consume less than 14 MWh/month.

As the baseline causes unnecessary complications for those who consume less than 14 MWh/month, a flat rate similar to RS 1827 is preferred.

C. Baseline Rate Provisions

(i) Baseline determination (slide 17 of 26 June Workshop 11B presentation)

≠ BC Hydro considered baseline determination on annual basis versus monthly baseline calculation, and

≠ Considered determining one-year and five-year rolling average baselines, versus status quo determination of three–year rolling average monthly baselines

Annual baseline could create cash flow burden for many customers at year end. five-year rolling average baselines will further increase the complexity of the rate; one-year baselines could cause bill instability as unusual consumption months cannot be levelled in baselines.

If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right.

(ii) Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation)

PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/- 10%) and increasing the PBL (i.e. +/-30%)

BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback.

If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB shoud be modified and if so,how. Please explain your response in the column to the right.

Workshop 11B: LGS Rate Structure

(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation) The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh. Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption. **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.**	**No baseline.**
(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation) In calculating HBLs, anomalously low consumption months from previous years are excluded: ≠ In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded ≠ Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule ≠ Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right**	**No baseline.**

Workshop 11B: LGS Rate Structure	
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Workshop 11B: LGS Rate Structure

D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation)

Option: Flatten LGS Energy rate for all consumption levels

Pros:

- Eliminates all complexity from baseline component of status quo LGS energy rate
- Easier and more accurate customer forecasting
- Improved customer understanding
- Aligns with other Cdn. Jurisdictions

Cons:

- Energy rate is well below lower end of energy LRMC

Observations:

- Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b
- There are bill impacts from flattening Part 1 Energy rates; typical customers better off
- No change in conservation – zero forecast for planning purposes

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.

Flatten LGS Energy rate for all consumption levels up to 14 MWh consumption.

Workshop 11B: LGS Rate Structure

E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation)

Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers

Rate may have following elements based on BC Hydro's existing TSR – RS 1823:

- Available to large LGS accounts
- Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate:
- 5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year
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- Initial annual CBL determined by historic baseline year(s)
- Allowable adjustments for DSM, plant capacity increases and force majeure
- Annual CBL approved each year by BCUC

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.

TSR-Like Energy Rate for those that consume more than 14 MWh.

Workshop 11B: Optional Rates and Other Issues	
A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation) **1. Voluntary Time of Use Rates** ≠ BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo **2. Interuptible Rates** ≠ BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **3. Efficiency Rate Credit concept** ≠ BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **4. Demand Charge Options** ≠ BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined **BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.**	**No Comment**

Workshop 11B: Optional Rates and Other Issues	
B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation) **1. Minimum Charges (Demand Ratchet)** Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March) Ratchet was reduced from 75% to 50% effective April 1, 1980 Based on F14 data: ≠ MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%) ≠ LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%) **BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.**	**The minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March). The demand ratchet should be set to 75% of the annual peak demand similar to TSR.**

**2015 Rate Design Application (RDA) –
General Service Rates Workshop 11, Sessions A (June 25, 2015)
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Workshop 11B: Optional Rates and Other Issues	
2. Transformer Ownership Discount (TOD) and Transformer Rentals ≠ TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential ≠ Last review of $0.25 /month discount was completed in August 2004 **BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right.** F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision. Design Considerations: • At-home charging (Residential) • Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power) • Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California 'super off-peak' concept to encourage late night to early morning charging? • Requirement of a separate meter? • Interaction with RIB? • Other? **BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.**	**Do not support changes to Transformer Ownership Discount unless cost recovery is an issue.** **No special consideration should be given to at home EV charging other than TOU rates.**

Additional Comments:

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:________Donald Flintoff______________________ Date: __August 12,2015__________________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

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THRIFTY FOODS™

(Thrifty Foods)

2014 POWER SMART LEADER BC hydro powersmart

BC Hydro Regulatory Group
16th Floor
333 Dunsmuir Street
Vancouver, BC V6B 5R3

July 9, 2015

ATT: 2015 RDA

To Whom It May Concern,

Thrifty Foods attended the recent Large General Service Rate Design Application Workshops and have reviewed the various proposed changes. We found the process very informative and transparent, and would like to offer the following comments;

In general we are in support of the current LGS rate structure. Since its implementation we have undertaken a rigorous program of energy conservation and have reduced the energy intensity at our stores by 20%. The current rate structure has allowed us to include the Part 2 savings in our business plans when considering energy conservation projects and this has often made the difference in whether to proceed by reducing the simple payback period by 25% or more.

Also, the ongoing Part 2 credits that result from the implementation of energy conservation projects serve to motivate both store management and our executive team to continue working toward further energy conservation savings. In this regard we are concerned that the removal of the Part 2 credit will reduce the savings that we anticipated when calculating the returns on our energy conservation investment. In fairness we feel that this must be considered before any changes are made to the current rate structure.

(Thrifty Foods)

Regarding the apparent lack overall of energy reduction within the LGS customer group, we wonder whether general growth has masked many of these savings. We have experienced this at some of our locations; however we realize that our energy conservation efforts have allowed us to avoid the penalty side of the equation. It would be interesting to study how companies that have implemented verified Power Smart projects have fared under this rate structure.

While we are in favour of the current rate structure we would like to suggest some possible improvements to the structure and to the current Power Smart Program in general;

1. Eliminate the Part 1, Tier 1 charge. It is insignificant and adds unnecessary complexity to the bill.
2. Simplify the bill and make it more readable – use it as an educational tool.
3. Make the Part 2 credits (and charges) more prominent. Celebrate the successes of those organizations that have received a credit and point out the costs to those that have received extra charges. In the case of large companies who are receiving electronic bills, there may be a need for special mailings or other forms of communication this message to the company decision makers.
4. **Eliminate the 85/15 rule for new accounts that are simply undergoing a name change. This rule can be very punitive and undermines the spirit of energy conservation that BC Hydro is striving to foster.**
5. Make Power Smart incentive applications simpler and less expensive for the consumer. Make incentive applications more prescriptive so that customers do not need to hire expensive consultants and endure long review periods in order to move forward with energy conservation measures.
6. Provide financial assistance to customers for on-site renewable energy. Thrifty Foods (and no doubt many other companies) are very interested in investing in on-site energy production technologies; however the costs are inhibiting our progress. We feel that British Columbia has fallen behind in this area, and that it is BC Hydro's responsibility to promote this technology by encouraging popular acceptance and thereby driving down costs

(Thrifty Foods)

In conclusion we would like to thank BC Hydro for the opportunity to be a part of this process and hope for a positive outcome. We have a long and strong business relationship with BC Hydro and hope to continue this relationship well into the future. Please feel free to contact me to discuss any of the issues brought forward in this letter.

Sincerely,

Jerry Wyshnowsky
Manager, Energy & Environment
Thrifty Foods
100-6776 Oldfield Crescent
Saanichton, BC V8M 2A3
jwyshnowsky@thriftyfoods.com

Head Office
6649 Butler Crescent
Saanichton, BC
V8M 1Z7
Tel: 250 483 1600
Fax: 250 483 1601
www.thriftyfoods.com

2015 Rate Design Application (RDA) – General Service Rates Workshop 11, Sessions A (June 25, 2015) and B (June 26, 2015) Feedback Form

Name/Organization:	
Whistler Blackcomb	**Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Workshop 11A: Segmentation, SGS and MGS	
A. Cost of Service Analysis: Segmentation Methodology (Slides 17 to 21 of June 25, 2015 Workshop 11A Presentation). BC Hydro discussed two methods of segmentation: Method 1: BC Hydro took samples of 1,000 customers from each of SGS, MGS and LGS classes; F16 Forecast costs assigned to GS rate classes pooled and re-allocated pro rata by individual customer kWh, 4 Coincident Peak (CP) demand, and Non-Coincident Peak (NCP) demand. Results of method 1 not conclusive: • NCP allocation varies depending on coincidence within classes. • Coincidence is better correlated with cost than customer size. • Transformer cost may vary with size but cost impact is small. Method 2: Consider cost allocation based on pre-assigned segments of customers. Customers will be grouped by size as opposed to evaluated individually – to be reviewed at July 30, 2015 wrap-up workshop. **BC Hydro seeks stakeholder feedback on what other analysis of segmentation should be conducted. Please provide any comments in the column to the right.**	Anything that makes bill calculations and forecasting even more complicated is not preferrable. Annual baselines might be better for Whistler Blackcomb because of fluctuations in snowmaking production in winter months. Method 1 preferable to method 2. Elimination of GS rates preferable overall. Rates need to be simplified.

<table>
<tr><th colspan="2">Workshop 11A: Segmentation, SGS and MGS</th></tr>
<tr><td>B. SGS –SGS Basic Charge (Slides 22 to 27 of June 25, 2015 Workshop 11A Presentation)

BC Hydro was asked to model increasing the SGS basic charge to a level comparable to the Residential Basic Charge cost recovery, from the current 35% level to 45%.

Results:
• Increasing SGS basic charge to 45% of cost recovery is closer to full fixed cost recovery
• Resulting energy rate remains within the LRMC and without substantial bill impacts

BC Hydro seeks feedback on whether BC Hydro should increase the SGS basic charge cost recovery comparable to Residential Basic Charge cost recovery. Please provide any comments in the column to the right.</td><td>45% basic charges that do not show significant bill impacts are not an issue for us on SGS accounts. Even on a flat rate for consumption beyond the basic charge, our conservation efforts will be reflected in savings at these smaller locations.</td></tr>
</table>

Workshop 11A: Segmentation, SGS and MGS	
C. MGS Demand Charges 1. BC Hydro presented three alternatives for demand charges: i. Status Quo ii. Alternative A - flat demand charge + flat energy rate iii. Alternative B – two step demand charge + flat energy rate **BC Hydro seeks feedback on which of the three demand charge structure alternatives is preferred (with reasons). Please provide any comments in the column to the right.** 2. Stakeholders requested BC Hydro model increased MGS demand charge cost recovery; BC Hydro modeled increasing the MGS demand cost recovery of flat demand from approximately 15% to 35% for Flat Energy Rate/Flat Demand Charge Alternative **BC Hydro seeks feedback on whether the MGS demand charge cost recovery should be increased, and if so to what level (with reasons). Please provide comments in the column to the right.** 3. BC Hydro considered Transition Strategies for moving to a flat energy rate, and flat demand charge: • three-year phase–in • 10% bill impact Cap **BC Hydro seeks feedback on which of the two high-level alternative MGS rate transition strategies is preferred (with reasons). Please provide any comments in the column to the right.**	1. Option ii preferred. To simplify rates for forecasting of annual utilities and operational/project costs 2. Increasing cost recovery in MGS is preferred to take burden from LGS accounts 3. 10% bill impact cap preferred for simplicity

Workshop 11B: LGS Rate Structure

A. Preferred LGS Rate Structure (Slides 9 to 54 of Workshop 11B Presentation)	A. Preference for Option 3 for energy rates. Simplify the rate. Cost increases will be enough of an incentive for conservation. Simplifies forecasting. This is what we do anyway because current rates are too complicated to explain without frustration from senior leadership team. We take total cost divided by number of kWh to determine cost per kWh.
BC Hydro is seeking stakeholder feedback on which of the four energy rate structure alternatives and the three demand charge structure alternatives are preferred, and why. Please provide any comments you have in the column to the right. **Energy rate alternatives:** 1. Status Quo LGS Energy rate (retain baseline) 2. Simplify energy rate structure (retain baseline): A. Flatten Part 1 Energy Rate B. Consider modify Baseline Rate Provisions: i. Determination of baselines (monthly versus annual versus rolling average, etc.) ii. Price limit bands (PLBs) to address concerns that rates are 'punitive to growing customers', and/or to encourage further conservation iii. Growth rules to make less restrictive iv. New account rules 3. LGS Flat Energy Rate (remove baseline structure) 4. LGS Flat Energy Rate for majority of LGS customers and create TSR-like rate with individually administered baselines for segment of very large LGS customers **Demand Charge alternatives:** 1. Status quo inclining three-step demand charge 2. Flat demand charge 3. Two-step demand charge	Demand Charge: Preference for Option 2. To simplify. No need for two or three stage as first stages are too small to be significant. We use one basic cost per kW for explanation and forecasting. Again, rate and demand cost increases are enough of an incentive for demand management. Demand charges even at a flat rate are significant enough on LGS accounts to warrant real efforts in demand management.

Workshop 11B: LGS Rate Structure	
B. Flatten Part 1 Energy Rate (Slide 16 of June 26, 2015 Workshop Presentation) Flat Part 1 energy rate would be nominal simplification, as Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers: • More customers better off than worse off, higher consuming customers have more adverse bill impacts **BC Hydro is seeking feedback on this option to flatten Part Energy Rate. Please provide any comments in the column to the right.**	B. Favour flattening of part 1 as it is not significant in LGS accounts.
C. Baseline Rate Provisions **(i) Baseline determination (slide 17 of 26 June Workshop 11B presentation)** • BC Hydro considered baseline determination on annual basis versus monthly baseline calculation, and • Considered determining one-year and five-year rolling average baselines, versus status quo determination of three–year rolling average monthly baselines Annual baseline could create cash flow burden for many customers at year end. five-year rolling average baselines will further increase the complexity of the rate; one-year baselines could cause bill instability as unusual consumption months cannot be levelled in baselines. **If the baseline structure is maintained, BC Hydro would recommend no change to status quo three-year rolling average monthly baseline and seeks further stakeholder feedback. Please explain your responses in the column to the right.**	C. i) Annual baseline would be preferable due to winter fluctuations due to snowmaking and simpler explanation to Senior Leaders. We would have to prepare for charges that may come at the end of the year, but when we are working toward one baseline, we are more easily able to track where we are at. Annual baseline might motivate more toward conservation because it is one target that is easier to explain. Anything that would further complicate this rate is not preferred. If baseline structure maintained, would prefer annual baseline based on three-year rolling average.
(ii) Price Band Limit (PLBs) (Slides 18 to 19 of Workshop 11B Presentation) PLB limits customer's exposure to Part 2 LRMC energy rate within a range of 80% of historic baseline (HBL) to 120% of HBP (+/- 20%). BC Hydro modelled decreasing the PLB (i.e. +/- 10%) and increasing the PBL (i.e. +/-30%) BC Hydro continues to believe there are no changes to PLBs that would improve performance of status quo LGS Energy rate in respect of conservation or customer understanding and acceptance, and is seeking further feedback. **If the baseline structure is maintained, BC Hydro seeks feedback on whether the PLB shoud be modified and if so,how. Please explain your response in the column to the right.**	ii) Because of the size of LGS accounts, changing the PLB is unlikely to have an impact on our bills. Increases or declines in energy usage are unlikely to exceed even 10%.

Workshop 11B: LGS Rate Structure	
(iii) Growth Mitigation – Formulaic Growth Rate (FGR) (Slides 20 to 21 of Workshop 11B Presentation) The Customer HBLs for the upcoming 12-month period will be re-determined by BC Hydro based on the two most recent years of consumption history if the Customer experiences significant growth i.e., following a year (Y3) in which energy consumption exceeded previous year's (Y2) energy consumption by at least: (i) 30%, or (ii) 4,000,000 kWh. Bill analysis showed 24% of accounts that qualified for FGR in F2015 ended up having higher bills with the baseline adjustment. Future bills are unpredictable due to multiple variables involved in billing – past, current and future consumption. **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the FGR provision and if so, what. Please explain your response in the column to the right.**	iii) 30% or 4,000,000 kWh is too high of a threshold for consideration of consumption increases due to growth. With the size of our accounts, even a very large addition to infrastructure would not meet the thresholds for any consideration and therefore would be subjected to conservation rate penalties. If LGS were to continue, there would need to be more consideration to business growth. This will further complicate the process and BCH would be unlikely to come up with a solution for most businesses that would be feasible or fair. A flat rate structure will be a simpler way to assess costs of new infrastructure and expanded operations. The time and effort that would be required for fair assessment of business infrastructure additions would make the LGS business case even less successful than it has been thus far.

(iv) Growth Mitigation- Anomaly Rule (Slides 22 to 23 of Workshop 11B Presentation) In calculating HBLs, anomalously low consumption months from previous years are excluded: • In calculating HBL for a particular month, consumption in a historical month that is less than half the consumption in the next lowest month of all months otherwise used for calculation would be excluded • Up to four HBLs can be adjusted per BCH's fiscal year in accordance with the Anomaly Rule • Customers will always end up with higher baselines; however, higher baselines sometimes create higher bills **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Anomaly Rule provision and if so, what. Please explain your response in the column to the right**	iv) This Anolmaly Rule is unlikely to ever apply to us. A flat rate would reflect cost reductions for less consumption and there would be no impact on baselines, because there would be no baselines.
Workshop 11B: LGS Rate Structure	
(v) Growth Mitigation – Prospective Growth Rule (TS82) (Slides 24 to 25 of Workshop 11B Presentation) Customers who anticipate 'significant', 'permanent' increases in energy consumption may apply to BC Hydro for modified pricing under TS 82 that may reduce their energy costs. Significant means a prospective first year annual increase in energy consumption totaling at least 30% or 4,000,000 kWh above the historical three-year average annual consumption. Permanent means arising from a significant capital investment. • Very few customers have applied due to high thresholds • Customers with lower consumption might meet the 30% threshold but may not benefit from the modified pricing structure • High administrative cost to BC Hydro **If the baseline structure is maintained, BC Hydro seeks feedback on whether there should be modifcations to or removal of the Prospective Growth Rule and if so, what. Please explain your response in the column to the right**	v) Again, this is too high a threshold for most customers to meet. Even with significant infrastructure additions, we would not meet these thresholds in LGS accounts. A flat rate structure will more accurately reflect the costs of growth and help with forecasting of the true costs. With such a high threshold, we will always be penalized for new infrastructure additions and extended operating hours due to the positive growth of our business.

(vi) New Accounts (85/15) (Slides 26 to 27 of Workshop 11B Presentation) • 85/15 applies when a new account is set up in BC Hydro's billing system, regardless of whether there were changes in customers' operation • First 85% of energy consumed in a monthly billing period is charged at the Part 1 rate. Last 15% of energy consumed in a monthly billing period is charged Part 2 LRMC rate • Established to prevent customers from 'gaming' by opening new accounts to reset baselines BC Hydro found no evidence of "gaming" in the LGS Three-Year Report. Customers raised concerns that 85/15 rate unfairly penalizes customers who have no change in operations during account ownership transfers. **If the baseline structure is maintained, BC Hydro would recommend applying 100% Part 1 rates for new accounts, and is seeking further stakeholder feedback. Please provide any comments in the column to the right.**	vi) Structure a flat rate and this will not be a problem. New accounts are based on their consumption and demand usage. Customers will be taxing BCH resources and infrastructure plans in an effort to establish new accounts. If we have a large construction project planned that could be on our existing account, we will go to great lengths to establish a new account because of LGS. This means engaging BCH staff for this infrastructure planning.

Workshop 11B: LGS Rate Structure

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D. LGS Flat Energy Rate (No Baseline) (Slides 29 to 30, June 26, 2015 Workshop Presentation)

Option: Flatten LGS Energy rate for all consumption levels

Pros:

- Eliminates all complexity from baseline component of status quo LGS energy rate
- Easier and more accurate customer forecasting
- Improved customer understanding
- Aligns with other Cdn. Jurisdictions

Cons:

- Energy rate is well below lower end of energy LRMC

Observations:

- Little to no bill impacts resulting solely from removal of baseline, as demonstrated in Workshop 8b
- There are bill impacts from flattening Part 1 Energy rates; typical customers better off
- No change in conservation – zero forecast for planning purposes

BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.

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D. I think the list of pros, cons and observations speak for themselves. Any further investment in a rate structure that is not understood by customers after years of trying and has no impact on conservation would be fiscally irresponsible. The rate is not delivering the intended results by any stretch and it is time to move on. With the statistics on the success of this rate, there should not even be any question. The flattening of the rates should be inevitable.

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Workshop 11B: LGS Rate Structure

E. TSR-Like Energy Rate (Slides 32 to 34 of June 26, 2015 workshop Presentation) Viterra and AMPC suggested a TSR-like rate for high consumption LGS customers Rate may have following elements based on BC Hydro's existing TSR – RS 1823: • Available to large LGS accounts • Energy Rate (F2017) – illustrative based on RS 1823 90/10 split and rate neutral to LGS Flat energy rate: • 5.48 cents/kWh applied to all kWh up to and including 90% of Customer Baseline load (CBL) in each billing year • 10.10 cents/kWh applied to all kWh above 90% of customer's CBL in each billing year • Initial annual CBL determined by historic baseline year(s) • Allowable adjustments for DSM, plant capacity increases and force majeure • Annual CBL approved each year by BCUC **BC Hydro is seeking feedback on this option. Please provide any comments in the column to the right.**	E. For our LGS accounts, a basic flat rate structure would be sufficient

Workshop 11B: Optional Rates and Other Issues	
A. General Service Optional Rates (Sides 56 to 62 of June 26, 2015 Workshop 11B Presentation) **1. Voluntary Time of Use Rates** • BC Hydro has no plan to proceed developing this option at this time for reasons set out in section 6.1 of Workshop 8A/8B Consideration Memo **2. Interuptible Rates** • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **3. Efficiency Rate Credit concept** • BC Hydro proposes to assess this option as part of RDA Module 2, after default GS rates determined **4. Demand Charge Options** • BC Hydro proposes to assess these options as part of RDA Module 2, after default GS rates determined **BC Hydro is seeking feedback on the above proposals, and also on preliminary comments on options identified to date, and if there are any other GS rate options BC Hydro should consider. Please explain your response in the column to the right.**	1. We would like to see what Voluntary Time of Use rates look like as our peak consumption times are outside of the usual peak times 2. We would like to see that this would look like and if it could be beneficial for us and for BCH 3. We would like to see how this would impact our business 4. We would like to see a flat rate on demand and a change in ratchet charge structure

Workshop 11B: Optional Rates and Other Issues	
B. Other Issues (Slides 64 to 66 of Workshop 11B Presentation) **1. Minimum Charges (Demand Ratchet)** Existing minimum charge is based on 50% of peak monthly demand registered in most recent winter period (November to March) Ratchet was reduced from 75% to 50% effective April 1, 1980 Based on F14 data: • MGS minimum charges: approximately $135,000 on total revenue of approximately $329 million (0.4%) • LGS minimum charges: approximately $1.6 million on about $764 million, excluding rate rider (0.2%) **BC Hydro is seeking feedback on the current Demand Ratchet. Please explain your response in the column to the right.**	B. 1. We do not support increase in rachet charges. With a business that is far busier in the winter than in the summer, we see summer ratchet penalties. This can be a disincentive to conservation in the summer months because there is a feeling that we are paying for it anyway. Maintaining a conservation culture in the organization requires incentive to conserve all year long.

(Whistler)

Workshop 11B: Optional Rates and Other Issues	
2. Transformer Ownership Discount (TOD) and Transformer Rentals • TOD rate is $0.25 per month per kW of billing demand if customer supplies transformation from primary potential to secondary potential • Last review of $0.25 /month discount was completed in August 2004 **BC Hydro proposes to evaluate TOD in conjunction with Distribution Extension Policy as part of RDA Module 2, and is seeking feedback on this recommended approach. Please explain your response in the column to the right.** F2015 RDA to first set the Residential default rate, and to consider the development of an EV rate after the 2015 RDA Module 1 decision. Design Considerations: • At-home charging (Residential) • Basis on which to determine cost of service and load implications for pricing – different pattern of energy consumption (battery storage of electric power) • Mechanism to enforce off-peak charging – time varying component (Time of Use; price differential is an issue; adopt California 'super off-peak' concept to encourage late night to early morning charging? • Requirement of a separate meter? • Interaction with RIB? • Other? **BC Hydro seeks stakeholder feedback on rate design considerations presented above and the timing of any future EV rate proposal. Please explain your response in the column to the right.**	2 The current structure works for our purposes

Additional Comments:

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:____Allana Williams____________________ Date: __September 14, 2015__________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

You can return completed feedback forms by:

Mail: BC Hydro, BC Hydro Regulatory Group – “Attention 2015 RDA”, 16th Floor, 333 Dunsmuir St. Van. B.C. V6B-5R3

Fax number: 604-623-4407 – “Attention 2015 RDA”

Email: bchydroregulatorygroup@bchydro.com

Form available on Web: http://www.bchydro.com/about/planning_regulatory/regulatory.html

Any personal information you provide to BC Hydro on this form is collected and protected in accordance with the ***Freedom of Information and Protection of Privacy Act***. BC Hydro is collecting information with this for the purpose of the 2015 RDA in accordance with BC Hydro’s mandate under the ***Hydro and Power Authority Act***, the BC Hydro Tariff, the ***Utilities Commission Act*** and related Regulations and Directions. If you have any questions about the collection or use of the personal information collected on this form please contact the BC Hydro Regulatory Group via email at: bchydroregulatorygroup@bchydro.com

2015 Rate Design Application

June 25, 2015/June 26, 2015

Workshop Nos. 11a and 11b

Large General Service (LGS)

Medium General Service (MGS)

Small General Service (SGS)

Rate Structures

BC Hydro Summary and

Consideration of Participant Feedback

Attachment 3

Default General Service Charges and Optional Rates Survey – Canada 2015, and Expanded Canadian Jurisdictional Review of General Service Segmentation

Index of Tables

Comment

- Tables 1 and 2 were included as Attachment 5 to BC Hydro's Workshop 8a/8b Consideration memo and also included as a Appendix to the Workshop 11b presentation materials and posted on the RDA website.
    - Tables 1 and 2 have been updated to include reference to Hydro Quebec's rates for Large Power customers
- Table 3 below was presented as 'Table 1' in Section 1 of BC Hydro's Workshop 8a/8b Consideration memo.
    - Table 3 has been corrected to remove the reference under Manitoba Hydro that defines a small general service class as 50kVa. The Manitoba small general service class is defined by demand <= 200 kVa. Customers within that class face an inclining block demand charge, but for demand less than 50kVa there is no charge under that structure.
    - Table 3 has also been corrected to remove the reference under Newfoundland Power that the small general service class does not pay a demand charge; rather, customers face a seasonal demand charge as reported in Table 1.
- The correction noted above that Manitoba Hydro small general service customers with demand less than 50kVa do not pay a demand charge suggests an important observation to note on the comparability of the BC Hydro small general service (**SGS**) class with other utility small general service classes and whether demand charges are applicable:
    - BC Hydro's SGS class is defined by demand less than 35 kW, and SGS customers do not face a demand charge.
    - Table 1 highlights that there is no demand charge for comparably low levels of demand (e.g. <50kVa, <50kW, <20kW).
    - Table 3 highlights that other surveyed utilities also do not charge for the demand of small general service customers.
    - Thus, BC Hydro observes that its SGS class is comparable to most utilities in Canada in not charging for demand.

Table 1: Overview of Default General Service Charges – June 2015 – Canada

Canadian Utility	General Service Rate Class	Definition of Class + Energy Charge	Demand Charge	Minimum Bill
SaskPower	Small Commercial	Commercial and municipal loads <= 75 kilovolt amperes (kVA) **Energy Charge = Declining 2 Step**	**Inclining 2 Step** First 50 kVA/month = $0 (Urban (U) & Rural (R)) Balance $/kVA = 13.10 (U) Balance $/kVA = 13.41 (R)	Basic Monthly Charge (~$27(U), ~$37 (R)) *plus* $4.24/kVA of the maximum recorded demand over 50 kVA over the past 11 months
	Standard	Non-residential & non-farm loads > 75 kVA **Energy Charge = Declining 2 Step**	**Inclining 2 Step** First 50 kVA/month = $0 (U & R) Balance $/kVA = 13.40 (U & R)	Basic Monthly Charge (~$50 (U), ~$58 (R)) *plus* $4.24/kVA of the maximum recorded demand over 50 kVA over the past 11 months)
Manitoba Hydro	Small	Non-residential loads <= 200 kVA **Energy Charge = Declining 3 Step**	**Inclining 2 Step** First 50 kVA/month = $0 Balance $/kVA = $9.09	Minimum monthly bill is the Basic Charge (~$28, 3 phase) + Demand Charge
	Medium	Non-residential loads > 200 kVA **Energy Charge = Declining 3Step**	**Inclining 2 Step** First 50 kVA/month = $0 Balance $/kVA = $9.09	Minimum monthly bill is the Basic Charge (~$29) + Demand Charge Demand Charge is applied to the Monthly Billing Demand defined as the greater of the following expressed in kVA: • measured demand • 25% of contract demand • 25% of the highest measured demand in any of the previous 12 months
Hydro Quebec	Rate G: Small Power	Minimum demand < 65 kW **Energy Charge = Declining 2 Step**	**Inclining 2 Step** First 50 kW/month = $0 Balance $/kW = $17.19	Minimum billing demand for any given consumption period is equal to 65% of the maximum power demand during a consumption period that falls wholly in the winter period included in the 12 consecutive monthly periods ending at the end of the given consumption period
	Rate M: Medium Power	Maximum demand > 50 kW at least once in last 12 billing periods **Energy Charge = Declining 2 Step**	**Flat** $14.37/kW	
	Rate L: Large Power (industrial)	Minimum billing demand >= 5MW and principally for an industrial activity **Energy Charge = Flat**	**Flat** $12.87/kW	Additional charge for billing demand in excess of 110% of contract power = $7.53/kW per day Monthly maximum charge = $22.59/kW

Canadian Utility	General Service Rate Class	Definition of Class + Energy Charge	Demand Charge	Minimum Bill
	Rate LG: Large Power (non-industrial)	Minimum billing demand >= 5MW and principally for non- industrial activity **Energy Charge = Flat**	**Flat** $13.05/kW	The minimum billing demand for any given consumption period is equal to 75% of the maximum power demand during a consumption period that falls wholly in the winter period included in the 12 consecutive monthly periods ending at the end of the given consumption period.
Nova Scotia Power	Small Commercial	Annual consumption < 32,000 kWh **Energy Charge = Declining 2 Step**	**No Demand Charge**	
	Commercial	Annual consumption >= 32,000 kWh & regular billing demand is less than 2,000 kVA or 1,800 kW **Energy Charge = Declining 2 Step**	**Flat** $10.497/month/kW maximum demand	The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65
	Large Commercial	Consumption for any use except industrial, where the regular billing demand is 2,000 kVA or 1,800 kW and over **Energy Charge = Flat**	**Flat** $13.345/month/kVA of maximum demand of the current month	Demand charge applied to maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months
Newfoundland Power	General Service	< 100 kW (110 kVA) **Energy Charge = Declining 2 Step**	**Seasonal** **(higher rates in 4 winter mo.)** $8.68 per kW of billing demand in the months of December, January, February and March and $6.18 per kW in all other months.	~22/month (single phase) (Basic) ~36/month (three phase)
		110 kVA (100 kW) – 1000 kVa **Energy Charge = Declining 2 Step**	**Seasonal** **(higher rates in 4 winter mo.)** $7.54 per kVA of billing demand in the months of December, January, February and March and $5.04 per kVA in all other months.	~50/month (Basic)
		> 1000 kVa **Energy Charge = Declining 2 Step**	**Seasonal** **(higher rates in 4 winter mo.)** $7.12 per kVA of billing demand in the months of December, January, February and March and $4.62 per kVA in all other months.	~85/month (Basic)

Canadian Utility	General Service Rate Class	Definition of Class + Energy Charge	Demand Charge	Minimum Bill
New Brunswick Power	Standard	Electricity use other than residential, small and large industrial, street lighting or unmetered categories **Energy Charge = Declining 2 Step**	**Inclining 2 Step** First 20 kW/month = $0 Balance $/kW = $10.05	Basic Charge: $21.78 per Billing Period
ATCO Electric Yukon	General Service	**Multiple Energy Structures** 1. Hydro – Gov. Municipal 2. Hydro – Gov. Federal 3. Hydro – Non-Government	**Flat** 1. $7.39/kW/month 2. $12.31/kW/month 3. $7.39/kW/month	1. $36.95 / month (5 kW) 2. $61.55 / month (5 kW) 3. $36.95 / month (5 kW)
FortisBC	Small Commercial	Demand generally < 40 kW **Energy Charge = Flat**	**Not applicable**	Customer Charge $34.87 (60 day billing period)
	Commercial	Demand > 40 kW, < 500 kW **Energy Charge = Declining 2 Step**	**Inclining 2 Step** First 40 kW/month = $0 Balance $/kW = $7.73	The greatest of: • 25% of Contract Demand • maximum Demand in kW (kVA Large Commercial) • 75% of the maximum Demand in kW (kVA Large Commercial) registered during the months previous eleven month period
	Large Commercial	Demand >= 500 kW **Energy Charge = Flat**	**Flat** $8.25 / kVA	
BC Hydro	Small	Demand < 35kW **Energy Charge = Flat**	**Not applicable**	Basic Charge = 22.57 cents per day
	Medium	Demand >= 35 kW, <150 kW, or energy consumption in any 12 month period equal to or less than 550,000 kWh **Energy Charge = Baseline Rate**	**Inclining 3 Step** • First 35 kW = $0 • Next 115 kW = $5.50/kW/mo • All additional kW = $10.55/ kW/mo	50% of the highest maximum Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding eleven Billing Periods
	Large	Demand >= 150 kW, or energy consumption in any 12 month period greater than 550,000 kWh **Energy Charge = Baseline Rate**	**Inclining 3 Step** • First 35 kW = $0 • Next 115 kW = $5.50/kW/mo • All additional kW = $10.55/ kW/mo	50% of the highest maximum Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding eleven Billing Periods

Table 2: Overview of General Service / commercial customer rate options – June 2015 – Canada

Canadian Utility	Option	General Service Availability
SaskPower	**Not available**	**Not available**
Manitoba Hydro	**Limited Use of Billing Demand – Lower Demand Charges & Higher Energy Charges** • Customers with relatively low load factors (approximately 18% or less) will benefit • Demand charge structure is the same as for default , but demand charges are lower • A comparatively higher and flat energy charge (structure is no longer 3-tier declining block)	All General Service demand customers
	Surplus Energy Program • Energy Charge varies week to week according to spot market conditions • Possible lengthy interruptions; working alternate back-up system required in most cases	Connected load > 200 kW + other eligibility requirements
Hydro Quebec	**Limited Use of Billing Demand** • Demand charges are lower • Comparatively higher and flat energy charge (structure is no longer 2-tier declining block)	Medium Power - not applicable to demand that never exceeds 65 kW
	Additional Electricity Option • Consume a small amount of electricity in excess of normal consumption during off-peak hours to meet short-term or exceptional need • Designed for customers who are able to adjust their production and to manage their electricity consumption under lower rates while working around the associated constraints	Medium Power Large Power

	Economic Development Rate (ends 2024)
	• Initial 20% rate deduction, to be reduced by 5 % points a year over the final 3 years, in order to ensure a gradual transition to applicable rates
	• Eligibility :
	  ◦ Build / commission a new facility with a power demand of at least 1,000 kW or to add at least 1,000 kW of demand to an existing facility
	  ◦ For an existing facility, the expected maximum power demand of the new equipment must not be less than 20% of the highest billing demand during the 12 consumption periods preceding its commissioning
	  ◦ Facility's electricity costs must account for at least 10% of operating expenses
	  ◦ The facility must have significant potential for the net addition of new loads within Québec.
	  ◦ Each project evaluated also on the project's value added and its economic benefits to Quebec	

	Running-in of New Equipment Option • Temporary exemption from conditions that apply contract power is exceeded. • Allows testing of new equipment without having to pay for the resulting increase in power demand during the running-in period	Medium Power Large Power
	Interruptible Electricity Options • Credits in exchange for curtailing your electricity consumption on request	Medium Power Large Power

Canadian Utility	Option	General Service Availability
Nova Scotia Power	**Not available**	**Not available**
Newfoundland Power	**Curtailable Service Option** • Curtailment credit available and determined based on whether: 1. Customer contracts to reduce demand by a specific amount during curtailment periods ; or 2. Customer contract to reduce demand to a Firm Demand level which cannot exceed maximum demand during a Curtailment period Curtailment periods will: 1. Not exceed 6 hours duration for any one occurrence 2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period 3. Not exceed 100 hours duration in total during a winter period	For customers or 110-100 kVA or >1000 kVA that can reduce their demand by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period.
New Brunswick Power	**Not available**	**Not available**
ATCO Electric Yukon	**Not available**	**Not available**
FortisBC	**Time of Use Options** • Primary and Secondary voltage customers. • Customers required satisfactory load factors, as determined by the Company • Available for a minimum of 12 consecutive months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive months after commencement of service	Commercial and Large Commercial
BC Hydro	**Not available**	**Not available**

Table 3: Expanded Canadian Jurisdictional Review of General Service Segmentation

Utility/Number of GS Customers	Small	Medium	Large	Extra Large
BC Hydro ~183,000 customers	<35 kW (160,000 customers) No demand charge	35-150 kW (16,000 customers)	>150 kW (7,000 customers)	
FortisBC	<40 kW No demand charge	40-500 kW	<500 kVA	
FortisAlberta ~59,000 customers	<75 kW (51,000 customers)	75 kW – 2 MW (8,000 customers)	>2 MW (170 customers)	
Enmax ~35,000 customers	<5000 kWh /month (24,000 customers) No demand charge	<150 kVA (9,000 customers)	>150 kVA (2,000 customers + 252 primary)	
Epcor ~34,000 customers	<50 kVA (28,000 customers) No demand charge	50 – 150 kVA (4,000 customers)	150 kVA – 5 MVA (2,000 customers + 110 primary)	>5 MVA (20 customers: site-specific rates)
SaskPower ~60,000 customers	<75 kVA	75 – 2 MVA	>2 MVA	
Manitoba Hydro ~69,000 customers	<200 kVA	>200 kVA (31 customers)		
Hydro One ~119,000 customers	<50 kW (111,000 customers) No demand charge	>50 kW (8,000 customers)		
Hydro Ottawa ~27,000 customers	<50 kW (24,000 customers) No demand charge	50 – 1500 kW (3,000 customers)	1500 kW – 5 MW (76 customers)	>5 MW (11 customers)
Toronto Hydro ~81,000 customers	<50 kW (69,000 customers) No demand charge	50 – 1000 kW (12,000 customers)	1 – 5 MW (440 customers)	>5 MW (49 customers)
Hydro Quebec ~311,000 customers	<65 kW (287,000 customers)	>50 kW (24,000 customers)	>5 MW (100 customers)	
Newfoundland Power ~22,000 customers	<10 kW (12,000 customers)	<100 kW (9,000 customers)	110 – 1000 kVA (1,000 customers)	>1000 kVA (65 customers)

2015 Rate Design Application

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Attachment 4

MGS and LGS Preferred Rate Structures

Phase-in Analysis

MGS: No phase-in

F2017 Outcomes:

- Demand: $4.92/kW
- Energy: 8.48c/kW
- Basic: $0.2347/day

- Estimated about 2000 accounts will experience bill impact above 10%, which are generally accounts with load factor of less than 20% with annual consumption less than 80 MWh.
- Maximum bill impact for typical customers (In blue circle) is estimated to be about 2.8% and of larger customers is about 10.4% (red circle).

	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%	50.1%	52.5%	12.0%	2.4%	-1.8%	-9.1%	-15.3%	-17.5%	-19.1%	-20.3%	-21.2%	-21.9%	-22.6%	-23.1%	-23.5%	-23.9%	-24.2%
20%	18.6%	19.4%	19.6%	6.8%	1.0%	-2.2%	-3.9%	-2.0%	-0.6%	-0.2%	-2.0%	-3.5%	-4.7%	-5.7%	-6.5%	-7.2%	-7.8%
30%	8.1%	8.3%	8.4%	8.4%	2.4%	-1.2%	-3.1%	1.0%	0.6%	1.9%	3.0%	3.9%	4.7%	5.4%	4.5%	3.5%	2.7%
40%	2.9%	2.8%	2.8%	2.8%	2.8%	-0.6%	-2.7%	-0.4%	1.3%	2.7%	3.9%	4.9%	5.7%	6.4%	7.0%	7.6%	8.0%
50%	-0.3%	-0.5%	-0.6%	-0.6%	0.6%	-0.6%	-2.4%	-0.1%	1.8%	3.3%	4.5%	5.5%	6.4%	7.1%	7.7%	8.3%	8.8%
60%	-2.4%	-2.7%	-2.8%	-2.8%	-2.9%	2.9%	-2.5%	0.2%	2.1%	3.6%	4.9%	5.9%	6.8%	7.6%	8.3%	8.8%	9.4%
70%	-3.9%	-4.3%	-4.4%	-4.4%	-4.5%	-4.5%	-4.1%	0.2%	2.1%	3.9%	5.2%	6.3%	7.2%	8.0%	8.6%	9.2%	9.8%
80%	-5.0%	-5.5%	-5.6%	-5.6%	-5.7%	-5.7%	-5.3%	-1.1%	2.3%	4.1%	5.4%	6.5%	7.5%	8.3%	8.9%	9.6%	10.1%
90%	-5.9%	-6.4%	-6.5%	-6.6%	-6.6%	-6.6%	-6.3%	-2.1%	1.3%	4.1%	5.6%	6.7%	7.7%	8.5%	9.2%	9.8%	10.4%

MGS: Phase-in:

- Escalate Demand Tier 1 to be 1/3 of the equivalent flat rate for that year, while Tier 2 and Tier 3 are combined and residually calculated
- Energy charge is flattened over 3 years
- Phase-in demand cost recovery over three years (F2017 at 22%)
- All else same as SQ

F2017 Outcomes:

- Demand: Tier 1: $1.04/kW; Tier 2 and Tier 3: $6.42/kW
- Energy: Tier 1: 9.66c/kW; Tier 2: 7.71c/kW (Ratio of Tier 1/Tier 2 at 1.25; phase-into-flat over 3 years)
- Basic: $0.2347/day

- Slight softening of bill impacts relative to “no phase-in, but it delays the demand revenue recovery adjustment by three years
- Estimated about 800 accounts to experience adverse bill impacts of greater than 10%, which are generally accounts with less than 40 MWh/year of annual consumption and a load factor of less than 10%
- Maximum bill impact for typical customers (In blue circle) is estimated to be about 3.2% and of larger customers is about 8% (red circle); both of which are similar to the no phase-in scenario.

	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%	3.0%	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%

LGS: No phase-in

F2017 Outcomes

- Demand: $10.34/kW
- Energy: 5.47c/kW
- Basic: $0.2347/day

- Estimated about 200 accounts will experience bill impact above 10%, which are generally accounts with load factor of less than 10% with annual consumption less than 150 MWh
- Estimated that the typical customers (In blue circle) will experience bill impacts of up to 6.7%, while the larger customers up to about 5.3% (red circle). Given that CARC is 4%, the increase in bill impacts is not substantial

	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%	12.1%	2.3%	1.6%	1.3%	1.1%	0.9%	0.8%	0.8%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%
20%	-2.6%	4.9%	3.8%	3.2%	2.9%	2.7%	2.5%	2.4%	2.3%	2.2%	2.2%	2.1%	2.1%	2.1%	2.0%	2.0%	2.0%
30%	-12.3%	6.7%	5.2%	4.5%	4.1%	3.8%	3.6%	3.5%	3.4%	3.3%	3.2%	3.1%	3.1%	3.0%	3.0%	3.0%	2.9%
40%	-18.0%	1.4%	6.3%	5.4%	5.0%	4.6%	4.4%	4.2%	4.1%	4.0%	3.9%	3.8%	3.8%	3.7%	3.7%	3.7%	3.6%
50%	-22.0%	-2.5%	5.2%	6.1%	5.6%	5.2%	5.0%	4.8%	4.7%	4.6%	4.5%	4.4%	4.3%	4.3%	4.2%	4.2%	4.1%
60%	-26.4%	-5.2%	2.5%	6.7%	6.1%	5.7%	5.5%	5.3%	5.1%	5.0%	4.9%	4.8%	4.7%	4.7%	4.6%	4.6%	4.5%
70%	-29.5%	-7.3%	0.5%	4.9%	6.5%	6.1%	5.8%	5.6%	5.4%	5.3%	5.2%	5.1%	5.0%	5.0%	4.9%	4.9%	4.8%
80%	-31.9%	-8.9%	-1.1%	3.3%	6.1%	6.4%	6.1%	5.9%	5.7%	5.6%	5.5%	5.4%	5.3%	5.2%	5.2%	5.1%	5.1%
90%	-33.7%	-10.2%	-2.4%	2.0%	4.8%	6.7%	6.4%	6.1%	6.0%	5.8%	5.7%	5.6%	5.5%	5.5%	5.4%	5.3%	5.3%

LGS Phase In:

- **Escalate Demand Tier 1 to meet flattened rates in 3 years while holding Tier 3 at the flattened rate and Tier 2 residually calculated**
- **Energy charge is flattened over 3 years**
- **Phase-in Demand Revenue Recovery over 3 years**
- **All else same as SQ**

F2017 outcomes:

- Demand: Tier 1: $3.02/kW; Tier 2: $11.14/kW; Tier 3: $9.06/kW
- Energy: Tier 1: 9.31c/kW; Tier 2: 5.42c/kW (Ratio of Tier 1/Tier 2 at 1.72; phase-into-flat over 3 years)
- Basic: $0.2347/day

- Phase-in produces inferior bill impact mitigation
- Results show that even typical customers will experience bill impacts of above 10%, which is much worse than no-phase-in, while the larger customers up to about 4.8% (red circle), which is comparable to no-phase-in

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	25.2%	2.4%	-1.5%	-3.3%	-4.5%	-5.2%	-5.8%	-6.2%	-6.5%	-6.7%	-6.9%	-7.1%	-7.2%	-7.4%	-7.5%	-7.6%	-7.6%
20%	13.8%	12.3%	6.1%	3.1%	1.2%	0.0%	-0.8%	-1.5%	-2.0%	-2.4%	-2.7%	-3.0%	-3.2%	-3.4%	-3.5%	-3.7%	-3.8%
30%	4.2%	19.0%	11.1%	7.3%	5.0%	3.5%	2.4%	1.6%	1.0%	0.5%	0.1%	-0.2%	-0.5%	-0.8%	-1.0%	-1.2%	-1.3%
40%	-1.4%	13.7%	14.7%	10.3%	7.7%	6.0%	4.7%	3.8%	3.1%	2.5%	2.1%	1.7%	1.4%	1.1%	0.8%	0.6%	0.5%
50%	-4.9%	9.8%	14.8%	12.6%	9.7%	7.8%	6.5%	5.5%	4.7%	4.1%	3.6%	3.1%	2.8%	2.5%	2.2%	2.0%	1.8%
60%	-6.1%	6.9%	11.9%	14.3%	11.3%	9.2%	7.8%	6.7%	5.9%	5.2%	4.7%	4.2%	3.9%	3.5%	3.3%	3.0%	2.8%
70%	-7.1%	4.8%	9.7%	12.5%	12.5%	10.4%	8.9%	7.7%	6.9%	6.2%	5.6%	5.1%	4.7%	4.4%	4.1%	3.8%	3.6%
80%	-7.8%	3.2%	8.0%	10.7%	12.5%	11.3%	9.7%	8.6%	7.7%	6.9%	6.3%	5.9%	5.4%	5.1%	4.8%	4.5%	4.3%
90%	-8.3%	1.9%	6.6%	9.4%	11.1%	12.1%	10.5%	9.3%	8.3%	7.6%	7.0%	6.5%	6.0%	5.7%	5.3%	5.1%	4.8%

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Small General Service (SGS)

Rate Structures

BC Hydro Summary and

Consideration of Participant Feedback

Attachment 5

Interpreting Sensitivity Analysis Outcomes

INTERPRETING SENSITIVITY ANALYSIS OUTCOMES

- F15/F16 illustrative bill impact shown
- Computed by assuming consumption and demand is identical for all months (i.e. the same load factor)

Annual Consumption kWh – Range that encompass most customers in the class

Highest kW

Load Factor

	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	-18.6%	-4.6%	0.0%	2.3%	3.6%	4.5%	5.2%	5.6%	6.0%	6.3%	6.6%	6.8%	6.9%	7.1%	7.2%	7.3%	7.4%
20%	-30.5%	-10.9%	-3.6%	0.1%	2.2%	3.6%	4.7%	5.4%	6.0%	6.5%	6.9%	7.2%	7.5%	7.7%	7.9%	8.1%	8.2%
30%	-34.5%	-15.2%	-5.9%	-1.4%	1.3%	3.1%	4.3%	5.3%	6.0%	6.6%	7.1%	7.5%	7.8%	8.1%	8.4%	8.6%	8.8%
40%	-36.8%	-16.7%	-7.6%	-2.5%	0.6%	2.6%	4.1%	5.2%	6.0%	6.7%	7.2%	7.7%	8.1%	8.4%	8.7%	8.9%	9.1%
50%	-38.4%	-17.[illegible]%	-8.6%	-3.2%	0.1%	2.3%	3.9%	5.1%	6.0%	6.7%	7.3%	7.8%	8.3%	8.6%	8.9%	9.2%	9.4%
60%	-39.4%	-18.4%	-9.1%	-3.8%	-0.3%	2.1%	3.8%	5.0%	6.0%	6.8%	7.4%	7.9%	8.4%	8.8%	9.1%	9.4%	9.6%
70%	-40.3%	-19.0%	-9.5%	-4.1%	-0.6%	1.9%	3.7%	5.0%	6.0%	6.8%	7.5%	8.0%	8.5%	8.9%	9.3%	9.6%	9.8%
80%	-40.9%	-19.4%	-9.8%	-4.3%	-0.8%	1.8%	3.6%	4.9%	6.0%	6.9%	7.5%	8.1%	8.6%	9.0%	9.4%	9.7%	10.0%
90%	-41.4%	-19.7%	-10.0%	-4.5%	-0.9%	1.6%	3.5%	4.9%	6.0%	6.9%	7.6%	8.2%	8.7%	9.1%	9.5%	9.8%	10.1%

Lowest kW

"Typical" customers as defined by kWh and Load Factor fall within the blue oval area

More intense green indicates higher bill impact (only positive impacts are colored)

Red means Bill Impact higher than Class Average Rate Changes (CARC) (6%)

The distribution of customer by kWh and load factor may not follow the same trend as the bill impact distributions and comparative distributions because:

- The median customer as defined by kWh and load factor is different than the median customer defined by bill impact of each rate design, dependent on which rate component is changed
- The "middle 60%" of customers in the kWh/load factor distribution above can be different than the ones in the bill impact of each rate design, also dependent on which rate component is changed