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October 11, 2016

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority ("BC Hydro") 2015 Rate Design Application, Project No. 3698781

We are counsel for the Commercial Energy Consumers Association of British Columbia ("CEC"). Attached please find the CEC's Final Submissions with respect to the above -noted matter.

Should you have any questions regarding the foregoing, please do not hesitate to contact the writer.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb

cc: CEC
cc: BC Hydro
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

FINAL SUBMISSIONS

British Columbia Hydro and Power Authority
2015 Rate Design Application
Project No. 3698781

October 11, 2016

Commercial Energy Consumers Association of British Columbia
Final Submissions - Table of Contents

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

Final Submissions

British Columbia Hydro and Power Authority
2015 Rate Design Application
Project No. 3698781

A. INTRODUCTION AND SUMMARY OF SUBMISSION

1. The Commercial Energy Consumers Association of British Columbia (CEC) has participated in the British Columbia Hydro and Power Authority (BC Hydro) 2015 Rate Design process over the past 24 months ensuring that BC Hydro and the Commission have representation from the general service rate classes. The CEC attended the helpful workshop process conducted by BC Hydro and participated in the processes and filed Final Submissions on both the LGS/MGS Part 1 100% Pricing process and the TSR RS 1827, 1852, 1853 and 1253 process. The CEC participated in the oral hearing process by filing two rounds of information requests as well as preparing and filing evidence in regard to proposed alternative general service rates. Ultimately the CEC's evidence resulted in a direction from the Commission that BC Hydro consult with the CEC on the proposed rate structures in order to have the issue addressed in the course of Module 2 proceeding and as a result no CEC witness was presented at the oral hearing.
2. The following submission represent the CEC's response to the Final Submissions of BC Hydro and British Columbia Old Age Pensioners' Organization, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre (BCOAPO) submitted on the oral hearing matters.
3. Generally much of the CEC's Submissions support BC Hydro's positions which is indicative of the responsiveness of BC Hydro's to stakeholder input throughout the consultation process last year.
4. The core portions of the CEC's Submissions are on: (1) the appropriateness and usefulness of the long-run marginal cost (LRMC) in assessing rate design; (2) the Low Income issues primarily pursued by the BCOAPO; (3) the Residential Rate Design; (4) the SGS/MGS/LGS rate design; (5) Transmission Service Rates; and (6) Terms and Conditions.
5. On LRMC, the CEC provides detailed submissions to support its view that too much reliance on LRMC, as presently defined, as a tool by which to measure/test rate designs. While a tool of convenience, variability which can arise due to multiple factors impacting the resulting LRMC weakens the value of a LRMC comparison. The CEC encourages the Commission to direct BC Hydro to further refine the utilization of LRMC, recognizing the issues and concern which are detailed in the CEC Submissions.
6. On Low Income issues, the CEC generally supports the BC Hydro jurisdictional argument which assets that the Commission does not have the jurisdiction to implement rate design

proposals based on income. There is no legal basis for implementation of the BCOAPO proposals. While the CEC is sympathetic to the concerns raised, low income solutions must come from the elected legislature and authority is simply not presently provided for in the *Utilities Commission Act*.

7. The CEC does support the steps which BC Hydro has proposed to partially mitigate some of the concerns raised by BCOAPO on behalf of their clients. Alternatively, should the Commission find that it has jurisdiction, the BCOAPO proposals have both practical and substantial weaknesses which are addressed in the CEC's Submissions below.

8. The CEC essentially supports BC Hydro with respect to its proposed residential general service, SGS/MGS rates, e-plus and transmission rate proposal as well as their terms and conditions of service proposals subject to the detailed comments provided throughout the CEC submission.

B. LRMC

9. The BC Hydro Long Run Marginal Cost (LRMC) is a key factor in the BC Hydro Rate Design Application. BC Hydro defines the LRMC as the price of the most cost-effective way of satisfying incremental customer demand beyond existing and committed resources as guided by the government approved Integrated Resource Plan (IRP) which ensures reliable and cost effective electricity service both in the near and long term while balancing multiple policy objectives.[1] BC Hydro's IRP identifies how much, when and what resources should be advanced to meet its customers' electricity needs.

(i) LRMC as a Single Point versus a Range

10. In its original Application BC Hydro identified an LRMC range of $85 to 100/MWh; which it indicated was necessary due to uncertainty.[2] However, in the Evidentiary Update BC Hydro established a specific point of $85/MWh as the LRMC for generation Energy LRMC. As stated in B-17," the energy LRMC has changed to the lower end of the previous range based upon updated information on both the reduced need for new resources and the anticipated IPP EPA renewals."[3] Exhibit B-17 also noted that "potential further changes to the LRB are not expected to impact the LRMC". BC Hydro outlines the following reasons:

- Regardless of any potential reductions in forecast load it is expected that DSM and IPP renewals will continue to be the marginal resource up to F2024; and
- The marginal cost of the DSM and IPP renewals even at reduced volumes of acquisition would not be expected to deviate significantly from $85/MW/h.

11. As such, BC Hydro feels that as with prior LRMC's, a single cost estimate is adequate at this time.[4]
12. BC Hydro states it utilized an LRMC range of $85 to 100/MWh which 'reflected the level of uncertainty at the time, on resource need as well as the costs of marginal resources.'[5]
13. The CEC notes that the BC Hydro context for setting a single point Energy LRMC has been motivated by the context of IPP EPA renewals. The CEC submits that the use of LRMC for rate setting is very different.
14. The CEC submits that an LRMC, for the purpose of benchmarking rate designs, is more appropriately established as a range. The reasons for this are to reflect the varying methods of the LRMC comparison, the range of potential methodologies for determining LRMC, as well as significant uncertainty associated with the LRMC analyses and with the environment in which BC Hydro operates. The remainder of this chapter will discuss the issues and the evidence for using an LRMC range for applying judgment in assessing the appropriateness of specific rate designs.

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[1] Exhibit B-17, Page 2
[2] Exhibit B-23, BCOAPO 2.241.1
[3] Exhibit B-23, BCOAPO 2.241.1
[4] Exhibit B-23, BCOAPO 2.241.1
[5] Exhibit B-23, BCOAPO 2.241.1

(ii) Rate Design Methodology for Comparison to LRMC

15. Fundamentally the rates for any rate class recover all of the costs of providing the service to the customer, leaving aside the revenue to cost ratio rebalancing issues. As such, a rate design component such as the variable charge for energy consumption charged on a cents/kWh basis may contain cost for energy cost, demand capacity cost, and customer service cost. The LRMC calculations typically cover only a subset of these costs. Therefore, in making judgments about rate designs based on comparison of LRMC to the rate design component can run the risk of comparing the proverbial 'apples to oranges'. In order to get a proper 'apples to apples' comparison it will be necessary to make adjustments to the elements of the comparison to ensure that a relatively fair comparison is being made and that it can usefully inform the required judgment.

16. The CEC submits that adjust of the comparison information is essential for properly understanding the comparison of LRMC information to rate design information. The CEC proposes a methodology for making these adjustments in the following sections of this chapter and recommends that the Commission use an adjustment methodology in order to make a relatively fair comparison and to make sound and reasonable judgements about the BC Hydro rate designs it is considering in this proceeding.

(iii) Types and Uses of LRMC

17. BC Hydro has identified an Energy LRMC of $85/MWh[6] and a Capacity LRMC of $50-$55/MW.[7]

18. BC states that Hydro does not have a marginal COS study that estimates the marginal cost of incremental transmission and distribution, and therefore cannot provide the requested information.[8]

19. BC Hydro has not identified an LRMC for customer costs.[9]

20. BC Hydro uses the LRMC in resource acquisition, and rate design, establishing cost efficiency, promoting conservation, DSM evaluation, and establishing codes and standards. The LRMC is used as a reference price by BC Hydro to inform the value that should be placed upon acquiring new resources such as IPP acquisitions, DSM savings, Resource Smart and equipment efficiency and loss valuations, where there is a need.[10] The LRMC is meant to set a steady price signal to allow consistency in determining/screening the cost effectiveness of these different resources. BC Hydro also uses LRMC as a basis for the step 2 rate of certain rate structures to maintain a steady price signal encouraging conservation.[11]

21. With respect to resource acquisition, the Energy LRMC is estimated as the price signal at which BC Hydro would acquire sufficient energy to meet its plans and system needs.[12] BC

[6] Exhibit B-17, Page 7
[7] Exhibit B-17, Page 8
[8] Exhibit B-5, BCUC 1.12.1
[9] Transcript, Volume 3, Page 436
[10] Exhibit B-17, Pages 2-3
[11] Exhibit B-17, Pages 2-3
[12] Exhibit B-5, BCUC 1.60.5

Hydro cannot rely on the spot market to meet its customers' forecasted energy demand so the LRMC must be based on the cost to acquire new BC-based Demand Side Management (DSM) or supply-side resources.[13] Over the next ten year period, these energy resources include DSM savings (through BC Hydro DSM programs, government codes and standards and BC Hydro rate structures such as RS 1823 and the RIB rate), and renewals of existing EPAs with IPPs.[14] EPA renewals are subject to a cost-effectiveness test with consistent LRMC values.[15]

22. With regard to Demand Side Management, the $85/MWh Energy LRMC upper limit was used to inform the development of the DSM plan including by ensuring that all DSM initiatives were cost effective in a Total Resource Cost (TRC) test against the $85/MWh threshold.[16] The TRC uses the energy LRMC together with the capacity LRMC to test cost-effectiveness of DSM initiatives.[17] Details of BC Hydro's DSM plan for F2017 to F2019 will be included in the revenue requirements application. The DSM savings shown in the LRB beyond F2019 are an outlook for DSM activities, which will be further explored in the next IRP due in November 2018.[18]

23. With respect to Rate Design, BC Hydro uses the LRMC in several ways and particularly as a basis for the Step 2 rate of certain rate structures to maintain a 'steady price signal encouraging conservation.'[19] Various Commission rate design decisions have referenced BC Hydro's energy LRMC for rate-making purposes such as for RS 1823, the Residential Inclining Block rate and for Large General Service and Medium General Service rates.[20]

24. BC Hydro provides the following table illustrating the relevance of the LRMC in various rate structures.

[13] Exhibit B-1, Page 2-4
[14] Exhibit B-1, Page 2-46
[15] Exhibit B-5, BCOAPO 2.239.1
[16] Exhibit B-17, Page 8
[17] Exhibit B-23, BCOAPO 2.239.1
[18] Exhibit B-17, Page 8
[19] Exhibit B-17, Pages 2-3
[20] Exhibit B-1, Page 2-3

Customer Class	Residential Inclining Block Rate	Small General Service (<35 kW)	Medium General Service (≥ 35 kW and < 150 kW and energy consumption is = or < 550,000 kWh)	Large General Service (≥150 kW)	Transmission Stepped Rate Over 60kV
Proposed rates and charges	Step 1: 8.29 cents/kWh Step 2: 12.43 cents/kWh Basic: $0.1835/day	Basic charge: $0.3200/day Energy rate: $0.1101/kWh	Energy rate: 8.54 cents/kWh Demand charge: $4.76/kW Basic charge: $0.2347/day	Energy rate: 5.37 cents/kWh Demand charge: 10.83 cents/kWh Basic charge: $0.2347/day	Energy Rate: Tier 1 - 3.981 cents/kWh Tier 2 – 8.920 cents/kWh Demand Charge: $7.635/kVA
Proposed energy LRMC range in Application (F2017)	9.46 to 11.13 cents/kWh	9.46 to 11.13 cents/kWh	9.46 to 11.13 cents/kWh	9.46 to 11.13 cents/kWh	8.92 to 10.50 cents/kWh
Proposed energy LRMC in Evidentiary Update (F2017)	9.46 cents/kWh	9.46 cents/kWh	9.46 cents/kWh	9.46 cents/kWh	8.92 cents/kWh
Proposed energy and capacity LRMC in Evidentiary Update (F2017)	10.61 cents/kWh	10.61 cents/kWh	10.61 cents/kWh	10.61 cents/kWh	10.08 cents/kWh

Reference/citation of Sources:

Customer Class	Residential Inclining Block Rate	Small General Service (<35 kW)	Medium General Service (≥ 35 kW and < 150 kW and energy consumption is = or < 550,000 kWh)	Large General Service (≥150 kW)	Transmission Stepped Rate Over 60 kV
Proposed rates and charges	Exhibit B-1 Table H-1A-4	Exhibit B-1 Table H-1A-43	Exhibit B-1 Table H-1A-34	Exhibit B-1 Table H-1A-22	Exhibit B-1, Table 7-3
Proposed energy LRMC range in Application	BC Hydro's Response to BCUC IR 1.10.1	BC Hydro's Response to BCUC IR 1.10.1	BC Hydro's Response to BCUC IR 1.10.1	BC Hydro's Response to BCUC IR 1.10.1	Exhibit B-1 Table 2-5
Proposed energy LRMC in Evidentiary Update	Equivalent to $85/MWh in $F2013 plus distribution loss of 6% BCUC IR 2.177.2 Table 2-6A				Equivalent to $85/MWh in $F2013 excluding distribution loss of 6% BCUC IR 2.177.2 Table 2-5A
Proposed energy and capacity LRMC in Evidentiary Update	Equivalent to $85/MWh in $F2013 plus distribution loss of 6% BCUC IR 2.177.2 Table 2-6A				Capacity is unchanged, equivalent to the UCC of Rev 6 at 1.1c/kWh BCUC IR 2.177.2 Table 2-5A

[21]

25. Exposure to the LRMC is intended to signal the long-run price of marginal electricity. This exposure is anticipated to induce efficient behaviour and conservation measures.[22] BC Hydro notes that setting energy rates based on LRMC may not always be achievable if the variable energy charge must also recover significant portions of demand and customer related costs.[23] They state that all else held equal it is preferential that energy rates equal BC Hydro's energy LRMC. However, in rate design it is necessary to take other factors into account such as intra-class bill impacts, fair apportionment of costs and rate stability. In some

[21] Exhibit B-23, BCUC 2.137.2
[22] Exhibit B-23, CEC 2.116.1
[23] Exhibit B-23, CEC 2.111.1

cases, when taking into account these other considerations it may not be possible to have the energy rate precisely equal LRMC.[24]

26. The CEC submits that evidence is clear that LRMC should not be used as a singular benchmark for mechanistically setting conservation rate price signals. The use of LRMC should be to provide context information to inform overall judgment in rate setting and not as a deterministic bright line for mechanistic setting of rate structures or components of rate structures.

(iv) Types of LRMC

27. BC Hydro has identified an Energy LRMC, a Generation Capacity LRMC, and a Regional Transmission Capacity LRMC.[25] The Bulk Transmission Capacity LRMC is incorporated into the Generation Capacity LRMC to bring power to the Lower Mainland.

(v) Energy LRMC

28. One of the most significant changes since the establishment of rate structures for BC Hydro's Residential, MGS and LGS customers between 2008 and 2010 has been the reduction in BC Hydro's energy LRMC as set out in the 2013 IRP.[26] As noted above, BC Hydro reduced its Energy LRMC from a range of $85/MWh - $100/MWh to $85/MWh for more recent uses of LRMC.

29. The Energy LRMC reflects only the cost of the energy contribution of a resource net of any capacity contribution from the resource.[27]

30. The current energy LRMC of $85/MWh is intended to represent the cost adjusted to the Lower Mainland and is therefore intended to have reflected the cost of transmission delivered to the bulk level in the Lower Mainland.[28] The $85/MWh includes transmission losses of 6% to the Lower Mainland, but does not include distribution losses of 6%.[29] Energy LRMC includes soft costs such as permits and First Nations issues.[30]

31. BC Hydro provides the following tables to specify Energy LRMC as they have calculated it. The CEC has removed the Generation Capacity Costs and Network Capacity costs included in the original response, which were requested in the IR but for which the methodologies were not supported by BC Hydro.

[24] Exhibit B-23, BCUC 2.137.1
[25] Transcript, Volume 3, Page 436
[26] Exhibit B-1, Page 2-46
[27] Exhibit B-23, BCOAPO 2.239.1
[28] Exhibit B-23, BCOAPO 2.243.1
[29] Transcript, Volume 3, Page 441
[30] Transcript, Volume 3, Page 443

TABLE 2-6A (Distribution Service)

Fiscal Year	LRMC Only (cents/kWh)
F2013	8.50
+ F2013 (Distribution loss 6 per cent):	9.01
+ Unit Capacity Cost of Revelstoke Unit 6 ($11/MWh in $F2013)	N/A
+ Network Capacity Cost of $36.60/kW-year converted to 0.78 cents/kWh (in $2015)	
F2014	8.98
F2015	9.10
F2016	9.27
F2017	9.46
F2018	9.65
F2019	9.84

TABLE 2-5A (Transmission Service)

Fiscal Year	LRMC Only (cents/kWh)
F2013	8.50
+ Unit Capacity Cost of Revelstoke Unit 6 ($11/MWh in $F2013)	N/A
+ Network Capacity Cost of $36.60 kW-year converted to 0.78 cents/kWh (in $2015)	
F2014	8.47
F2015	8.58
F2016	8.75
F2017	8.92
F2018	9.10
F2019	9.28

[31]

32. BC Hydro estimates both distribution losses and transmission losses at 6 per cent each (average energy losses).[32]

33. The CEC submits that BC Hydro's methodology, for establishing a Distribution Energy LRMC for the distribution service system level and a Transmission Energy LRMC for the transmission service level distinguished by the 6% addition of distribution losses to the base Energy LRMC, is an appropriate methodology.

[31] Exhibit B-23, BCUC 2.177.2
[32] Exhibit B-23, BCUC 2.177.3

34. The Energy LRMC does not include costs associated with Site C because BC Hydro does not include committed resources in the calculation of LRMC. BC Hydro defines "committed resources" in its approved 2013 IRP as those resources for which material regulatory approvals have been secured (BCUC approval, either secured or through exemption; and environmental assessment related), if required, and for which the BC Hydro Board of Directors has authorized implementation. Material approvals such as from environmental assessment agencies and BC Hydro Board of Directors have been secured. Site C is in implementation phase with construction started on July 27, 2015.[33]

35. Tables 1 and 3 provide the Energy Load Resource Balance with Existing and Committed Resources (Table 1), and After Planned Resources (Table 3)

Table 1 Energy LRB with Existing and Committed Resources[6]

				Operating	Planning															
(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		46,935	46,054	46,228	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Site-C									388	4,435	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	46,935	46,054	46,228	48,671	48,671	48,671	48,671	49,059	53,106	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	13,919	14,735	14,208	16,205	15,948	15,359	13,225	12,688	12,319	11,528	11,816	11,500	10,963	10,167	9,723	9,654	9,608	9,447
Total Supply	(c) = a + b	60,853	60,789	60,436	64,876	64,619	64,031	61,897	61,748	65,425	65,699	65,589	65,271	64,734	63,958	63,494	63,426	63,379	63,218
Demand - Integrated System Total Gross Requirements																			
2015 Oct Mid Load Forecast Before DSM*		-60,231	-61,986	-63,832	-65,432	-66,676	-67,843	-68,850	-69,650	-70,420	-71,440	-72,288	-73,316	-74,277	-75,292	-76,381	-77,515	-78,441	-79,350
Expected LNG Load		-289	-355	-518	-2,020	-2,544	-2,570	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(d)	-60,520	-62,221	-64,350	-67,452	-69,220	-70,413	-71,850	-72,650	-73,420	-74,440	-75,288	-76,316	-77,277	-78,292	-79,381	-80,515	-81,441	-82,350
Demand Side Management & Other Measures																			
SMI Theft Reduction		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
2016 DSM Plan F15 and F16 savings		1,343	1,390	1,367	1,335	1,357	1,383	1,391	1,401	1,397	1,242	1,107	1,108	1,072	1,021	1,003	1,018	1,016	1,005
Sub-total	(e)	1,536	1,582	1,560	1,528	1,550	1,576	1,585	1,594	1,590	1,435	1,300	1,301	1,265	1,214	1,196	1,211	1,209	1,198
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(f) = c + d + e	**1,869**	**150**	**(2,355)**	**(1,048)**	**(3,051)**	**(4,807)**	**(8,369)**	**(9,308)**	**(6,405)**	**(7,306)**	**(8,398)**	**(9,743)**	**(11,277)**	**(13,120)**	**(14,690)**	**(15,879)**	**(16,853)**	**(17,934)**
Low Load Forecast Surplus / Deficit		4,842	4,479	3,333	5,833	4,594	3,507	224	(534)	2,873	2,101	1,367	234	(977)	(2,783)	(3,825)	(4,779)	(5,247)	(6,379)
High Load Forecast Surplus / Deficit		(1,110)	(4,340)	(8,496)	(8,635)	(11,547)	(13,752)	(17,783)	(18,964)	(16,645)	(17,942)	(19,324)	(20,974)	(22,804)	(24,962)	(26,687)	(28,317)	(29,754)	(31,135)

[33] Exhibit B-5, BCUC 1.9.1

Table 3 Energy LRB After Planned Resources

				Operating	Planning															
(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		46,935	46,054	46,228	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Site-C									388	4,435	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	46,935	46,054	46,228	48,671	48,671	48,671	48,671	49,059	53,106	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	13,919	14,735	14,208	16,205	15,948	15,359	13,225	12,688	12,319	11,928	11,818	11,500	10,963	10,187	9,723	9,654	9,608	9,447
Future Supply-Side Resources																			
IPP Renewals		94	241	569	683	811	1,108	3,168	3,586	3,850	4,171	4,255	4,442	4,850	5,583	6,048	6,099	6,141	6,302
Standing Offer Program		75	168	279	389	500	611	721	832	943	1,053	1,164	1,275	1,385	1,496	1,607	1,717	1,828	1,939
North Coast Capacity Additions		0	0	0	0	0	154	154	154	154	154	154	154	154	154	154	154	154	154
Sub-total	(c)	159	409	848	1,072	1,311	1,873	4,043	4,572	4,947	5,378	5,573	5,871	6,389	7,233	7,808	7,970	8,123	8,395
Total Supply	(d) = a + b + c	61,012	61,199	61,284	65,948	65,930	65,903	65,940	66,320	70,372	71,077	71,162	71,142	71,123	71,192	71,302	71,396	71,503	71,613
Demand - Integrated System Total Gross Requirements																			
2015 Oct Mid Load Forecast Before DSM*		-60,231	-61,866	-63,632	-65,432	-66,676	-67,943	-68,850	-69,650	-70,420	-71,440	-72,288	-73,316	-74,277	-75,292	-76,361	-77,515	-78,441	-79,350
Expected LNG Load		-289	-355	-518	-2,020	-2,544	-2,570	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(e)	-60,520	-62,221	-64,350	-67,452	-69,220	-70,413	-71,850	-72,650	-73,420	-74,440	-75,288	-76,316	-77,277	-78,292	-79,361	-80,515	-81,441	-82,350
Demand Side Management & Other Measures																			
SMI Theft Reduction		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
Voltage and VAR Optimization		111	200	220	237	268	289	302	307	312	316	334	339	344	348	353	358	363	369
2016 DSM Plan F15 and F16 savings		1,343	1,390	1,367	1,335	1,357	1,383	1,391	1,401	1,397	1,242	1,107	1,108	1,072	1,021	1,003	1,018	1,016	1,005
2016 DSM Plan F2017+ savings		690	1,289	1,785	2,448	2,968	3,415	3,814	4,153	4,423	4,853	5,203	5,399	5,626	5,869	6,082	6,178	6,095	6,077
Sub-total	(f)	2,328	3,072	3,564	4,212	4,786	5,279	5,701	6,054	6,325	6,604	6,837	7,039	7,235	7,431	7,632	7,746	7,667	7,643
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(g) = d + e + f	**2,819**	**2,046**	**498**	**2,709**	**1,496**	**769**	**(209)**	**(276)**	**3,277**	**3,241**	**2,711**	**1,866**	**1,082**	**331**	**(447)**	**(1,373)**	**(2,272)**	**(3,094)**
Small Gap Surplus / Deficit		5,611	6,137	5,903	9,251	8,743	8,654	7,917	8,001	11,833	12,192	11,931	11,280	10,782	10,050	9,784	9,062	8,898	7,829
Large Gap Surplus / Deficit		*(341)*	*(2,602)*	*(5,926)*	*(5,217)*	*(7,368)*	*(6,609)*	*(10,090)*	*(10,429)*	*(7,464)*	*(7,942)*	*(8,799)*	*(9,947)*	*(11,045)*	*(12,126)*	*(13,076)*	*(14,450)*	*(15,809)*	*(16,927)*

34

36. As illustrated above, factors affecting the Energy Load Resource Balance include the costs associated with heritage resources, IPP resources, DSM expectations, expectations regarding theft reduction attributable to smart meters, and variations on the load forecast. BC Hydro's evidence for Energy LRMC is summarized below.

Table 3-10 Marginal Energy Resources and Related Cost

Marginal Resources	Period of Applicability	$/MWh
Demand-Side Management and Electricity Purchase Agreement renewals	fiscal 2022 to fiscal 2033	Less than: $87/MWh (fiscal 2016$) or $85/MWh (fiscal 2013$)
Greenfield IPPs	fiscal 2034 and beyond	$102/MWh (fiscal 2016$) or $100/MWh (fiscal 2015$)

35

37. The Greenfield clean or renewable IPP long-run marginal cost is still relevant in the case of:

- Demand-side management, reflecting "the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia for the purpose of section 4.1.1 of the Demand Side Management Regulation";
- Longer term stable pricing signals for rates; and
- Long lived assets where electricity supply benefits extend to and beyond fiscal 2034.[36]

[34] Exhibit B-17, Pages 10 – 12, Table 1 and Table 3
[35] Exhibit B-37, Page 3-49 and Page 10 of 11
[36] Exhibit B-37, Page 3-46

38. Additionally, beyond fiscal 2034 BC Hydro will be back into the greenfield resources on an expected basis, which would increase the cost up to the $100 a megawatt hour again (delivered to the lower mainland).[37]

39. The CEC submits that under the Large Gap scenario the Energy LRMC would be more appropriately the $100/MWh range and above, while under the Small Gap scenario the Energy LRMC would be expected to be in the $85/MWh range and below.

40. BC Hydro does not expect to acquire all available resources up to the LRMC nor does it expect the LRMC to be the clearing price.[38] Given the reduced need for new energy resources going forward, BC Hydro is focusing on non-price factors for both supply-side and demand-side resources. Non-price factors for supply-side resources include benefits to the system, and demand-side measures include opportunities for customers across rate classes.[39] BC Hydro also states that they have also shifted the focus of their DSM efforts in consideration of opportunities to reduce costs, be innovative and take advantage of new technologies, and respond to changing customer expectations and system needs and indicates that details of their DSM plan for F2017 to F2019 will be provided in their revenue requirements application.[40]

41. The CEC submits that the evidence in this proceeding clearly shows that BC Hydro's LRB planning covers a range of potential scenarios from Small Gap to Large Gap and that across this range the Energy LRMC would be expected to be considerably different (specifically lower under the Small Gap and higher under the Large Gap). The CEC recommends that the Commission recognize that the Energy LRMC can have a range depending upon the circumstances BC Hydro is facing and as such when using it to assess rate designs the Commission's judgments can be cognizant of the range of these realities and take them into consideration by ensuring that the Energy LRMC is not used as a mechanistic determinative marker for setting components of the rate design.

(vi) Generation Capacity LRMC

42. The Generation Capacity LRMC reflects the requirement, timing and cost of new generation resources. The Generation Capacity LRMC cost of $50 to 55/kW-year is intended to include the transmission costs to deliver to the bulk level in the Lower Mainland.[41] The current Generation Capacity LRMC is $50-55/kW-year ($F2013) which is based on the levelized unit cost of Revelstoke Unit 6.[42] The next generation capacity resources that could be developed and are being advanced for contingency planning purposes include Revelstoke Unit 6 (Rev 6) and natural gas fired simple-cycle gas turbine generators SCGTs.[43] Revelstoke Unit 6 is being advanced as either a contingency resource for its earliest

[37] Transcript, Volume 3, Page 440
[38] Exhibit B-17, Page 3
[39] Exhibit B-17, Page 3
[40] Exhibit B-17, Page 3
[41] Exhibit B-23, BCOAPO 2.243.1
[42] Exhibit B-23, BCOAPO 2.239.2
[43] Exhibit B-23, CEC 2.109.5

in-service date in fiscal 2022 or for the need in the mid-level forecast in fiscal 2027. The next capacity resource after Revelstoke Unit 6 is not needed until fiscal 2029. The resulting marginal resources and related costs are as follows:

Table 3-11 Marginal Capacity Resources and Related Costs

Marginal Resources	Period of Applicability	$/kW-year
Revelstoke Unit 6	Fiscal 2020 to fiscal 2028	$50 - $55/kW-year (fiscal 2013$)
Simple-Cycle Gas Turbine	Fiscal 2029 and beyond	$117/kW-year (fiscal 2016$) or $115/kW-year (fiscal 2015$)

[44]

43. The CEC submits that the record shows a considerable range of cost variability for capacity additions and therefore, the Commission should not treat the Generation Capacity LRMC as a mechanistic determinative benchmark for any component of the rate designs being considered.

44. In Exhibit B-17, BC Hydro states 'While Revelstoke Unit 6 is expected to be needed shortly after Site C, it is not yet a committed resource. As such, the current Generation Capacity LRMC will continue to be $50-$55/kW-year ($2013).[45]

45. The CEC notes that the derivation of the Capacity LRMC is based on just the next unit of resource addition, which in this case BC Hydro is proposing as Revelstoke 6. However, particularly where there are rising cost curves for a resource in the future it would be technically more correct to calculate the Generation Capacity LRMC or for that matter any other LRMC based on the full future stream of costs for the relevant resource being provided.

46. The CEC submits that the Commission should consider the higher cost of future capacity as a factor in assessing rate design issues involving capacity related components of rates. The CEC submits that the appropriate range for consideration of this issue would be costs for capacity up to 50% greater than the base value for Generation Capacity LRMC.

47. The CEC has taken the specific data on the record and produced future cost curves for the resources and for illustrative purposes determined what a blended cost curve would need to be in order to equal a blended resource curve for future capacity costs. The table below shows the results making the blended resource equal to the staged future resource curve. The CEC submits that this shows that the effect of high cost future resources is not trivial and should be considered by the Commission in forming its judgment.

48. Based on Table 4 below "Peak Capacity LRB After Planned Resources," BC Hydro is planning on requiring capacity addition at an average of 177 MW/year. The following table shows the present value cost of adding 1 MW per year under different cost assumptions and

[44] Exhibit B-37, Page 3-50
[45] Exhibit B-17, page 6

shows a blended cost assumption which matches the expected cost curve, including after Revelstoke 6 costs. The cost of capacity taking into account the future more expensive cost curve may be between $72/kW-year and $88/kW-year $2016.

Discount Rate 6.50%		Next Unit of Capacity Revelstoke 6 $/kW-year		New Future Capacity SCGT $/kW-year	Expected Combined Future Rev 6 and SCGT $/kW- year		Blended Expected Rev 6 and SCGT $/kW-year	
	NPVs	$820	$902	$1,812	$1,340	$1,113	$1,361	$1,115
2013		50.0	55.0	110.4	50.0	50.0	83	68
2014		51.0	56.1	112.7	51.0	51.0	85	69
2015		52.0	57.2	115.0	52.0	52.0	86	71
2016		53.1	58.4	117.3	53.1	53.1	88	72
2017		54.1	59.5	119.6	54.1	54.1	90	74
2018		55.2	60.7	122.0	55.2	55.2	92	75
2019		56.3	61.9	124.5	56.3	56.3	93	77
2020		57.4	63.2	127.0	57.4	57.4	95	78
2021		58.6	64.4	129.5	58.6	58.6	97	80
2022		59.8	65.7	132.1	59.8	59.8	99	81
2023		60.9	67.0	134.7	134.7	60.9	101	83
2024		62.2	68.4	137.4	137.4	62.2	103	85
2025		63.4	69.8	140.2	140.2	63.4	105	86
2026		64.7	71.1	143.0	143.0	64.7	107	88
2027		66.0	72.6	145.8	145.8	66.0	110	90
2028		67.3	74.0	148.8	148.8	67.3	112	92
2029		68.6	75.5	151.7	151.7	68.6	114	93
2030		70.0	77.0	154.8	154.8	154.8	116	95
2031		71.4	78.6	157.9	157.9	157.9	119	97
2032		72.8	80.1	161.0	161.0	161.0	121	99
2033		74.3	81.7	164.2	164.2	164.2	123	101
2034		75.8	83.4	167.5	167.5	167.5	126	103
2035		77.3	85.0	170.9	170.9	170.9	128	105
2036		78.8	86.7	174.3	174.3	174.3	131	107
2037		80.4	88.5	177.8	177.8	177.8	134	109
2038		82.0	90.2	181.3	181.3	181.3	136	112
2039		83.7	92.0	185.0	185.0	185.0	139	114
2040		85.3	93.9	188.7	188.7	188.7	142	116
2041		87.1	95.8	192.4	192.4	192.4	145	118
2042		88.8	97.7	196.3	196.3	196.3	147	121
2043		90.6	99.6	200.2	200.2	200.2	150	123

49. The CEC submits that the Commission in applying its judgment with respect to rate design price signal components recognizing that the future cost curves have a significant influence on what should be understood as the cost of capacity.

50. BC Hydro provides the following Capacity Load Resource Balance Tables in Exhibit B-17.

Table 2 Peak Capacity LRB with Existing and Committed Resources

					Operating	Planning														
(MW)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	11,113	11,113	11,113	11,113	11,113	11,113	11,527	11,527	11,527	11,527
Site-C									0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Sub-total	(a)	11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	12,213	12,213	12,213	12,213	12,213	12,213	12,627	12,627	12,627	12,627
Existing and Committed IPP Resources	(b)	1,688	1,664	1,601	1,552	1,530	1,453	1,165	1,121	1,059	1,017	1,017	968	930	798	798	794	788	764
14% of Supply Requiring Reserves	(c)	-1,806	-1,808	-1,801	-1,794	-1,790	-1,787	-1,746	-1,742	-1,837	-1,831	-1,831	-1,824	-1,819	-1,800	-1,858	-1,857	-1,857	-1,853
Effective Load Carrying Capability	(d) = a + b + c	11,300	11,312	11,263	11,221	11,203	11,193	10,945	10,906	11,435	11,399	11,399	11,357	11,325	11,211	11,567	11,563	11,558	11,537
Demand - Integrated System Peak																			
2015 Oct Mid Load Forecast Before DSM*		-11,022	-11,402	-11,628	-11,807	-12,021	-12,186	-12,340	-12,502	-12,690	-12,879	-13,084	-13,299	-13,518	-13,750	-13,985	-14,223	-14,464	-14,701
Expected LNG Load		-45	-45	-95	-285	-326	-326	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380
Sub-total	(e)	-11,067	-11,447	-11,723	-12,092	-12,347	-12,512	-12,720	-12,882	-13,070	-13,259	-13,464	-13,679	-13,898	-14,130	-14,365	-14,603	-14,844	-15,081
Demand Side Management & Other Measures																			
SMI Theft Reduction		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
2016 DSM Plan F15 and F16 savings		266	268	259	252	261	261	258	256	252	231	212	210	203	195	191	190	187	185
Sub-total	(f)	293	295	286	279	288	288	285	283	279	258	239	237	230	222	218	217	214	212
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(g) = d + e + f	**526**	**160**	**(173)**	**(592)**	**(656)**	**(1,031)**	**(1,489)**	**(1,693)**	**(1,356)**	**(1,603)**	**(1,826)**	**(2,084)**	**(2,342)**	**(2,698)**	**(2,581)**	**(2,822)**	**(3,072)**	**(3,332)**
Low Load Forecast Surplus / Deficit		1,072	962	872	658	529	468	55	(117)	279	91	(59)	(281)	(475)	(816)	(599)	(792)	(939)	(1,198)
High Load Forecast Surplus / Deficit		(22)	(673)	(1,301)	(1,970)	(2,398)	(2,644)	(3,181)	(3,428)	(3,200)	(3,518)	(3,799)	(4,115)	(4,433)	(4,853)	(4,770)	(5,096)	(5,442)	(5,770)

Table 4 Peak Capacity LRB After Planned Resources

					Operating	Planning														
(MW)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	11,113	11,113	11,113	11,113	11,113	11,113	11,527	11,527	11,527	11,527
Site-C									0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Sub-total	(a)	11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	12,213	12,213	12,213	12,213	12,213	12,213	12,627	12,627	12,627	12,627
Existing and Committed IPP Resources	(b)	1,688	1,664	1,601	1,552	1,530	1,453	1,165	1,121	1,059	1,017	1,017	968	930	798	798	794	788	764
Future Supply-Side Resources																			
IPP Renewals		10	23	55	79	92	135	419	436	446	480	480	508	532	665	665	668	674	699
Standing Offer Program		5	11	19	26	34	41	49	56	63	71	78	86	93	101	108	116	123	130
North Coast Capacity Additions							100	100	100	100	100	100	100	100	100	100	100	100	100
Revelstoke 6											488	488	488	488	488	488	488	488	488
Sub-total	(c)	15	35	73	106	126	276	568	592	609	1,139	1,146	1,182	1,213	1,353	1,361	1,372	1,385	1,417
Total Supply	(d) = a + b + c	13,122	13,155	13,137	13,120	13,119	13,256	13,259	13,240	13,881	14,369	14,376	14,362	14,357	14,364	14,785	14,792	14,800	14,807
14% of Supply Requiring Reserves	(e)	-1,809	-1,813	-1,811	-1,808	-1,808	-1,826	-1,825	-1,825	-1,922	-1,990	-1,991	-1,989	-1,988	-1,989	-2,048	-2,049	-2,050	-2,051
Effective Load Carrying Capability	(f) = d + e	11,313	11,342	11,327	11,312	11,311	11,430	11,433	11,415	11,959	12,379	12,385	12,373	12,369	12,375	12,737	12,743	12,750	12,756
Demand - Integrated System Peak																			
2015 Oct Mid Load Forecast Before DSM*		-11,022	-11,402	-11,628	-11,807	-12,021	-12,186	-12,340	-12,502	-12,690	-12,879	-13,084	-13,299	-13,518	-13,750	-13,985	-14,223	-14,464	-14,701
Expected LNG Load		-45	-45	-95	-285	-326	-326	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380
Sub-total	(g)	-11,067	-11,447	-11,723	-12,092	-12,347	-12,512	-12,720	-12,882	-13,070	-13,259	-13,464	-13,679	-13,898	-14,130	-14,365	-14,603	-14,844	-15,081
Demand Side Management & Other Measures																			
SMI Theft Reduction		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F15 and F16 savings		266	268	259	252	261	261	258	256	252	231	212	210	203	195	191	190	187	185
2016 DSM Plan F2017+ savings		119	224	311	444	550	622	683	732	768	825	871	867	926	956	980	991	982	990
Sub-total	(h)	412	519	598	723	837	910	968	1,015	1,047	1,083	1,110	1,135	1,157	1,177	1,198	1,208	1,196	1,202
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(i) = f + g + h	**658**	**414**	**201**	**(58)**	**(199)**	**(172)**	**(318)**	**(452)**	**(64)**	**202**	**31**	**(170)**	**(372)**	**(578)**	**(431)**	**(651)**	**(898)**	**(1,123)**
Small Gap Surplus / Deficit		1,177	1,176	1,194	1,125	1,106	1,232	1,120	1,011	1,459	1,754	1,640	1,463	1,311	1,110	1,349	1,180	1,048	833
Large Gap Surplus / Deficit		83	(459)	(979)	(1,503)	(1,820)	(1,880)	(2,116)	(2,300)	(2,030)	(1,855)	(2,101)	(2,371)	(2,647)	(2,926)	(2,822)	(3,124)	(3,455)	(3,739)

[46]

51. As illustrated above the value of peak capacity LRB is dependent upon the existing and committed Heritage Resources, existing and committed IPP resources, requirement for spinning reserves,[47] demand, DSM, and changes to the load forecast.

52. The CEC notes that Generation Capacity LRMC does not include spinning reserve resources in its calculation. These resources are required behind all delivered capacity and therefore should be costed into the Generation LRMC determination. The CEC submits that spinning reserve should be added to the Generation Capacity LRMC by adding 14% to the proposed cost for Generation LRMC. If the Revelstoke 6 cost estimate of $50/kW-year is accepted the cost would be $57/kW-year ($2013) or $60.5/kW-year ($2016), if the $55/kW-year is accepted then the cost would be $62.5/kW-year ($2013) or $66.3/kW-year ($2016), if the

[46] Exhibit B-17, Pages 11-12, Tables 2 and 4

[47] Transcript, Volume 3, Page 442

$88/kW-year is accepted then the costs would be $100.3/kW-year ($2016) if the $72/kW-year is accepted then the costs would be $82.1/kW-year ($2016). The evidence supports a range of cost estimates for Generation Capacity LRMC.

53. The CEC submits that the Commission should ensure that in applying its judgment with respect to the use of Generation Capacity LRMC cost estimates that it keep in mind the range of valuation methodologies which can have a bearing on the comparisons made to rate designs or designs of components to rate structures.

54. DSM and IPP resources can each provide capacity contributions (as well as energy) however, the degree to which their capacity is valued is dependent upon whether is it dispatchable when it is needed and the extent to which it is anticipated the resource would be available during system peak demand periods.[48]

55. The value of capacity, in $/MWh, for each EPA renewal depends on the dependable capacity of the facility and the annual expected energy. BC Hydro's current inventory of IPP resources has dependable capacities that range from 0 MW for wind and or run-of-river facilities to 275 MW for a natural gas-fired facility. Appendix 3A-34 of BC Hydro's 2013 Integrated Resource Plan demonstrates that using the capacity LRMC of $50/kW-year, the value of capacity can range from $0/MWh to $11/MWh depending on the characteristics of the resource. A summary table for each resource type is provided below and provides an indicative range for EPA renewals.[49]

Resource Type	Capacity Credit ($2013/MWh)
Biogas	6
Biomass	6
Coal-fired generation with CCS	7
Cogeneration	6
Gas Fired Thermal	8
Geothermal	6-7
Large Hydro	11
Municipal Solid Waste	6
Run of River	0
Wind	0

56. To come up with costs in the Lower Mainland, plant gate resource costs are traditionally adjusted for bulk transmission costs (infrastructure costs and losses) for delivery to the Lower Mainland. The transmission cost adjustment is estimated using either the costs of specific transmission projects and specific marginal loss estimate for a known resource or is based upon a study of the Cost of Incremental Firm Transmission (CIFTs) and a study of the Peak Load Incremental Losses (PLIL). Similarly, the current energy LRMC of $85/MWh is intended to represent the cost adjusted for transmission losses to the Lower Mainland and is

[48] Exhibit B-23, BCOAPO 2.239.1
[49] Exhibit B-23, BCOAPO 2.239.2

therefore intended to have reflected the cost of transmission delivered via the bulk level in the Lower Mainland. Similarly, the LRMC generation capacity cost of $50 to 55/kW-year based upon Revelstoke Unit 6 is intended to include the transmission costs to deliver to the bulk level in the Lower Mainland.[50]

57. The following table[51] provides estimated costs for incremental future capacity additions.

Capacity Resource	UCC at Point of Interconnection ($kW-year)	
	Table 6-3 of the 2013 IRP Real F2013$	Current estimate (Including Soft Costs) Real F2015$
GMS Units 1 to 5 Capacity Increase	35*	75
Revelstoke Unit 6	50*	51
SCGT	≥ 84**	≥ 79
Pumped Storage – Mica	100	109
Pumped Storage - Other	≥ 118	130

* These estimates include soft costs.

** The corresponding SCGT estimate including soft costs was $88/kW-year.

58. The CEC submits that the evidence supports an Generation Capacity LRMC in a range of $60.5/kW-year to $66.3/kW-year up to somewhere between $82/kW-year and $88/kW-year ($2016) to cover spinning reserve adjustments and future cost curve adjustments all brought to the $2016 level.

(vii) Transmission and Distribution (Network) LRMC

59. BC Hydro defines the Network LRMC as the total LRMC for Transmission and Distribution.[52] BC Hydro believes that the appropriate values to use for the BC Hydro 'network LRMC' should be based on a methodology that recognizes the characteristics of the BC Hydro system.[53]

60. BC Hydro has not undertaken the analysis to develop an overall transmission and distribution LRMC. BC Hydro provides the following discussion.

> An overall transmission and distribution LRMC would include marginal costs for bulk transmission, regional transmission and distribution. The energy and generation capacity LRMCs, defined as the LRMC for energy and capacity delivered to the Lower Mainland, already reflect marginal transmission costs for the bulk transmission system (generally the 500-kV network) as well as Network Upgrades associated with generating plants. The

[50] Exhibit B-23, BCOAPO 2.243.1
[51] Exhibit B-23, CEC 2.107.3
[52] Exhibit B-23, BCUC 2.177.1
[53] Exhibit B-23, BCUC 2.177.1

> DSM regional transmission and distribution capacity benefit estimates are indicative of these costs.
>
> […]
>
> The transmission and distribution capacity benefit values used in BC Hydro's response to BCOAPO IR 1.22.3 come from an analysis undertaken for the 2009 DSM Plan. That review estimated which regional transmission and distribution infrastructure projects could be deferred by the successful implementation of the DSM Plan. BC Hydro believes that the $11/kW-year (F2011$) for regional transmission and $1/kW-year (F2011$) for distribution saved by implementing DSM are likely similar to incremental usage LRMC for regional transmission and distribution.[54]

61. The Transmission and Distribution LRMC evidence shows at a minimum a need to add $11/kW-year for regional transmission ($2011) or $12.1/kW-year ($2016).

62. The distribution costs are largely not subject to marginal cost changes based on changing demand levels because they need to be sized to a fixed level to deliver peak capacity to end customers. Therefore, where the rates contain cost recovery for the distribution costs one methodology would be to deduct those from the rate being considered and thereby compare just the rate for energy, generation capacity and transmission capacity to the range of values for the Energy LRMC, Generation Capacity LRMC and the Transmission Capacity LRMC (noting that this is regional transmission because the bulk transmission is included in the generation capacity costing). The CEC submits that such a methodology would be useful in obtaining 'apples to apples' comparisons to LRMC values.

63. The CEC recommends that the Commission have as one key piece of evidence, in making its judgments about rate designs, the comparison of the energy, generation capacity and transmission capacity components of the rate to the relevant Energy LRMC, Generation Capacity LRMC and the Transmission Capacity LRMC. Where the rate component is determined as a $/kWh value the Generation Capacity and Transmission Capacity LRMC values can be converted to $/kWh values.

(viii) Customer LRMC

64. There has been little discussion of customer costs in establishing the LRMC. BC Hydro has not identified an LRMC for customer costs, however BC Hydro states that might be derived by adding the different cost components together.[55]

65. Customer cost are not all recovered in the basic charge to customers and in some of the rate classes are, in part, recovered in the energy charge component of the rate. The CEC recommends that the Commission deal with this fact by deducting the cost recovery for the customer costs included in an energy charge from the energy rate component of the rate design. In this way, along with adjustments for distribution capacity costs also recovered in

[54] Exhibit B-23, BCOAPO 2.243.1
[55] Transcript, Volume 3, Page 436

the energy charge rate design component, the remainder will be a useful comparison of the rate to the Energy LRMC, Generation Capacity LRMC and the Transmission LRMC.

(ix) Rate Design and Calculations of LRMC Comparisons

66. The CEC submits that the varying rate design methodologies use in each rate class result in different perspectives on the value of the LRMC and what might be appropriately included in the calculation.

67. The CEC has agreed with BC Hydro that it is useful to have a discussion of LRMC with a context of both the Energy LRMC and the Capacity LRMC. To do this the CEC incorporated the energy and capacity components into one combined blended LRMC for comparison to the RIB and SGS rates, which do not have demand charges. For rates with demand charges the CEC has approximated the rates including an amount for the demand charge converted to cents/kWh in order to make them additive and comparable to the combined blended LRMC.

(x) Residential Inclining Block (RIB)

68. BC Hydro utilizes the Energy LRMC as a comparison in establishing Step 2 of the Residential Inclining Block rate. BC Hydro continues to believe that the RIB's primary purpose is to send a signal as to the incremental cost of providing energy to encourage customers to conserve energy.[56] BC Hydro considers the RIB rate to be complementary to its DSM programs as it provides a greater incentive in the higher Step 2 rate to undertake DSM initiatives.[57] Nevertheless, BC Hydro states that deriving economically efficient electricity rates is only one of many goals in residential rate design. BC Hydro continues to believe that the simple two-step RIB design carefully balances competing design goals of fairness, customer acceptance and understanding, efficiency, and stability.[58]

[56] Exhibit B-23, BCOAPO 2.242.1
[57] Exhibit B-23, BCUC 2.178.3
[58] Exhibit B-23, CEC 2.93.1

Figure 5-18 is reproduced below, with the updated LRMC forecasts.

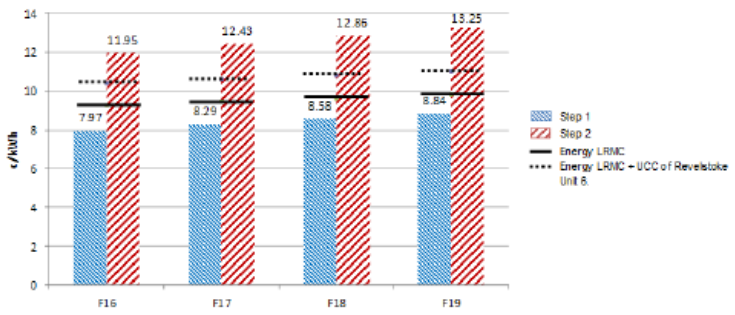
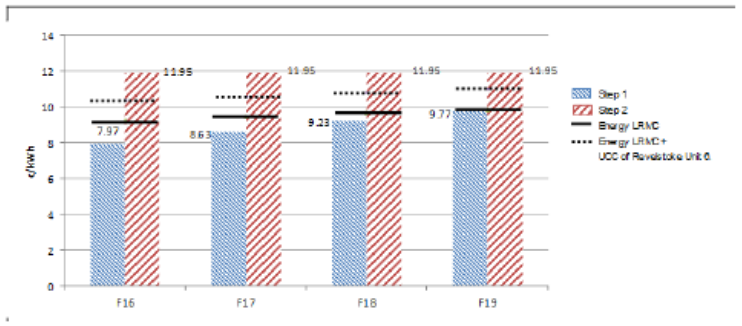


Figure 5-19 is reproduced below, with the updated LRMC forecasts.



[59]

69. BC Hydro illustrates the positioning of the RIB rate with regard comparison to LRMC values in the above graphics Figure 5-18 and Figure 5-19. The CEC submits that this comparison is flawed because it still contains 'apples to oranges' comparisons, although the inclusion of generation capacity as an additional component for the comparison clearly improves the comparison from one using just the Energy LRMC.

70. The CEC notes that the Residential Energy charge recovers all energy related costs and demand related charges plus 55% of residential customer costs. Demand related charges account for approximately 52.6% of residential energy charges.[60]

71. The CEC notes that the customer and demand costs allocated to rate classes are provided in the cost of service evidence and are shown below.

[59] Exhibit B-23, BCOAPO 2.250.1
[60] Exhibit B-23, BCUC 2.271.1

Summary of Costs by Classification

Rate Class	Energy Related Costs	Generation Demand Related Costs	Transmission Demand Related Costs	Distribution Demand Related Costs	Total Demand Related Costs	Customer Related Costs	Total
Residential	660.2	344.3	364.3	413.6	1,122.1	273.5	2,055.7
GS Under 35 kW	130.4	54.2	57.4	80.8	192.4	45.2	367.9
MGS < 150 kW	120.4	48.4	51.2	71.6	171.2	16.1	307.7
LGS > 150 kW	389.3	138.3	146.3	143.7	428.3	8.1	825.7
Irrigation	2.8	0.0	0.0	3.2	3.2	0.9	6.9
Street Lighting BCH	1.7	1.5	1.6	1.7	4.7	5.4	11.9
Street Lighting Cust	6.4	3.0	3.1	3.4	9.5	1.1	17.0
Transmission	533.3	161.3	170.6	0.0	331.9	1.7	866.9
Total	1,844.5	750.8	794.4	718.0	2,263.2	352.0	4,459.7

[61]

72. To make an appropriate adjustment to the rates the CEC has calculated that the 45% of customer costs collected in the basic charge would represent $123.1 of the total $2055.7 of costs above thereby calculating that the remaining $1932.6 would be collected in the energy charge component of the RIB rate. The distribution demand costs being collected in the RIB rate are a cost recovery for the investment in the distribution system. The $413.6 of distribution demand costs divided by $1932.6 represents 21.4%. This is the amount by which the RIB rates should be reduced to get down to a comparison of like elements for the LRMC. The 55% of customer costs collected in the energy charge component of the RIB rate would be $150.4, which when divided by $1932.6 gives 7.78%. The CEC submits that this is the amount by which the RIB rate should be reduced to get down to like elements for the LRMC comparison.

73. For the RIB rates these costs would indicate that a 21.4% reduction in the rates would be required to take the distribution demand costs out of the LRMC comparison and a 7.78% reduction to take out the 55% of customer costs collected in the RIB energy charge. The following table shows the adjusted rates for which comparisons to LRMC can and should be made to ensure an 'apples to apples' comparison. In total the adjustment required to the RIB rates to get to a reasonable comparison would be 29.18%. The following table shows the appropriate components of the RIB rate for comparison to the LRMC's for the remaining elements.

[61] BCUC Order G-47-16, Page 36 of 56

	Initial Rate from Figure 5-18			
	2016	2017	2018	2019
Step 2	11.95	12.43	12.86	13.25
Step 1	7.97	8.29	8.58	8.84
29.18%	Reduction for Customer Costs & Distribution Demand in Rate			
	Adjusted Rates Representing Energy, Generation & Transmission Demand			
	2016	2017	2018	2019
Step 2	8.46	8.80	9.11	9.38
Step 1	5.64	5.87	6.08	6.26

74. The CEC notes that BC Hydro does not adjust its proposal to accommodate a change in LRMC. Although BC Hydro has reduced its forecast LRMC to $85, BC Hydro is not proposing any changes to its RIB rate proposals. BC Hydro notes that they prioritized customer understanding and acceptance, rate stability and fair apportionment of costs above the efficiency criterion when the LRMC range was $85 to $100. They argue that an updated LRMC near the lower end of the range does not change BC Hydro's opinion that the bill impacts of approximately 20 per cent in F2017 for the average customer associated with flattening the rate are not acceptable nor does BC Hydro believe that cumulative bill impacts (F2017 to F2019) of approximately 20 per cent for average customers associated with pricing principle Option 2 of applying all RRA increases to Step 1 are acceptable. In BC Hydro's view it is also important to keep rates stable and to send a consistent long-run signal that continues to encourage customers to reduce energy consumption. BC Hydro continues to believe that in spite of the decreases in the marginal cost of energy, there are many cost-effective energy efficient investments that its customers can make to reduce their bills, and the proposed RIB design continues to send that message.

75. Making changes to the RIB that would dampen the price signal is not BC Hydro's preferred course at this time. Departing from a strict adherence to Step 2 being set exactly equal to the latest estimate of LRMC is reasonable at this time given a desire to have a stable and consistent long-run signal, that the marginal resource after Site C energy is utilized will likely be higher cost Greenfield IPPs and that some of the decisions made by customers today will have long lasting impacts.[62]

76. The CEC submits that there is not sufficient evidence before the Commission to indicate that there has ever been a 'strict adherence' to Step 2 being set exactly equal to the latest estimate of LRMC. There is no evidence that this has been a consistent past practice nor that the Commission has adopted such a policy position. In the past evidence of the comparison to LRMC values has factor into the Commission's judgments about where the rate increases should be applied and how the RIB rate design should evolve. The CEC submits that the process followed by BC Hydro and by the Commission has always been one of applying judgment against all of the evidence and factoring in the multiple criteria for rate design.

[62] Exhibit B-23, BCUC 2.140.1

77. BC Hydro expects the RIB rate to deliver capacity savings as a by-product of customer energy reductions.[63]

78. BC Hydro notes that there may be merit in exploring the inclusion of a generation capacity value in the energy LRMC for the purpose of the RIB Step 2 rate[64] as there may be an additional need for capacity resources in the system.[65] The addition of a generation capacity value to the energy LRMC could increase the LRMC for Residential Inclining Block from $95/MWh (based on $85/MWh in $F2013 adjusted for distribution losses and inflated to $2017) to $106/MWh in $F2017.[66]

79. BC Hydro is cognizant that incremental consumption may require incremental capacity depending on the time of when that consumption takes place. As such, there is an economic basis for recognizing both energy and capacity costs in the establishment of price signals. The addition to the energy LRMC of BC Hydro's marginal generation capacity (Revelstoke Unit 6) would provide such recognition.

80. BC Hydro states that whether the LRMC used for rate making purposes includes a generation capacity cost or not, BC Hydro continues to believe that the status quo RIB and status quo pricing principles remain appropriate[67] for the reasons described above.

81. The CEC submits that it is appropriate to compile the comparative LRMC in terms of $/MWh which would be the measure units for the RIB energy charge. This means converting the Capacity LRMC costs into $/MWh. BC Hydro has provided a basis for this calculation based on characteristics of the whole class. The CEC submits that given that the judgment required when making the comparison for rate design assessment purposes involves finding that the step 2 rate is a conservation rate reflecting a useful signal about the long run marginal cost of future energy and capacity to serve the residential rate class.

82. The CEC submits that the appropriate comparison of LRMC to the RIB rate would start with compiling the comparative LRMC components. The table below provides the components of LRMC for comparison based on the preceding discussions of the evidence.

[63] Exhibit B-5, BCUC 1.13.1
[64] Exhibit B-23, BCUC 2.137.1
[65] Exhibit B-17, Page 9
[66] Exhibit B-17, Page 9
[67] Exhibit B-23, BCOAPO 2.242.1

RIB		LRMC Component Analysis for Aggregated Comparison					
		Units	Base 2016	2016	2017	2018	2019
Energy LRMC (Low)		$/MWh	90	95.4	97.3	99.3	101.2
Energy LRMC (High)		$/MWh	102	108.1	110.3	112.5	114.7
Generation Capacity LRMC (Low)		$/kW-year	60.5	60.5	61.7	62.9	64.2
Generation Capacity LRMC (High)		$/kW-year	85	85	86.7	88.4	90.2
Generation Capacity LRMC (Low)*		$/MWh	12.9	12.9	13.2	13.5	13.7
Generation Capacity LRMC (High)*		$/MWh	18.2	18.2	18.6	18.9	19.3
Transmission Capacity LRMC		$/kW-year	12.1	12.3	12.6	12.8	13.1
Transmission Capacity LRMC*		$/MWh	2.6	2.6	2.7	2.7	2.8
	Total (Low)	$/MWh	105.5	111.0	113.2	115.5	117.8
	Total (High)	$/MWh	122.8	129.0	131.5	134.2	136.8
RIB Rate Components for Comparison							
	Step 2	$/MWh		84.6	88.0	91.1	93.8
	Step 1	$/MWh		56.4	57.8	60.8	62.6

*Conversion 0.214 $/MWh per $/kW-year

[68]

83. The CEC submits that the above comparison of LRMC information to the RIB rate energy charge component provides a useful back drop to assessing that the RIB rate provides a useful conservation price signal, is not an excessive price signal for the Step 2 component of the rate, and has sufficient room to enable future rate increases to be added to the Step 1 and Step 2 rates based on equal percentage increases.

(xi) General Service and LRMC

a. SGS

84. BC Hydro also makes no changes to its SGS proposals or to its basic and flat energy rates as a result of the reduction in the LRMC. BC Hydro believes that there was no conflict between the Bonbright fairness and efficiency criteria in respect of its proposed increase in SGS basic charge recovery to 45 per cent of customer-related costs (which improved fairness) and the associated reduction in the SGS energy rate (which remained reflective of LRMC). BC Hydro noted that any reduction in natural conservation (at the default -0.5 per cent elasticity BC Hydro assumes for RRA rate increase-related price responsiveness) would be very small.

85. BC Hydro believes the SGS rate design will be expected to have a small impact on natural conservation which will also not change significantly. They state that while the reduction in the energy LRMC has raised a theoretical trade-off between fairness and efficiency, there are no practical implications to BC Hydro's proposal from the reduction in the energy LRMC:

- BC Hydro has prioritized fairness over efficiency;

[68] Exhibit B-23, CEC 2.109.5

- BC Hydro targeted an increase in the SGS basic charge cost recovery in reference to the RIB rate basic charge customer-related cost recovery level and this reference remains appropriate and independent of the energy;
- LRMC; and
- The SGS flat energy rate design is the status quo rate design.[69]

86. BC Hydro provides the SGS Flat Energy Rates as compared to the Updated LRMC for the years F2017-F2019.

Fiscal Year	SGS Flat Energy Rate (cents/kWh) (Refer to Exhibit B-1, Appendix H-1A, Table H-1A-43, Table H-1A-44, and Table H-1A-45)	Updated LRMC (cents/kWh) (Refer to Exhibit B-5, BC Hydro Response to BCUC IR 1.10.1, Lower End of Energy LRMC Range)
F2017	11.01	9.46
F2018	11.39	9.65
F2019	11.73	9.84

[70]

87. BC Hydro confirms that the LRMC quoted is for energy only and the rate for SGS includes recovery of costs for both energy and capacity.[71] BC Hydro also confirms that the flat energy charge of 11.01 cents/KwH would be $110/MWh and that this would be above the $85/MWh LRMC in the Load Resource Balance Evidentiary Update.[72] The CEC notes that this would also be above the combined Energy and Capacity LRMC of $106.10[73] as presented by BC Hydro.

88. The CEC submits that the comparison of Energy LRMC only to the SGS rate is insufficient to form an appropriate judgment with respect to the suitability of the rate design. The CEC submits that the evidence on the record in this proceeding is clear in identifying that the proposed SGS rate includes: (1) recovery of a portion of customer costs moving to 55%, the same as the RIB rate; (2) all of the capacity demand charges similar to the RIB rate; and (3) various other utility operating costs that are not included in LRMC calculations. The CEC submits that to make a suitable comparison to LRMC adjustments in the comparisons are needed.

89. BC Hydro confirms that the inclusion of the marginal cost of generation capacity with the energy LRMC may be helpful in comparing how the SGS energy rate reflects BC Hydro's total incremental cost of energy as capacity may be required as consumption increases. However, BC Hydro does not believe that reducing the basic charge to recover a greater proportion of the customer costs through the energy rate is appropriate as these customer-

[69] Exhibit B-23, BCUC 2.154.1
[70] Exhibit B-23, BCOAPO 2.272.1
[71] Exhibit B-23, CEC 2.109.2
[72] Exhibit B-23, CEC 2.109.1
[73] Exhibit B-23, BCUC 2.137.2

related costs are generally fixed costs that do not vary by consumption and should properly be recovered through the customer charge which is consistent with BC Hydro's proposal to increase the proportion of customer related costs recovered through the basic charge.[74]

90. As with the RIB rate comparison the CEC adopts the same view that depending on the future scenario to unfold the Energy LRMC should have a range of future potential costs. Also as with the RIB rate the CEC adopts the same view that capacity demand in the form of the Generation Capacity LRMC should be added to the comparison and that the Generation Capacity LRMC should cost in the spinning reserve capacity. As well the future stream of generation capacity costs should be used to provide a range of future Generation LRMC that may be applicable to informing the Commission's judgment about the rate design. The CEC also adopts the view that Regional Transmission LRMC should be accounted for as part of the LRMC cost set to be used for making suitable and technically correct comparisons. Finally, the CEC adopts the same view as it has with respect to the RIB rate that the customer costs collected in the SGS energy charge rate should be deducted from the SGS rate as should the distribution demand costs collected in the SGS energy charge rate.

Summary of Costs by Classification

Rate Class	Energy Related Costs	Generation Demand Related Costs	Transmission Demand Related Costs	Distribution Demand Related Costs	Total Demand Related Costs	Customer Related Costs	Total
Residential	660.2	344.3	364.3	413.6	1,122.1	273.5	2,055.7
GS Under 35 kW	130.4	54.2	57.4	80.8	192.4	45.2	367.9
MGS < 150 kW	120.4	48.4	51.2	71.6	171.2	16.1	307.7
LGS > 150 kW	389.3	138.3	146.3	143.7	428.3	8.1	825.7
Irrigation	2.8	0.0	0.0	3.2	3.2	0.9	6.9
Street Lighting BCH	1.7	1.5	1.6	1.7	4.7	5.4	11.9
Street Lighting Cust	6.4	3.0	3.1	3.4	9.5	1.1	17.0
Transmission	533.3	161.3	170.6	0.0	331.9	1.7	866.9
Total	1,844.5	750.8	794.4	718.0	2,263.2	352.0	4,459.7

[75]

91. The CEC has calculated that the 45% of customer related cost total of $45.2 would be $20.24 which is being collected in the proposed SGS Basic Charge independent of the SGS Energy Charge. Therefore, the total being collected in the SGS Energy Charge would be $367.9 minus the $20.24 or $347.56. The 55% of the customer costs being collected in the SGS Energy Charge would be $24.86 or 7.15% of all the costs being collected in the SGS Energy Charge. The CEC submits that to make a useful 'apples to apples' comparison this 7.15% should be deducted from the SGS Energy Charge rate.

92. The CEC has calculated that the distribution demand charges of $80.8 represent 23.2% of the $347.56 total costs being collected in the SGS Energy Charge rate. The CEC submits that

[74] Exhibit B-23, CEC 2.109.3
[75] BCUC Order G-47-16, Page 36 of 56

this 23.2% should be deducted from the SGS Energy Charge rate in order to make a useful comparison to LRMC costs.

93. The CEC submits that in total 30.4% of the SGS Energy Charge rate should be deducted before making a comparison to LRMC costs. The CEC provides the calculation below.

SGS Rate	Initial Proposed Rate[76]			
¢/kWh	2016	2017	2018	2019
Energy		11.01	11.39	11.73
30.4%	Reduction for Customer Costs & Distribution Demand in Rate			
Energy		7.66	7.93	8.16

94. The CEC submits that the comparison of these rates to the LRMC rates would then be similar to the RIB rate comparison, which adjusted for SGS is provided below for convenience.

SGS Rate		LRMC Component Analysis for Aggregated Comparison					
		Units	Base 2016	2016	2017	2018	2019
Energy LRMC (Low)		$/MWh	90	95.4	97.3	99.3	101.2
Energy LRMC (High)		$/MWh	102	108.1	110.3	112.5	114.7
Generation Capacity LRMC (Low)		$/kW-year	60.5	60.5	61.7	62.9	64.2
Generation Capacity LRMC (High)		$/kW-year	85	85	86.7	88.4	90.2
Generation Capacity LRMC (Low)*		$/MWh	12.9	12.9	13.2	13.5	13.7
Generation Capacity LRMC (High)*		$/MWh	18.2	18.2	18.6	18.9	19.3
Transmission Capacity LRMC		$/kW year	12.1	12.3	12.6	12.8	13.1
Transmission Capacity LRMC*		$/MWh	2.6	2.6	2.7	2.7	2.8
	Total (Low)	$/MWh	105.5	111.0	113.2	115.5	117.8
	Total (High)	$/MWh	122.8	129.0	131.5	134.2	136.8
SGS Rate Components for Comparison							
[77]	SGS Flat Rate	$/MWh			76.6	79.3	81.6

*Conversion 0.214 $/MWh per $/kW-year

95. The CEC submits that the above comparison of LRMC information to the SGS rate energy charge component provides a useful back drop to assessing that the SGS rate provides a useful conservation price signal, and is not an excessive price signal for this component of the rate.

b. MGS and LGS

96. BC Hydro also does not suggest any changes to its MGS or LGS proposals as a result of the reduced LRMC. BC Hydro states it has prioritized customer understanding and acceptance,

[76] Exhibit B-23, BCOAPO 2.272.1
[77] Exhibit B-23, CEC 2.109.5

practicality and fairness over efficiency in the RDA. This is reflected in its development of rate design proposals to address the following key issues with the status quo MGS and LGS rates:

- The existing MGS and LGS two-part energy rates do not provide clear price signals for conservation and are poorly understood by customers;
- The existing MGS and LGS three-step inclining block demand charges do not align with BC Hydro's cost to serve MGS and LGS customer peak demand; and
- The existing levels of MGS and LGS demand charge cost recovery under.

97. BC Hydro's proposals can be increased to improve fairness in cost allocation offset or dampen disproportionate customer bill impacts across size and load factor.

98. The performance of BC Hydro's MGS and LGS rate design proposals in addressing these issues, in particular respect to its identified priorities, would be adversely impacted if BC Hydro were to target the respective MGS and LGS flat energy rates to the energy LRMC. In any event the proposed MGS flat rate of 8.83 cents/kWh ($F2018) is reflective of the updated LRMC. Further, the proposed LGS flat rate remains below the energy LRMC but no more and arguably less than it did before the update.[78]

99. BC Hydro provides the following comparisons for its MGS Energy Rates relative to the updated Energy LRMC.

	Energy LRMC (cents/kWh)	MGS Proposed Design Flat Energy Rate (cents/kWh)	Difference (cents/kWh)
F2017	9.46	8.54	-0.92
F2018	9.65	8.83	-0.82
F2019	9.84	9.10	-0.74

[79]

100. The CEC adopts the same or similar LRMC comparison methodology for the LGS and MGS as it has for the RIB and the SGS rates.

101. The LGS and MGS rates unlike the RIB and SGS rates have a Demand Charge component to the rates as well as the Basic Charge component and the Energy Charge component. The Basic Charge and the Demand Charge do not recover all of these fixed costs from customers but rather recover only a percentage of the costs. The remainder of the costs is recovered in the Energy Charge for each of the LGS and MGS rates

102. The proposed recovery of customer costs in the Energy Charge is 9% for MGS and 7% for LGS.[80]

103. The proposed recovery of demand costs in the Energy Charge is 35% for MGS[81] and 65% for LGS.[82]

[78] Exhibit B-23, BCUC 2.154.2
[79] Exhibit B-23, CEC 2.103.1
[80] Exhibit B-5, BCUC 1.54.1

Summary of Costs by Classification

Rate Class	Energy Related Costs	Generation Demand Related Costs	Transmission Demand Related Costs	Distribution Demand Related Costs	Total Demand Related Costs	Customer Related Costs	Total
Residential	660.2	344.3	364.3	413.6	1,122.1	273.5	2,055.7
GS Under 35 kW	130.4	54.2	57.4	80.8	192.4	45.2	367.9
MGS < 150 kW	120.4	48.4	51.2	71.6	171.2	16.1	307.7
LGS > 150 kW	389.3	138.3	146.3	143.7	428.3	8.1	825.7
Irrigation	2.8	0.0	0.0	3.2	3.2	0.9	6.9
Street Lighting BCH	1.7	1.5	1.6	1.7	4.7	5.4	11.9
Street Lighting Cust	6.4	3.0	3.1	3.4	9.5	1.1	17.0
Transmission	533.3	161.3	170.6	0.0	331.9	1.7	866.9
Total	1,844.5	750.8	794.4	718.0	2,263.2	352.0	4,459.7

104. The MGS customer costs are $16.1 and 9% of MGS customer costs are recovered from the Basic Charge, leaving 91% recovered from the Energy Charge or $14.65. From $307.7 of total MGS costs this would leave $293.0 as costs related to energy and demand. To remove the impact of the distribution demand costs from the LRMC value comparison to the Energy Charge, the 65% demand costs recovered in the Energy Charge would require a reduction of 65% of $71.6 in distribution demand costs or $46.54 leaving a total of $246.5 related to energy and the generation & transmission demand costs.

105. To deduct this customer cost from the comparison of rates to LRMC values requires a 5.94% reduction in the total MGS costs related to the energy and the generation & transmission demand costs. To deduct the distribution demand costs in the MGS Energy Charge would require a reduction of 18.9% in the MGS Energy Charge. The total deduction from the Energy Charge rate therefore would need to be 24.82%.

106. The adjustment to the MGS rate to move toward an 'apples to apples' comparison of LRMC values to the MGS rate would be as follows.

MGS Rate	Initial Proposed Rate			
¢/kWh	2016	2017	2018	2019
Energy		8.54	8.83	9.1
24.82%	Reduction for Customer Costs & Distribution Demand in Rate			
Energy		6.42	6.64	6.84
Demand		2.21	2.29	2.36
Total		8.63	8.93	9.20

[81] Exhibit B-1, Page 1-7
[82] Exhibit B-1, Page 1-8

107. The CEC has calculated that the total cost of service in the Energy Charge MGS rate is approximately $231.7 million dollars and that each 1 cent of rate would be driven by approximately $27.1 million dollars of cost which when divided into the total of the generation and transmission demand costs in the demand charge of $59.9 gives a 2.21 c/kWh addition to the energy component of the rate.

108. The CEC submits that the comparison of these rates to the LRMC rates would then be similar to the RIB rate comparison, which adjusted for MGS is provided below for convenience.

MGS Rate		LRMC Component Analysis for Aggregated Comparison					
		Units	Base 2016	2016	2017	2018	2019
Energy LRMC (Low)		$/MWh	90	95.4	97.3	99.3	101.2
Energy LRMC (High)		$/MWh	102	108.1	110.3	112.5	114.7
Generation Capacity LRMC (Low)		$/kW-year	60.5	60.5	61.7	62.9	64.2
Generation Capacity LRMC (High)		$/kW-year	85	85	86.7	88.4	90.2
Generation Capacity LRMC (Low)*		$/MWh	8.4	8.4	8.6	8.7	8.9
Generation Capacity LRMC (High)*		$/MWh	11.8	11.8	12.1	12.3	12.5
Transmission Capacity LRMC		$/kW-year	12.1	12.3	12.6	12.8	13.1
Transmission Capacity LRMC*		$/MWh	1.7	1.7	1.7	1.8	1.8
	Total (Low)	$/MWh	100.1	105.5	107.6	109.8	112.0
	Total (High)	$/MWh	115.5	121.7	124.1	126.6	129.1
MGS Rate Components for Comparison							
[83]	MGS Flat Rate	$/MWh			86.3	89.3	92.0

*Conversion 0.139 $/MWh per $/kW-year

109. The CEC submits that the above comparison of LRMC information to the MGS rate energy charge component provides a useful back drop to assessing that the MGS rate provides a useful conservation price signal.

110. The CEC recommends that the Commission request BC Hydro to explore in Module 2 the potential for voluntary DSM rate initiatives to compensate for the flattening of the MGS rate.

111. The LGS rate proposed by BC Hydro is for a flat Energy Charge of 5.34 cents/kWh[84] for 2017. The 2018 and 2019 LGS rates using the same increase in rates as BC Hydro has used for other rates 3.5% for 2018 and 3% for 2019 the LGS rates for 2018 and 2019 are 5.56 and 5.75 cents/kWh.

112. The LGS customer costs are $8.1 and 7% of LGS customer costs are recovered from the Basic Charge, leaving 93% recovered from the Energy Charge or $7.44. From $825.7

[83] Exhibit B-23, CEC 2.109.5
[84] Exhibit B-1, Page 6-50

million of total LGS costs this would leave $818.2 million as costs related to energy and demand. To remove the impact of the distribution demand costs from the LRMC value comparison to the Energy Charge, the 35% demand costs recovered in the Energy Charge would require a reduction of 35% of $143.7 million in distribution demand costs or $50.3 million leaving a total of $757.9 million related to energy and the generation & transmission demand costs.

113. To deduct this customer cost from the comparison of rates to LRMC values requires a .98% reduction in the total LGS costs related to the energy and the generation & transmission demand costs. To deduct the distribution demand costs in the MGS Energy Charge would require a reduction of 6.55% in the LGS Energy Charge. The total deduction from the Energy Charge rate therefore would need to be 7.53%.

114. The adjustment to the LGS rate to move toward an 'apples to apples' comparison of LRMC values to the LGS rate would be as follows.

LGS Rate	Initial Proposed Rate			
¢/kWh	2016	2017	2018	2019
Energy		5.37	5.56	5.75
7.53%	Reduction for Customer Costs & Distribution Demand in Rate			
Energy		4.97	5.14	5.32
Demand		2.57	2.66	2.74
Total		7.54	7.80	8.06

115. The CEC has calculated that the total cost of service in the Energy Charge LGS rate is approximately $539 million dollars and that each 1 cent of rate would be driven by approximately $108.5 million dollars of cost which when divided into the total of the generation and transmission demand costs in the demand charge of $284.6 million gives a 2.57 c/kWh addition to the energy component of the rate.

116. The CEC submits that the comparison of these rates to the LRMC rates would then be similar to the RIB rate comparison, which adjusted for LGS is provided below for convenience.

LGS Rate		LRMC Component Analysis for Aggregated Comparison					
		Units	Base 2016	2016	2017	2018	2019
Energy LRMC (Low)		$/MWh	90	95.4	97.3	99.3	101.2
Energy LRMC (High)		$/MWh	102	108.1	110.3	112.5	114.7
Generation Capacity LRMC (Low)		$/kW-year	60.5	60.5	61.7	62.9	64.2
Generation Capacity LRMC (High)		$/kW-year	85	85	86.7	88.4	90.2
Generation Capacity LRMC (Low)*		$/MWh	8.4	8.4	8.6	8.7	8.9
Generation Capacity LRMC (High)*		$/MWh	11.8	11.8	12.1	12.3	12.5
Transmission Capacity LRMC		$/kW-year	12.1	12.3	12.6	12.8	13.1
Transmission Capacity LRMC*		$/MWh	1.7	1.7	1.7	1.8	1.8
	Total (Low)	$/MWh	100.1	105.5	107.6	109.8	112.0
	Total (High)	$/MWh	115.5	121.7	124.1	126.6	129.1
LGS Rate Components for Comparison							
[85]	LGS Flat Rate	$/MWh			75.4	78.0	80.6

*Conversion 0.139 $/MWh per $/kW-year

117. The CEC submits that the above comparison of LRMC information to the LGS rate energy charge component provides a useful back drop to assessing that the LGS rate provides a useful conservation price signal.

118. The CEC recommends that the Commission apply its judgment on the basis of all of the evidence before it in this proceeding and reach similar conclusions as the ones submitted by the CEC above. The CEC recommends that the Commission request BC Hydro to explore in Module 2 the potential for voluntary DSM rate initiatives to recognize the flattening of the LGS rate.

(xii) Transmission Service

119. Although BC Hydro notes that there may be merit in exploring the inclusion of a generation capacity value in the energy LRMC for the purpose of the RIB Step 2 rate BC Hydro is not convinced that this is as true for other rate classes that include a demand charge and in particular RS 1823 that has a time differentiated demand charge. BC Hydro also notes that there are many other rate design objectives that may make energy price deviations from LRMC prudent.[86]

120. BC Hydro favours the customer bill neutrality approach to determine RS 1823 rates in F2017 so that the Tier 2 rate is set at the lower range of LRMC. BC Hydro states that

[85] Exhibit B-23, CEC 2.109.5
[86] Exhibit B-23, BCUC 2.137.1

although the RS 1823 F2017-F2019 Pricing Principles (Option 1) is not forecast revenue neutral in F2017, the under-recovery of revenue is relatively small and the pricing is close to revenue neutral as required by Recommendation #8; 1 the Tier 2 rate is increased by a higher than RRA rate increase in F2017 so that it is within the energy LRMC range. This allows the Tier 1 and Tier 2 rates to be increased across the board by the RRA rate increase in F2018 and F2019 which is both forecast revenue neutral and customer bill neutral. Therefore, customer bill neutrality is achieved underpricing principle Option 1 for all of F2017, F2018 and F2019."[87]

121. BC Hydro is not proposing any changes to its transmission service rate proposals as a result of the more current LRMC. As illustrated below, the Tier 2 RS 1823 rate remains reflective of the LRMC.

122. BC Hydro provides the following table which compares the Tier 2 rate under BC Hydro's preferred Option 1 with the revised nominal LRMC (based on $85/MWh in F2013 dollars):

	F2017	F2018	F2019
Option 1 Tier 2 Rate ($/MWh)	89.20	92.32	95.09
Nominal LRMC ($/MWh)	89.20	91.00	92.80
Percent Difference (T2-LRMC) x100/T2 (%)	0	1.45	2.41

123. It notes that the bottom row of the table shows that the Tier 2 rate under Option 1 is only slightly higher than the nominal LRMC in F2018 and F2019, and these differences are not substantive. Therefore, the Tier 2 rate still reflects the energy LRMC as required by Recommendation #8 of the Heritage Contract Report.[88] Given that BC Hydro has not changed its preferred RS 1823 pricing option, it does not propose any changes to its RS 1825 and RS 1880 pricing proposals.[89]

124. The CEC has applied the same LRMC principles to the TSR rates as it has to all of the other BC Hydro rates and submits that the LRMC values should not be used to create a mechanistic adjustment to the TSR rate but should be used as background context information for the Commission when making rate setting judgments.

125. The TSR customer costs are $1.6 million and 0% of TSR customer costs are recovered from a Basic Charge as there is not a Basic Charge for TSR customers, leaving 100% recovered from the Energy Charge or $1.6 million. From $866.9 million of total TSR costs this would leave $865.9 million as costs related to energy and demand.

[87] Exhibit B-23, BCUC 2.157.1
[88] Exhibit B-23, BCUC 2.158.1
[89] Exhibit B-23, BCUC 2.158.1

126. To deduct this customer cost from the comparison of rates to LRMC values requires a .185% reduction in the total TSR costs related to the energy and the generation and transmission demand costs. The adjustment to the TSR rate to move toward an 'apples to apples' comparison of LRMC values to the LGS rate would be as follows.

TSR Rate	Initial Proposed Rate			
¢/kWh	2016	2017	2018	2019
Energy T2	8.05	8.92	9.23	9.51
0.185%	Reduction for Customer Costs & Distribution Demand in Rate			
Energy	8.04	8.90	9.21	9.49
Demand	0.142	0.149	0.154	0.159
Total	8.18	9.05	9.37	9.65

TSR Rate	Initial Proposed Rate			
¢/kWh	2016	2017	2018	2019
Energy T1	3.84	3.98	4.12	4.2
0.185%	Reduction for Customer Costs & Distribution Demand in Rate			
Energy	3.83	3.97	4.11	4.24
Demand	1.278	1.338	1.385	1.426
Total	5.11	5.31	5.50	5.66

The CEC has calculated that the total cost of service in the Energy Charge TSR rate is approximately $649.5 million dollars and that each 1 cent of rate would be driven by approximately $145.1 million dollars of cost which when divided into the total of the generation and transmission demand costs in the demand charge of $215.7 million gives a 1.486 c/kWh addition to the energy component of the rate. The Tier 2 component of the rate addition is .149 c/kWh while the Tier 1 component is 1.338 c/kWh.

127. As can be seen above the adjustment to view TSR rates in terms of energy and capacity LRMC is minimal. The Tier 1 comparable rate adjusted for demand charges is provided in order to understand the whole rate

128. The comparison to a blended energy and capacity LRMC for TSR is provided below.

Transmission		LRMC Component Analysis for Aggregated Comparison					
		Units	Base 2016	2016	2017	2018	2019
Energy LRMC (Low)		$/MWh	90	95.4	97.3	99.3	101.2
Energy LRMC (High)		$/MWh	102	108.1	110.3	112.5	114.7
Generation Capacity LRMC (Low)		$/kW-year	60.5	60.5	61.7	62.9	64.2
Generation Capacity LRMC (High)		$/kW-year	85	85	86.7	88.4	90.2
Generation Capacity LRMC (Low)*		$/MWh	7.2	7.2	7.3	7.5	7.6
Generation Capacity LRMC (High)*		$/MWh	10.1	10.1	10.3	10.5	10.7
Transmission Capacity LRMC		$/kW-year	12.1	12.3	12.6	12.8	13.1
Transmission Capacity LRMC*		$/MWh	1.4	1.5	1.5	1.5	1.6
	Total (Low)	$/MWh	98.6	104.1	106.1	108.3	110.4
	Total (High)	$/MWh	113.6	119.7	122.1	124.5	127.0
TS Rate Components for Comparison							
	TSR Tier 2 Rate	$/MWh			89.0	92.1	94.9

*Conversion 0.119 $/MWh per $/kW-year

[90]

129. The CEC submits that the above comparison of LRMC information to the TSR rate energy charge component provides a useful back drop to assessing that the TSR rate provides a useful conservation price signal.

(xiii) Summary

130. The CEC provides the following summary of the evidence it sees on the record for this proceeding with respect to the appropriate methodologies for comparing LRMC values to the rate design components which should be informed by LRMC considerations.

131. The CEC concludes from this summary that there is a reasonable consistency with respect to the price signals being provided by the rate designs, albeit that the price signals are contained in different rate structure. The CEC further concludes that the LRMC values and the potential ranges for those values leave considerable room for the Commission in this proceeding and future proceedings to continue consideration of conservation measures in regard to rate design, while such considerations may not take the form of two tier rate structures.

[90] Exhibit B-23, CEC 2.109.5

132. The CEC recommends that the Commission continue to encourage BC Hydro and its stakeholders to evolve the concepts with respect to conservation price signals in rates and the appropriate comparisons to LRMC values.

CEC Summary on BC Hydro Rate Design Component Comparison to LRMC Values							
TSR LRMC Values	Total (Low)	$/MWh	98.6	104.1	106.1	108.3	110.4
	Total (High)	$/MWh	113.6	119.7	122.1	124.5	127.0
TS Rate Components for Comparison							
	TSR Tier 2 Rate	$/MWh			89.0	92.1	94.9
LGS LRMC Values	Total (Low)	$/MWh	100.1	105.5	107.6	109.8	112.0
	Total (High)	$/MWh	115.5	121.7	124.1	126.6	129.1
LGS Rate Components for Comparison							
	LGS Flat Rate	$/MWh			75.4	78.0	80.6
MGS LRMC Values	Total (Low)	$/MWh	100.1	105.5	107.6	109.8	112.0
	Total (High)	$/MWh	115.5	121.7	124.1	126.6	129.1
MGS Rate Components for Comparison							
	MGS Flat Rate	$/MWh			86.3	89.3	9.2
SGS LRMC Values	Total (Low)	$/MWh	105.5	111.0	113.2	115.5	117.8
	Total (High)	$/MWh	122.8	129.0	131.5	134.2	136.8
SGS Rate Components for Comparison							
	SGS Flat Rate	$/MWh			76.6	79.3	81.6
	Total (Low)	$/MWh	105.5	111.0	113.2	115.5	117.8
	Total (High)	$/MWh	122.8	129.0	131.5	134.2	136.8
RIB Rate Components for Comparison							
	Step 2	$/MWh		84.6	88.0	91.1	93.8

(xiv) Other Issues

a. LRMC and Rate Price Signals

133. The CEC submits that inclusion of the demand costs in a blended rate and LRMC can be done for the purpose of informing the Commission's judgment with respect to rate setting and that the methodology discussed by the CEC in this argument, and based on the evidence on the record, will provide an improved methodology to comparing a single point Energy LRMC to the Energy Charge component of the various rate classes.

134. BC Hydro has commented that blending the demand charge into the comparison may lead to confusion because of the demand charge is a peak price signal and would have time dependent characteristics versus the energy charge component.[91]

135. The CEC submits that this would not be the case because the price signals are in the rates not in the LRMC comparisons, which are intended to determine whether or not the price signals are reflecting approximately the LRMC costs to the utility.

136. The CEC submits that there is a significant range with respect to the appropriate calculation of the LRMC, depending upon its use, and the assumptions which are built into the assessment.

b. Components

137. The appropriate component parts of the LRMC are not clearly established within individual rate classes, and might vary between rate classes as well. Both the appropriateness of the different values plus the effect of the different values can be expected to vary considerably, and may also be unknown. BC Hydro notes that 'there may be merit in exploring the inclusion of a generation capacity value in the energy LRMC for the RIB Step 2 rate.[92] However, BC Hydro is not certain of the effects of including a capacity figure in the Tier 2 rates. They state:

> The inclusion of generation capacity value in the energy L RMC used as a reference for the RIB Step 2 rate would not necessarily result in a more economically efficient price than the use of the energy-only LRMC. The problem is that the generation capacity marginal cost is a peak-demand-based cost, not an energy cost. Signaling the cost of capacity via a non-time-differentiated energy rate would distort the capacity price signal. The uniform energy price signal would be too low at the time of peak demand and too high at all other times. Therefore, itis not clear whether the inclusion of the generation capacity cost for purposes of the RIB Step 2 rate would be more or less economically efficient than a rate based on the energy-only LRMC.[93]

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[91] Exhibit B-5, 1.9.2 and Exhibit B-23, 2.91.1
[92] Exhibit B-23, BCOAPO
[93] Exhibit B-5, CEC 1.9.2

138. The distortion impact referred to is that customers may over consume at peak times and under consume at non-peak times relative to efficient consumption levels given the non-time differentiated aspect of the marginal rate.[94]

139. Additionally, BC Hydro states that 'when a customer conserves energy at the meter and reacts to the price signal that the RIB sends there's obviously going to be some level of savings with respect to distribution related costs, transmission costs. None of those are included in long-run marginal costs, so there are additional savings beyond just the long-run marginal cost of energy.'[95]

140. BC Hydro is also not convinced of the merit for including a capacity figure in the LRMC for other rate classes that include a demand charge and in particular RS 1823 that has a time differentiated demand charge. Furthermore, the $11/MWh generation capacity adder is only reflective of the residential load shape and is not appropriate for Transmission Service.'[96]

141. The CEC submits that this BC Hydro discussion is clear evidence of a problem with making an 'apples to apples' comparison. The CEC submits that it is useful that BC Hydro has recognized the issue and is more inclined to use the comparison for RIB and by implication SGS.

142. The CEC submits that following through with the logic as the CEC has done by making a more 'apples to apples' comparison for all rates and adjusting for all the issues raised by BC Hydro above provides the Commission with important perspective that the all the rate designs BC Hydro has proposed are well within the boundaries of a reasonable calculation of the Energy LRMC and the Capacity LRMC ranges.

143. Further the CEC submits that this enables the Commission to review rate designs without falling into the potential trap of comparing an Energy LRMC to an Energy Charge component of a rate and thinking that the differences may need to lead to different regulation such as placing rate increases on only the tier 2 component of a rate.

c. Timing of Future Costs

144. The timing of future costs is also an important component of the assessment of the LRMC which can vary considerably. In CEC 2.107.1 BC Hydro confirms that given the new Load Resource Balance Evidence that BC Hydro's demand capacity future costs which could be deferred would not only include Revelstoke 6 at $55 per KW-year, but would also include requirements coming after Revelstoke 6, which are shown to increase to the size requirement of an additional Revelstoke 6, within 5 years of in-service date for Revelstoke 6.[97]

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[94] Exhibit B-23, CEC 2.91.1
[95] Transcript, Volume 3, pages 434 and 435
[96] Exhibit B-17, Page 9
[97] Exhibit B-23, CEC 2.107.1

Capacity Resource	UCC at Point of Interconnection ($kW-year)	
	Table 6-3 of the 2013 IRP Real F2013$	Current estimate (Including Soft Costs) Real F2015$
GMS Units 1 to 5 Capacity Increase	35*	75
Revelstoke Unit 6	50*	51
SCGT	≥ 84**	≥ 79
Pumped Storage – Mica	100	109
Pumped Storage - Other	≥ 118	130

* These estimates include soft costs.

** The corresponding SCGT estimate including soft costs was $88/kW-year.

[98]

145. The CEC understanding of the $55/kW-year for F2013$ is that it is the cost at the point of connection for Revelstoke 6 to the BC Hydro grid and that it includes the transmission costs to deliver the capacity to the Lower Mainland bulk transmission interface with regional transmission and the distribution system. The CEC understands that this is the more appropriate base. Clearly if the future may include SCGTs or Pumped Storage the cost curves for future capacity may well be increasing significantly.

146. The CEC submits that under these circumstances it is appropriate to reflect the future stream of costs because the single point in time estimate will under value the deferral in time of the entire future cost curve.

d. Direct Costs, Soft Costs and Externalities

147. The CEC submits that there is also significant variation that can occur as a result of the selection of the direct costs and the order in which they are selected.

148. Direct costs for any of the resources such as Revelstoke 6 or EPAs can change depending upon the economy or other circumstances.

149. DSM and IPP resources can provide both energy and capacity to the system, however, the degree to which their capacity is valued is dependent upon whether it is dispatchable for when it is needed and the extent to which it is anticipated the resource would be available during system peak demand periods.[99] EPA renewals are also subject to a cost effectiveness test with consistent LRMC values.[100]

150. BC Hydro acknowledges that when the savings from conservation and efficiency initiatives are relied upon for planning purposes, other supply options may be deferred. However, factors other than cost will also need to be considered when determining the order. Examples of other factors include climate change policy and implementation

[98] Exhibit B-23, CEC 2.107.3
[99] Exhibit B-23, BCOAPO 2.239.1
[100] Exhibit B-23, BCOAPO 2.239.1

requirements for the option.[101] BC Hydro has been using Revelstoke 6 for the basis of its marginal generation capacity cost for the last few years for planning purposes.[102] BC Hydro provides its latest cost estimates in CEC 2.107.3.

151. These cost estimates would be inflated to arrive at nominal dollars for future years. The current estimates include an allowance for the soft costs of developing a project such as mitigation, First Nations consultation, public engagement and regulatory review costs.[103] Adjustments to the soft costs could be significant depending upon current circumstances and alter the cost of capacity substantially. These cost uncertainties are clear evidence that the LRMC estimates need to be thought of as having a range.

152. The BC Hydro IRP planning includes analysis of many of the externality impacts of a project such as area flooded or footprint alienated, GHG and other air pollution emissions, impacts on water quality and wildlife habitat, socioeconomic impacts and many others. The Commission when considering the public interest for specific project CPCNs will consider a full range of issues many of which are externality impacts. While these are not converted into LRMC financial valuations they nevertheless represent tradeoffs to be made with respect to future impacts of alternatives and a just as much savings to the public interest as cost savings from conservation.

153. The CEC submits that the reality of externality impacts means that the LRMC values are best thought of as having a range and importantly that they should not be used a determinative estimates for setting specific rate design components in a mechanistic way.

e. Scenarios

154. The CEC notes there are very significant differences in the load scenarios in the LRB which significantly changes the requirement and timing for capacity resources. Under the Small Gap scenario the Energy LRB After Planned Resources stays in surplus through to F2034, whereas under the Large Gap scenario the Energy LRB After Planned Resources is in deficit in F2017. Similarly, under the Small Gap scenario Peak Capacity LRB After Planned Resources stays in surplus through to 2034, but hits a deficit in F2018 under the Large Gap scenario.[104]

[101] Exhibit B-23, CEC 2.107.4
[102] Exhibit B-23, CEC 2.107.3
[103] Exhibit B-23, CEC 2.107.3
[104] Exhibit B-17, Pages 12 and 13

Table 3 Energy LRB After Planned Resources

(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
				Operating	Planning														
Existing and Committed Heritage Resources		46,935	46,054	46,228	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Site-C									388	4,435	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	46,935	46,054	46,228	48,671	48,671	48,671	48,671	49,059	53,106	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	13,919	14,735	14,208	16,205	15,948	15,369	13,225	12,688	12,319	11,928	11,818	11,500	10,963	10,187	9,723	9,654	9,608	9,447
Future Supply-Side Resources																			
IPP Renewals		84	241	568	683	811	1,108	3,168	3,586	3,850	4,171	4,255	4,442	4,850	5,583	6,048	6,099	6,141	6,302
Standing Offer Program		75	168	279	389	500	611	721	832	943	1,053	1,164	1,275	1,385	1,496	1,607	1,717	1,828	1,939
North Coast Capacity Additions		0	0	0	0	0	154	154	154	154	154	154	154	154	154	154	154	154	154
Sub-total	(c)	159	409	848	1,072	1,311	1,873	4,043	4,572	4,947	5,378	5,573	5,871	6,389	7,233	7,808	7,970	8,123	8,395
Total Supply	(d) = a + b + c	61,012	61,198	61,284	65,948	65,930	65,903	65,940	66,320	70,372	71,077	71,162	71,142	71,123	71,192	71,302	71,396	71,503	71,613
Demand - Integrated System Total Gross Requirements																			
2015 Oct Mid Load Forecast Before DSM*		-60,231	-61,866	-63,832	-65,432	-66,678	-67,843	-68,850	-69,850	-70,420	-71,440	-72,288	-73,316	-74,277	-75,292	-76,381	-77,515	-78,441	-79,350
Expected LNG Load		-289	-355	-518	-2,029	-2,544	-2,570	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(e)	-60,520	-62,221	-64,350	-67,452	-69,220	-70,413	-71,850	-72,850	-73,420	-74,440	-75,288	-76,316	-77,277	-78,292	-79,381	-80,515	-81,441	-82,350
Demand Side Management & Other Measures																			
SMI Theft Reduction		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
Voltage and VAR Optimization		111	200	220	237	268	289	302	307	312	316	334	339	344	348	353	358	363	369
2016 DSM Plan F15 and F16 savings		1,343	1,390	1,367	1,335	1,357	1,383	1,391	1,401	1,397	1,242	1,107	1,108	1,072	1,021	1,003	1,018	1,016	1,006
2016 DSM Plan F2017+ savings		680	1,289	1,785	2,448	2,958	3,415	3,814	4,153	4,423	4,653	5,203	5,399	5,628	5,889	6,082	6,178	6,095	6,077
Sub-total	(f)	2,328	3,072	3,564	4,212	4,786	5,279	5,701	6,054	6,325	6,604	6,837	7,039	7,236	7,431	7,632	7,746	7,667	7,643
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(g) = d + e + f	**2,819**	**2,048**	**498**	**2,709**	**1,496**	**769**	**(209)**	**(276)**	**3,277**	**3,241**	**2,711**	**1,866**	**1,082**	**331**	**(447)**	**(1,373)**	**(2,272)**	**(3,094)**
Small Gap Surplus / Deficit		5,611	6,137	5,903	9,251	8,743	8,654	7,917	8,001	11,833	12,102	11,931	11,260	10,782	10,050	9,784	9,082	8,896	7,829
Large Gap Surplus / Deficit		(341)	(2,682)	(5,926)	(5,217)	(7,388)	(8,606)	(10,093)	(10,429)	(7,484)	(7,942)	(8,780)	(9,947)	(11,045)	(12,128)	(13,078)	(14,455)	(15,508)	(16,927)

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Table 4 Peak Capacity LRB After Planned Resources

(MW)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
				Operating	Planning														
Existing and Committed Heritage Resources		11,419	11,467	11,463	11,463	11,463	11,527	11,527	11,527	11,113	11,113	11,113	11,113	11,113	11,113	11,527	11,527	11,527	11,527
Site-C									0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Sub-total	(a)	11,419	11,467	11,463	11,463	11,463	11,527	11,527	11,527	12,213	12,213	12,213	12,213	12,213	12,213	12,627	12,627	12,627	12,627
Existing and Committed IPP Resources	(b)	1,688	1,664	1,601	1,552	1,530	1,453	1,165	1,121	1,059	1,017	1,017	968	930	798	798	794	788	764
Future Supply-Side Resources																			
IPP Renewals		10	23	55	79	92	135	419	436	446	480	480	508	532	665	665	668	674	699
Standing Offer Program		5	11	19	26	34	41	49	56	63	71	78	86	93	101	108	116	123	130
North Coast Capacity Additions							100	100	100	100	100	100	100	100	100	100	100	100	100
Revelstoke 6											488	488	488	488	488	488	488	488	488
Sub-total	(c)	15	35	73	106	126	276	568	592	609	1,139	1,146	1,182	1,213	1,353	1,361	1,372	1,385	1,417
Total Supply	(d) = a + b + c	13,122	13,166	13,137	13,120	13,119	13,256	13,259	13,240	13,881	14,369	14,376	14,362	14,357	14,364	14,785	14,792	14,800	14,807
14% of Supply Requiring Reserves	(e)	-1,809	-1,813	-1,811	-1,808	-1,808	-1,826	-1,825	-1,825	-1,922	-1,990	-1,991	-1,989	-1,988	-1,989	-2,048	-2,049	-2,050	-2,051
Effective Load Carrying Capability	(f) = d + e	11,313	11,342	11,327	11,312	11,311	11,430	11,433	11,415	11,959	12,379	12,385	12,373	12,369	12,375	12,737	12,743	12,750	12,756
Demand - Integrated System Peak																			
2015 Oct Mid Load Forecast Before DSM*		-11,022	-11,402	-11,628	-11,807	-12,021	-12,186	-12,340	-12,502	-12,690	-12,879	-13,084	-13,299	-13,518	-13,750	-13,985	-14,223	-14,464	-14,701
Expected LNG Load		-45	-45	-95	-285	-326	-326	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380
Sub-total	(g)	-11,067	-11,447	-11,723	-12,092	-12,347	-12,512	-12,720	-12,882	-13,070	-13,259	-13,464	-13,679	-13,899	-14,130	-14,365	-14,603	-14,844	-15,081
Demand Side Management & Other Measures																			
SMI Theft Reduction		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F15 and F16 savings		266	268	259	252	261	261	258	256	252	231	212	210	203	195	191	190	187	186
2016 DSM Plan F2017+ savings		119	224	311	444	550	622	683	732	798	825	871	897	928	956	989	991	982	990
Sub-total	(h)	412	519	598	723	837	910	968	1,015	1,047	1,083	1,110	1,135	1,157	1,177	1,198	1,208	1,196	1,202
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(i) = f + g + h	**658**	**414**	**201**	**(58)**	**(199)**	**(172)**	**(318)**	**(452)**	**(64)**	**202**	**31**	**(170)**	**(372)**	**(578)**	**(431)**	**(651)**	**(898)**	**(1,123)**
Small Gap Surplus / Deficit		1,177	1,176	1,194	1,125	1,106	1,232	1,120	1,011	1,450	1,754	1,640	1,463	1,311	1,110	1,349	1,180	1,048	833
Large Gap Surplus / Deficit		83	(459)	(979)	(1,503)	(1,820)	(1,880)	(2,118)	(2,300)	(2,030)	(1,866)	(2,101)	(2,371)	(2,647)	(2,929)	(2,822)	(3,124)	(3,456)	(3,739)

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155. The CEC submits that in its IRP planning BC Hydro will examine a number of potential future scenarios and that these future scenarios can have quite different LRMC values. For instance BC Hydro has evaluated future scenarios with and without significant LNG development, with and without significant electrification of Northeastern BC oil and gas development. The fact that these scenarios can have significantly different future requirements and therefore cost curves further argues for the importance of considering the LRMC values as something representing a range of potential costs.

f. Costs of Supporting Activity and Meeting Risks and Contingencies

156. The costs of capacity include not just the cost of the provision of the base capacity but must also include the costs of all supporting activity. For instance, the costs of spinning

[105] Exhibit B-17, Page 12
[106] Exhibit B-17, Page 13

reserve capability are an essential and complementary cost to the direct costs of supplying capacity. Also the costs of supplying capacity must include the costs for providing the capacity to meet the requirements for losses in the system.

157. The CEC understands that the costs for spinning reserve are not included in the BC Hydro capacity cost estimates. The CEC understands that the BC Hydro capacity cost estimates do include cost for capacity to deliver the capacity to the Lower Mainland bulk transmission interface. To the extent that there are additional peak losses in the distribution system and regional transmission systems which the CEC understands are estimated to be about 6% then the costs for capacity should be amended to reflect this additional capacity requirement.

158. BC Hydro when planning the BC Hydro system will expend funds to ensure that there is a full contingency plan capability ready and available to meet the BC Hydro customer needs if the base plan cannot meet the needs. These expenditures are all covered in the rates that BC Hydro charges but are not incorporated into the LRMC calculations. To the extent that base plans change the contingency plans may also change and are part of the overall cost of supplying energy and capacity.

159. BC Hydro spends considerable time, effort and funds on managing risks in the system. Risks such as dam safety can result in significant costs all of which are being recovered in rates. When comparing LRMC values to rates it is important to recognize the differences between the two different perspectives. While such costs may be viewed as a fixed future necessity and therefore not deferrable based on conservation, the LRMC future marginal costs should not be compared to these cost recoveries but rather to the cost recoveries for comparable components.

160. The CEC submits that because there are many costs being recovered in the rates that are not computed into the LRMC calculations it is important to conceive of the LRMC as having a significant range and not as a single point estimate.

(xv) Uncertainty

161. The CEC submits that the evidence is that there is significant uncertainty with respect to the calculation of all the different the LRMCs and also with the expected outcomes from matching rates to the LRMC.

162. In BCUC 1.60.5 BC Hydro confirms that ‘the introduction of LRMC as a range in the 2015 RDA is an admission that the LRMC is not a precise number. They state:

> ‘In periods when BC Hydro had energy supply needs that exceeded DSM and IPP renewals, the LRMC for energy was based upon the energy costs of greenfield clean or renewable IPP resources. In these circumstances, the LRMC was estimated based upon either the last open clean call (e.g., the F2006 Open Call for Tenders, the 2009 Clean Power Call) or the best estimate of the cost of new resources through BC Hydro’s Resource Options Report (e.g., Chapter 3 of the 2013 IRP). The LRMC developed at that time was an estimate of the cost of a

> new open clean call and could vary. Currently, the LRMC is estimated as the price signal at which BC Hydro would acquire sufficient energy to meet its plans and system needs. However, neither the marginal cost of the next unit of DSM savings consistent with energy policy and broad customer participation nor the precise cost of IPP EPA renewals are clearly known. As such, a range was developed to represent this uncertainty.[107]

163. AMPC addressed the issue of precision in calculating the LRMC in its 1.8 series of Information Requests. BC Hydro confirmed that the LRMC is a projection that is a function of a number of external factors including legislation, technology and market conditions in.[108] BC Hydro confirmed that because of these external factors there is uncertainty in determining the projected LRMC.[109] BC Hydro confirmed that as a result of the uncertainty in determining LRMC, any determination of LRMC must be viewed as a range of potential LRMCs that reflect the uncertainty that goes into the LMRC determination.[110]

164. BC Hydro references the 'issue of false precision' in its response to BCUC 1.60.1. In addition to the uncertainties BC Hydro refers to, BC Hydro acknowledges that it 'is doubtful that there is any universally 'correct' element of a rate design including a LRMC based marginal rate.[111]

165. BC Hydro acknowledges that LRMC is more of a reference point than a hard and fast figure[112] and that ratemaking as whole is more of an art as opposed to a science.[113]

166. BC Hydro accepts that there is uncertainty in the costs that will arise for its resources. They state:

> There is no specific price premium that BC Hydro would be willing to pay for bio-energy EPA renewals over run-of-river EPA renewals. BC Hydro's willingness to pay higher prices for EPA renewals from different resource types will depend on the need for the EPA energy and capacity at the time of negotiation and the characteristics of the resources including time of delivery, restrictions on firm energy allocations and other non-energy benefits such as dependable capacity. In its EPA renewal negotiations, BC Hydro will consider the seller's opportunity cost, the electricity spot market, the cost of service for the seller's plant, and other factors such as the attributes of the energy produced and other non-energy benefits.
>
> The $25/MWh difference reflects a point-in-time estimate of the difference in BC Hydro's average opportunity cost for the two categories of EPA renewals based on

[107] Exhibit B-5, BCUC 1.60.5
[108] Exhibit B-5, AMPC 1.8.2
[109] Exhibit B-5, AMPC 1.8.3
[110] Exhibit B-5, AMPC 1.8.3
[111] Exhibit B-23, CEC 2.111.1
[112] Transcript Volume 5, Page 845
[113] Transcript Volume 5, Page 846

> BC Hydro's LRMC, the attributes of the energy produced and other non-energy benefits such as dependable capacity. Please also refer to BC Hydro's response to CEC IR 2.4.1.
>
> As described in Exhibit B-17, BC Hydro does not expect to acquire all available resources up to the LRMC nor does it expect the LRMC to be the clearing price. BC Hydro currently estimates that the renewal volumes in the plan can be acquired at or below the LRMC of $85/MWh.[114]

167. BC Hydro also points out that some of the decisions customers make today will have long range impacts[115] which remain unknown.

> The RIB Evaluation survey shows 50 per cent of Residential customers appear to be aware of the RIB rate as of February 2012). However, no firm conclusions can be drawn about how RIB awareness is related to the customer price response. The customers' choices on whether and how to reduce consumption, and to what magnitude, are influenced by a range of factors such as their electricity consumption level, the volatility and size of their bills, the manner in which they use electricity, and their unique lifestyle preferences. BC Hydro's RIB Evaluation estimated energy savings on an aggregate basis, which produces average savings estimates across groups of customers. It did not estimate the customer response to the RIB rate, in terms of energy savings, for each customer who reported they were or were not aware of the design. BC Hydro did not estimate a demand curve consisting of a large range of consumption demand and prices as part of the RIB Evaluation. The evaluation estimated the class average price elasticity using regression models to produce a Step 2 estimate of elasticity of demand for the class. The results are shown in Table 3.1 on Appendix C-3B page 128 of 609.[116]

168. Similarly, DSM remains uncertain at this time. Details of BC Hydro's DSM plan for F2017 to F2019 will be included in the revenue requirements application. The DSM savings shown in the LRB beyond F2019 are an outlook for DSM activities, which will be further explored in the next IRP due in November 2018.[117]

169. The range of areas in the BC Hydro cost structure where uncertainty is a significant factor is quite large.

170. The CEC does not expect to enumerate all of these areas and the relevant ranges of uncertainty but rather submits that the evidence is substantial that the LRMC values should be thought of as a range and a reference for applying judgment about the rate designs. The CEC strongly agrees with BC Hydro that the LRMC values should not be

[114] Exhibit B-23, CEC 2.4.2
[115] Exhibit B-23, BCUC 2.140.1
[116] Exhibit B-23, CEC 2.93.1
[117] Exhibit B-17, Page 8

thought of as a hard and fast determinative reference but as reference benchmarks to inform judgment about rate setting issues in this case.

171. The CEC submits that the Commission should place significant weight on the evidence in this proceeding that shows that LRMC comparisons to rate designs can have many components, and many perspectives on those components. The CEC recommends that the Commission: (1) not use the LRMC values as single point information; (2) recognize the range of potential valuation and comparison; (3) use the LRMC comparisons and evidence as a basis of applying judgment about the rate designs; (4) avoid determinative mechanistic uses of the LRMC values for setting rates; and (5) give significant weight to the BC Hydro arguments that there are many factors to consider in rate design which should not be overlooked because of an ability to provide calculations of LRMC values and comparisons to rate design components.

C. LOW INCOME

(i) Introduction

172. BCOAPO is requesting that the Commission direct BC Hydro to implement several programs for qualified low income customers including an Essential Services Usage Block (ESUB) rate, a Crisis Intervention Fund, plus amendments to the BC Hydro Electric Tariff for qualified low income customers and residential ratepayers more generally. BCOAPO also requests that BC Hydro be directed to adopt several business practices, such as offering increased flexibility in installment plans, conducting a customer segmentation analysis, engaging in enhanced data reporting, and setting up a low income Customer Assistance Unit. Finally, BCOAPO asks that the Commission direct BC Hydro to increase the number of Energy Conservation Assistance Program (ECAPs) it carries out for eligible low income ratepayers.[118]

173. BCOAPO provides evidence of poverty in BC, with examples of individuals living in difficult circumstances. The low-income measure after-tax measure of poverty suggests that in 2013, 14 percent of the population is living below the poverty line in British Columbia. The market basket measure indicates that in 2013 about 13 percent of the population was living below the poverty line. The Low Income Cut Off after-tax measure indicates about 10% of the BC population is living below the poverty line.[119]

174. Although BCOAPO discusses the issue of ‘energy poverty’, a situation where a household's quality of life is compromised by the high cost of energy needed for heating, hot water, lighting and appliances.[120] The CEC submits that foundation of BCOAPO’s Low Income proposal request relates more to the likelihood that those living below the poverty line in BC may not be receiving sufficient assistance to meet their overall living requirements as opposed to there being an issue of ‘energy poverty’. As noted in previous

[118] BCOAPO Final Submissions, Page 2
[119] Transcript, Volume 5, Page 811
[120] BCOAPO Final Submission, Page 12

Commission decisions, energy rates in BC are among the lowest in the country, and continue to be so.[121]

175. The CEC submits that the evidence is not that the BC Hydro bills are too high; but rather that the income is too low, or rent/housing or other costs are too high for the level of income. BCOAPO argues that the cost of energy must be examined in context of other costs[122] facing customers. They state "evidence about poverty and energy poverty provides important context for those, including the Honourable Minister responsible for BC Hydro, who has rejected the proposition that BC Hydro residential rates pose an energy poverty challenge, given that BC Hydro rates are among the lowest in North America. While it is true that BC Hydro residential rates remain relatively low compared to other jurisdictions, BCOAPO assesses the problem with this response is that it views electricity in isolation from other costs."[123] BCOAPO cites an example of a customer who receives approximately $650 per month from the Ministry of Social Development and Social Innovation (MSDSI) and has a monthly rent of $500, leaving the customer to pay his monthly hydro bill of $67 from the remaining $150. This leaves only about $83 for food, clothing and transportation.

176. The CEC submits that the 'energy poverty' should not be viewed out of context of the problem overall and the solution should not be examined 'in isolation'. A well-known rule of thumb is that the cost of housing should not exceed 25%-30% of net income each month. In the above customer's case, rent is consuming 77% of net monthly income resulting in inadequate finances for all the necessities such as food, clothing, medicine, transportation as well as utility bills.

177. The CEC agrees that the poor in the province experience great difficulty in meeting their bills and is very sympathetic to the issues they face. However, the CEC does not accept that the electric energy bill is the appropriate place for remediation to occur. Not only does the proposal fail to address the root cause of the issue, but the CEC submits that the proposal may not make a significant enough impact on the poor's ability to have a reasonable and safe standard of living. The CEC also notes that BCOAPO references two reports "Poverty Reduction Plan for BC", co-authored by Mr. Klein (lead author) in 2008 and a 2011 report by Ms. Ivanova. The 2008 report itemizes 7 key elements, none of which included a need to address 'energy poverty,'[124] and the report by Ms. Ivanova similarly does not mention the issue of 'energy poverty'.[125]

178. The CEC submits that the appropriate responsibility resides with the provincial government and not with BC Hydro as the electric utility. As noted in Exhibit C2-20, CEC 1.27.1:

[121] BCOAPO Final Submission, Page 13
[122] BCOAPO Final Submission, Page 13
[123] BCOAPO Final Submission, Page 13
[124] Transcript, Volume 5, Pages 799-800
[125] Transcript, Volume 5, Page 804

> "There are numerous organizations that assist individuals with accessing social assistance programs, and the extent and format of such assistance varies widely from organization to organization. ...BCOAPO notes that such a list would be very onerous to compile"[126]

179. They also acknowledge that there are programs and services available to British Columbians to address child care fees and housing, although point out that they are far from adequate.[127]

180. To the extent that electricity is an essential service, the CEC notes the BCUC Panel Chairperson's observation that:

> "If you look at another essential service, ...or essential product like food, if someone is low income and needs food, then...they can quite likely get some form of assistance like a food stamp or some sort of voucher to get food, but you don't ask the food industry to somehow subsidize that person's purchase of food"[128].

181. Mr. Colton answers:

> "I would agree with that. Which is one of the reasons that the ESUB is based not solely as an affordability program as a social service program, such as a food subsidy that you're talking about, but it has the three legs of the justification. The improving cost reflectivity and improving the efficiency of the utility operation in collecting its money, and affordability is only one of the three links."

182. Mr. Colton goes on to underpin his argument that BC Hydro is specifically singled out because Mr. Colton believes that low income customers will cause less cost to provide service to them and that lower rate for low income customers will enable BC Hydro to improve its efficiency.

183. The CEC submits that Mr. Colton and the BCOAPO have not established specific BC Hydro cost of service and or cost/benefit analysis sufficient to support their argument. By implication if these arguments cannot be supported Mr. Colton's expert advice would appear to be that the social response to the issues of affordability for low income customers should be through third parties and or specifically the government programs designed to provide such assistance. The CEC submits that the Commission should give significant weight to this evidence and the adequacy of the cost of service and cost/benefit arguments. The CEC also submits that in weighing whether or not BC Hydro should be providing discriminatory support to low income customers the

[126] Exhibit C2-20, CEC 1.27.1
[127] Exhibit C2-20, CEC 1.30.1
[128] Transcript, Volume 7, Page 1370

Commission should give significant weight to the degree to which BC Hydro already provides significant support for low income customers, albeit in common with all low consumption customers, and the extent to which BC Hydro provides support through to all levels of government through the dividend returned to the province by BC Hydro which in 2016 is approximately $700,000,000.00.[129]

(ii) Legal Jurisdiction

184. The CEC has reviewed the submissions of BC Hydro at paragraphs 180 through to 254 and adopts and supports this comprehensive review of the jurisdiction of the Commission under the *Utilities Commission Act* and submits that BC Hydro has properly and comprehensively demonstrated that the Commission has no jurisdiction to approve low income rates as argued by the BCOAPO.

185. The present cost of service revenue to costs ratios see residential customers cover 93.9% of their costs demonstrates a clear subsidy to all residential customers, including low income customers at the expense of other classes of customers. That the provincial government has precluded the Commission from undertaking rate rebalancing in this Rate Design Application would indicate the legislature has turned their mind to residential rates and has taken steps to provide some subsidy to all residential customers, including low income customers. If the legislature intends that the Commission to take any further steps to reduce rates for low income customers, it is clearly within the power of the legislature to take legislative steps and issue such direction. It has not done so except to direct continuation of the existing cross subsidy.

186. The CEC highlight that there have been three instances in which the provincial Legislative Assembly considered the issue of amendments to the *Utilities Commission Act* to provide authority to the Commission to create a discounted low-income rate, and that in each instance the bill was either defeated or did not pass first reading. The most recent instance was in March 2016, or only about 6 months past. The CEC submits that it is quite clear from this evidence first that the BCUC does not currently have the legal authority to introduce a discounted low-income rate, and secondly that the provincial government has not been persuaded of the value of the proposed rate.

(iii) Reply to BCOAPO

187. The CEC does not agree with BCOAPO's submissions on the statutory power of the Commission to implement the low income programs put forward in this proceeding set out at pages 29 and 49 of BCOAPO's Final Argument. The *Utilities Commission Act* simply does not provide either explicit or implicit authority to the Commission to implement these programs. BCOAPO sets out the correct test that the Commission cannot exceed the powers that were granted by the enabling statute[130] and the CEC submits that implementing the programs would do precisely that.

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[129] Transcript, Volume 7, Page 1256

[130] *ATCO Gas and Pipeline Ltd. v. Alberta (Energy and Utilities Board)*, [2006] 1 S.C.R. 140, 2006 SCC at para. 35.

188. The CEC submits that sections 23, 38, 59 and 60 of the *Utilities Commission Act* as referenced by the BCOAPO[131] do provide the Commission jurisdiction to ensure utilities provide safe, adequate, efficient and secure service to their customers and that their rates are fair, just and reasonable. What the legislation does not provide is any reference to "ability to pay". If the legislature had an intention of making that a relevant criteria for the Commission it has had multiple opportunities to give such direction and the legislature has not done so. Rather it has effectively maintained a significant cross subsidy to all residential customers by directing that no rate rebalancing occur until after the expiration of the rate cap period in 2019.

189. The CEC submits that BCOAPO has misinterpreted Special Direction No. 7 at page 311 of its submissions. CEC submits the intent of section 5(c) of Special Direction is to enable the use of Performance Based Regulation and nowhere does it direct rate making be based on assessment of affordability or income.

190. The CEC would highlight that as a representative of the commercial class of customers which pays in excess of their cost of service relative to residential customers, and therefore already pays subsidy to that class of customer, any further cross subsidy would arguably be "undue discrimination" to the general service class of customers.

191. With regard to BCOAPO's reliance on Ontario Energy Board decisions to support its low income programs being within the jurisdiction of the Commission in British Columbia as BCOAPO notes at page 42 of its Final Submissions the legislation in Ontario contains a provision explicitly setting out its "interests of consumers" objection which has been extended to enable creation of low income residential customers.

192. The CEC notes that in support of extending this similar type of jurisdiction to British Columbia BCOAPO relies on the BC Utilities Commission decision in *Hemlock Valley Electrical Services Ltd.'s (HVES)* 1990 Rate Application Commission Order G-91-11.[132] CEC notes that this decision was overturned by the British Columbia Court of Appeal on the specific point for which BCOAPO relies in its Submissions. The Court of Appeal restricted the attempt of the Commission to broaden the scope of its jurisdiction in the manner now argued by BCOAPO.

(iv) Undue Discrimination and Bonbright Principles of Rate Design

193. BCOAPO acknowledges that its proposals do discriminate between low income and other members of the residential rate class. They submit however, that the discrimination is not "undue" in that it is not excessive, disproportionate, unjustifiable or improper. Additionally, they state that their proposals do not have a serious distortion effect on residential rates, and are not divorced from the nature and quality of electricity service, including cost of service[133].

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[131] BCOAPO Final Submissions, Pages 29-32

[132] *Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission)*, B.C.C.A. 66 B.C.L.R. 2(d) 1 1992; [1992] B.C.J. No. 649.

[133] BCOAPO Final Submission, Page 110

194. The CEC submits that the evidence supports the proposition that low income customers, being closely related to low consumption customers particularly where the BCOAPO proposals are concerned, are already receiving significant benefits of lower rates for electricity than the applicable costs to provide service to them.

195. BCOAPO raises the Bonbright Principles in their discussion of issue of undue discrimination[134] in their Final Submission at page 36. They state:

> "The prohibition on "undue discrimination" (as opposed to mere "discrimination") also reflects established approaches to utility regulation, premised on the Bonbright principles. Charles F. Phillips writes in *The Regulation of Public Utilities* (1984) at p. 62:
>
> It should be noted at this point that discrimination is accepted in the rate structures of public utilities, but that such discrimination must be "just and reasonable." Discrimination is both unintentional and purposive. It is unintentional in that some discrimination results from the efforts of utilities and commissions to simplify the rate structures by grouping customers into a limited number of classifications. It is purposive in that discrimination may be the only way in which service can be provided to some customers. Low-density routes may be subsidized by high density routes (even under competition), small towns by large cities. Rather than preventing discrimination, regulation merely seeks to control what discrimination takes place".

196. BCOAPO goes on to define what has been considered 'undue' discrimination by BC Hydro and the Commission in prior Commission decisions. The CEC submits that the Bonbright references to 'unintentional and purposive' are also important considerations in defining the positive aspect of the issue; that is, being what might be considered as 'just and reasonable' discrimination. The phrase 'unintentional and purposive' and its further explanation would suggest that just and reasonable discrimination will occur as a byproduct of establishing other rate design issues, rather than as an end goal in and of itself.

197. The CEC recommends that the Commission recognize that the BCOAPO proposal is intentional in its discrimination by selecting a specific group on whom to confer additional preferential rates over and above those received as part of a low consumption set of customers. The CEC submits that the intentional creation of a preferential rate for a specific subset of ratepayers that is not based on cost of service or other explicitly established ratemaking principles is not consistent with the overarching Bonbright principles of rate design.

[134] BCOAPO Final Submission, Page 36

(v) Existing BC Hydro Low Consumption Residential Ratepayer Benefits

198. As noted, the evidence in this proceeding is that the residential class as a whole would be paying less that their cost of service being approximately 93.6%[135] of their cost of service in 2016 meaning that they have 6.4% less in rates than their cost of service.

199. The evidence in this proceeding is that the residential rate recovers in the Basic Charge only 45%[136] of the 'customer costs' that are allocated to the residential class of customers under the BC Hydro cost of service rate making process. These costs are recovered in the Energy Charge for residential customers. Consequently, the higher consuming customers for BC Hydro are, proportional to their consumption difference from low income/low consumption customers, paying more for 55% of their 'customer costs' than they would be causing.

Summary of Costs by Classification

Rate Class	Energy Related Costs	Generation Demand Related Costs	Transmission Demand Related Costs	Distribution Demand Related Costs	Total Demand Related Costs	Customer Related Costs	Total
Residential	660.2	344.3	364.3	413.6	1,122.1	273.5	2,055.7
GS Under 35 kW	130.4	54.2	57.4	80.8	192.4	45.2	367.9
MGS < 150 kW	120.4	48.4	51.2	71.6	171.2	16.1	307.7
LGS > 150 kW	389.3	138.3	146.3	143.7	428.3	8.1	825.7
Irrigation	2.8	0.0	0.0	3.2	3.2	0.9	6.9
Street Lighting BCH	1.7	1.5	1.6	1.7	4.7	5.4	11.9
Street Lighting Cust	6.4	3.0	3.1	3.4	9.5	1.1	17.0
Transmission	533.3	161.3	170.6	0.0	331.9	1.7	866.9
Total	1,844.5	750.8	794.4	718.0	2,263.2	352.0	4,459.7

[137]

200. Further, the evidence shows that customer related costs recovered in the residential rates are $273.5 million out of a total of $2,055.7 million allocated to the residential class of customers. This means that 13.3% of the total costs collected by the residential rates are customer costs and that 7.3% of these costs that would otherwise be attributable to customers on a per customer basis through the Basic Charge are instead collected based on a proportional use of energy basis. This means that the low consumption, low income block that BCOAPO are concerned about, by definition those below 4800 kWh/year, would have approximately 7.2% of their customer costs paid by the higher consuming customers.

201. The evidence in this proceeding is that the low consumption customers, who by definition would be consuming energy based on the tier 1 rate and would have no consumption based on the tier 2 rate, would be paying rates that are approximately 22% below the average rate for the residential class.

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[135] Exhibit B-1, Appendix C-1B, Slide 20
[136] Exhibit B-1, Page 5-30
[137] BCUC Order G-47-16, Page 36 of 56

Residential Class Energy Charge Recovery of Costs				
Energy Revenue				
Year		Rate Step 1	Step 1 Costs	GWh
2017		7.97	834,939,849	10,476
2018		8.29	868,523,202	10,477
2019		8.84	893,995,110	10,113
	Total	25.10	2,597,458,161	31,066
	Proportion	39.4%	48.2%	
		Rate Step 2	Step 2 Costs	GWh
2017		12.43	896,267,415	7,211
2018		12.86	931,855,130	7,246
2019		13.25	959,277,216	7,240
	Total	38.54	2,787,399,761	21,696
	Proportion	60.6%	51.8%	

Source: CEC 1.9.5 (Appendix H-1A of Exhibit B-1, pages 7 to 9)

202. The average rate or cost for residential customers is calculated using the total costs above divided by the total GWh and the percentage differences are calculated between the average rate and the tier 1 rate.

Residential Class Average Rate	Residential Percent Tier 1 Below Average Rate
9.79	22.8%
10.16	22.5%
10.68	20.8%
30.63	22.0%

203. With these factors in mind the low consumption customers with low incomes would have rates that are 22% lower than other ratepayers on average because of the two tier rate, 7.2% lower than other ratepayers on average because most of the 55% of their customer costs collected in the energy charge are recovered from higher consuming customers and 6.4% lower than other customers because the residential class has lower rates than their cost of service versus other ratepayers on average. This totals an existing 35.6% advantage already incorporated into the existing proposed rate structure.

204. The existing benefits available to the low consumption low income customers is also one which has been increasing since 2008 when the two tier RIB rate was introduced. At that time the RIB rate tier 2 was set at $.0721/kWh and the tier 1 was set at $.0598/kWh as recorded in the BC Hydro news release at the time. In 2016 the tier 1 rate was

$.0797/kWh and the tier 2 rate was $.1195/kWh. The tier 1 rate has increase by 33.3% from 2008 to 2016 and the tier 2 rate has increased by 65.7% from 2008 to 2016. By 2019 the increase in tier 1 from 2008 will be 47.8% and the tier 2 from 2008 will increase by 83.8%.[138] This evidence means that the benefit for low consumption low income customers of BC Hydro will continue to grow proportionally.

205. The CEC submits that the Commission should give considerable weight to the evidence of existing benefits enjoyed by low consumption low income residential customers of BC Hydro on top of having one of the lowest residential rates in North America.

(vi) Existing BC Hydro Options

206. BC Hydro is looking at ways to meet the objective of better serving low income customers without incurring material costs if they can be avoided.[139] In its Final Submissions BC Hydro notes 14 actions that it is, has, or is currently undertaking to address Low Income issues. These include:

- Equal Payment Plans: BC Hydro's Equal Payment Plans are substantively the same as the OEB equalized billing portion of the Electricity Low Income Customer Rules;
- Pay as You Go: applicants may select this plan as an alternative to providing a security deposit;
- Instalment Plans: BC Hydro offers instalment plans to customers who are having difficulty making payments; overdue amounts do not incur further late payment charges; and, BC Hydro is working on business process changes to allow repayment over longer periods provided that bills are paid before the next winter heating season;
- Payment Deferrals: BC Hydro offers payment deferrals for customers who cannot pay their balance by the due date;
- Extended Payment Deferrals and Instalment Plans for Customers Receiving MSDSI Direct Employment Assistance: BC Hydro and MSDSI work together with respect to payment plans, suspension of late payment charges, and deferral of arrears for customers on employment assistance;
- •Working with MSDSI: avoid security deposits and postpone disconnections for customers awaiting MSDSI decisions on applications for income support;
- Residential low-income DSM Programs: such as Energy Savings Kits, the Energy Conservation Assistance Program and others;
- The RIB Rate: under the default Residential rate, the majority of BC Hydro's low-income customers are better off as compared to a flat rate;
- Changes to its Standard Charges and Security Deposits: such as the reduction in the Minimum Reconnection Charge and Returned Payment Charge, and, amendments to the amount of the security deposit assessed;

[138] Exhibits C1-20 and C1-21
[139] Transcript, Volume 3, Page 462

- Opened in-person customer service desks: BC Hydro has opened an in-person customer service desk at its Dunsmuir, Edmonds and Vernon offices and expects to open one in Prince George in late 2016/early 2017;
- Delay disconnections for demonstrated medical reason: BC Hydro is implementing changes that will allow a customer to delay a disconnection where they are able to demonstrate a medical reason for requiring power;
- Establish a low-income advisory group; and
- Post business practices online regarding payment options and other identified subject-areas.

207. BC Hydro has also implemented a winter moratorium pilot for the 2016-17 winter period. This moratorium will be geographically and temperature-based and BC Hydro will submit a report to the Commission identifying the impacts, if any, of the moratorium and a proposal for standard business practices in mid-2017.[140]

208. BCOAPO is supportive of the above changes that BC Hydro has either already made or has committed to making to assist low income customers.[141]

209. The CEC submits that the above constitute several important measures that are suitable to addressing the issue of customer ability to pay and supports BC Hydro in these efforts.

(vii) Eligibility

210. BCOAPO defines a "qualified low income customer" for the purposes of its proposals as residential ratepayers who are at or below Statistics Canada's pre-tax Low Income Cut Off (LICO). The only exception to this definition is that BCOAPO is asking that expanded offerings of ECAP be available to ratepayers who have incomes at or below LICO plus 30%.[142]

211. The CEC submits that the definition of a 'qualified low income customer' should not be based exclusively on income, but should rather reflect the ability of the customer to afford electricity to meet their most basic living needs. Mr. Colton confirms that income does not relate to wealth[143] but also indicates that wealth does not necessary imply affordability.[144] Mr. Klein acknowledges under cross-examination that a low income person on social assistance is in a different circumstance than a low income retired person with a fully-owned and mortgage free house, living in the Lower Mainland; and a woman -- or a person with family responsibilities and no family support, in a minimum wage job, is in a different circumstance than a university student who may also be low income, but has financial support from his or her parents.

212. The CEC submits that affordability relates to several factors and may include both income and wealth. The CEC submits that an eligibility that focuses on income alone is

[140] BC Hydro Final Argument, Pages 76-77
[141] BCOAPO Final Submission, Page 112
[142] BCOAPO Final Argument, Page 4
[143] Exhibit C2-20, CEC 1.4.1
[144] Exhibit C2-20, CEC 1.4.1.1

unsupportable and open to creating significant unfairness, such as the prospect of a family with a modest income and no assets subsidizing lower income retired individuals with limited outside expenditures and millions in housing or other assets such as large savings accounts, recreational properties etc. The BCOAPO argues that low income individuals who are asset rich should not necessarily be forced to use these assets.[145] The CEC disagrees and submits that not only does it create a very unfair burden on those without assets, but it contributes to ongoing disparities as these assets can then be inherited by the next generation and will have been subsidized by those less fortunate ratepayers who cannot afford homes or other assets such as recreational properties,

213. The CEC agrees with BCOAPO that it is difficult to distinguish those ratepayers who have asset-based wealth but limited income, from those ratepayers who have limited assets and limited income,[146] but submits that in the event that low income programs which provide for cost reduction are approved, it would be prudent for BC Hydro to work with the government to consider total affordability overall including assets and circumstances. As indicated in Exhibit C2-20, individuals in receipt of social assistance may have already been required to liquidate their assets.

214. BCOAPO believes that eligibility qualification can be undertaken at minimal cost.

215. BC Hydro believes implementation of an eligibility process would cost a minimum of $1.25 million and that annual operating expenditures would be at least $0.55 million per year.[147] BC Hydro also notes in its rebuttal evidence that 'low income residential customers of BC Hydro cannot be qualified for the purposes of any low-income discounts or preferences by the Ministry of Social Development and Social Innovation without its agreement to amend the privacy consents it current obtains from low-income customers.[148] Additionally, the operational requirements of low-income rates or terms and conditions wouldn't stop with the determination of eligibility. Additional operational requirements would include a mechanism for BC Hydro to be aware of a customer's continuing eligibility through an "eligibility flag" logic within the billing system to reflect differences in customer treatment because of eligibility and BC Hydro would also need to develop customer service processes within its call centre, web and Interactive Voice Response (IVR) system to enable proper treatment of eligible customers.[149]

216. BC Hydro notes that upfront costs related to Ontario Electricity Support Program were in the order of $13 million. In addition, each local distribution company has incurred costs to make internal changes to processes and systems.[150]

217. The CEC submits that such evidence indicates that there is a possibility of very high expenditures which should not be ignored in any consideration of a Low Income program

[145] Exhibit C2-20, CEC 1.28.1
[146] Exhibit C2-20, CEC 1.28.1
[147] Exhibit B-31, BC Hydro Rebuttal Evidence, Page 1
[148] Transcript, Volume 7, Page 1379
[149] Exhibit B-31, BC Hydro Rebuttal, Pages 7-8
[150] Exhibit B-31, BC Hydro Rebuttal, Page 12

for BC Hydro. The CEC submits that no program should be developed without full understanding of all the costs and benefits involved.

(viii) Essential Service Usage Block

218. BCOAPO proposes to institute an Essential Service Usage Block (ESUB) which would provide a price reduction of $0.04/kWh for an initial block of 400 kWh to low income customers. BCOAPO relies heavily on evidence from Mr. Colton. Mr. Colton states that the need for an Essential Services Usage Block occurs for the following reasons: lack of cost reflectivity for low use customers, providing meaningful assistance without imposing an unreasonable burden on nonparticipating ratepayers, and improving the efficient operations of BC Hydro.[151] He acknowledges that it would be inappropriate to provide an Essential Services Usage Block if those circumstances did not exist.[152] Mr. Colton has not undertaken a comparative review of the "circumstances [that] create the need for an Essential Services Usage Block" in British Columbia relative to those same circumstances in other Canadian jurisdictions,[153] nor a jurisdictional comparison of Essential Services Usage rates in Canada, including basic terms and conditions.[154]

219. BCOAPO states that there is an empirical basis for the 400 KWh figure in that 400 kWh is an appropriate demarcation of a 'low use' customer, and provides neither excessive consumption for very small users nor inadequate consumption for larger customers. The $0.04/kWh would provide a bill reduction of between $9 and $16 per month on low-use, low income bills. BCOAPO believes this would provide 'meaningful assistance' to low income customers without imposing an unreasonable burden on non-participants,[155] The CEC notes that BC Hydro's definition of 'low use' is in fact between 370 kWh per month and 380 kWh per month.[156]

220. BC Hydro acknowledges that there is no,[157] or only very modest,[158] apparent systematic increase in usage based on low-income customer discounts.

221. The CEC recognizes that savings of between $9 and $16 per month would be of value to low income customers, however there does not appear to be substantive evidence to suggest that the savings could not be used simply to allow people to pay other bills, such as a car loan, instead of their utility bill.[159] The CEC submits that a lower utility bill without the oversight government provides through its support and assistance programs and that this would be potentially less effective welfare for the province. The CEC

[151] Exhibit C2-20, CEC 1.1.2
[152] Exhibit C2-20, CEC 1.1.3
[153] Exhibit C2-20, CEC 1.1.2
[154] Exhibit C2-20, CEC 1.2.2
[155] BCOAPO Final Submission, Page 51
[156] Exhibit C2-12, Pages 14 and 15
[157] Transcript, Volume 4, Page 737
[158] Transcript, Volume 4, Page 739
[159] Exhibit C2-20, CEC 1.18.1

submits that evidence providing a full understanding of the impact of benefits is key to an understanding of the cost/benefits of the program.

222. BC Hydro points out that by itself a $16 reduction in monthly electricity bills for low-income customers would not have a material impact on the number of dunning communications or disconnections. Even if BC Hydro were to accept the proposition that on-time payments would be reduced for low-income customers under the ESUB rate, the rate increase of 1.5 to 3 per cent would also impact arrears for customers that are not low-income, leading to increased bad debts and borrowings from delayed revenues for those customers.[160]

223. BCOAPO is recommending a staged eligibility process for ESUB with the 130,000 people who currently receive social assistance from the provincial Government and who therefore make up a large part of the 170,000 people who would be eligible, being the first group to become eligible for the ESUB.[161]

224. At a 100% take-up rate, ESUB would impose a cost of roughly $26.9 million annually[162] plus administrative expenses of approximately $550 thousand.[163] Mr. Colton only expects a 50% uptake, however this appears to be supported only by his experience in the United States.[164] Given the expected take-up of approximately 50%[165] the bill impact for non-participating customers, at median usage, would be in the range of about $0.52.[166] [167]

225. BC Hydro provides the following estimates of the bill impact for non-participating customers based on whether or not the Loss Revenue from ESUB is re-distributed to Step 1 and Step to in Equal Proportions (Scenario A) or if the Loss revenue from ESUB is re-distributed to Step 2 (Scenario B). The percentage increases are in the order of 1.5% for each of Step 1 and Step 2 if re-distributed equally, and 3% for Step 2 if re-distributed to Step 2 exclusively.

Table A Comparison of F2017 Revenue Neutral Rates: Status Quo vs. ESUB Scenario A

Estimated Tariff Rates	Status Quo (Proposal)	Rate with ESUB Scenario A	Difference (%)
ESUB (c/kWh)		4.42	*4 cents less than Step 1*
Step 1 (c/kWh)	8.29	8.42	1.57
Step 2 (c/kWh)	12.43	12.62	1.53
Basic ($/day)	0.1835	0.1835	0

[160] Exhibit B-31, BC Hydro Rebuttal, Page 6
[161] Transcript, Volume 3, Page 381
[162] BCOAPO Final Submission, Page 52
[163] BCOAPO Final Submission, Page 52
[164] Exhibit C2-120, CEC 1.17.1
[165] BCOAPO Final Submission, Page 52
[166] BCOAPO Final Submission, Page 52
[167] $0.50/month + $0.23/annum

Table B Comparison of F2017 Rates: Status Quo vs. ESUB Scenario B

Estimated Tariff Rates	Status Quo (Proposal)	Rate with ESUB Scenario B	Difference (%)
ESUB (c/kWh)		4.29	*4 cents less than Step 1*
Step 1 (c/kWh)	8.29	8.29	0
Step 2 (c/kWh)	12.43	12.80	3.0
Basic ($/day)	0.1835	0.1835	0

[168]

226. The CEC notes that the assumption in the BC Hydro calculation is based on all low-income accounts participating in ESUB.[169]

227. BC Hydro identified an additional $1.5 million in start-up ($1.25 million) and technology costs ($0.23 million). Mr. Colton argues that the $1.5 million in start-up and technology costs do not impose 'an incremental burden' on ratepayers because there is a ramp up period in which ratepayers are paying for a penetration level that is not achieved, and the over-collected funds can be used to fund the start-up costs.[170]

228. The CEC submits Mr. Colton's argument is incorrect and is equivalent to arguing that if ratepayers are not aware that they are paying for a service they are not being provided with (fully ramped up service), then the costs don't constitute a burden. The CEC submits that this is nonsensical. The CEC recommends that the Commission include the start-up and technology costs of the $1.5 million in their assessment of the Essential Service Usage Block cost implications.

229. BCOAPO states in BCUC 1.9.1 that none of the costs from the proposed ESUB would be absorbed by non-residential customers. BC Hydro disagrees and states that based on current allocation methods, incremental implementation and ongoing administration costs would be spread across all customer classes.[171]

230. By way of regulatory justification, BCOAPO relies on the three principles of cost reflectivity, improved cost efficiency and improved affordability. With regard to cost reflectivity, BCOAPO argues that lower income customers, are also lower use customers, and therefore impose lower costs on the system and merit a lower rate. However, BC Hydro provides evidence that low-income customers have about the same cost of service as residential customers as a whole based on the shape of their load profiles.[172] Under cross-examination Mr. Doyle pointed out that BCOAPO's calculations were not based on the common calculations and that BC Hydro's calculations do not differ materially from the industry norm.[173] BC Hydro also confirms in its rebuttal evidence that 'In all cases it is apparent that residential customers peak at about the same time, and their load profiles are substantially the same. In the absence of a formal cost of service analysis this

[168] Exhibit B-36, Pages 1 and 2
[169] Exhibit B-36, Page 2
[170] BCOAPO Final Argument, Page 53
[171] Exhibit B-31, BC Hydro Rebuttal Evidence, Page 13
[172] Exhibit B-31, BC Hydro Rebuttal Evidence, Page 4
[173] Transcript, Volume 4, Page 747

evidence demonstrates that residential customers cause BC Hydro to incur demand related and customer fixed costs that are recoverable through their kilowatt hour energy rates."[174]

231. The CEC submits that BC Hydro's analysis is more appropriate and that the BCOAPO logic rests on evidence such as the tendency for low income customers to be lower use customers and therefore have lower absolute bills. The BC Hydro analysis is supported by evidence that the low income customers and all customers have essentially the same shape load profiles and therefore proportionately cause the same proportional cost. The logic follows that the energy charge reflects the proportional cost difference and therefore cost reflectivity is accurate with the BC Hydro proposals. The CEC submits that Mr. Colton is wrong in his assumptions and that the factual evidence does not support his assertions.

232. The CEC recommends that the Commission accept the BC Hydro rebuttal evidence and reject Mr. Colton's evidence. Further, Mr. Colton conceded that he does not have expertise in cost of service issues so it is understandable that he has not identified the issues in the way BC Hydro has.

233. The CEC submits that even to the extent that lower use customers do create lower costs, cost causation principles would suggest it is reasonable for all customers causing lower costs to receive lower rates, not just lower income customers. Mr. Colton accepts the accuracy of this principle but argues that the proposal is based on the 'synergistic' impacts of the proposal.[175]

234. With regard to improved cost efficiency, BCOAPO argues that adoption of the ESUB will improve the efficiency of BC Hydro operations in terms of revenue collection. In response to CEC 1.7.1 BCOAPO references several reports related to American utilities.[176] Mr. Colton is unable to answer whether or not the same revenue collection improvements would apply to BC Hydro as the calculation has not been performed on BC Hydro.[177] Mr. Colton also states that they do not assert that BC Hydro will necessarily earn more revenue and incur fewer expenses, but that they will be more cost-effective.[178] BCOAPO provides an overview of its Business Case in Exhibit C2-19, BCUC 1.12.2 Attachment. The evidence examines average arrears, their ages and efficiency of collection efforts.[179] Mr. Colton is not able to provide the appropriate calculation for a reduction in working capital[180] or collection expenses.[181]

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[174] Transcript, Volume 7, Page 1379
[175] Exhibit C2-20, CEC 1.13.1
[176] Exhibit C2-20, CEC 1.7.1
[177] Exhibit C2-20, CEC 1.12.3
[178] Exhibit C2-17, BC Hydro 1.19.2
[179] Exhibit C2-19, BCUC 1.12.2 Attachment
[180] Exhibit C2-20, CEC 1.14.2
[181] Exhibit C2-20, CEC 1.14.3

235. BC Hydro argues that they have no evidence that that BC Hydro's costs would be materially reduced by the ESUB but do know that the revenues would be reduced.[182] BC Hydro did not review the reports provided by Mr. Colton but made an examination of their own costs as outlined in Transcript Volume 7, pages 1388 to 1390. In its Rebuttal Evidence BC Hydro points out that a reduction of $16 is not likely to create a material impact on communication and dunning costs, and further that the proposed increase to ratepayers could result in increased bad-debts and delayed revenues.[183]

236. The CEC submits that the analysis provided by BC Hydro is reliable and should be accepted by the Commission in its determinations.

237. The CEC submits that none of the three pillars cited by Mr. Colton are persuasive. Mr. Colton is wrong on there being a cost reflectivity benefit to be accorded to low income or low consumption customers. Mr. Colton's evidence is limited with respect to cost efficiency and is effectively countered by the BC Hydro rebuttal evidence. The CEC submits that on affordability, apart from payment terms on which BC Hydro has made significant adjustments, the Commission has no jurisdiction to discriminate based on income for rate setting.

238. With regard to cost-efficiency, the CEC does not find the BCOAPO argument that cost savings will accrue to be adequately supported and the CEC prefers BC Hydro's evidence which is based on BC Hydro's own cost structures. With regard to affordability, the CEC does not find 'affordability' to be a regulatory consideration in the Bonbright principles beyond acceptance and bill payment collection terms and conditions. The CEC reiterates its views above with respect to the inappropriateness of addressing provincial poverty through its energy utility.

239. The CEC submits that the cost of the ESUB is a significant cost at about $30 million and several aspects of the costs are not agreed upon such as the assumptions regarding 'bounce back', elasticities and rate impact.[184] Additionally, there is not a great deal of clarity with respect to the actual benefits that will accrue from the proposed $30 million in costs.

240. The CEC recommends that the Commission deny the ESUB as proposed by BCOAPO.

(ix) Crisis Intervention Fund

241. BCOAPO proposes the development of a $5.4 million crisis intervention program that would involve providing funds when a low income customer faces a situation that threatens the continuing ability of that customer to take electric service.[185] Mr. Colton states that a crisis intervention fund 'responds to the fragility of income of many customers.[186]

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[182] Transcript, Volume 7, Page 1387
[183] Exhibit B-31, BC Hydro Rebuttal Evidence, Page 6
[184] Transcript, Volume 5, Pages 826 - 839
[185] BCOAPO Final Submissions, Page 67
[186] Transcript, Volume 7, Page 1233

242. The fund would be administered by a third party but is not clearly defined as to exactly how it would be run. Mr. Colton states 'Such a crisis situation may, but need not necessarily, involve providing a grant to prevent the disconnection of service for non-payment. In the alternative, a crisis intervention grant might respond to a level of arrears that the program administrator deems is of sufficient size that the customer will simply never be able to retire that arrears. Moreover, a crisis situation might involve circumstances where a customer is currently off-system and lacks sufficient funds to make an arrearage payment along with paying the other fees, such as the cash security deposit. And that would prevent that customer from coming back.[187] BCOAPO also proposes that the Commission should not insert itself into the day to day operations, but rather approve the reasonableness of the funding.[188] The CEC submits that it is impossible to determine the reasonableness of the funding without a greater understanding of the proposal and how it would operate.

243. The CEC notes that BC Hydro's bad debt and restructured payment terms policies amount to a crisis response and that these are backed up by the full financial capability of BC Hydro. The CEC submits that establishing a fund for crisis management is unnecessary and duplicative of government programs available for similar purposes.

244. BCOAPO claims that the Crisis Intervention fund will also contribute to BC Hydro cost-effectiveness in responding to utility non-payment. They distinguish it from other social services as being a benefit to BC Hydro. They state:

> 'BCOAPO's proposed crisis intervention program was presented "as a way to respond more effectively and more efficiently by the utility to non-payment, and to improve the complete timely, regular, unsolicited payment of bills. It was not a social program. It is a program to help the utility improve its own efficiency of operations. And it will do so.'[189]

245. The CEC submits that the Crisis Intervention fund is indeed properly classified as a 'social program'. The CEC does not find the evidence regarding improvements to the utility to be persuasive and further does not accept that even if there was a marginal benefit to the utility, that the program is not primarily a social one. The CEC notes that the Commission is directed 'to ensure that the utility for 2017 would be … (required) … to yield a distributable surplus of $684 million; for fiscal 2018 it's necessary to yield a distributable surplus of $698 million; and for 2019 it would be necessary to yield a distributable surplus of $712 million', and that those dollars are available to the government without further restriction.[190]

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[187] Transcript, Volume 7, Pages 1232 and 1233
[188] BCOAPO Final Submission, Page 68
[189] BCOAPO Final Submissions, Page 68 and Transcript, Volume 7, Page 1252
[190] Transcript, Volume 7, Page 1256

246. The CEC submits that the evidence is clear that BC Hydro customers contribute significantly to government and that those funds support government programs to benefit all manner of public interest, including support and assistance for low income persons and families. The CEC recommends that the Commission give weight to this evidence into its considerations of Mr. Colton's evidence and the BCOAPO proposals.

247. The $5.4 million fund would be funded through the addition of a $0.25 charge to the fixed monthly customer charge from all BC Hydro customers.[191] BCOAPO argues that the fund should be funded by all customer classes because it benefits all customer classes 'including commercial, large commercial and large general service however ... define(d).[192] They point to the potential for addressing financial issues for employees which contribute to lack of employee productivity.[193] This appears to come from a single American study which found that financial issues are the chief contributor to a lack of productivity.[194]

248. The CEC submits that the cost ($0.25/month/customer) to the customer is not adequately justified and the benefits are not adequately established. The size of the fund $5.4 million was derived from the size of the charge, as an 'easily explainable figure.'[195] The CEC submits this is an inappropriate method to determine the appropriate size of a fund. BCOAPO is not able to provide an appropriate answer as to why $5.4 million is the appropriate size for the fund[196] nor how many people the fund is likely to assist.[197] The CEC does not find that there is sufficient detail and cost/benefit analysis to justify the creation of a Crisis Intervention fund by the energy utility. The CEC does not find sufficient merit in this proposal to warrant BC Hydro deviating from its approach to work on the terms and conditions affecting all customers in their bill payment and affordability.

249. BCOAPO suggests that should the Commission determine that it requires further information prior to implementing a Crisis Intervention Fund for low income residential customers, BC Hydro should be directed to prepare and file, within six months of the date of the Commission's order, a proposed crisis assistance program for low income customers who have arrears with BC Hydro and are unable to pay their electricity bills.

250. The CEC recommends that the Commission deny the request for the development of a Crisis Intervention Fund based on the basis of its social program nature, duplication of government assistance programs and the lack of detail and cost/benefit analysis. The CEC recommends that if the Commission is inclined to approve the Crisis Intervention fund it should require further development of the plan, with a full cost/benefit analysis undertaken.

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[191] BCOAPO Final Submission, Page 68
[192] Transcript, Volume 7, Page 1252
[193] BCOAPO Final Submission, Page 68
[194] Transcript, Volume 7, Page 1251
[195] Exhibit C2-20, CEC 1.19.2
[196] Exhibit C2-20 CEC 1.19.3
[197] Exhibit C2-20, CEC 1.19.4

251. Additionally, to the extent that the Commission does approve a Crisis Intervention Fund the CEC submits that it should be funded exclusively by the residential sector, who would be the only participants and the primary beneficiaries. The CEC submits that benefits to the commercial sector are spillover and are not justification for imposing an additional burden on the commercial sector.

(x) Low Income Customer Terms and Conditions

252. BCOAPO proposes that the Commission amend the Electric Tariff to allow for Low Income Terms and Conditions relating to reconnection and account charge exemptions, waived security deposits, and late payment fee exemptions.

(xi) Reconnection and Account Charges Exemptions

253. BCOAPO proposes that BC Hydro exempt low income customers from its proposed mandatory reconnection and account charges. Their primary rationale is based on the understanding that customers who are unable to pay bills get caught in a never-ending loop of non-payment and assessment of additional charges, leading to yet more non-payment. The CEC accepts that the addition of more costs can be counterproductive in facilitating repayment and future payment stability. BC Hydro has significantly increased their disconnection and reconnection rate as a result of smart meter capability which created a significant revenue stream for the company.[198] The CEC notes that BC Hydro has proposed to lower its reconnection fee to $30 from $125 in this application. BCOAPO estimates the cost of exempting low income customers from the reconnection fee to be in the order of $95,000.[199]

254. The CEC submits that the significantly lower reconnection fee will make a material difference to the existing burden of reconnection fees and recommends that the Commission allow these fees to stand for all customers unless it is demonstrated that the $30 fee is an unreasonable hurdle. The CEC submits that even if the reconnection charge is relevant to the cycle of increasing costs once a customer has defaulted, the account charge should not be waived as it is levied under many different circumstances, not just when a customer defaults.

255. The CEC recommends that the Commission adopt the BC Hydro proposals and not the BCOAPO proposals.

(xii) Waived Security Deposits

256. BCOAPO proposes modifications to BC Hydro's cash security deposits. BCOAPO quotes BC Hydro's acknowledgement of the financial repercussions that arise from the requirement from cash security deposits:

[198] Transcript, Volume 3, Pages 469 to 473
[199] Exhibit C2-20, CEC 1.26.1

> BCOAPO stated that security deposits may be counter-productive to the collection of bills when customers cannot afford to pay their bills. A low-income customer who has experienced a disconnection of service would face not only the financial burden of paying the unpaid bills that led to the disconnection in the first instance, but the additional financial burden of paying a new deposit. The deposit, rather than protecting the company, could represent an insurmountable barrier to the customer, thus both harming the customer and preventing the company from collecting the outstanding amount. *BC Hydro acknowledges this concern* 332 (emphasis added).[200]

257. BCOAPO recommends that low income customers be exempted from posting cash security deposits and that BC Hydro accept certain specified alternatives to posting *cash* security deposits. They point to inaccurate assessment of risk (73% of deposits returned) and the lack of data regarding any link between the security deposit and the reduction in financial risk for BC Hydro.[201]

258. BC Hydro has a number of options with respect managing security deposit requirements and or ensuring that it is providing supply to customers who will pay their bills. The CEC recommends that the Commission prefer BC Hydro's approach in managing its bill payment risks and the impacts on the customers who may have payment issues.

(xiii) Late Payment Charge Exemption

259. BCOAPO proposes to exempt low income customers from late payment charges. BC Hydro estimates a total late payments cost of approximately $7.8 million which is recovered through its Late Payment Charges.[202] BCOAPO challenges the appropriateness of these costs relative to the Late Payment charges which it states are not cost-justified.[203] BC Hydro provides evidence of its cost-justification in its Rebuttal evidence at pages 31-35. BC Hydro also indicates that "when transition issues relate to smart meters and other business process changes are accounted for, it is clear that BC Hydro's collection processes are not only very good they are also improving...." BC Hydro's late payment charges are cost-based and recover the costs of BC Hydro's collection activities and carrying costs incurred from the time that service is provided."[204] BC Hydro does not charge a late payment charge to balances entered into under an instalment plan.[205]

260. BCOAPO note that if a customer is truly unable to pay, then collection efforts that further increase a customer's bill are not effective.[206] BCOAPO charges that a Late Payment

[200] BCOAPO Final Submission, Page 86
[201] BCOAPO Final Submission, Pages 87 and 88
[202] BCOAPO Final Submission, Page 81
[203] BCOAPO Final Submission, Page 82
[204] Transcript, Volume 7, Pages 1379 and 1380
[205] Transcript, Volume 5, Page 1109
[206] BCOAPO Final Submission, Page 79

Charge imposed on low-income customers pushes bills into an unaffordable and unpayable range and the result places collection of both the original balance and of the unpaid Late Payment Charges in jeopardy. Under such circumstances, the Company loses more money than it generates by imposing Late Payment Charges on low-income customers. They also argue that the Company cannot demonstrate that Late Payment Charges are serving to promote full and timely payment by residential customers generally, and the imposition of a late payment charge will have even less of an impact on low-income customers in this regard.

261. The CEC recommend that the Commission prefer BC Hydro's management of its late payment charge processes.

(xiv) New Customer Service Practices and Reporting Requirements

262. BCOAPO proposes that the Commission amend the Electric Tariff to allow for new customer service rules for all Residential customers relating to the provision of sureties in lieu of cash security deposits and the use of an equal payment plan in lieu of security deposits and the adoption of additional reporting requirements.

(xv) Sureties in Lieu of Cash Security Deposits

263. BC Hydro has agreed to bring forward a proposal allowing for the use of sureties and guarantors in lieu of cash security deposits. BCOAPO disagrees with the BC Hydro proposal to require the surety to be a BC Hydro customer, and that the surety must extend to the customer's entire bill, rather than just the security deposit amount. Otherwise, BCOAPO supports BC Hydro's proposal.

264. The CEC agrees that BC Hydro's proposal should be implemented. The CEC submits that BCOAPO's requested changes are also reasonable. The CEC recommends that the Commission approve BC Hydro's proposal with the changes recommended by BCOAPO.

(xvi) Equal Payment Plan in Lieu of Security Deposits

265. BCOAPO also proposes that BC Hydro should permit customers to enter into an equal payment plan in lieu of providing a security deposit. BC Hydro states that the Equal Payment Plan (EPP) could help make electricity charges more consistent and on that basis, could be beneficial to customers by helping them improve their budgeting. However, BC Hydro does not have any data available to support a correlation between EPP participation and the reduced risk of EPP customers leaving unpaid final bills.

266. The CEC recommends that the Commission prefer the BC Hydro management of the EPP rather than dictate changes with unstudied implications.

(xvii) Reporting

267. In his testimony Mr. Colton concludes that BC Hydro does not routinely engage in the fundamental data collection and reporting that would underlie reasonable and prudent utility management of the inability to pay customers, and recommends that BC Hydro be

required to begin no later than six months after a final decision reporting basic consumer credit and collection activities and outcomes.[207] BCOAPO proposes that BC Hydro adopt the National Association of State Utility Consumer Advocates data reporting recommendations.

268. The CEC recommends that the Commission not proceed to propose additional reporting without understanding the cost implications of such. The CEC recommends that the Commission request BC Hydro as compliance filing to identify the reporting that it would find reasonable in regard to the Commission decision and that the Commission review reporting at that time and address anything the Commission is concerned about upon receipt and review of a report.

(xviii) Changes to Business Practices

269. BCOAPO proposes that the Commission direct BC Hydro to change certain business practices relating to the changes to installment payment plans for low income customers, implementation of a delay on disconnections for certain family situations, limitations on late payment charges, and a prohibition on the use of external credit reporting agencies. BCOAPO is unable to provide an estimate of the revenue reductions as a result of their proposals regarding late payment charges.[208]

(xix) Changes to Installment Payment Plan for Low Income Customers

270. BCOAPO outlines their concerns with BC Hydro's existing repayment terms in Section 6.3.3 of their Final Submission. They note that when customers experience payment problems, BC Hydro experiences collection problems.[209] BCOAPO charges that BC Hydro current deferred payment plans are ineffective and not affordable,[210] so that the unpayable payment plans not only place the underlying debt payment in jeopardy, but also the bill for current service.[211]

271. BCOAPO provides the following recommendations regarding installment payment plans.

- Setting the down payment at no more than 10% of arrears;
- Limiting the term to not less than 12 months; or
- In the alternative to the second recommendation, placing a limit on required arrearage payments so that arrearage payments would not exceed an average monthly bill.

272. BC Hydro does not agree that its installment plans should be restricted based on a view that its success rate is not high. BC Hydro believes there is a trade-off between minimizing the payment period and making the repayment affordable. They state that repayment plans are not intended to be used as long term payment solutions, and that

[207] Transcript, Volume 7, Pages 1243-1244
[208] Exhibit C2-12, CEC 1.25.1
[209] BCOAPO Final Submission, Page 72
[210] BCOAPO Final Submission, Page 75
[211] BCOAPO Final Submission, Page 75

longer repayment plans should not be mandatory and are problematic if they extend into the next winter season.[212] Additionally, a 12-month minimum repayment term could result in the repayment term extending into the subsequent winter heating season which can exacerbate a situation in which a customer experiences financial inability to pay and a moratorium on winter disconnection creates backlogs for the utility.[213]

273. The CEC agrees that BC Hydro should have discretion to provide an Installment Plan that accommodates a customers' ability to pay while balancing the reasonable costs to the utility.[214] The CEC submits that BC Hydro's current prohibition on customers having installment terms that extend into the next winter season are somewhat restrictive and do not consider individual circumstances. The CEC submits it would not be unreasonable for BC Hydro to consider relaxing this regulation, enabling decision for repayment to be determined on a case by case basis.

(xx) Implementation of a Delay on Disconnections for Certain Family Situations

274. BC Hydro has proposed to implement changes that will delay disconnections where customers demonstrate a medical reason for requiring power. Mr. Colton recommends that BC Hydro adopt shut-off protections for the very young, for seniors and for households facing medical emergencies[215] and BCOAPO recommends that the proposal be increased from 20 days to 20 business days. BCOAPO endorses BC Hydro's proposal with two caveats including the extended application and the establishment of a right to file a complaint regarding a proposed payment plan.[216]

275. The CEC recommends that the Commission approve the proposal as provided for by BC Hydro.

(xxi) Limitation of Late Payment Charges to 60 days overdue

276. BCOAPO also proposes Late Payment charges should be limited to account balances that are at least 60 days overdue, and that this limitation should extend to all residential customers.[217] BCOAPO's position is that in order to provide proper cost matching, a late payment charge should not be issued until the commencement of the cost-causing activities, which occur substantially later than when the late payment charge is issued.[218]

277. BCOAPO also argues that at the very least, the late payment charge for all residential customers should be reduced to the short-term cost of debt.[219]

278. BCOAPO proposes to set the Late Payment Charges equal to BC Hydro's Weighted Average Cost of Debt rounded to ½ percent for all customers, and start LPCs at Day 60 beyond due date for all customers.[220]

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[212] Exhibit B-31, BC Hydro Rebuttal, Appendix A, Pages 24 to 26
[213] Exhibit B-31, BC Hydro Rebuttal, Pages 24 and 25
[214] Exhibit B-31, BC Hydro Rebuttal, Page 26
[215] Transcript, Volume 7, Page 1241
[216] BCOAPO Final Submission, Page 107
[217] BCOAPO Final Submission, Page 82
[218] BCOAPO Final Submission, Page 84
[219] BCOAPO Final Submission, Page 84

279. The CEC recommends that the Commission prefer BC Hydro's approach to late payment charges and any ongoing management of this process taking into account its ongoing consultations with stakeholders. The CEC does not think it good regulatory practice for the Commission to engage too extensively in managing the BC Hydro payment and collections processes, particularly when the evidence points to BC Hydro doing a reasonable and creditable job of managing these processes and their current flexibility to be making changes which it sees as responsive to many of the issues raised by BCOAPO.

(xxii) Prohibit the Use of External Credit Scores for Security Deposits for All Customers.

280. BCOAPO proposes that BC Hydro should be prohibited from making use of Equifax or other external credit rating agencies in determining whether or not a cash security deposit is required. They state that it is consistent with long-standing utility regulatory principles proscribing denial of service for 'collateral matters', and that it is not relevant to ratepayers if a customer does not pay other bills, if they do pay their utility bill. BC Hydro observes that among the new accounts that were assessed a security deposit during 2011 to 2013, about one-third are existing customers who did not have a good payment history. The remaining two-thirds were new customers to BC Hydro.[221]

281. The CEC submits that credit scores are standard method of determining credit-worthiness where existing customer experience is not available. Further, the addition of other options such as the proposed surety in lieu of cash should improve accessibility.

(xxiii) Conduct a Customer Segmentation Analysis

282. BCOAPO requests that BC Hydro undertake a customer segmentation study that is specifically directed toward characterizing patterns of nonpayment; identifying the characteristics of non-payers; identifying predictors of nonpayment; and identifying early indicators of non-payment.[222]

283. The CEC submits that Commission directed management of the micro-details of the BC Hydro processes is not ideal. The CEC recommends that BC Hydro be judged on its payment and collections management through evaluation of its performance, which can be reviewed in successive RRA hearings.

(xxiv) Expand ECAP to Reach More Low Income Households

284. BCOAPO is requesting that the Commission recommend that BC Hydro be required to expand installs of BC Hydro's low-income ECAP program to serve a significantly higher percentage of the low income households than it is currently serving.[223] ECAP is an income-based energy efficiency program that is limited to low income customers.[224]

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[220] BCOAPO Final Submission, Page 112
[221] Exhibit B-31, BC Hydro Rebuttal, Page 23
[222] BCOAPO Final Submission, Page 102
[223] BCOAPO Final Submission, Page 6
[224] Transcript, Volume 5, Page 1072

First Nations communities typically participate in ECAP using a bulk application process and that through this process, individual community members are not required to submit proof of income documents to BC Hydro. Instead, the First Nations Band identifies income qualified community members and informs them of the program and Band members choose to participate in the program by completing an application form and a similar bulk application process is used for nonprofit housing providers.[225]

285. BCOAPO is not asking for expenditures related to ECAP.

286. The CEC recommends that expanded use of ECAP can be evaluated in the upcoming RRA proceeding and is not a rate design issue but a quantum of use issue better suited to the RRA proceeding.

(xxv) Totality of BCOAPO Proposals

287. The CEC submits that together the size of the proposals made by BCOAPO in this application are significant. The total cost of the ESUB and Crisis Intervention fund alone are well over $30 million and experience has shown that start-up costs for the Ontario Electricity Support Program were in the order of $13 million with annual operating costs of $9 million[226] with additional costs to local distribution companies of about $250 thousand annually.[227] Additionally, BC Hydro has raised the spectre of possible misuse which has been experienced in Ontario.[228]

288. The CEC submits that overall the proposals are not especially well developed in terms of the ultimate benefits that would be derived. The CEC recommends that the Commission deny the BCOAPO proposal and encourage BC Hydro and BCOAPO to continue working together to develop suitable plans that are both beneficial and demonstrably cost-effective.

289. The CEC commends BC Hydro's approach of working closely with its customer group representatives and notes that while the CEC recommends rejection of the BCOAPO proposals the BCOAPO has added value and moved BC Hydro to make significant improvements for the benefits of all customers.

[225] Transcript, Volume 5, Page 1073
[226] Exhibit B-31, BC Hydro Rebuttal Evidence, Page 12
[227] Exhibit B-31, BC Hydro Rebuttal Evidence, Page 12
[228] Exhibit B-31, BC Hydro Rebuttal Evidence, Page 13

D. RESIDENTIAL RATE DESIGN

(i) Residential RS 1101/RS 1121

290. BC Hydro is proposing to retain the status quo as it relates to the residential inclining block (RIB) rate structure that has been in place since 2008.[229] Under this structure, 52% of the total costs assigned to the Residential Rate are demand related costs, 35% are energy related and 13% are customer related.[230]

291. BC Hydro proposes to apply revenue requirement rate increases uniformly to each of the RIB rate's three main pricing elements, which are the basic charge, Step 1 energy rate and Step 2 energy rate, in each of F2017, F2018 and F2019 (RIB Pricing Principles). [231] BC Hydro seeks a final order approving continuation of the RIB Pricing Principles for each of F2017 to F2019[232].

292. BC Hydro prioritized customer understanding and acceptance,[233] rate stability and fair apportionment of costs above the efficiency criterion which it believes reflects both customer views and the context in which BC Hydro is currently operating.[234] BC Hydro does not believe that the Bonbright Principles lend themselves to hierarchical ranking.[235] BC Hydro does not propose changing either the Step 1-Step 2 threshold, nor the ratio between Step 1 and Step 2 nor the basic charge.[236] Table A in BCUC 2. 170.1 provides BC Hydro's view of the Proposed Residential Rate Relative to its Option 2. The BC Hydro proposal is unfavourable in terms of Price Signals that encourage efficient use and discourage efficient use and fair apportionment of costs among customers.[237]

293. BC Hydro outlines positive aspects of the RIB rate with regard to customer understanding at page 23 of their Final Argument.

294. The RIB rate is a conservation rate and is intended to encourage larger energy consumers to use less energy.[238] The incremental rate structure conservation for each year (incorporated in the DSM plan) is forecasted by subtracting the incremental conservation from the total incremental conservation (computed using an elasticity of -0.05, incorporated in the load forecast before DSM) from the total incremental conservation (using elasticity of -0.1 for RIB rate Step 2 marginal consumption and -0.05 for Step 1 marginal consumption).[239] RIB induced DSM savings are identified in BCSEA 2.24.1 Overall the residential class is considered to be price inelastic as the Step 2 price

[229] BC Hydro Final Argument, Page 20
[230] Exhibit B-23, CEC 2.92.1
[231] BC Hydro Final Argument, Page 20
[232] BC Hydro Final Argument, Page 21
[233] Exhibit B-23, BCUC 2.140.1
[234] Exhibit B-23, BCUC 2.141.1
[235] Exhibit B-23, BCUC 2.170.2
[236] BC Hydro Final Argument, Page 20
[237] Exhibit B-23, BCUC 2.170.1
[238] BC Hydro Final Argument, Page 21
[239] Exhibit B-5, BCUC 1.37.2

elasticity was found to be between -0.8 and -0.13.[240] Step 2 price elasticity is provided in BCOAPO 1.61.1

295. The CEC submits that the evidence is that the current RIB rate is performing adequately in terms of customer awareness and effectiveness in generating conservation as outlined in BC Hydro's Final Argument at pages 23 and 24. Of customers who were aware of the RIB rate, 79% reported that the rate served as an incentive to manage their electricity use.[241] BC Hydro considers 55% awareness level to be reasonable because it has continued to increase and is consistent with awareness in other jurisdictions.[242] If the trend (to keeping the RIB rate) is continued it would be expected that there may be a moderately higher percentage of customers aware of the RIB rate than in 2014[243] and there are initiatives underway which can serve to increase RIB awareness as well.[244] It is reasonable to expect that if awareness of the RIB were to increase, more customers may act on the price signal which could lead to additional conservation.[245]

296. The CEC submits that the Commission should give considerable weight to the above-noted evidence before considering alternatives which would require further development and delay in terms of customer understanding and acceptance, and could be less effective in generating conservation.

(ii) Alternative Rate Structures to the Residential Inclining Block (RIB)

297. BC Hydro considered 5 alternatives to the RIB rate including a flat rate, three step rates, customer specific baseline, and two seasonal rates.

298. The movement from the RIB rate to a flat rate structure would result in lost conservation from customers with usage that extends past the Step 2 threshold. There could be additional losses in conservation from a perceived de-emphasis on conservation that would be signaled by the elimination of the RIB rate. Such related conservation effects are not explicitly estimated by BC Hydro.[246]

299. The essential trade-off between the RIB rate and a flat rate is greater economic efficiency on the one hand, and loss of conservation and bill impacts on the other hand.[247] Only 18% of customers (mainly high users), and 9% of low income customers would be better off under a flat rate.[248]

300. BC Hydro indicates that no stakeholder supported the flat rate after BC Hydro conducted a review and modelling.[249] The CEC is opposed to the introduction of a flat rate because it would reasonably be expected to reduce the conservation benefits of the rate, and

[240] Exhibit B-5, AMPC 1.9.11
[241] Exhibit B-23, CEC 2.997.2
[242] Exhibit B-23, CEC 2.90.1
[243] Exhibit B-23, CEC 2.90.2
[244] Exhibit B-23, CEC 2.90.3
[245] Exhibit B-23, CEC 2.93.2
[246] Exhibit B-5, CEC 1.38.1.1
[247] Exhibit B-1, Page 5-22
[248] Exhibit B-1, Page 5-23
[249] BC Hydro Final Argument, Page 25

potentially result in increased use requiring new energy supply resources to be acquired earlier, and at greater expense than currently anticipated. The RIB rate is complementary to DSM because it provides a greater incentive through higher Step 2 rates to undertake DSM initiatives.[250]

301. BC Hydro does not support a 3 step rate for residential rates which is only implemented in one Canadian jurisdiction.[251] Most participants agreed that only Three Step A should be advanced for the RDA and that the Three Step A was inferior to the RIB Rate.[252] BC Hydro states that it does not anticipate much incremental conservation by adopting a 3-step rate A option and there would be moderate decreases in customer understanding and acceptance, as compared to the RIB rate.[253] The CEC is also opposed to three step rates because, in the CEC's view, they are excessively complicated, particularly for the residential sector. The CEC submits that there is no evidence that such rates would provide any further benefits than are already being provided by the two step rate structure.

302. The CEC submits that the residential sector should be provided with simple rate structures in order to facilitate the customer understanding and acceptance principles or rate design as articulated by Bonbright.

303. BC Hydro points out that stakeholders have generally agreed that that customer specific baselines are not a feasible alternative, and as such it was not advanced.[254] The CEC is opposed to the prospect of a customer specific baseline for the residential sector as it is difficult to administer, an unknown impact on revenue[255] and has not been demonstrated to be effective in achieving conservation benefits for the MGS rate class.[256]

304. BC Hydro also indicates that stakeholders also generally agreed that the two seasonal rates are not feasible and such were also not advanced.[257] The CEC submits that seasonal rate alternatives involving either a higher winter Step 1/Step 2 threshold (to potentially moderate bill impacts for customers with space heating), or a higher rate targeted to the four winter months could be appropriate to be carried forward for discussion in Module 2.

305. The CEC submits that either of these rate alternatives could be appropriate as optional rates. The CEC submits that BC Hydro should provide further development of these options and bring them forward in Module 2 for consideration at that time.

306. BC Hydro points out that the RIB rate performs well in the fairness, customer understanding and acceptance and (if retained), stability Bonbright criteria. Further, the majority of customers are aware of the RIB rate as discussed above, however no firm

[250] Exhibit B-23, BCUC 2.178.3
[251] Exhibit B-1, Pages 5-25 to 5-29
[252] Exhibit B-1, Page 5-26
[253] Exhibit B-1, Page 5-29
[254] BC Hydro Final Argument, Page 25
[255] Exhibit B-1, Appendix C-3A
[256] Exhibit B-1, Page 6-49
[257] BC Hydro Final Argument, Page 25

conclusions can be drawn about how the RIB awareness is related to customer price response.[258]

(iii) Delivering the RIB Rate

307. BC Hydro developed several different alternatives for delivering the RIB rate. Option 1 (proposed by BC Hydro) applies RRA increases equally to all three RIB rate pricing elements, while Option 2 applies RRA increases to Step 1 energy rate and basic charge only while holding Step 2 rate at its current level.[259] Option 1 continues with the existing F2015/16 RIB rate pricing principles, so all customer bills under this option will be the same as the existing RIB rate. The bill impacts of all customers, as defined at (Exhibit B-1, page 2-58) is the same as RRA since the Deferral Account Rate Rider (DARR) is projected to be held constant at 5 per cent for the duration of the modelling.[260]

Table 5-8 Bill Impacts under Pricing Principle Option 1, F2017-F2019

F2017 (%)	4
F2018 (%)	3.5
F2019 (%)	3

[261]

308. In contrast, RIB rate pricing principle Option 2 results in bill impacts that are either higher or lower than Class Average Rate Change (CARC) depending on the consumption level.[262] BC Hydro provides an overview of bill impacts in Exhibit B-1, Section 5. Most customers are worse-off under Option 2 across all segments examined, and that proportion increases over time.[263]

309. The CEC submits that applying rate increases across all three pricing elements has the effect of mitigating the impact of the rate increase to lower use customer by spreading it more evenly to customers based on their usage. Otherwise, customers with larger usage (i.e., those who use Step 2 energy) would receive a rate increase over only a portion of their bill, resulting in higher rate increases for those not using Step 2 energy. BC Hydro notes that it would also have the effect of narrowing the Step 1 and Step 2 differential over time, reducing conservation and generating higher bill impacts for most customers.[264]

310. The CEC favours BC Hydro's proposal to apply rate increases equally to all three RIB rate pricing elements.

[258] Exhibit B-23, CEC 2.93.1
[259] Exhibit B-1, Pages 5-34 to 5-35
[260] Exhibit B-5, BCSEA 1.7.1
[261] Exhibit B-1, Page 5-34
[262] Exhibit B-5, BCSEA 1.7.1
[263] Exhibit B-1, Page 5-36
[264] BC Hydro Final Argument, Page 26

311. With respect to the Basic Charge, BC Hydro was directed to examine the interaction of the basic charge with the RIB rate structure. BC Hydro rejected an increase to the basic charge on the basis that it would have significant bill impacts to lower use customers.[265]

312. The CEC submits that directionally, and over time, BC Hydro should increase the Basic Charge to recover all, or at least significantly more than 45%[266] of customer costs. The CEC submits that being attached to the BC Hydro electric grid is an important benefit for customers, and on a cost of service basis, customers should pay for the costs that they create from doing so. The CEC submits that high energy users should not be effectively subsidizing the attachment of all other customers who create costs for the system without contributing significantly, or even half of those costs.

313. The CEC recognizes that increases to the Basic Charge could aggravate an already difficult situation for low income customers. The CEC submits that increases to the Basic Charge should be conducted in conjunction with those initiatives BC Hydro has already, and may in the future, develop to mitigate the financial hardship to low income customers.

314. The CEC notes that BC Hydro's plan is not to just stop engagement once this design application is done but rather is to continue evaluation and assessment of its rate structures.[267]

315. Accordingly, the CEC recommends that the Commission approve the current proposal by BC Hydro to apply rate increases equally to all three elements of the RIB rate at the present time, and direct BC Hydro to examine options and generate a proposal for increasing the Basic Charge to recover more of the Customer Costs in the future.

(iv) Step 1/Step 2 Threshold and Spread

316. The Step 1/Step 2 energy rate threshold is established at 1,350 kWh per two-month billing period, and represents approximately 90% of BC Hydro's median residential consumption.[268] BC Hydro states that moving the Step 1/Step 2 threshold results in no expected substantive changes from status quo conservation forecasts,[269] but would have significant bill impacts for customers.[270] BC Hydro rejects the notion of having two separate RIB rate thresholds for Single Family Dwellings and apartments/condos.[271]

317. The existing RIB rate differential is about 50% and is consistent with jurisdictions surveyed in Canada and the US.[272] Forecast revenue from Step 1 and Step 2 are outlined in CEC 1.9.5 showing that Step 2 delivers about 7% more revenue than Step 1.[273]

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[265] BC Hydro Final Argument, Page 26
[266] Exhibit B-1, page 5-41
[267] BC Hydro Final Argument, Page 20, Footnote 59
[268] BC Hydro Final Argument, Page 22
[269] Exhibit B-1, Page 5-46
[270] Exhibit B-1, Page 5-46
[271] Exhibit B-5, COPE 1.7.1
[272] Exhibit B-5, BCUC 1.37.3
[273] Exhibit B-5, CEC 1.9.5

318. Although BC Hydro believes that any activities or rate design features that lead to greater customer awareness and understanding would promote efficiency by allowing customers to make more informed consumption decisions, it is not clear that the use of an explicit 50 per cent Tier 1/Tier 2 pricing differential (to make it easy to remember) would necessarily improve awareness and understanding.[274] From a conservation standpoint, BC Hydro found through assessing RIB rate F2017-F2019 pricing principle Option 2, which narrows the existing differential between Step 1 and Step 2, that narrowing the Step 1/Step 2 differential can result in a loss of conservation.[275] BC Hydro believes that conservation would be increased by a higher Step 2 rate and increased customer understanding and acceptance; but that it is the magnitude of the Step 2 rate, and not the differential that should be the conservation driver for an informed customer. BC Hydro does not believe there is an optimum Step 1/Step 2 spread that would maximize conservation.[276]

319. Of customers who were aware of the RIB rate (55%), 79 per cent reported that the rate served as an incentive to manage their electricity use. Of these customers, 33 per cent reported that the difference between the Step 1 and Step 2 prices incents their household to manage electricity. This corresponds to 13 per cent of total customers who demonstrated awareness of the RIB rate and reported the difference between Step 1 and Step 2 price incents their household to manage their electricity consumption.

320. BC Hydro conducted a sensitivity analysis of alternative Step 1/Step 2 thresholds and the forecasted conservation (Exhibit B-1, Appendix C-3A, page 60 of 184). The outcomes show the bill impacts and conservation outcomes within the threshold range of 635 GWh/month (85 per cent of F2013 median) to 917 GWh/month (F2013 Mean).

321. Generally, higher thresholds yield higher conservation and more adverse bill impacts. At 917 GWh/month, the analysis shows an increase of 143 GWh/year in conservation relative to status quo, but bill impacts exceed BC Hydro's 10 per cent amber signal.

322. The CEC agrees that there is no driving need for adjusting the Step 1/Step 2 threshold or differential, particularly when it would result in uneven disruption to customer rates depending on the variable adjusted.

323. The CEC supports BC Hydro's proposal with respect to the RIB Step 1/Step 2 threshold and differential.

(v) Minimum Charge

324. BC Hydro does not propose to introduce a Minimum Charge for the RIB rate, as they were unable to precisely target a Minimum Charge that materially improved cost recovery from dormant or low use accounts. The CEC submits that it is important that low use customers, and particularly those on the BC Hydro peak, contribute proportionally to the costs they create. The CEC submits that a separate Minimum

[274] Exhibit B-23, BCUC 2.178.2.1
[275] Exhibit B-5, CEC 1.39.2
[276] Exhibit B-5, BCUC 1.37.3

Charge is an unnecessary complication if the Basic Charge is appropriately increased in the future.

(vi) Relationship to LRMC

325. The BC Hydro RIB rate proposal will result in Step 2 Energy rates that are slightly higher than the Energy LRMC.[277] Customer bills with Step 2 consumption account for 80% of BC Hydro's residential consumption.[278]

326. BC Hydro considers it unfavourable under the Bonbright principle relating to rates that encourage efficient use and discourage efficient use and fair apportionment of costs among customers.[279] However, BC Hydro also points out that a decrease in the Step 2 rate or the move to a flat rate would send customers mixed messages,[280] and that it is more important to send a strong and consistent signal than it is to match a changing LRMC.[281] The CEC submits that additional issues such as societal benefits and energy policy as they relate to the cost of natural gas,[282] fuel switching and other factors could also be considered when evaluating the appropriateness of Step 2 energy rates.

327. BC Hydro believes that the RIB rate is designed to produce energy conservation. While BC Hydro expects the RIB rate to result in capacity savings, those capacity savings are a byproduct of the customer energy reductions. The RIB Step 2 rate does not have a peak period component to directly incent peak demand reductions.[283] In its Evidentiary Update BC Hydro notes that 'a steady price signal is beneficial for encouraging conservation, and that there could be merit in exploring the addition of a capacity value in the energy LRMC for the purpose of the RIB rate.[284] However, BC Hydro notes that

> "The inclusion of generation capacity value in the energy L RMC used as a reference for the RIB Step 2 rate would not necessarily result in a more economically efficient price than the use of the energy-only LRMC. The problem is that the generation capacity marginal cost is a peak-demand-based cost, not an energy cost. Signaling the cost of capacity via a non-time-differentiated energy rate would distort the capacity price signal. The uniform energy price signal would be too low at the time of peak demand, and too high at all other times. Therefore it is not clear whether the inclusion of the generation capacity cost for purposes of the RIB Step 2 rate would be more or less economically efficient than a rate based on the energy-only LRMC."[285]

[277] BC Hydro Final Argument, Page 27
[278] Exhibit B-23, BCUC 2.178.1
[279] Exhibit B-23, BCUC 2.170.1
[280] Exhibit B-23, BCUC 2.185.1
[281] Exhibit B-23, CEC 2.111.1
[282] Exhibit B-23, BCUC 2.174.2
[283] Exhibit B-5, BCUC 1.13.1
[284] Exhibit B-17, Page 9
[285] Exhibit B-5, BCUC 1.41.1

328. When BC Hydro uses the term "energy LRMC" it does not include any generation or network capacity costs.[286] However, the RIB energy charge recovers costs including customer costs and capacity costs[287] that are not related directly to the consumption of energy. BC Hydro points out the converse, which is that LRMC does not reflect distribution capacity and distribution losses.[288]

329. The CEC has shown an appropriate comparison results in the Energy LRMC and Capacity LRMC for BC Hydro to the rate design rates in an earlier section to this argument.

330. The CEC submits that an option which increases Step 2, lowers Step 1 and increases the Basic Charge maybe a useful path forward for the RIB rate in the future and appropriate within a suitably developed and understood LRMC context.

331. The CEC recommends that the Commission approve BC Hydro's RIB rate proposal and direct BC Hydro to examine options and generate a proposal for increasing the Basic Charge, and Lowering the Step 1 rate to recover directly more of the Customer Costs in the future, while managing bill impacts.

(vii) Residential E Plus Amendment RS 1105 (Dual Fuel)

332. RS 1105, the Residential E-Plus rate, is a non-firm rate closed to new customers in 1990 under which customers pay a discounted rate for space and water heating loads on condition of having an alternative fuel back-up heating system.[289] There are approximately 7,700 Residential E-Plus customers[290] E-Plus who account for approximately 0.3% of the revenue from the Residential rate class in F2016.

333. BC Hydro has never interrupted E-Plus load, because Special Condition 1 'restricts BC Hydro's right to interrupt the supply of electricity.' The condition requires there to be 'a lack of surplus hydro energy' and 'the service cannot be provided economically from other energy sources.'[291] BC Hydro outlines the issue in BCUC 2.142.1. They explain that the current flexibility of BC Hydro's system and its access to energy markets has made it difficult to define 'lack of surplus hydro energy.' [292]

334. Importantly the inability to interrupt E-Plus customers has meant that BC Hydro has been required to include E-Plus loads in its Peak demand forecast and planning assumptions; meaning that ratepayers are not receiving the cost savings that should accrue from an interruptible service. BC Hydro has not to date taken E-Plus customer loads out of actuals when establishing the load forecast either for energy or peak demand so the E-Plus load is in the forecast.[293] When BC Hydro is satisfied that E-Plus customers will

[286] Exhibit B-23, BCUC 2.176.2
[287] Exhibit B-23, CEC 2.91.3
[288] BC Hydro Final Argument, Page 28
[289] Exhibit B-1, Page 5-48
[290] Exhibit B-23, BCUC 2.147.4
[291] Exhibit B-1, Appendix F-1D, Page 1 of 5
[292] BC Hydro Final Argument, Page 32
[293] Exhibit B-23, BCUC 2.145.1

only be supplied when surplus electricity, either energy or capacity, is available their load will be removed from the load forecast for planning purposes. BC Hydro notes that total E-Plus energy and capacity is about 90 GWh and 25 MW, respectively which are relatively small from a planning perspective.[294]

335. BC Hydro continues to assign Generation, Transmission and Distribution demand-related costs to Residential E-Plus customers.[295] The CEC submits that unless the Peak demand forecast and planning assumptions can be reduced as a result of the interruptible rate, the interruptible rate provides few benefits to other non-participating rate payers. The CEC submits that an interruptible rate must be truly interruptible.

336. BC Hydro proposes to amend Special Condition 1 of RS 1105 Residential Service – Dual Fuel (among other changes) to enable interruption. BC Hydro will compare forecasted demand to forecasted resources to determine whether E-Plus customers will be interrupted.[296]

337. The proposed Amendment is detailed in Blackline in Appendix F-1D.

338. Special Condition 1 will read:

> "BC Hydro will provide electricity under this rate schedule only to the extent that it has energy and capacity to do so. BC Hydro may, at any time and from time to time, interrupt the supply of electricity under this rate schedule where BC Hydro does not have sufficient energy or capacity."[297]

339. The proposed amendments to the terms of the Residential E-Plus rate provide BC Hydro with a practical option to interrupt service in response to short term energy needs, and also provide to interrupt service in response to a capacity constraint. The 2013 IRP identifies a need for capacity in F2019 assuming BC Hydro continues with its current DSM initiatives and renews IPP contracts as recommended in the 2013 IRP.[298] Aggregation of many small loads, including Residential E-Plus loads, could have a material benefit for localized constraints and/or contribute to overall tactics to address system level needs.[299] It is envisioned that E-Plus would become one of the resources that BC Hydro could call upon during cold weather events.[300] The CEC submits that the value of capacity is significant, and is higher than BC Hydro's current capacity value of $50-$55 based on Revelstoke Unit 6.[301] The CEC submits that the proposed changes can

[294] Exhibit B-23, BCUC 2.145.2
[295] Exhibit B-1, Page 5-50
[296] Exhibit B-23, BCUC 2.142.3
[297] Exhibit B-1, Appendix F-1D, Page 1 of 5
[298] Exhibit B-23, BCUC 2.142.2
[299] Exhibit B-23, BCUC 2.142.2
[300] Exhibit B-23, BCUC 2.142.3
[301] Exhibit B-23, BCUC 2.142.2

create benefits for non-participating ratepayers and will be effective in interrupting customers and reducing load without incurring undue costs.[302]

340. The proposed Amendment is also consistent with the wording found in BC Hydro's other non-firm (interruptible) rates such as the Shore Power Rates recently approved by the Commission and RS 1880, and will enable BC Hydro to practically interrupt the service.[303] Additional changes are proposed for Special Conditions 2 through 7, and to terms and conditions.

341. The CEC has reviewed the changes to the Special Conditions and submits that they are all reasonable. The CEC notes that BC Hydro has removed certain wording in Special Condition 3 that pertained to notice by registered mail or hand delivery.

> 3. BC Hydro may interrupt the supply of electricity by either manual or automatic means or by written notice ~~by registered mail or hand delivery~~ to the customer to cease the use of electricity under this rate schedule. A customer who has been given such written notice to cease the use of electricity under this rate schedule shall in accordance with the requirements of the notice cease such use and shall not begin to use electricity again until so authorized by BC Hydro, by written notice.
>
> If a customer fails to cease using electricity when required, ~~comply with these requirements,~~ BC Hydro may in its sole discretion, and without limiting its rights under special condition 7, ~~:~~
>
> ~~(a)~~ continue to supply electricity for the whole or any part of such Period of Interruption, in which case the rate shall be the rate for electricity during a Period of Interruption as stated in this rate schedule~~,~~.

[304]

342. The CEC submits that it is appropriate to remove the reference to registered mail and hand delivery which would place an unreasonable burden on BC Hydro. The CEC submits that the wording in the paragraph however could be clarified to separate out how BC Hydro would interrupt the supply from how notice would be provided. The CEC submits that the following wording would represent an improvement in the first paragraph of Special Condition 3.

> 3. BC Hydro may interrupt the supply of electricity by either manual or automatic means. BC Hydro will provide notification to the customer through written communication which may take the form of electronic mail, or other written means.

[302] Exhibit B-23, BCUC 2.147.4
[303] Exhibit B-1, Page 5-48
[304] Exhibit B-1, Appendix F-1D, Page 2 of 5

343. The language changes are challenged by the E-Plus Homeowner's Group (EPHG) who state that:

> "...the changes proposed go beyond what is necessary to achieve the stated goals of making E-Plus "practically interruptible" or to "function as originally intended". In fact the changes are intended to change the fundamental understandings on which E-Plus was originally based, and to considerably increase the potential for curtailments by removing key protections that were intended to ensure fairness, and reduce hardship, in their implementation.[305]

344. The CEC submits that the intent of the E-Plus rate has always been to provide an interruptible rate, and that facilitating the interruption is sensible in order to achieve the benefits for the non-participating ratepayers. The CEC does not accept EPHG's argument that the changes go beyond what is necessary, and that the proposed changes to Special Condition 1 reflect an appropriate definition with respect to a truly interruptible rate and do not exceed conditions consistent with other interruptible rates. The CEC submits that BC Hydro's proposed wording is appropriate in ensuring that both energy and capacity constraints are appropriately considered and allow for the benefits of an interruptible rate to be captured. The CEC believes it is inappropriate from a non-participating customers' perspective to offer a reduced rate to one customer segment without being able to achieve the benefits that should be associated with it.

345. BC Hydro proposes to issue a new business practice as follows:

- interruptions will be confined to the October to April period;
- a seasonal notice each year prior to the October-April period reminding E-Plus customers that interruptions are possible in the coming months;
- two calendar days' notice for E-Plus residential customers to switch to their alternative back-up systems. Such an 'interruption notice' will be provided at any time during October through April if BC Hydro decides that an E-Plus interruption is warranted in accordance with the proposed terms of RS 1105; and
- an interruption closure notice when the period of interruption is over.[306]

346. It is expected that, based on similar curtailment or capacity product definitions, interruptions could last five to 12 days per cold weather event, with one to three cold weather events each winter. Other system issues could occur, but are much less frequent.[307] E-Plus service interruption would have both unplanned and planned

[305] Exhibit C10-4, EPHG Intervener Evidence page 2
[306] BC Hydro Final Argument, Page 30
[307] Exhibit B-23, BCUC 1.43.1

elements.[308] It would be used to mitigate expected resource deficits due to, for example, cold weather events or major generation outages[309] or other situations.[310]

347. The CEC submits that the Business Practices proposed by BC Hydro are appropriate, although the CEC expects that more refined timing of the interruption definition to the high load hours could also be helpful. The CEC submits that that confining interruptions to October through April is beneficial for both existing E-Plus customers and non-participating customers, although the interruption period could well be restricted to the November to February peak month period. E-Plus customers receive non-interrupted service for 5 months and non-participating customers receive the benefit of reductions to peak demand.

348. The two-day period reflects the effective prediction of cold weather[311] and preserves the benefits to the peak. It is also reasonable because needing to provide E-Plus customers Interruption Notice of several days limits the ability to call upon E-Plus in the last moment as system constraints are realized. It is anticipated that BC Hydro would call in advance when cold weather events are forecast and system resources are limited.[312] Two days of notice is valuable to E-Plus customers in ensuring that interruptions are not overly scheduled.[313] BC Hydro would interrupt E-Plus customers when resources are forecast to be limited even if the situation does not actually materialize.[314]

349. The EPHG object to BC Hydro's proposed business practices. They state:

> Most importantly the proposed Business Practice ignores prior commitments that:
>
> - Residential E-Plus customers will have priority over other non-firm power customers; and
> - 30 days' notice will be given for interruptions of more than a few hours duration.[315]

350. The CEC has provided its comments with respect to notice. The CEC submits that the proposed seasonal notice could be provided by September 1 in order to allow 30 days of advance warning. The CEC does not believe that Residential E-Plus customer should have 'priority over other non-firm power customers', particularly when receiving uninterrupted firm service from the utility.

351. The CEC notes that the basis for EPHG argument stems from commitments made by BC Hydro that were included in Informational Brochures and other venues, but not incorporated into the tariff. The CEC acknowledges that in the past information was

[308] Exhibit B-23, BCUC 2.143.2
[309] Exhibit B-23, BCUC 2.143.6
[310] Exhibit B-23, BCUC 2.143.8
[311] BC Hydro Final Argument, Page 30, Footnote 103
[312] Exhibit B-23, BCUC 1.43.1
[313] BC Hydro Final Argument, Page 30, Footnote 103
[314] Exhibit B-23, BCUC 2.143.4
[315] Exhibit C10-4, EPHG Intervener Evidence, Page 2

provided through certain channels that would generate some expectations on the part of E-Plus customers. Nevertheless, the CEC submits that it is not uncommon for rates and terms to change over the course of many years, and that this is to be expected in all walks of life, including utility services. The CEC has reviewed the evidence with respect to the issue of EPHG's perceived 'contract' with BC Hydro, and the jurisdiction of the Commission. The CEC agrees with BC Hydro that the Commission has jurisdiction to establish and manage the rates according to their best judgment under the *Utilities Commission Act*.[316]

352. The EPHG also complain that BC Hydro has neglected other important elements, as follows:

"
- they have not adequately demonstrated that they cannot currently interrupt E-Plus power ;
- they have not adequately quantified financial considerations, including the impact on E-Plus and other customers;
- their Application does not reflect broad, informed input from stakeholders and E-Plus customers;
- they have not demonstrated that the proposed changes benefit the public and have not acknowledged the disproportionate impact on the E-Plus customers directly affected; and
- their approach challenges the integrity of the process of power supply and regulation in British Columbia Overall BC Hydro makes little attempt to justify their proposals. For the most part they do little more than characterize understandings that they themselves created and that have stood unchallenged for almost 30 years as "impractical". At the same time they have ignored or attempted to minimize the potential impact of their proposals on E-Plus customers.[317]"

353. The CEC does not find the EPHG arguments to be convincing. The CEC submits that BC Hydro has provided a good explanation for why they have not been able to interrupt service and have provided evidence that the E-Plus rate has not facilitated savings from its peak demand forecast, which would provide the financial benefit to non-participating ratepayers. The CEC submits that BC Hydro has demonstrated sincere consideration for E-Plus customers in developing Option 3, which enables e-plus customers to continue at their current rate. The CEC submits that requiring e-plus customers to actually interrupt from time to time is reasonable and should not be considered an undue hardship for customers receiving an interruptible rate of about 50% discount.[318] The CEC notes that

[316] BC Hydro Final Argument, Pages 35 and 36
[317] Exhibit C10-4, EPHG Intervener Evidence page 2
[318] BC Hydro Final Argument page 30

customers have already invested in alternative fuel back-up heating system which was estimated at a cost of between $1300 and $2800 in 1987[319] which must be kept in good working order,[320] so the facility is available for use at any time. The customers will continue to receive the benefit of the rate.[321]

354. The CEC notes that the revenue to cost ratio for the E-Plus rate is particularly low for a heating load, which is a relatively costly service for other residential ratepayers.

355. BC Hydro provides the following Revenue/Cost ratios (Table 5-13) for the E-Plus rate in its Application at page 5-51. BC Hydro notes that it would be circular to include E-Plus load in the load forecast for the purposes of determining if there is a surplus of hydro energy. However, when generation costs are assigned, the Revenue/Cost ratio is only about 45%.[322] The CEC submits that since BC Hydro has been consistently supplying energy to the E-Plus rate class, it is reasonable to include generation energy costs in an assessment of their revenue/cost ratio, which is extremely low by any standard. The CEC submits that the cost of the E Plus rate to other ratepayers is in the order of $6.7 million, with no benefits.

Table 5-13 Residential E-Plus R/C Ratios

Row	F2014	Total Revenue ($ million)	Total Cost ($ million)	Revenue Shortfall ($ million)	R/C Ratio (%)
1A	Residential E-Plus – Heating load, Generation energy costs not assigned	4.7	7.4	2.7	~ 65
1B	Residential E-Plus – Heating load, Generation energy costs assigned	4.7	11.0	6.3	~ 45
2	Residential E-Plus – Remaining load	7.6	8.1	0.4	~ 95

356. Despite the above grievances, the EPHG also state:

‘E-Plus customers fully understand and accept that E-Plus is an interruptible power supply and that they may at times face curtailments in the event of legitimate supply shortage’s (sic).[323].

357. The CEC submits that BC Hydro’s proposals allow for interruption on a reasonable and consistent basis with cost causation principles, and provides an appropriate alternative which provides a continuing service for the existing E-Plus ratepayers who have invested in back-up energy systems while providing a useful benefit to non-participant ratepayers.

[319] Exhibit B-23, BCUC 2.146.5
[320] Exhibit B-23, BCUC 2.148.3
[321] Exhibit B-23, BCUC 2.147.1
[322] Exhibit B-1, page 5-50
[323] Exhibit C10-4, EPHG Intervener Evidence, Page 2

358. The CEC submits that in the event that the Commission does not approve BC Hydro's proposals, that it would be preferable to either terminate the program and gradually migrate existing customers to the residential RIB rate. The CEC submits it is inappropriate to continue delivering full firm electricity service at the existing markedly reduced rates. The CEC believes that a transition to the RIB rate could occur over 10 years[324] and would appropriately respond to the fair percentage (42% median,[325] 40% average[326]) increase that existing customers would experience given that rate benefits to non-participating customers would only be in the order of 0.3%.[327]

359. The CEC notes that the EPHG have cited evidence that rates would not exceed two thirds of the regular price of electricity.[328] The CEC submits that rates setting is the jurisdiction of the Commission and that the Commission is not constrained by any such evidence.

360. The CEC recommends that the Commission approve BC Hydro's amendments to the E Plus Residential Rate as filed by BC Hydro.

[324] Exhibit B-23, BCUC 2.148.1
[325] Exhibit B-1, Page 5-50
[326] BC Hydro Final Argument, Page 33
[327] Exhibit B-23, BCUC 2.148.2
[328] Exhibit C10-4, EPHG Intervener Evidence, Pages 19-20

E. GENERAL SERVICE

361. Each of BC Hydro's General Service rate proposals includes a pricing proposal that is intended to allow BC Hydro to recover certain percentages of costs as identified in a COS study.[329]

362. BC Hydro summarizes its General Service proposal as follows:

363. SGS Rates:

- Retaining the existing flat energy rate; and
- Increasing the SGS basic charge recovery of customer-related costs from approximately 33% to 45%.

364. MGS Rates:

- Replacing the existing MGS two-part energy rate with a flat energy rate;
- Replacing the existing MGS three-step inclining block demand charge with a flat demand charge; and
- Increasing the demand charge recovery of demand-related costs from approximately 15 % to 35%.

365. LGS Rates:

- Replacing the existing LGS two-part energy rate with a flat energy rate;
- Replacing the existing LGS three-step inclining block demand charge with a flat demand charge; and
- Increasing the demand charge recovery of demand-related costs from approximately 50% to 65%.[330]

366. The CEC submits that the general trends BC Hydro has advanced in the application are towards greater fixed cost recovery in basic and demand charges, flatter demand charges and flatter energy charges. The CEC submits that these are appropriate and that BC Hydro has been successful in balancing these directions, minimizing bill impacts and meeting other customer requirements such as simplicity and ease of administration.

367. The CEC submits that recovering more fixed costs in the demand and basic charges is appropriate from a cost-causation principle point of view and should be continued in the future as it provides the truest reflection of the costs that customers create on the system. The CEC submits that customers should be provided with the information and the natural price signals that emerge from a rate structure built primarily on cost causation principles.

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[329] BC Hydro Final Arguments, Page 37
[330] Exhibit B-1, Page 6-4

368. The CEC recognizes that increasing cost recovery of demand costs in demand charges reduces the costs to be recovered in the energy charges, and creates an inherent trade-off with the objective of establishing energy charges suitably proportional to the Energy LRMC. Presumably, the Energy LRMC would most often be higher than the existing costs to be recovered in the energy charge. Establishing the energy rate at or near the Energy LRMC without recovering fixed costs in that element is particularly difficult given the move to flatten energy charges, as there would be no tier 2 rate to reach that objective.

369. BC Hydro believes there is no single 'correct' level of demand charge cost recovery. BC Hydro expects demand charge cost recovery cannot be targeted in isolation from other factors.[331] Questions such as whether a flat rate should always be set within a LRMC range or whether basic and particularly demand charges should be lowered to maintain a higher energy charge cannot be answered in the absolute. Rather, such questions raise fundamental trade-offs between rate design objectives, such as fairness, economic efficiency and customer understanding and acceptance. Given BC Hydro's current priorities as discussed in section 1.5 of Exhibit B-1, and for the reasons set out in section 6.3 of Exhibit B-1 and section 6.3.5 in particular, BC Hydro considers that its MGS energy rate and demand charge proposals strike an appropriate balance between these objectives given the current issues with MGS rates.[332]

370. The CEC supports the moves to flatten energy and demand rate structures. Flattened energy and demand rate are simpler, more equitable for a range of business circumstances, and will be better understood by customers. The CEC submits that the evidence (provided below) is that the MGS and LGS rate schedules have been unduly complicated, have not delivered conservation benefits, and that there is little price elasticity. Business customers examine and attempt to manage their total bill and are not especially influenced by the rate structure beyond how it affects their bottom line.

371. The CEC submits that BC Hydro has been generally successful in fixing the main MGS and LGS issues and has provided appropriate options and final solutions. The CEC provides its views regarding the appropriate calculation of the LRMC earlier in this document and notes that both the Energy LRMC and the Demand LRMC are necessary for considering the appropriateness of the price signal provided by the energy charge and the demand charge. The CEC submits that for commercial customers the energy and demand charges are both key pricing signals.

372. Additionally, there appears to have been some tendency towards establishing some general consistency between rate classes, such as having the percentage recovery in the basic charge in the SGS class equate with that in the residential class. However, the CEC notes that there is no consistency in the General Service demand charge recoveries in that

[331] Exhibit B-1, Page 6-30
[332] Exhibit B-5, BCUC 1.59.2

SGS does not have a demand charge, MGS will recover 45% and LGS will recover 65% of demand related costs, and further that the energy rates are also different.

373. The CEC recognizes that a general theme of the rate design has been the need to balance competing Bonbright principles, and the pre-eminent considerations of managing bill impacts. Although efficiency is one of BC Hydro's rate design objectives, BC Hydro has prioritized customer understanding and acceptance, practicality and fairness over efficiency in the RDA, with the emphasis on each factor reflecting the different characteristics among the different customer classes. This is reflected in its proposals to simplify the MGS and LGS rate structures. BC Hydro does not suggest any changes to its MGS or LGS proposals as a result of the reduced LRMC provided in the Load Resource Balance update.

374. The CEC submits that while recognizing that balancing of principles is required, it could be valuable if BC Hydro provided some greater clarity as to the long term direction for its rate design. For instance, it appears that BC Hydro has preferred to establish the general level of the energy price signal at or near the energy LRMC, and determined the appropriate demand recovery after that, while also addressing a goal of inter-class consistency. BC Hydro identifies specifics as to when prioritizing the LRMC might not be beneficial in BCUC 2.175.1 (see below). Determining an appropriate path forward to a fully rationalized rate structure would be important. Otherwise, the specific rationales for decisions can become lost in the general language of balancing the Bonbright principles.

(i) Small General Service

375. The SGS rate class consists of General Service customers whose billing demand is less than 35 kW. The current default rate structure for SGS customers consists of a flat energy rate[333] of $0.1073 per kWh[334] and a basic charge[335] of $0.2257 per day.[336]

376. The CEC has no significant areas of concern for the SGS rate structure, and the only area to be reviewed was whether or not the basic charge should recover more customer costs than the 33% it currently recovers.[337]

377. The SGS class is considered heterogeneous. An illustrative distribution is provided below.

[333] BC Hydro Final Arguments, Page 37
[334] Exhibit B-1, Page 6-8
[335] BC Hydro Final Argument, Page 37
[336] Exhibit B-1, Page 6-8
[337] Exhibit B-1, Page 6-10

SGS illustrative distribution

Load Factor	Annual Consumption MWh 0	4	8	12	16	20	24	28	32	36	40	44	48	52	56	60	64	Total
0%	8.2%	2.2%	1.0%	0.8%	0.7%	0.5%	0.5%	0.5%	0.2%	0.5%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	15.2%
10%	3.3%	8.0%	5.5%	3.2%	1.9%	1.4%	1.0%	0.7%	0.4%	0.4%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	27.2%
20%	1.0%	2.9%	5.8%	5.5%	2.7%	1.9%	1.7%	0.9%	0.9%	0.8%	0.4%	0.4%	0.5%	0.2%	0.5%	0.1%	0.1%	22.0%
30%	0.8%	1.2%	1.1%	1.2%	1.5%	1.6%	1.1%	1.0%	1.0%	0.7%	0.6%	0.5%	0.5%	0.5%	0.3%	0.3%	0.3%	14.1%
40%	0.4%	0.9%	0.6%	0.5%	0.5%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%	0.3%	0.3%	0.4%	0.2%	0.2%	0.2%	6.9%
50%	0.4%	0.4%	0.3%	0.3%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	3.2%
60%	0.1%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	1.3%
70%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
80%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
90%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
100%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Total	14.5%	16.1%	12.9%	9.8%	7.7%	6.1%	4.8%	3.6%	3.1%	2.9%	2.1%	2.0%	1.6%	1.5%	1.2%	1.0%	1.0%	90.4%

Note that about 9.6 per cent of accounts have consumption above 64 MWh.

[338]

378. BC Hydro is proposing to retain the existing flat energy rate structure while increasing the customer-related cost recovery of the basic charge.

379. BC Hydro seeks a final order approving a one-time increase to the RS 13xx basic charge to enable 45 % recovery of customer-related costs attributable to the SGS class (in the F2016 COS study) and a one-time offsetting reduction of the energy rate, to maintain forecast revenue neutrality based on the SGS revenue target calculated using any applicable rate increases arising from the F2017 RRA, to be effective April 1, 2017.[339] Thereafter RRA increases would be applied equally to each pricing element of RS 13xx.[340]

380. The proposed rates for F2017 are depicted below. The energy rate will decrease by about $0.0015/kWh, and the Basic Charge will increase by about $0.0853/day.

Table 6-2 Alternative SGS Pricing

Pricing Element (F2017)	BC Hydro Proposal (Increase basic charge to 45% of customer-related costs)	Status Quo
Energy rate (cents/kWh)	11.01	11.16
Basic charge (cents/day)	32.00	23.47

[338] Exhibit B-23, CEC 2.102.1
[339] BC Hydro Final Argument, Page 38
[340] BC Hydro Final Argument, Page 38

a. Basic Charge

381. The SGS Basic Charge currently recovers about 33 % of customer-related costs allocated to the SGS rate class. BC Hydro's proposal will recover 45% of customer-related costs allocated to the SGS rate class.

382. BC Hydro proposes the change to align the SGS rate cost recovery of the basic charge with the RIB rate,[341] which is also at 45%.[342] The CEC is not certain as to the value of aligning the recovery of the basic charge with that of another rate, and particularly a non-general service rate, except to the extent that they have might have similar cost structures so the appropriate cost recovery happens to be the same. Customer-related costs account for about 12% of SGS costs and 13% of Residential costs.[343]

383. Nevertheless, the CEC reiterates its position that an increase in the basic charge will improve fairness.[344] The CEC submits that directionally it is preferable for the Basic Charge to recover more of the customer related costs in order to conform with cost causation principles and provide clear price signals to customers regarding the costs they create on the system.

384. BC Hydro considers the change is appropriately in line with cost-causation principles and there is no conflict with the Bonbright economic efficiency criterion.[345] The CEC agrees with this position.

385. The CEC notes that rate impacts are expected to be low or minimal to the majority of SGS customers on both a percentage and absolute basis. The basic charge is a relatively high percentage of the total bill for only a very small percentage of SGS customers. The analysis found that the bill difference is below 10 per cent for almost all SGS customers, and below 5 % for 80 per cent of SGS customers.[346]

386. The CEC supports BC Hydro's proposed increase in the cost recovery of the basic charge for SGS rate schedule.

b. Energy

387. BC Hydro believes that the existing flat energy structure is appropriate, and that there are few suitable alternatives. An inclining block rate is impractical because of the heterogeneity in the rate class[347] which would not support a one size fits all threshold for the step change. 'Typical' customers in the 20th to 80th percentile of class consumption range from about 5,000 to 35,000 kWh/year.[348]

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[341] BC Hydro Final Argument, Page 38
[342] Exhibit B-1, Page 5-41
[343] BC Hydro Final Argument, Page 40
[344] Exhibit B-1, Page 6-12
[345] Exhibit B-1, Page 6-2
[346] Exhibit B-1, Page 6-13
[347] Exhibit B-1, Page 6-11
[348] Exhibit B-1, Page 6-9

388. Additionally, a baseline-based energy rate for SGS customers is considered too complex and not appropriate as SGS default rate structure at this time given BC Hydro's historical problems with the baseline-based MGS and LGS rate structures.[349]

389. The CEC agrees with BC Hydro's assessment regarding the preferred SGS rate structure. The CEC submits that the problems in the MGS and LGS classes outlined in Sections 6.3 and 6.4 of the Application are appropriately being addressed in this application by moving towards flat rate structures, and it would be unwise to re-establish them in the SGS rate, particularly given that there appear to be no major concerns with this rate class structure.

390. BC Hydro has not previously studied the price response of the SGS class and cannot reasonably assume any price elasticity estimate beyond the natural conservation estimate of -0.05 associated with general rate increases.[350]

391. The CEC also supports the flat rate structure for the reasons outlined above.

c. Demand Charge and Minimum Charge

392. BC Hydro did not consider a minimum bill for SGS customers separate from or as a replacement to the SGS basic charge.[351]

393. BC Hydro rejects a demand charge for the SGS class independent of the level of the energy or basic charges, because:

• Almost all surveyed Canadian electric utilities do not bill smaller general service customers separately for demand. The main distinguishing rate design feature between larger general service rates and rates for the smallest class is that the smaller class is typically considered too small to justify the expense and added complexity of demand meters and rate structures;

- No stakeholder suggested that the SGS rate structure should have a demand charge; and
- A demand charge would make the SGS rate more complex to understand and would also require a demand meter, which not all SGS customers have. The requirement for a demand meter on all SGS customers makes the demand charge less practical and cost-effective to administer.[352]

394. By extension BC Hydro rejects a demand ratchet minimum charge for the SGS class.[353]

395. The CEC agrees that a minimum charge is unnecessary and that a demand charge would also be unnecessarily complex for the SGS customers at this time.

[349] Exhibit B-1, Page 6-11
[350] Exhibit B-23, BCUC 2.180.1
[351] Exhibit B-23, BCUC 2.171.4
[352] Exhibit B-23, BCUC IR 2.154.1
[353] Exhibit B-23, BCUC 2.171.4

d. Bill Impacts

396. BC Hydro provides the following anticipated rate impacts from their proposal.

Table 6-3 Annual bill impacts of an increase in the SGS Basic Charge to recover 45 per cent of customer-related costs

Percentile by Consumption	Annual kWh	F2017 Annual Bill Status Quo ($)	F2017 Annual Bill BC Hydro Proposal ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo (%)	Bill Impact (%) of F2017 BC Hydro Proposal (vs. F2016 Rates)
Min	1	86	117	31	36	42
10	2,001	309	337	28	9	13
20	4,773	618	642	24	4	8
30	7,797	956	975	19	2	6
40	11,184	1,334	1,348	14	1	5
50	15,288	1,792	1,800	8	0	4
60	20,648	2,390	2,390	0	0	4
70	28,435	3,259	3,247	-12	0	-4
80	40,838	4,643	4,613	-30	-1	-3
90	65,174	7,359	7,292	-67	-1	-3
Max	615,810	68,810	67,918	-892	-1	-3

[354]

397. As shown above, the bill impacts from the transition are low on both a dollar and percentage basis. Only those below the 10th percentile experience an increase above 10%, which remains small in $, being about $31.

398. The CEC submits that with limited bill impacts there is no reason not to approve the BC Hydro proposal.

e. Alternatives

399. There is general agreement from stakeholders that there is no strong basis to depart from the existing rate structure.[355] It is easy to understand and simple to administer. It generally reflects LRMC in its flat energy structure.[356]

400. All stakeholders except COPE have supported the change and one time increase.[357] BC Hydro provides the following comparison of the proposed SGS Rate relative to the status

[354] Exhibit B-1, Page 6-14
[355] Exhibit B-1, page 6-11
[356] Exhibit B-1, page 6-10
[357] Exhibit B-1, page 6-12

quo in BCUC 2.170.1. BC Hydro believes their proposal is supported by the assessment with no material tradeoffs.[358]

Table B Proposed SGS Rate relative to Status Quo

Bonbright Criteria (from Table 2-7)	Evaluation
1. Price signals that encourage efficient use and discourage inefficient use	Neutral Price signal is similar for both options (section 6.2.4, Exhibit B-1, page 6-12)
2. Fair apportionment of costs among customers	Favourable Increasing SGS basic charge recovery better aligns with Bonbright fairness criterion (section 6.2.4, Exhibit B-1, page 6-12)
3. Avoid undue discrimination	Neutral
4. Customer understanding and acceptance, practical and cost effective to implement	Neutral Proposed SGS rate has same rate structure relative to Status Quo (Table 6-2, Exhibit B-1, page 6-10)
5. Freedom from controversies as to proper interpretation	Neutral
6. Recovery of the revenue requirement	Neutral Both options recover the revenue requirement on a forecast basis.
7. Revenue stability	Neutral
8. Rate stability	Neutral Bill impacts of proposed SGS rate are minimal (Table 6-3, Exhibit B-1, page 6-14)

[359]

401. The CEC recommends that the Commission approve the BC Hydro SGS proposal as filed.

(ii) Medium General Service

402. The MGS rate class consists of 16,427 accounts with total consumption of about 3,329 GWh (F2015).[360] Medium general service customers are considered very heterogeneous as outlined in BC Hydro's application at pages 6-19 to 6-21. BC Hydro provides the following illustrative distribution in CEC 2.102.1.

[358] Exhibit B-23, BCUC 2.170.1
[359] Exhibit B-23, BCUC 2.170.1
[360] Exhibit B-1, page 6-15

MGS illustrative distribution (Appendix C-4A page 26 of 813)

Annual Consumption MWh

Load Factor	0	30	60	90	120	150	180	210	240	270	300	330	360	390	420	450	480	Total
0%	0.0%	0.6%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%
10%	1.6%	2.1%	2.2%	1.0%	0.5%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.8%
20%	1.1%	1.3%	2.5%	4.0%	2.6%	1.4%	1.0%	0.8%	0.5%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.5%
30%	0.8%	1.3%	1.2%	3.0%	4.7%	3.8%	2.6%	1.6%	1.4%	1.0%	0.7%	0.6%	0.3%	0.2%	0.1%	0.1%	0.0%	23.3%
40%	0.6%	1.0%	1.0%	0.8%	2.3%	3.4%	2.9%	2.1%	1.9%	1.3%	1.0%	0.9%	0.7%	0.6%	0.5%	0.4%	0.2%	21.4%
50%	0.5%	0.7%	0.5%	0.5%	0.4%	1.1%	1.7%	1.8%	1.3%	1.3%	0.9%	0.7%	0.7%	0.7%	0.6%	0.4%	0.4%	14.1%
60%	0.2%	0.5%	0.4%	0.3%	0.2%	0.2%	0.6%	0.9%	0.8%	0.7%	0.7%	0.5%	0.7%	0.5%	0.3%	0.2%	0.3%	7.9%
70%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.3%	0.5%	0.5%	0.4%	0.3%	0.3%	0.3%	0.2%	0.2%	0.1%	4.2%
80%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%	1.4%
90%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
100%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	5.0%	7.8%	8.1%	9.9%	10.8%	10.3%	9.0%	7.5%	6.5%	5.0%	3.9%	3.1%	2.8%	2.4%	1.8%	1.3%	1.1%	96.4%

Note that about 3.6 per cent of accounts have consumption above 480 MWh

[361]

403. The current default rate structure for MGS customers consists of:

- a basic charge;
- a three-step inclining block demand charge;
- a two-part energy rate, including declining Tiers in Part 1; and
- a monthly minimum charge.[362]

404. The evidence is that the current rate structure is difficult to understand and ineffective in delivering savings. BC Hydro conducted Evaluation Reports of the MGS and LGS rates in 2011/2012, and 2014, which provided evidence that the MGS and LGS rate structures have been ineffective in terms of customer understanding and incenting conservation.[363]

405. BC Hydro's current priority is to address the following key issues in MGS rate design:

- The existing MGS two-part energy rate does not provide a clear price signal for conservation and is poorly understood by customers – it has not met the purpose for which it was intended;
- The existing MGS three-step inclining block demand charge does not align with BC Hydro's cost to serve MGS customer peak demand; and
- The existing level of demand charge cost recovery under BC Hydro's proposals disproportionately impacts high load factor customers with high consumption as well as low load factor customers with low consumption.

[361] Exhibit B-23, CEC 2.102.1
[362] BC Hydro Final Argument, Pages 42-43
[363] Exhibit B-1, Pages 6-22 to 6-23

406. The CEC agrees with BC Hydro's priorities with respect to the MGS rate structure and submits that the MGS current rate structure is also exceedingly complex and requires significant simplification and re-structuring. Only approximately 25% of MGS customers correctly identified their rate structures out of only four possible options.[364]

407. The CEC agrees with BC Hydro that status quo is not an appropriate option with respect to MGS.

408. BC Hydro proposes to:

- Leave the Basic Charge intact;
- Replace the existing MGS three-step inclining block demand charge with a flat demand charge;
- Increase the demand charge recovery of demand-related costs from approximately 15 per cent to 35 per cent;
- Replace the existing MGS two-part energy rate with a flat energy rate;[365] and
- Retain the monthly minimum charge.

409. BC Hydro proposes a one-time transition on April 1, 2017 from the current MGS rate structure to BC Hydro's proposed MGS Rate structure.[366]

410. BC Hydro compares its proposal to the Status Quo in its Application at page 6-34, which is also summarized in the table below.

- The proposed F2017 MGS flat rate (8.54 cents/kWh) is less than the Part 2 rate under the status quo (10.10 cents/kWh);
- The proposed F2017 MGS flat rate (8.54 cents/kWh) is less than the Part 1 Tier 1 rate under the status quo (10.33 cents/kWh); and
- The proposed F2017 MGS flat rate (8.54 cents/kWh) is greater than the Part 1 Tier 2 rate under the status quo (7.21 cents/kWh).[367]

[364] Exhibit B-1, page 6-23
[365] BC Hydro Final Arguments page 41
[366] BC Hydro Final Arguments page 42
[367] Exhibit B-5, CEC 1.61.1

Table 6-12 MGS Rate Estimates for Rate Structure Transition in F2017

MGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (35% Demand Recovery)	F2017 Sensitivity (15% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1		–	4.76 Flat	2.14 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	9.89	10.33	8.54 Flat	9.35 Flat
T2	6.90	7.21		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

[368]

411. BC Hydro is not forecasting any rate structure conservation from either the existing MGS rate structure or the proposed MGS rate structure. BC Hydro is forecasting natural conservation from the proposed MGS rate structure using an elasticity of -0.05, which is the class average price elasticity assumption used to determine the natural conservation baseline.[369]

412. The CEC agrees that status quo is not an appropriate option for MGS, and that conservation is also not a necessary key objective. The CEC intends to address this issue further in Module 2.

a. Basic Charge

413. BC Hydro proposes no changes to the Basic Charge. The basic charge is a fixed charge per day to recover customer-related costs associated with remaining attached to BC Hydro's system.[370] Customer-related costs assigned to the MGS class are about 5 per cent of total MGS assigned costs ($16.2 million of $307.9 million), however only approximately 9% of customer related costs are recovered from the Basic Charge.[371]

414. BC Hydro states given the context of the proportion of customer-related costs, and the overall priority of the RDA in addressing key MGS rate design issues, adjusting the level of the MGS basic charge to recover a greater proportion of customer-related costs was considered to be of limited importance and materiality. BC Hydro will review the level of

[368] Exhibit B-1, Page 6-34, Note: Partial table shown
[369] Exhibit B-5, BCUC 1.58.1
[370] Exhibit B-5, CEC 1.55.1
[371] Exhibit B-5, BCOAPO 1.144.3

the MGS basic charge in future rate design efforts and its preference for one level over another.[372]

415. The CEC submits that overall a 9% recover of customer costs in the Basic Charge is not appropriate and should be addressed at some point in time. The CEC is prepared to work within BC Hydro's proposed ongoing rate design adjustment concept to deal with this issue in the future.

b. Demand Charge- Cost Recovery

416. The demand charge is a charge per kW to recover BC Hydro's demand related costs typically associated with BC Hydro's costs to ensure it can serve peak system demand in winter along with localized demands in the system.[373]

417. The following provides BC Hydro's existing demand charges.

Table 6-6 Existing MGS Demand Charges (F2016)

First 35 kW of Billing Demand per Billing Period (Tier 1)	$0.00 per kW
Next 115 kW of Billing Demand per Billing Period (Tier 2)	$5.50 per kW
All additional kW of Billing Demand per Billing Period (Tier 3)	$10.55 per kW

[374]

418. The demand costs for MGS customers are primarily related to distribution expenses and currently recover only about 15% of demand-related costs.

A	B	C	D
Rate Class	**Generation Demand (%)**	**Transmission Demand (%)**	**Distribution Demand (%)**
MGS	**24**	**32**	**44**
LGS	**28**	**36**	**36**

[375]

419. BC Hydro proposes to increase the demand recovery to 35%. The proposed demand rates for LGS and MGS however, cannot be directly compared to the status quo's in terms of a general "increase" or "decrease" because they are structurally different - the proposed demand charge is a flat rate, whereas the status quo is a three-tier design.[376]

420. BC Hydro states that BC Hydro's decision to propose an increase in the demand charge recovery to recover 35 per cent of demand-related costs reflects prioritization of the Bonbright fairness and customer understanding criteria:

[372] Exhibit B-23, BCUC 2.151.1
[373] Exhibit B-23, BCUC 2.172.2
[374] Exhibit B-1, Page 6-19
[375] Exhibit B-23, CEC 2.105.1
[376] Exhibit B-23, BCUC 2.181.1.1

- Fairness – improve alignment of embedded cost recovery in rates with cost causation. Increasing the level of demand charge cost recovery more fairly matches the recovery of the cost to serve a customer's peak demand with the customer's utilization of the system, but within limits based on avoiding excessive bill impacts (for example, such as associated with 100 per cent demand charge cost recovery); and
- Customer Understanding – BC Hydro's proposal leads to a general offsetting in the bill impacts of its energy and demand rate structure proposals, and in particular with respect to customers with high utilization and load factor.[377]

421. The CEC submits that fairness and customer understanding are key principles and are appropriately pursued in this rate design. The CEC also submits that reflecting a stronger demand charge price signal reflects the Bonbright principle of efficient price signal for the MGS demand profile cost causation.

422. As discussed above, there is a significant tradeoff in establishing the demand recovery percentage relative to the energy charge. The 35% recovery level was arrived at by targeting an increase that would result in a flat energy rate that remained generally reflective of the energy LRMC. BC Hydro believes this balances the competing Bonbright economic efficiency criterion. The effect of an increase to 35% cost recovery is to more evenly offset and distribute the bill impacts of BC Hydro's preferred MGS flat energy rate and MGS flat demand charge among customers with differing load factors and consumption levels.

423. In response to BCUC 1.60.1 BC Hydro states:

> This question raises the issue of false precision in rate design generally and in particular with respect setting an energy charge that equals LMRC. Absent a specific criteria for what a single 'correct' level of demand charge cost recovery ought to be in isolation of other factors, BC Hydro's initial estimation of an increase in demand-related cost recovery was based on targeting a flat energy rate equal to the lower end of the LRMC range. With subsequent updates to the forecast inputs to rate determinations, the MGS flat energy rate is no longer precisely equal to the lower bound of the range in BC Hydro's energy LRMC, although still generally reflective of it. BC Hydro does not agree that the Bonbright efficiency criterion should always trump the remaining seven Bonbright criteria, including the Bonbright fairness and customer understanding criteria. BC Hydro also raises the Bonbright rates stability criterion of continually adjusting rates to ensure energy rates equal the energy LMRC.[378]

[377] Exhibit B-5, BCUC 1.63.2
[378] Exhibit B-5, BCUC 1.60.1

424. BC Hydro also provides the following rationales:

> It is correct that 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 (refer to sections 6.3.4 and 6.3.5 of Exhibit B-1 and to the Workshop 11a/11b Consideration Memo at Appendix C-4B of Exhibit B-1):
>
> - 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;
> - 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. This outcome was considered unfair and unacceptable given that high load factor customers make more efficient use of BC Hydro's system;
> - As summarized in section 6.3.4.2 of Exhibit B-1, an increase in demand charge recovery of demand-related costs from 15 per cent to 35 per cent was initially arrived at by targeting an increase that would result in a flat energy rate that remained generally reflective of the energy LRMC, with the intent to balance the competing Bonbright efficiency criterion; and
> - The specific effect of the increase in the level of demand cost recovery to 35 per cent is to more evenly offset and distributed 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.

425. Overall, the proposed 35 per cent level was considered to best balance the competing Bonbright criteria across the entirety of BC Hydro's MGS rate design proposals. Figures 6-6 and 6-7 in section 6.3 of Exhibit B-1 demonstrate the sensitivity of bill impacts to a change in the level of demand charge cost recovery.

> Thus, BC Hydro would consider an increase greater than 35 per cent to not be acceptable at this time. BC Hydro has expressed that there is no single "correct" level of demand charge cost recovery; nor can demand charge cost recovery be targeted in isolation from other factors. Thus, BC Hydro would continue to

evaluate and review whether future increases to demand charge cost recovery would be warranted.[379]

426. The CEC submits that directionally it is appropriate for the Demand charge to recover more demand-related costs based on the principle of cost-causation to provide an appropriate price signal, and also because the residual demand-related costs are collected via uniform energy charges, the higher load factor customers will generally pay more than they would have if the demand-related costs were collected wholly through demand charges. This means that for customers with the same demand, the high load factor customer is subsidizing the low load factor customers, other consumption patterns being equal.[380] Although in BC Hydro's view aligning the MGS and LGS demand charge recover of demand-related costs is not contingent on increasing electricity demand requirements. BC Hydro does confirm that as the size of the electricity demand requirements increase for BC Hydro's customers the issues of the efficiency of use of investment in the infrastructure to serve the demand becomes more critical to both BC Hydro and the customers in terms of opportunity to cost-effectively reduce the costs of service, providing a logic for explicit alignment of demand recovery more closely with cost causation.[381]

427. The CEC submits that it would be reasonable for BC Hydro to continue to undertake to increase the proportion of demand cost recovery under the demand charges in order to provide a clear understanding and signal of cost causation to customers and improve fairness, and that this should be given a higher priority in future rate designs. The CEC submits that increases in the future subject to rate impacts, Bonbright principles and other important considerations that may be identified upon weighing the benefits.

428. BC Hydro considered increasing the demand charge to recover 100% of demand-related costs however this was ruled out as producing excessive bill impacts.[382]

429. The CEC recognizes that bill impacts must be given significant consideration and therefore finds the 35% to be an appropriate percentage at this time.

c. Demand Charge- Flat Structure

430. As illustrated above, the present Demand Charge is a three-step inclining block rate. The existing three-step demand charge structure has been in place since 1980 and has applied to General Service customers with demand greater than 35 kW.[383] BC Hydro accepts that each step in the current MGS and LGS three-step demand charge corresponds to the level of demand that defines each rate class; that is, a SGS customer by definition does not pay for demand up to 35 kW, a MGS customer by definition would generally pay for demand

[379] Exhibit B-23, BCOAPO 2.279.1
[380] Exhibit B-5, BCUC 1.82.3
[381] Exhibit B-5, CEC 1.68.3
[382] Exhibit B-1, Page 6-26
[383] Exhibit B-5, CEC 1.68.1

up to 150 kW, and a LGS customer would generally pay for demand at levels greater than 150 kW.[384]

431. The three-step inclining block demand charge is unique to BC Hydro[385] and most jurisdictions have flat or declining demand charges.[386] The main issue identified with respect to the existing MGS three-step inclining block demand charge is that it does not align with BC Hydro's cost to serve MGS customer peak demand.[387] The cost to serve a General Service 1 customer's peak demand is generally flat on a $/kW basis,[388] Figure 4-2 on page 4-12 of Exhibit B-1 shows that the cost in $/kW for customers under 150 kW is generally flat though with a slight decline of $0.24/kW from the smallest to the largest segments in the MGS class.[389]

432. BC Hydro confirms that under a flat rate demand charge proposal MGS customers will see demand charges increase (decrease) linearly in absolute dollars as their kW demand may increase (decrease), subject to meeting threshold amounts associated with a minimum charge.[390]

433. BC Hydro is no longer charging a first Tier demand charge of zero, and retaining the first tier of demand (35 kW) at zero cost would not necessarily smooth the bill impact of any customer transitioning between SGS and MGS rates under BC Hydro's SGS and MGS proposals.[391]

434. BC Hydro believes that the single flat demand charge will improve fairness between customers through the improvement in cost-causation noted above. Additionally, a flat demand charge simplifies the rate structure, which will improve customer understanding and acceptance relative to the existing inclining block demand charge structure.[392] For MGS, further support for a flat demand charge relates to the fact that the existing demand charge structure does not substantially differ from an alternative two-step demand charge (with the first block of 35 kW at zero cost) in terms of fairness and bill impact considerations – please refer to pages 6-29 to 6-30 of Exhibit B-1 for further discussion.[393]

435. The CEC submits that the flat demand charge is appropriate and will provide important improvements to customer understanding and acceptance that are very much required in the MGS rate structure.

436. The CEC recommends that the Commission approve a flat demand structure for the MGS rate class.

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[384] Exhibit B-5, CEC 1.68.2
[385] Exhibit B-1, Page 6-28
[386] BC Hydro Final Argument, Page 44
[387] BC Hydro Final Argument, Page 44
[388] Exhibit B-1, Page 6-28
[389] Exhibit B-5, BCUC 1.57.1
[390] Exhibit B-5, CEC 1.56.1
[391] Exhibit B-5, BCUC 1.57.3
[392] Exhibit B-5, BCUC 1.57.3
[393] Exhibit B-5, BCUC 1.57.3

d. Energy Charge

437. BC Hydro's existing energy charges is a complex structures and includes a two-part rate, with part 1 having two tiers. The Part 1 Tier 1 energy rate applies to the last 14,800 kWh of an individual customer's historically determined monthly consumption level, or 'baseline' (HBL), and the Part 1 Tier 2 energy rate applies to all remaining baseline consumption. The Part 2 energy rate is a credit on the difference between actual billed consumption and baseline consumption when consumption is lower than baseline and a charge on the difference between actual consumption and baseline consumption when consumption is higher than baseline. The LRMC-based credits or charges under the Part 2 energy rate are limited to differences of plus or minus 20 per cent of baseline consumption, defined as the Price Limit Band (PLB). Consumption differences beyond the PLB receive credits or charges under the applicable Part 1 energy rates.[394]

438. The overarching objective of the two-part energy rate structure was to provide MGS customers with an efficient price signal to induce energy conservation.[395]

439. BC Hydro proposes to change to a single flat energy rate, which is significantly lower than the Part 1 Tier 1 and Part 2 rates, as shown below for F2017.[396]

Energy rate (cents/kWh)	Part 1, Tier (T) 1: Part 1, T2: Part 2:	10.33 7.21 10.10	8.54

440. BC Hydro has discovered that the objective of encouraging conservation without unduly harming or benefitting customers is incompatible with the diversity of the MGS customer group.[397]

441. The existing structure is atypical and to BC Hydro's knowledge, along with the LGS two part energy rate structure, the only baseline-based default rate for general service customers in North America.[398] The general consensus regarding the MGS rate is that it is poorly understood by customers, and those who do understand the design do not like it because the two-part rate structure is detrimental under business growth conditions.[399] Additionally, it is administratively complex and does not deliver conservation benefits.[400] BC Hydro summarizes the evidence at page 45 of its Final Argument.

442. The CEC submits that the primary failure, to provide conservation savings, of the MGS two step rate structure was that the economic price signal dissipates over 3 years and does

[394] Exhibit B-1, Pages 6-17 to 6-18
[395] BC Hydro Final Argument, Page 43
[396] Exhibit B-1, Page 6-24
[397] Exhibit B-5, BCUC 1.56.1
[398] BC Hydro Final Argument, Page 43
[399] Exhibit B-1, Page 6-28
[400] Exhibit B-1, Page 6-28

not provide a clear consistent stable payoff price signal to support a business decision to make changes.

443. The CEC submits that the evidence is that customers are concerned about price, but are either unable or unwilling to effect conservation and should be considered price inelastic. To the extent that the rate structure has contributed to a lack of conservation is unknown, but it is likely a contributing factor.

444. Customer response to the MGS two-part energy rate has been considerably lower than forecast. Evaluated net energy savings for MGS rate were not statistically different than zero in 2011, 2012 and F2014, relative to calendar year 2010. The poor response is generally attributed to the structure's complexity and lack of customer understanding.[401] BC Hydro believes that there are probably multiple factors that led to the existing rate being ineffective. One factor was the complexity of the design, which led to a lack of customer awareness and understanding. Part of the reason the rate was complex was because it was designed to cover a diverse class.[402]

445. In BCOAPO 2.278.1 BC Hydro notes that evaluation of multiple lines of evidence indicated that awareness and demonstrated understanding of the MGS rate was low: for example, about 25 per cent of MGS customers correctly identified their rate structure out of four possible rate structure selections, and results from focus groups indicate low demonstrated understanding of the two-part energy rate. Further, rate structures were rarely mentioned as a motivator for conservation.[403]

446. The 2014 MGS/LGS Evaluation Report notes that the relationship between energy conservation response and general service customers is complex, and can be due to a number of factors, such as complexity of rate structure and customer awareness, in addition to the pricing alone.[404]

447. BC Hydro notes that MGS customers are price responsive, but appear to be having difficulty minimizing their energy charges.[405] BC Hydro states that in respect of overall energy charges, survey results presented in the Evaluation of the Large and Medium General Service Conservation Rates: F2014, provide evidence that MGS customers are price responsive. They cite evidence that 44 per cent and 57 per cent (by year) of MGS1 and MGS2/3 customers report that they are making either a fair amount, or a great deal of effort to minimize their energy charges. However, in spite of these efforts, MGS customers are not finding it easy to minimize their energy charges.[406]

448. The CEC notes BC Hydro's other evidence that MGS customers are generally price inelastic.[407] BC Hydro states that it cannot reasonably assume any price elasticity for the

[401] Exhibit B-23, BCOAPO 2.278.1
[402] Exhibit B-5, BCUC 1.56.1.1
[403] Exhibit B-23, BCOAPO 2.278.1
[404] Exhibit B-23, BCUC 2.180.1
[405] Exhibit B-23, BCOAPO 2.278.1
[406] Exhibit B-23, BCOAPO 2.278.1
[407] Exhibit B-5, AMPC 1.9.11

LGS or MGS classes.[408] Elasticity for MGS customers has not been studied by BC Hydro. The F2014 LGS and MGS Evaluation Report estimated the conservation achieved for MGS but did not perform an econometric analysis to determine the elasticity of this class. However, based on the non-residential demand studies used to support BC Hydro's 2008 LTAP BC Hydro expects that MGS customers would have an elasticity of between -1 and zero, and therefore be price inelastic.[409]

449. It is possible that inadequate economic justification may also have been a factor that limited MGS response to the two-part rates among MGS customers that were aware of and understood the complex rate structure.[410] Under the MGS and LGS two-part rates, a baseline load for each month is determined on a three-year rolling average of historical consumption in that month. Therefore, as baselines catch up with a new consumption level, Part 2 credits resulting from conservation initiatives diminish over the three-year period, and are not sustained.[411] However, it is expected that such MGS customers would be relatively few in number given the low awareness and demonstrated understanding of the MGS rates overall. BC Hydro notes that customer payback is only one of several barriers to energy conservation. Evidence presented in the Evaluations of the Large and Medium General Service Rates suggests that other barriers, including low awareness, other operational priorities, and difficulty understanding the rate structure for budgeting purposes could also affect the potential for the usefulness of the LGS and MGS rate structure in achieving conservation.[412] The focus groups associated with F2014 LGS and MGS Evaluation Report identified the three-year rolling average as a contributing factor to perceived complexity of the existing MGS rate.[413]

450. The CEC posed the question as to whether fairness issues become a priority in the rate design considerations when customers are not responding to price signals, and if this is primarily what BC Hydro's proposal is designed to respond.

451. BC Hydro replied that:

> 'Fairness is a priority but it is not the only objective underpinning BC Hydro's MGS proposal. As suggested by the question, with customers not responding to price signals, customer acceptance and understanding (including the overall practicality of the rate) is also a priority in the rate design considerations underlying BC Hydro's MGS proposal.'[414]

452. The CEC submits that to the extent that customers do not respond to price signals, the conservation aspect of the rate structure are obviously diminished, and that fairness,

[408] Exhibit B-23, BCUC 2.180.1
[409] Exhibit B-5, AMPC 1.9.11
[410] Exhibit B-23, CEC 2.104.1
[411] Exhibit B-5, CEC 1.58.1
[412] Exhibit B-23, CEC 2.104.1
[413] Exhibit B-5, CEC 1.58.2
[414] Exhibit B-5, CEC 1.61.13

along with customer understanding and acceptance should be a high priority. The CEC submits that the flat energy rate is appropriate from a fairness perspective.

453. The BC Hydro flat rate proposal is clearly simpler and easier for customers to understand. The CEC submits that simplicity and customer understanding are key Bonbright considerations and should be weighted very heavily in addressing the issues of the MGS energy rate structure along with fairness. The CEC submits that the BC Hydro proposal is appropriate in emphasizing these elements.

454. Additionally, BC Hydro anticipates minor savings as a result of the MGS flat rate energy proposal.[415] BC Hydro determined that a block rate would not be feasible given that it would be very difficult to set a fair and reasonable threshold between Tier 1 and Tier 2 pricing for the heterogeneous MGS rate class. An alternative that retained the baseline and adjusted the Part 2 rate structure to provide for credit-only pricing, and not charges, was also not suitable as this alternative resulted in Part 1 energy rate increases to all customers with only some growing customers substantively benefitting, and not mitigation of baseline-related complexity issues.[416]

455. The CEC submits that the flat energy charge is far superior to the existing two part charge that exists today. The CEC recognizes the validity of the original attempt at generating conservation while applying fairness in a diverse rate group but submits the evidence is clear that a simpler flat rate structure is superior for this rate class.

456. The CEC submits that it is important to recognize that most commercial customers look at their total bill and not at their rate structures.[417] Accordingly, a simpler rate structure will have benefits in customer understanding and acceptance and conservation can be promoted with the simple result of having lower bills from consuming less.

e. Relationship to LRMC

457. The proposed MGS flat rate will be below the energy LRMC on a going forward basis as illustrated below.

	Energy LRMC (cents/kWh)	MGS Proposed Design Flat Energy Rate (cents/kWh)	Difference (cents/kWh)
F2017	9.46	8.54	-0.92
F2018	9.65	8.83	-0.82
F2019	9.84	9.10	-0.74

[418]

[415] Exhibit B-23, BCOAPO 2.280.2
[416] Exhibit B-1, Page 6-26
[417] BC Hydro Final Argument, Page 45
[418] Exhibit B-23, CEC 2.103.1

458. The CEC notes that BC Hydro's initial estimation of an increase in demand-related cost recovery was targeting a flat energy rate equal to the lower end of the LRMC.[419]

459. BC Hydro does not consider it necessary for a flat rate to be reflective of the LRMC[420], although all else held equal it is preferential that energy rates equal BC Hydro's energy LRMC. BC Hydro states that in rate design it is necessary to take other factors into account such as intra-class bill impacts, fair apportionment of costs and rate stability. In some cases, when taking into account these other considerations it may not be possible to have the energy rate precisely equal LRMC.[421]

460. BC Hydro did not explicitly quantify the efficiency differences between a slightly lower MGS flat energy rate with a 35 per cent demand cost recovery as compared to a MGS flat energy rate with a 15 per cent demand cost recovery. BC Hydro considers both rate options to be economically efficient, as both energy rates are reflective of the energy LRMC. BC Hydro notes that there is only an 8.7 per cent difference in the respective flat energy rates. With the elasticity assumption of -0.05, that would translate to a maximum difference in natural conservation of less than one per cent. BC Hydro did not estimate conservation differences between the two rate options, but believes that such an analysis would show minimal differences in conservation because of: (1) the counteracting impacts of demand and energy charge changes on customer bills; and (2) the poor understanding of customers regarding their current rates, which makes it difficult for customers to respond to price signals.[422]

461. BC Hydro states that economic efficiency does not require that prices be equal to LRMC. Prices that exceed LRMC are not automatically economically inefficient. Economic efficiency is a largely relative criterion – prices are considered more economically efficient the closer they are to actual LRMC.[423]

462. BC Hydro does not suggest any changes to its MGS or LGS proposals as a result of the reduced LRMC. BC Hydro has prioritized customer understanding and acceptance, practicality and fairness over efficiency in the RDA. This is reflected in its development of rate design proposals to address the following key issues with the status quo MGS and LGS rates:

- The existing MGS and LGS two-part energy rates do not provide clear price signals for conservation and are poorly understood by customers;
- The existing MGS and LGS three-step inclining block demand charges do not align with BC Hydro's cost to serve MGS and LGS customer peak demand; and

[419] Exhibit B-5, BCUC IR 60.1, BCUC IR 60.3; Exhibit B-17; Evidentiary Update, Page 9, Energy Rate and LRMC
[420] Exhibit B-23, BCUC Question 2.137, References to Exhibit B-5, BCUC IR 60.1, BCUC IR 60.3; Exhibit B-17, Evidentiary Update, p. 9 Energy rate and LRMC
[421] Exhibit B-23, BCUC 2.137.1
[422] Exhibit B-5, COPE 1.16.1
[423] Exhibit B-5, BCUC 1.60.4

- The existing levels of MGS and LGS demand charge cost recovery under BC Hydro's proposals can be increased to improve fairness in cost allocation offset or dampen disproportionate customer bill impacts across size and load factor.

463. The performance of BC Hydro's MGS and LGS rate design proposals in addressing these issues, in particular respect to its identified priorities, would be adversely impacted if BC Hydro were to target the respective MGS and LGS flat energy rates to the energy LRMC. In any event the proposed MGS flat rate of 8.83 cents/kWh ($F2018) is reflective of the updated LRMC. Further, the proposed LGS flat rate remains below the energy LRMC but no more and arguably less than it did before the update.[424]

464. BC Hydro also notes the following:

- Rate designs for customers who are not price responsive - there is generally less priority to send efficient LRMC based price signals to customers who are generally not price responsive;
- Rate designs for customers who have short pay back periods – BC Hydro believes that these customers may or may not make efficient decisions based on stable and consistent LRMC based rate designs;
- Rate designs where the customers are considering short term operational decisions (such as a temporary increase/decrease in production) - a rate based on short run marginal cost would provide a more efficient price signal than one aligned with long-run marginal costs for short term usage change decisions but BC Hydro's rates also support longer term customer investments in energy efficiency;
- Rate designs where customers can fuel switch or otherwise bypass BC Hydro's network – these decisions would likely have long-lived impacts, so a rate based on long-run marginal cost would promote an economically efficient decision if the marginal prices of other fuels were also based on long-run marginal costs. Generally, if the competing products are both based on longer term costs, the customer will be encouraged to make decisions that are economically efficient; and
- Rate designs where the customer responds to the total electricity bill as opposed to the incremental price – BC Hydro does not have any specific evidence for this in the context of its current LGS and MGS rates (please refer to sections 6.3.3.2 and 6.4.3.2 of Exhibit B-1). If customers did respond in this way, then less reliance would be placed on an "energy LRMC reference; energy conservation" being indicative of a rate design that will encourage efficient use and discourage inefficient use.[425]

[424] Exhibit B-23, BCUC 2.154.2
[425] Exhibit B-23, BCUC 2.175.1

465. The CEC agrees with BC Hydro that the energy price need not match the LRMC, particularly when there are other rate design issues to be traded-off, such as cost causation in demand charges. The CEC provides a discussion of its views of the LRMC and its role in rate design earlier in this Submission.

466. The CEC submits that, for MGS and LGS customers, the demand charge is every bit as important as the energy charge in their response to price signals and that it is therefore essential to compare Energy LRMC and Demand LRMC to the combined energy and demand rates charges to the customers to understand the nature of the price sensitivity.

f. Minimum Charge (Demand Ratchet)

467. Both MGS and LGS rate classes have minimum charges that are applicable and calculated automatically by BC Hydro's billing system.[426]

468. BC Hydro states that:

> 'Associated with BC Hydro's demand charge and acknowledgement that winter peak loads drive a substantial portion of BC Hydro's infrastructure costs, a minimum charge (the demand ratchet) ensures that customers with high winter consumption and low summer consumption pay a share of BC Hydro's costs to maintain its infrastructure related to serving peak demand in winter.'[427]

469. BC Hydro indicates that the amount of demand ratchet revenue is a very small percentage of both MGS and LGS class revenue.[428]

Table 6-11 Summary of F2015 demand ratchet charges, MGS and LGS

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

470. BC Hydro proposes to leave the demand ratchet at 50%, (rather than increasing it to 75% to provide consistent treatment with RS 1827[429]) because 'it is not a major issue with customers.'[430]

471. The CEC disagrees with BC Hydro regarding the importance of the minimum charge and submits that the minimum charge can be a very significant issue for certain customers due to its calculation, and can be extremely onerous and unfair even in its revenue collection depending upon the customer's consumption patterns.

[426] Exhibit B-23, BCUC 2.153.1
[427] Exhibit B-5, CEC 1.55.1
[428] Exhibit B-1, Page 6-30
[429] Exhibit B-1, Page 6-31
[430] Exhibit B-1, Pages 6-31 to 6-32

472. The CEC inquired if, given the few customers affected and the small revenues, it could be eliminated. BC Hydro replied that it is important to have a demand ratchet for the MGS and LGS classes:

- For the reasons described in BC Hydro's response to CEC IR 1.55.1, a demand ratchet is an important component of the overall rate structure applicable to MGS and LGS customers; and
- A form of minimum charge through a demand ratchet is common utility practice in the rates for larger general service customers, as highlighted by BC Hydro's survey of default general service charges in Canada, at Attachment 5 to the Workshop 8a/8b Consideration Memo at Appendix C-4A of Exhibit B-1 (pages 394 to 396).

473. The CEC submits that Minimum Charges should be examined in detail in the near future.

g. Bill Impacts

474. BC Hydro provides an overview of the bill impacts for its MGS proposal at pages 6-34 to 6-37 of its Application.

Figure 6-6 F2017 Bill Impacts less RRA – BC Hydro MGS Proposal (Demand 35 Per Cent Recovery)

Annual Consumption kWh — Highest kw

Load Factor *	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	44.6%	47.0%	0.9%	-2.6%	-6.8%	-14.0%	-20.1%	-22.3%	-23.9%	-25.1%	-26.0%	-26.8%	-27.4%	-27.9%	-28.3%	-28.7%	-29.0%
20%	14.1%	14.9%	15.1%	2.4%	-3.4%	-6.6%	-8.3%	-6.4%	-5.0%	-4.6%	-6.4%	-7.9%	-9.1%	-10.1%	-10.9%	-11.6%	-12.2%
30%	4.0%	4.2%	4.3%	4.3%	-1.7%	-5.3%	-7.3%	-5.4%	-3.5%	-2.2%	-1.1%	-0.2%	0.6%	1.2%	0.3%	-0.6%	-1.5%
40%	-1.1%	-1.1%	-1.2%	-1.2%	-1.2%	-4.6%	-6.7%	-4.4%	-2.6%	-1.2%	0.0%	0.9%	1.7%	2.5%	3.1%	3.6%	4.1%
50%	-4.1%	-4.3%	-4.4%	-4.4%	-4.4%	-4.4%	-6.3%	-3.9%	-2.1%	-0.6%	0.6%	1.7%	2.5%	3.3%	3.9%	4.5%	5.0%
60%	-6.1%	-6.5%	-6.6%	-6.6%	-6.6%	-6.6%	-8.2%	-3.5%	-1.6%	-0.1%	1.1%	2.2%	3.1%	3.9%	4.5%	5.1%	5.6%
70%	-7.6%	-8.0%	-8.1%	-8.2%	-8.2%	-9.2%	-7.8%	-3.5%	-1.3%	0.2%	1.5%	2.6%	3.5%	4.3%	5.0%	5.6%	6.1%
80%	-8.7%	-9.2%	-9.3%	-9.3%	-9.3%	-9.4%	-9.0%	-4.8%	-1.3%	0.5%	1.8%	2.9%	3.8%	4.6%	5.3%	5.9%	6.5%
90%	-9.5%	-10.0%	-10.2%	-10.2%	-10.3%	-10.3%	-9.9%	-5.7%	-2.3%	0.5%	2.0%	3.1%	4.1%	4.9%	5.6%	6.2%	6.8%

Lowest kw

Red underline indicates bill impact higher than RRA
Blue oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load

*Note: Very high sensitivity on low load factor, lower consumption customers due to T1 kW charge. [431]

475. Under the MGS Proposal, the 20th to 80th percentile bill impact for F2017 ranges from zero per cent to 7 per cent, with the full range between -17 per cent to +168 per cent. This trend is similar across the major sectors. About 6 per cent of customers are expected to experience bill impacts over 10 per cent. Of these customers (the 6 per cent), the highest bill impact in terms of nominal dollars is about $6,000 (a bill impact of 14 per cent). Overall, about half of the MGS customers (53 per cent) are better off in terms of bill impacts under the MGS Proposal as compared to the status quo.[432]

[431] Exhibit B-1, Page 6-36
[432] Exhibit B-1, Page 6-35

476. Typical customers (shown by the blue circle) are mostly better-off. The larger consuming customers tend to have small bill impacts during the transition. The customers experiencing the highest bill impact are characterized by low consumption and low load-factor, with bill impacts mostly triggered by having demand charges for all kW.[433]

477. BC Hydro has not determined that "there is no conservation rate alternative that would be fair to the diverse customer base of the MGS class," but BC Hydro has not identified a viable alternative at this time.[434]

h. Alternatives

478. BC Hydro considered two major alternatives including status quo and the flat energy rate and flat demand charge proposed. The CEC submits that Status Quo is clearly not suitable as has been discussed above. Annually adjusted baselines in general may not be suitable for such a large rate class. BC Hydro's view is that it is not the heterogeneous nature of MGS and LGS rate classes that makes annually adjusted baselines not feasible; rather it is the large number of customer accounts in each rate class (over 23,000 accounts).[435]

479. BC Hydro also provides the following analysis of its proposed MGS rate relative to a Sensitivity Rate option in BCUC 2.170.

Table C Proposed MGS Rate Relative to the Sensitivity Rate Option

Bonbright Criteria (from Table 2-7)	Evaluation
1. Price signals that encourage efficient use and discourage inefficient use	Neutral Proposed MGS flat rate is still reflective of LRMC (section 6.3.5 Exhibit B-1, page 6-32)
2. Fair apportionment of costs among customers	Favourable Proposed MGS rate recovers 35 per cent of demand-related costs relative to 15 per cent (section 6.3.4 of Exhibit B-1, page 6-23) benefiting MGS customers with higher load factors, who make more efficient use of BC Hydro's system.
3. Avoid undue discrimination	Neutral
4. Customer understanding and acceptance, practical and cost effective to implement	Favourable The proposed MGS rate has broader acceptance among customers because of the benefits to high load factor customers. (section 6.3.5.2 Exhibit B-1 page 6-36)
5. Freedom from controversies as to proper interpretation	Neutral
6. Recovery of the revenue requirement	Neutral Both options recover the revenue requirement on a forecast basis.
7. Revenue stability	Neutral
8. Rate stability	Neutral Both are a departure from the status quo two-part rate.

[433] Exhibit B-1, Page 6-36
[434] Exhibit B-5, BCUC 1.56.1.1
[435] Exhibit B-5, BCUC 1.59.1

480. The CEC submits that BC Hydro has provided an appropriate solution to the current issues surrounding the MGS rate structure. The CEC recommends that the Commission approve the MGS proposal as filed by BC Hydro.

481. The CEC submits that the BC Hydro rate proposal is appropriate and superior to the Sensitivity rate option above as the analysis shows either neutral or favourable comparisons across all the Bonbright principles. In particular, the CEC submits that that fair apportionment of costs among customers is important in competitive business environments.

i. Implementation

482. BC Hydro proposes a one year implementation for MGS rates. They believe that a three year phase in would be complex and have only minor mitigation for bill impacts.[436] A three year MGS phase-in softens bill impacts only modestly, and BC Hydro's simulations show that in F2017, the maximum bill impact of the largest MGS customers is about 8 per cent vs. the no-phase-in of 10.4 per cent. There are also no substantive differences on the maximum bill impact of typical customers, at 3.2 per cent for phase-in vs. 2.8 per cent for no phase-in, and both are under the RRA increase of 4 per cent. Finally, under the no-phase-in scenario, the highest bill impact in terms of nominal dollars (with low consumption and low load factor customer) is modest at $6,000, with a bill impact of 14 per cent, as stated on Exhibit B-1, page 6-35. The MGS rate change is unique in that the changes to energy charges and demand charges result in offsetting bill impacts for many customers - limiting the combined impact of the changes. That is why the phase-in of the proposed MGS rate is not that effective at mitigating the bill impacts of the design change. Given the poor understanding of the existing rate by MGS customers, BC Hydro cannot produce a meaningful estimate of customer usage changes from the existing rate. The total rate-structure conservation for the existing MGS rate is assumed to be zero for F2017 to F2019, regardless of whether there is a phase-in. Under the Bonbright criteria assessment, the increase in complexity, lower customer understanding and a much delayed adjustment to demand cost recovery outweighs the benefits experienced from a very modest softening of bill impact. Thus, BC Hydro concludes that a three year phase-in is not a preferred option.[437]

483. While it is true that some high load factor/high consumption (MGS) customers would be better off under a phase-in, the majority of customers would be better off under no phase-in to the MGS rate proposals, including the typical customers between the 20th and 80th percentile (by annual consumption and load factor as illustrated by the oval in Figures 6-14 and 6-15 on page 6-68 of Exhibit B-1). These facts, when combined with the complexity of implementing a phase-in that would be difficult for customers to

[436] Exhibit B-1, Page 6-68
[437] Exhibit B-5, BCUC 1.79.2

understand, and would make bills difficult to predict, led BC Hydro to propose no phase-in for the MGS class. There were no explicit weights used to arrive at this position.[438]

484. BC Hydro is seeking final order effective April 1, 2017 with respect to the MGS and LGS rates. Among other things, this effective date was chosen to allow for the development and implementation of a communication strategy, as BC Hydro anticipates a Commission decision on RDA Module 1 by fall 2016. Conceptually, a communications strategy would include notifications to inform customers about the LGS and MGS rate changes, as well as information about how customers can do energy budgeting and estimate bill savings from energy efficiency projects. Communications activities would likely include:

- A letter to each MGS and LGS customer to inform them of the change;
- Messaging on BC Hydro owned channels, such as emails, bchydro.com, bill inserts and bill messages;
- Key account customer visits;
- DSM program marketing materials;
- Awareness messaging through BC Hydro's business account services team; and
- Workshops or messaging delivered through industry associations.[439]

485. The CEC submits that the proposed implementation plan is appropriate and recommends no phase in for the MGS rate design proposal.

(iii) Large General Service

486. The LGS rate class consists of 6,852 accounts with total consumption of 10,885 GWh (F2015)[440] whose billing demand is equal to or greater than 150 kW or whose energy consumption in any 12 month consecutive period is greater than 550,000 kWh.[441] The LGS rate class is diverse[442] and consumption is variable by site type.[443] Customer characteristics are laid out in the Application at pages 6-43 to 6-44. BC Hydro provides an illustrative distribution of LGS customer consumption below.

[438] Exhibit B-5, BCUC 1.82.5
[439] Exhibit B-5, BCSEA 1.18.2
[440] Exhibit B-1, Page 6-38
[441] Exhibit B-1, Page 6-1
[442] Exhibit B-1, Page 6-43
[443] Exhibit B-1, Page 6-43

LGS illustrative distribution (Appendix C-4A page 22 of 813)

Annual Consumption (1000 kWh)

Load Factor	0	200	400	600	800	1,000	1,200	1,400	1,600	1,800	2,000	2,200	2,400	2,600	2,800	3,000	3,200	Total
0%	1.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
10%	1.1%	2.6%	0.8%	0.3%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.1%
20%	1.0%	2.3%	2.6%	1.2%	0.8%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	9.2%
30%	1.1%	1.4%	3.8%	3.1%	1.8%	1.0%	0.6%	0.4%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	14.2%
40%	0.7%	1.0%	2.0%	4.1%	2.8%	1.8%	1.3%	0.9%	0.6%	0.4%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	17.0%
50%	0.6%	1.0%	1.4%	3.7%	3.3%	1.9%	1.4%	1.1%	0.8%	0.6%	0.6%	0.3%	0.4%	0.2%	0.2%	0.2%	0.1%	17.8%
60%	0.4%	0.9%	0.9%	2.8%	1.9%	1.6%	1.0%	1.0%	0.5%	0.5%	0.4%	0.5%	0.3%	0.3%	0.3%	0.2%	0.2%	13.7%
70%	0.3%	0.4%	0.5%	1.6%	1.2%	0.8%	0.8%	0.5%	0.6%	0.5%	0.5%	0.4%	0.3%	0.2%	0.2%	0.1%	0.1%	9.2%
80%	0.2%	0.3%	0.2%	0.6%	0.4%	0.2%	0.3%	0.3%	0.1%	0.2%	0.3%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	3.6%
90%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
100%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Total	6.5%	10.3%	12.4%	17.6%	12.5%	7.8%	5.7%	4.4%	3.0%	2.6%	2.1%	1.7%	1.4%	1.2%	1.2%	0.7%	0.7%	90.9%

Note that about 9.1 per cent of accounts have consumption above 3200 MWh.

[444]

487. BC Hydro identifies the following key issues to be addressed in the LGS rate class design.
    - The existing LGS two-part energy rate does not provide a clear price signal for conservation and is poorly understood by customers;
    - The existing LGS three-step inclining block demand charge does not align with BC Hydro's cost to serve LGS customer peak demand; and
    - An increase to the existing level of demand charge cost recovery under BC Hydro's proposals will improve fairness in cost allocation and will further offset the impacts of energy rate flattening and dampen the range of bill impact variation among LGS customers across size and load factor.[445]

488. BC Hydro notes that the relationship between energy conservation response and general service customers (MGS and LGS) is complex, and can be due to a number of factors, such as complexity of rate structure and customer awareness, in addition to pricing alone. At this point BC Hydro cannot reasonably assume any price elasticity for the LGS and MGS classes.[446]

489. BC Hydro's proposal is summarized in the table below, compared to status quo and a 50% demand recovery sensitivity.

[444] Exhibit B-23, CEC 2.102.1
[445] Exhibit B-23, BCUC 2.152.1
[446] Exhibit B-23, BCUC 2.180.1

Table 6-20 LGS Rate estimates given rate structure transition in F2017

LGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (65% Demand Recovery)	F2017 Sensitivity (50% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1			10.83 Flat	8.35 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	10.66	11.17	5.37 Flat	5.98 Flat
T2	5.13	5.37		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

[447]

a. Basic Charge

490. The Basic Charge is proposed to remain the same at $0.2357/day under all options considered. This translates into approximately $7 per month. The CEC submits that the Basic Charge is very small given the size of the LGS customer bills and demand charges and could potentially be eliminated.

491. The CEC inquired as to the rationale for having a basic charge, demand charge and monthly minimum charge in the rate structure. BC Hydro noted that a number of surveyed Canadian utilities have demand charges and basic charges for large general service customers, including SaskPower, Manitoba Hydro, Newfoundland Power and New Brunswick Power.[448]

492. Customer related costs for the LGS rate class are in the order of $8.1 million, representing about 1% of the LGS rate class assigned costs of $829 million.[449] However, only approximately 7% of customer related costs ($0.57 million) are recovered from the Basic Charge.[450]

493. The CEC submits that it is inappropriate to recover only 7% of customer costs in the basic charge and recommends that this be addressed in the near future. The Commission should direct BC Hydro to work with stakeholders to have this addressed within the context of BC Hydro's concept of ongoing rate design adjustment.

494. BC Hydro states that in this context and given the overall priority of the RDA in addressing key LGS rate design issues, adjusting the level of the LGS basic charge to

[447] Exhibit B-1, Page 6-63
[448] Exhibit B-5, CEC 1.55.1
[449] Exhibit B-23, BCUC 2.152.1
[450] Exhibit B-5, BCOAPO 1.150.2

recover a greater proportion of customer-related costs was considered to be of limited importance and materiality. BC Hydro will review the level of the LGS basic charge in future rate design efforts and its preference for one level over another.[451]

495. The CEC accepts BC Hydro's proposal to leave the Basic Charge at its current rate in consideration of the significant changes being undertaken in the Demand Charge and the Energy Charges. The CEC submits it would be reasonable from a cost-causation perspective for the Basic Charge to be increased to recover significantly all or more of the customer charges in the future. The CEC submits that given the low rate for the Basic Charge relative to the overall cost of LGS customer bills, an increase would not make significant impacts to customers.

496. The CEC recommends that the Commission approve the Basic Charge as proposed by BC Hydro.

b. Demand Charge – Cost Recovery

497. BC Hydro currently has a three-step inclining block demand charge for the LGS rate class which is the same structure and the same charges as applicable to the MGS rate class.[452]

Table 6-6 Existing MGS Demand Charges (F2016)

First 35 kW of Billing Demand per Billing Period (Tier 1)	$0.00 per kW
Next 115 kW of Billing Demand per Billing Period (Tier 2)	$5.50 per kW
All additional kW of Billing Demand per Billing Period (Tier 3)	$10.55 per kW

[453]

498. The demand costs for LGS customers are fairly evenly distributed between Generation Demand, Transmission Demand and Distribution Demand.

A	B	C	D
Rate Class	**Generation Demand (%)**	**Transmission Demand (%)**	**Distribution Demand (%)**
MGS	**24**	**32**	**44**
LGS	**28**	**36**	**36**

[454]

499. The key issue with the LGS demand structure is also the same as that identified with respect to the MGS demand structure; that is that the LGS three-step inclining block demand charge does not align with BC Hydro's cost to serve LGS customer peak demand which is generally flat.

500. The current demand charge currently recovers approximately 50 % of demand costs. BC Hydro proposes to increase the proportion to 65%, which is consistent with RS 1823

[451] Exhibit B-23, BCUC 2.152.1
[452] Exhibit B-1, Page 6-43
[453] Exhibit B-1, Page 6-19
[454] Exhibit B-23, CEC 2.105.1

demand cost recovery[455] but nearly double that proposed for the MGS rate class of 35%. The CEC submits that there is no apparent justification for consistency between the current demand recovery with Transmission customers as opposed to matching the Medium General service demand recovery though the CEC nevertheless supports the transition to a higher demand cost recovery.

501. The proposed demand rates for LGS cannot be directly compared to the status quo in terms of a general "increase" or "decrease" because they are structurally different - the proposed is a flat rate, whereas the status quo is a three-tier design.[456]

502. BC Hydro states that an increase in demand cost recovery will improve fairness in cost allocation and will further offset the impacts of energy rate flattening and dampen the range of bill impact variation among LGS customers across size and load factor.[457]

503. BC Hydro provides the following Bonbright analysis comparing the proposed 65% demand recovery to that of remaining at approximately 50% demand recovery.

Table D Proposed LGS Rate Relative to the Sensitivity Rate Option

Bonbright Criteria (from Table 2-7)	Evaluation
1. Price signals that encourage efficient use and discourage inefficient use	Neutral Neither alternative reflects LRMC. (Table 6-18, section 6.4.4, page 6-50)
2. Fair apportionment of costs among customers	Favourable Increasing the level of demand-cost recovery from 50 per cent to 65 per cent improves fairness in cost allocation (section 6.4.5.2 of Exhibit B-1 page 6-62) benefiting LGS customers with higher load factors, who make more efficient use of BC Hydro's system.
3. Avoid undue discrimination	Neutral
4. Customer understanding and acceptance, practical and cost effective to implement	Favourable The proposed LGS rate has broader acceptance among customers because of the benefits to high load factor customers. (section 6.4.5.5 Exhibit B-1 page 6-65).
5. Freedom from controversies as to proper interpretation	Neutral

Bonbright Criteria (from Table 2-7)	Evaluation
6. Recovery of the revenue requirement	Neutral Both options recover the revenue requirement on a forecast basis.
7. Revenue stability	Neutral
8. Rate stability	Neutral Both are a departure from the status quo two-part rate.

BC Hydro's proposed LGS rate is supported overall by the foregoing assessment with no trade-offs.

458

[455] Exhibit B-1, Page 6-56
[456] Exhibit B-23, BCUC 2.181.1.1
[457] Exhibit B-1, Page 6-62

504. The CEC agrees with BC Hydro's assessment and submits that the 65% cost recovery is clearly preferable to the 50% cost recovery. The CEC recognizes that the higher cost recovery will impact the energy rate, keeping it significantly below the LRMC but dampening the effects of BC Hydro's transition to flat energy rates. CEC discusses its views with respect to matching the LRMC below and earlier in these Submissions.

505. The CEC reiterates its comments above that an increase in the demand charge such that it recovers more of demand-related costs is directionally appropriate and should be considered as the correct direction for the future, subject to rate impacts, Bonbright principles and other important considerations that may be identified upon weighing the benefits.

506. The CEC submits that 65% cost recovery is a suitable recovery at this point, but could be increased in the future.

507. The CEC recommends that the Commission approve the 65% demand cost recovery for the LGS rate.

c. Demand Charge – Flat Structure

508. BC Hydro proposes to replace the current three tier charge with a flat rate. They state that it improves fairness by aligning cost recovery with the cost to serve a LGS customer's peak demand, which is generally flat on a $/kW basis; and simplifies the rate structure and will improve customer understanding and acceptance. As compared to the existing three-step inclining block structure, a flat LGS demand charge will also better reflect the rate design practice of other utilities, which either have flat or two step demand charges; and 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 demand charge structure).[459]

509. The CEC submits that the flat demand charge is appropriate as it is for MGS, and that creating a rate structure that is understandable is the foundation to providing meaningful price signals. The CEC submits that, to the extent the flat rate structure improves understanding the proposed flat rate structure combined with increased recovery of demand costs is an important step in establishing a rate that is fair and meaningful to customers.

510. The CEC supports a flat rate structure for general service customers.

511. The CEC recommends that the Commission approve a flat demand structure for the LGS rate class.

d. Energy Charge

512. The LGS Part 1 energy rate differs from the MGS Part 1 energy rate as it is not inverted: for LGS customers, the Part 1 Tier 1 energy rate applies to the first 14,800 kWh of baseline consumption in one month and the Part 1 Tier 2 energy rate applies to all

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[458] Exhibit B-23, BCUC 2.170.1
[459] Exhibit B-1, Pages 6-61 t 6-62

remaining consumption of a customer's monthly baseline.[460] The mechanism of LGS Part 2 energy rate is the same as described for the MGS rate structure. Additional rules related to anomalies, growth adjustment, prospective growth adjustments, exemptions and new accounts are outlined in the Application at page 6-41 to 6-42.

513. BC Hydro has the following existing LGS energy rates.[461]

Table 6-14 Existing LGS Energy Rates (F2016)

Part 1 Energy Rate – Tier 1 (cents/kWh)	10.66
Part 1 Energy Rate – Tier 2 (cents/kWh)	5.13
Part 2 Energy Rate (cents/kWh)	9.90

514. The overarching objective of the LGS two-part energy rate was to provide LGS customers with an efficient price signal to induce conservation.[462]

515. The evidences is that the LGS rate structure suffers from similar issues as have been found to exist in the MGS rate class, although contrary to MGS, the LGS energy rate has delivered some conservation benefits.[463] The key issue with the existing LGS two-part energy rate is that it does not provide a clear price signal for conservation and is poorly understood by customers. The result is that minimal conservation savings have been delivered to date, and that BC Hydro cannot count on and does not forecast any conservation savings going forward.[464]

516. 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 general service energy rates.[465]

517. The CEC supports BC Hydro's proposed flat LGS energy charge and reiterates its comments that the Status Quo simplified energy rate provides unnecessary complexity and too little to no benefit in energy conservation savings.

518. At $53.70/MWh (F2017) the BC Hydro LGS energy rate will be considerably lower than BC Hydro's Energy LRMC of $85/MWh (F2013),[466] though arguably closer than it was prior to the LRMC change in the Evidentiary Update, when it included a higher range.

519. BC Hydro does not propose any change to its LGS energy proposal[467] as a result of the change in the LRMC. BC Hydro states they have prioritized customer understanding and

[460] Exhibit B-1, Page 6-40
[461] Exhibit B-1, Page 6-40
[462] Exhibit B-1, Page 6-40
[463] Exhibit B-1, Page 6-49
[464] Exhibit B-1, Page 6-43
[465] Exhibit B-1, Page 6-60
[466] Exhibit B-17, Page 1
[467] Exhibit B-23, BCUC 2.154.2

acceptance, practicality and fairness over efficiency in the RDA which could be adversely impacted if BC Hydro were to adjust its proposals.[468]

520. The CEC is not opposed to having the energy charge lower than the LRMC. The CEC provides its views with respect to the Energy charge relationship to the LRMC earlier in these Submissions. The CEC submits that the combined price signal of energy and demand charges is understood by the customers and that the appropriate comparison is to the combined Energy LRMC and Demand LRMC.

e. Minimum Charge

521. BC Hydro proposes to continue with the current monthly minimum charge definition.[469]

522. The CEC has provided its comments with respect to minimum charges for LGS and MGS under the MGS section of this submission.

f. Bill Impacts

523. Bill impacts are generally low (1 per cent to 3 per cent) and evenly distributed across LGS customer consumption and load factor.[470] The following Table 6-21 provides bill impacts for a 'typical' customer in the LGS class with consumption of 744,240 kWh per year and billed demand 185 kW each month, which is near the median in terms of consumption and load factor. Due to the elimination of the baseline, the amount of benefits would be slightly lower for customers who experienced a reduction in consumption, due to removal of credits at the Part 2 energy rate, and higher for customers who experienced an increase in consumption, due to avoidance of charges at Part 2 energy rate.[471]

Table 6-21 F2017 Illustrative Customer Bill – BC Hydro LGS Proposal (Demand 65 Per Cent Recovery)

Customer Scenario	Demand Charge ($)	Energy Charge ($)	Basic Charge ($)	Total Bill ($)	SQ Bill ($)	Variance ($)
Consume at baseline	24,045	39,953	86	64,085	62,864	1,221 (2%)
+5% from baseline	24,045	41,951	86	66,082	66,622	-539 (-1%)
-5% from baseline	24,045	37,956	86	62,087	59,106	2,981 (5%)

[472]

524. The CEC has reviewed the evidence with respect to bill impacts and submits that the benefits from simplifying the rate structure in both the demand and energy charges, and

[468] Exhibit B-23, BCUC 2.154.2
[469] Exhibit B-1, Page 6-38
[470] Exhibit B-1, Page 6-62
[471] Exhibit B-1, Page 6-64
[472] Exhibit B-1, Page 6-64

increasing the cost recovery from the demand charge to more accurately reflect cost causation will outweigh the relatively small increases that can accrue to some customers.

g. Alternatives

525. BC Hydro provided three options for consideration including a flat energy rate and flat demand charge (proposal), a simplified version of the status quo with the 2-part energy rate and flat demand charge, and status quo. The reason for carrying forward the SQ LGS Simplified Energy Rate is that, in contrast to the MGS rate, the LGS energy rate has resulted in some energy conservation. Some LGS customers desire to retain the baseline-based rate structure and as described below, the LGS flat energy rate is not reflective of the energy LRMC range, so simplification does in this case have some trade-off with losses in efficiency and conservation.[473]

526. The CEC submits that the interests of these customers who have found it useful to respond to energy efficiency and conservation price signal will be addressed in Module 2 options and will enhance the potential benefits for such customers. Therefore, the CEC submits there will be little to no need to consider preserving any of the 2 tier nature to the LGS rate structure.

527. The CEC submits that the Status Quo has clearly been shown to be relatively ineffective and difficult to understand and should not be considered as an appropriate option.

528. The CEC submits that the proposed alternative of a flat energy rate and flat demand charge are preferable to the simplified status quo in its simplicity and fairness.

529. The CEC submits that the BC Hydro LGS proposal should be approved as filed.

h. Implementation

530. BC Hydro proposes a one-time transition on April 1, 2017 from the current LGS rate structure to BC Hydro's proposed LGS rate structure, similar to that for the MGS rate structure. No stakeholder objected to the one-step transition.[474] BC Hydro states that a phase-in for the proposed LGS rates would delay the offsetting benefits and result in the opposite effect of what a phase-in is intended to accomplish.[475]

531. The CEC submits that the implementation plan is appropriate and recommends Commission approval.

532. The CEC recommends Commission approval of the BC Hydro LGS proposal as filed.

(iv) MGS and LGS Related Requests

533. BC Hydro has three requests relating to the elimination of TS 82 (modified LGS pricing) and transfer of any remaining LGS customers on TS 82 to RS 16xx effective April 1, 2017., and amendment to RS 12xx to enable dissolution of previously established LGS and MGS Control Groups, and elimination of RX 26xx.

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[473] Exhibit B-1, Page 6-49
[474] BC Hydro Final Argument, Page 57
[475] Exhibit B-1, Page 6-70

534. TS 82 will not be required if the proposed LGS pricing is approved. The CEC submits that if the LGS pricing is not approved it is reasonable for customers on that tariff to remain on that tariff.

535. The CEC agrees with the dissolution of the control groups. The control groups have been of value and the Power Smart Evaluation used them to evaluate the LGS and MGS energy savings.[476] RX 26xx (flat pricing structure) is also not required if the LGS proposal is approved. Corix (the sole customer) is not opposed to the elimination of the tariff if the new rate structures are approved.

536. The CEC recommends approval of the MGS and LGS related requests assuming approval of the MGS and LGS rate structures as provided in the application.

[476] Exhibit B-1, Appendix C4-A, page 2

F. TRANSMISSION SERVICE RATES

537. Transmission Service customers are served at transmission voltage level (69 kV and above). There are eight existing Transmission Service rate schedules including RS 1823 (Default, Stepped rate), RS 1825 (Time of Use rate) RS 1827 (Exempt customers); 1852 (Modified Demand); RS 1853 (IPP Station Service) RS 1880 (Standby and Maintenance Supply); RS 1891 (Shore Power) and RS 3808 (BC Hydro and FortisBC Power Purchase Agreement).

538. The rate schedules are all considered to be working well, being well-understood and achieving conservation.[477] BC Hydro requests only a minor change with respect to change to RS 1823.[478]

(i) RS 1823

539. Rate schedule 1823 consists of a flat Energy Rate A, Tier 1 energy rate, Tier 2 Energy Rate B, Demand Charge, and the Minimum monthly charge as illustrated below. BC Hydro proposes to retain the status quo stepped rate structure as it works well and is well understood and supported by customers and industry.[479]

Table 7-1 Existing RS 1823 Rates (F2016)

Energy Rate A	4.303 cents/kWh (this is the flat rate for new accounts and customers that do not have a CBL)
Energy Rate B Tier 1	3.836 cents/kWh
Energy Rate B Tier 2	8.503 cents/kWh
Demand	7.341 $/kV.A

[480]

540. Energy Rate A is the flat rate for new accounts and customers that do not have a Customer Baseline (CBL). Under Energy Rate B a customer purchases annual energy volumes at the Tier 1 rate up to 90 per cent of its CBL and at the Tier 2 rate above 90 per cent of CBL (Tier 1/Tier 2 90/10 split).[481]

541. BC Hydro notes that there are approximately 140 Transmission Service customers taking service under RS 1823. The relatively small number of such customers makes annually adjusted baselines practical to administer.[482]

[477] Exhibit B-5, BCUC 1.6.3
[478] BC Hydro Final Argument, Page 59
[479] BC Hydro Final Argument, Page 59
[480] Exhibit B-1, Page 7-5
[481] Exhibit B-1, Page 7-5
[482] Exhibit B-5, BCUC 1.59.1

542. The competing rate design objectives as they impact RS 1823 Tier 1 and Tier 2 pricing include:

- Efficiency (through Tier 2 price signal);
- Fairness;
- Rate and bill stability;
- Recovery of revenue requirement (relates to revenue neutrality definition); and
- Customer understanding and acceptance.[483]

543. There has been significant regulatory history with respect to RS 1823 and the Commission's jurisdiction with respect to several aspects of the core rate is restricted, including the Tier 1/Tier 2 90/10 split. The Commission's jurisdiction is limited to:

- pricing principles for F2017 to F2019;
- the demand charge; and
- the interpretation of 'revenue neutrality.'[484]

544. Section 7.2.1 of Exhibit B-1 summarizes the legislative constraints on the Commission in designing RS 1823 Tier 1 and Tier 2 rates for BC Hydro's Transmission Service customers. RS 1823 must adhere to the following:

- The Tier 2 rate should reflect BC Hydro's energy LRMC;
- The quantity of Tier 1 power sold to Transmission Service customers should be set at 90 per cent, and the Tier 2 quantity should make up the remaining 10 per cent; and
- •The Tier 1 rate should be derived from the Tier 2 rate and the Tier 1/Tier 2 90/10 split to achieve, to the extent reasonably possible, revenue neutrality.[485]

545. BC Hydro believes that intent of RS 1823 should continue to be to send a price signal for the cost of new supply and encourage conservation. This is consistent with Recommendation No. 8 of the 2003 BCUC Heritage Contract Report and Recommendations that the Tier 2 rate should reflect the cost of new supply. RS 1823 also sends a direct capacity signal through the determination of billing demand which is based on peak demand during the 16-hour High Load Hour block (i.e., 0600 to 2200 Monday to Saturday, except statutory holidays).[486]

546. The CEC agrees with BC Hydro's stated intent for the rate class.

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[483] Exhibit B-5, BCUC 1.90.1
[484] Exhibit B-1, Page 7-3
[485] Exhibit B-5, BCUC 1.90.1
[486] Exhibit B-23, BCOAPO 2.240.2.1

(ii) Energy Charges

547. The customer-related costs of about $1.7 million are recovered in the RS 1823 energy charge.[487]

a. Flat Energy Rate A

548. BC Hydro proposes no changes to the Flat Energy Rate A. The CEC agrees with this direction.

b. Energy Rate B

549. BC Hydro proposes a very slight adjustment to the Tier 1 and Tier 2 energy charges in F2017 so that the Tier 2 energy charge is set to the energy LRMC and Tier 1 is set so that customer bill neutrality results.[488]

550. BC Hydro identifies the following LRMCs for Transmission.

TABLE 2-5A (Transmission Service)

Fiscal Year	LRMC Only (cents/kWh)	Plus Generation Capacity Costs (cents/kWh)	Plus Network Capacity Costs (cents/kWh)
F2013	8.50	8.50	8.50
+ Unit Capacity Cost of Revelstoke Unit 6 ($11/MWh in $F2013)	N/A	9.60	9.60
+ Network Capacity Cost of $36.60 kW-year converted to 0.78 cents/kWh (in $2015)		N/A	10.38
F2014	8.47	9.57	10.34
F2015	8.58	9.70	10.48
F2016	8.75	9.88	10.68
F2017	8.92	10.08	10.89
F2018	9.10	10.28	11.11
F2019	9.28	10.48	11.33

551. BC Hydro provides the following comparison of the various rate classes and their relationships to LRMC in BCOAPO 2.137.2

[487] Exhibit B-5, BCOAPO 1.151.1
[488] BC Hydro Final Argument, Pages 59-60

Customer Class	Residential Inclining Block Rate	Small General Service (<35 kW)	Medium General Service (≥ 35 kW and < 150 kW and energy consumption is = or < 550,000 kWh)	Large General Service (≥150 kW)	Transmission Stepped Rate Over 60kV
Proposed rates and charges	Step 1: 8.29 cents/kWh Step 2: 12.43 cents/kWh Basic: $0.1835/day	Basic charge: $0.3200/day Energy rate: $0.1101/kWh	Energy rate: 8.54 cents/kWh Demand charge: $4.76/kW Basic charge: $0.2347/day	Energy rate: 5.37 cents/kWh Demand charge: 10.83 cents/kWh Basic charge: $0.2347/day	Energy Rate: Tier 1 - 3.981 cents/kWh Tier 2 – 8.920 cents/kWh Demand Charge: $7.635/kVA
Proposed energy LRMC range in Application (F2017)	9.46 to 11.13 cents/kWh	9.46 to 11.13 cents/kWh	9.46 to 11.13 cents/kWh	9.46 to 11.13 cents/kWh	8.92 to 10.50 cents/kWh
Proposed energy LRMC in Evidentiary Update (F2017)	9.46 cents/kWh	9.46 cents/kWh	9.46 cents/kWh	9.46 cents/kWh	8.92 cents/kWh
Proposed energy and capacity LRMC in Evidentiary Update (F2017)	10.61 cents/kWh	10.61 cents/kWh	10.61 cents/kWh	10.61 cents/kWh	10.08 cents/kWh

552. As illustrated above, Tier 2 is established at BC Hydro's proposed Energy LRMC in the Evidentiary Update, while Tier 1 is considerably lower at 3.981 cents/kWh.

553. There is very limited consumption at Tier 2 pricing as evidence in BCOAPO 1.55.1.

	Estimated Share of Total F2014 RS 1823 Sales that are Tier 2 (%)
Forestry	**4**
Mining	**1**
Oil & Gas	**11**
Ports	**12**
Pipelines	**0**

[489]

(iii) Forecast Revenue and Bill Neutrality

554. As identified above, the Tier 1 energy rate is calculated residually to result in 'Customer Bill Neutrality'. The Commission has the jurisdiction to approve the definition of Revenue Neutrality.

555. The term "revenue neutrality" used in Heritage Contract Report Recommendation No. 8 is not defined, and could be either 'customer bill neutrality' or 'forecast revenue neutrality.'[490] BC Hydro is not seeking any order regarding the general application of a revenue neutrality definition.[491] 'Forecast revenue neutrality' was used to determine RS 1823 energy rates under Direction No. 6. RRA increases were applied to both RS 1823 Tier 1 and Tier 2 energy rates for F2015 and F2016. This methodology is easily understood and consistent with how RRA increases have been applied to other rates.[492]

[489] Exhibit B-5, BCOAPO 1.55.1
[490] Exhibit B-5, BCUC 1.91.1
[491] Exhibit B-1, Page 7-12
[492] Exhibit B-5, BCUC 1.91.1

The RIB, SGS, MGS and LGS rate schedules are all determined on a forecast revenue neutrality basis.[493]

556. The 'bill neutrality' definition of revenue neutrality is unique to RS 1823.[494] Revenue neutrality is achieved under Policy Action No. 21 if the total cost to the customer and the total revenue to BC Hydro are the same under the stepped rate as under the flat rate at the customer's existing consumption level. Under this definition, RS 1823 is intended to cause no change in a customer's annual bill, provided the customer continues to consume at its existing (CBL) consumption level.[495]

557. BC Hydro's view is that a Commission determination of definition of revenue neutrality in the context of RS 1823 may reduce the flexibility that BC Hydro has in pricing RS 1823 energy rates given Direction No. 7 and other legislative constraints. BC Hydro's preferred Option 1 pricing uses customer bill neutrality in F2017 and both customer bill neutrality and forecast revenue neutrality in F2018 and F2019. Customer bill neutrality in F2017 has the advantage of maintaining the price differential between Tier 2 and Tier 1 the same while keeping Tier 2 in the LRMC range.

558. A Commission determination regarding revenue neutrality may provide certainty regarding future rate designs, but may limit feasible rate options. BC Hydro's view is that each rate design should be examined on its own merits, including assumptions regarding revenue neutrality. In this way, trade-offs using rate design evaluation criteria can be made. This is the approach that has been used in previous BC Hydro rate design filings.[496]

559. BC Hydro indicates that the Association for Major Power Consumers (AMPC) believes that the forecast revenue neutrality approach would unfairly impact customers who have undertaken conservation in response to the Tier 2 price signal. BC Hydro provides the following evidence in BCUC 1.95.3.

[493] Exhibit B-1, Page 7-9
[494] Exhibit B-1, Page 7-9
[495] Exhibit B-5, BCUC 1.94.1
[496] Exhibit B-5, BCUC 1.91.1

The table below shows a simple example of how a customer conserving energy under DSM would pay more under F2017 rates using the forecast revenue neutrality approach compared to F2017 rates using the bill neutrality approach.

	F2017
F2016 Consumption MWh	100
CBL MWh	100
DSM MWh	5
Consumption MWh	95
Tier 1 Load MWh	90
Tier 2 Load MWh	5
Bill Neutrality (Option 1 Table 7-3 Exhibit B-1)	
Tier 1 ($/MWh)	39.81
Tier 2 ($/MWh)	89.2
Forecast Revenue Neutrality (Option 1 BC Hydro response to BCOAPO IR 1.160.7)	
Tier 1 ($/MWh)	39.86
Tier 2 ($/MWh)	89.2
Customer Bill under Bill Neutrality ($000)	4028.9
Customer Bill under Forecast Revenue Neutrality ($000)	4033.4

[497]

560. The use of the 'bill neutrality' definition results in a revenue shortfall for the Transmission class. BC Hydro discusses the revenue shortfall of $2.2 million in Exhibit B-1 as follows:

561. Revenue neutrality is achieved under Policy Action No. 21 if the total cost to the customer and the total revenue to BC Hydro are the same under the stepped rate as under the flat rate at the customer's existing consumption level. Under this definition, RS 1823 is intended to cause no change in a customer's annual bill, provided the customer continues to consume at its existing (CBL) consumption level. Therefore, under F2017 Option 1 pricing, 90 per cent of the CBL priced at the Tier 1 price plus 10 per cent of the CBL priced at the Tier 2 price produces the same revenue as the total CBL priced at the flat rate (RS 1823 energy rate A). This pricing when applied to forecast F2017 consumption results in a $2.2 million revenue shortfall. If forecast revenue neutrality was applied by raising the Tier 1 price to recover the shortfall in revenue, customer bill neutrality would no longer be achieved since a customer consuming at its CBL will no longer pay the same bill as under the flat rate.[498]

562. Page 7-13 of Exhibit B-1 shows the revenue impacts associated with the three pricing principle options relative to forecast revenue neutrality. The under-recoveries from the Transmission Service rate class are $2.2 million (Options 1 and 2) and $8.8 million (Option 3) in F2017. To calculate the impact on other rate class R/C ratios, BC Hydro

[497] Exhibit B-5, BCUC 1.95.3
[498] Exhibit B-5, BCUC 1.94.1

assumes the above under-recoveries existed in F2016 as the filed F2016 COS study is based on F2016 costs and revenues.[499]

	Total class revenue in the F2016 COS ($millions)	Increase in Revenue as a result of the under-recovery in transmission rate class revenue ($millions)	
		Options 1 and 2	Option 3
Residential	1,917.6	+1.18	+4.73
SGS	411.8	+0.25	+1.02
MGS	360.5	+0.22	+0.89
LGS	836.1	+0.52	+2.06
Irrigation	6.0	+0.00	+0.01
BC Hydro owned Street Lighting	20.6	+0.01	+0.05
Customer owned Street Lighting	17.8	+0.01	+0.04
Total ($ million)		+2.2	+8.8

[500]

563. BC Hydro also assumes any under-recoveries are allocated to other rate classes on a pro-rata basis using share of total revenue.[501]

564. The CEC inquired if the application of a rate increase, which is not forecast revenue neutral, is effectively creating a rebalancing in contravention of the LGIC direction.

565. BC Hydro replied:

> The application of RRA increases to RS 1823 using either definition of revenue neutrality (i.e., bill neutral or forecast revenue neutral) will lead to differing projected revenues if in aggregate customers are not expected to consume exactly at their respective Customer Baseline Load (CBL) during the test year.
>
> Subsection 9(3) of Direction No. 7 provides that for F2017-F2019, the Commission "must not set rates for [BC Hydro] for the purpose of changing the revenue-cost ratio for a class of customers." Since any projected revenue shortfall or surplus for the test year results from differing definitions of revenue neutrality rather than an effort to adjust R/C ratios between rate classes, the application of RRA increases using the bill neutrality definition of revenue neutrality does not create a rebalancing in contravention of the Rate Rebalancing Amendment.[502]

[499] Exhibit B-5, CEC 1.73.2
[500] Exhibit B-5, CEC 1.73.2
[501] Exhibit B-5, CEC 1.73.2
[502] Exhibit B-5, CEC 1.73.1

566. The CEC submits that the differing definition of revenue neutrality is not necessarily appropriate and that it would be preferable if the definition of revenue neutrality were to be made consistent across rate schedules.

567. BC Hydro's F2011 Demand Side Management Milestone Evaluation Summary Report shows that industrial customers have a RS1823 Tier 2 price elasticity of demand of -0.16. While industrial customers tend to demonstrate more price-elasticity than other rate classes, an elasticity of demand that is between -1 and zero is defined as inelastic. Therefore, based on BC Hydro's F2011 report, industrial customers are price inelastic.[503]

568. The CEC submits that the increased price responsiveness of industrial customers relative to other rate classes reinforces the value of a conservation rate structure, and also of the use of the 'bill neutrality' definition of revenue neutrality.

569. The CEC submits however that the use of the 'customer bill' definition has been used for the Transmission rate class in the past, and that the impacts are not especially onerous for customers in the other rate classes. The CEC recommends that the Commission accept the proposed BC Hydro definition of revenue neutrality for the Transmission class at this time.

(iv) LRMC

570. No change was required to the BC Hydro proposal as a result of the Evidentiary Update to the LRMC, as Option 1 as based on the lower end of the LRMC. BC Hydro noted that there may be merit in exploring the inclusion of a generation capacity value in the energy LRMC for the purpose of the RIB Step 2 rate, but is not convinced that this is as true for other rate classes that include a demand charge and in particular RS 1823 that has a time differentiated demand charge. Furthermore, the $11/MWh generation capacity adder is only reflective of the residential load shape and is not appropriate for Transmission Service.[504]

571. The CEC provides its views with respect to the LRMC in an earlier section of these Submissions.

(v) Demand Charges

572. The 65 per cent calculation for Transmission Service customers is based on about $196 million in demand charge revenue divided by demand-related costs of $303 million.[505]

573. BC Hydro proposes no changes to the Demand Charges. There was general consensus among stakeholders that the existing demand charge is appropriate as it is consistent with industry practice, matches BC Hydro's system peak period and recovers 65 per cent of demand-related costs.

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[503] Exhibit B-5, AMPC 1.9.10
[504] Exhibit B-23, BCUC 2.177.2
[505] Exhibit B-5, BCOAPO 1.151.1

574. The Commission has jurisdiction to alter the percentage of demand –related costs that are recovered through the demand charge provided that the Tier 2 rate does not fall below the lower end of the energy LRMC.[506]

575. BC Hydro obtained the following transmission class demand charge demand-related cost recovery percentages for comparable Canadian utilities (based on having significant hydro generation):

- Hydro Quebec – 100 per cent (last estimated in 2004);
- Manitoba Hydro – 163 per cent (for General Service Large > 100 kV class); and
- Newfoundland Hydro – 109 per cent.

576. It is possible to reduce the demand charge to 50 per cent recovery and to increase the Tier 2 price. However, BC Hydro's view is that the current demand charge, which recovers 65 per cent of demand-related costs, is appropriate. The proposed RS 1823 pricing also meets the requirement that the Tier 2 price remains within BC Hydro's energy LRMC.[507]

577. The CEC submits that BC Hydro's proposal is appropriate.

(vi) Minimum Charge

578. BC Hydro is not proposing any changes to the RS 1823 monthly minimum charge (demand ratchet). Most Canadian electric utilities reviewed employ a demand ratchet for their large industrial customers. No issues were raised during stakeholder consultation with Transmission service customers, nor has the demand ratchet been an issue in previous Transmission Service rate proceedings.[508]

579. The CEC accepts BC Hydro's proposal with respect to Minimum Charges for the TSR.

(vii) Bonbright

580. BC Hydro provides the following Bonbright evaluations of its proposal:

> "Option 1 prioritizes the Bonbright rate and bill stability, and customer understanding and acceptance, criteria by continuing with the Direction No. 6 approach, and is supported by Transmission Service customers who take service under RS 1823, and by organizations representing such customers (AMPC, who speaks for MABC on matters concerning RS 1823, and CAPP);"[509]

[506] Exhibit B-5, BCOAPO 1.158.2
[507] Exhibit B-5, BCUC 1.90.1
[508] BC Hydro Final Argument, Page 64
[509] Exhibit B-23, AMPC 2.4.3

Table F: Transmission Rate (RS 1823) Proposal – Option 1 Stand-alone Evaluation: No Relative Comparison

Bonbright Criteria (from Table 2-7)	Evaluation
1. Price signals that encourage efficient use and discourage inefficient use	Favourable Tier 2 Rate reflects LRMC of $85 /MWh ($F2013). Please refer to BC Hydro's response to BCUC IR 2.158.1
2. Fair apportionment of costs among customers	Favourable The TSR rate class recovers 65 per cent of its demand costs through its demand charge. (Exhibit B-1 section 7.2.4.1).
3. Avoid undue discrimination	Neutral

Bonbright Criteria (from Table 2-7)	Evaluation
4. Customer understanding and acceptance, practical and cost effective to implement	Favourable Continues Direction 6 approach through to F2019 and is supported by RS 1823 customers (section 7.2.2.2, Exhibit B-1, page 7-9)
5. Freedom from controversies as to proper interpretation	Neutral
6. Recovery of the revenue requirement	Favourable Option 1 recovers revenue target on forecast basis. Please refer to BC Hydro's response to BCOAPO IRs 1.160.4 and 2.282.3.2
7. Revenue stability	Neutral
8. Rate stability	Favourable Continues Direction 6 approach through to F2019 and is supported by RS 1823 customers (section 7.2.2.2, Exhibit B-1, page 7-9)

[510]

581. The CEC agrees with the BC Hydro analysis and recommends that the Commission approve the BC Hydro Transmission rate proposal as outlined in the Application.

[510] Exhibit B-23, BCUC 2.170.1

G. TERMS AND CONDITIONS

582. BC Hydro groups its proposed changes with respect to its Terms and Conditions and Standard Charges into three main categories:

- Updates to Standard Charges to improve cost apportionment;
- Update the Electric Tariff language regarding the conditions under which a security deposit can be requested and the amount that can be assessed; and
- Update the general language of the Terms and Conditions to reflect modern drafting concepts[511].

583. Additionally, BC Hydro addresses BCOAPO's proposals for Terms and Conditions relating to Low Income customers.

(i) Updates to Standard Charges to cost apportionment

584. BC Hydro provides the following summary Table in its Final Argument at page 67.

Table 8-1 Summary of Proposed Standard Charges

Standard Charge	Current	Proposed	Section of Chapter/Rationale
Minimum Reconnection Charge – default	$125	$30	Section 8.3.2 - Updated to reflect current costs; does not include IT costs based on stakeholder input
Late Payment Charge	1.5% per month	1.5% per month	Section 8.3.3 - Late Payment Charge recovers BC Hydro's costs and is a means to incent prompt payments
Returned Cheque Charge, to be re-named Returned Payment Charge	$20	$6	Section 8.3.4 - Currently, this charge is tied to BC Hydro's lead bank's non-sufficient funds (NSF) fee; change to reflect BC Hydro's actual costs
Account Charge	$12.40	$12.40	Section 8.3.5 - Two different cost drivers offset each other so charge remains the same
Meter Test Charge	$125 (Minimum Reconnection Charge)	$181	Section 8.3.6 - Proposed new charge reflecting cost recovery of first meter connection charge
Collection Charge	$39	Remove	Section 8.3.7 - Outdated as most meters are disconnected remotely
DataPlus Service	$360 per year	Remove	Section 8.3.7 - New enhanced data download service planned to be released to customers in early 2016 free of charge

585. BC Hydro provides an overview of the changes at pages 69-70 of its Final Argument.

[511] BC Hydro Final Argument page 65

586. The CEC notes that with the exception of Meter Test charge, the charges are all either the same or lower than previously and therefore tend to represent savings for customers. The new Meter Test charge is significant at $181. Customers who are found to have a faulty meter will not incur the charge. BC Hydro customers experiencing higher than expected bills are advised to perform a breaker test and informed of online tools available to monitor their consumption.[512] Online hourly electricity use is available to customers.[513] BC Hydro notes that most customers, including those in apartment buildings are able to gain access[514] in order to check their meter. The CEC inquired as to approximate cost of sending a meter to Measurement Canada which is $295.99.[515]

587. The CEC has reviewed the evidence with respect to the other charges and finds the costing to be acceptable. The rationale for late payment charges is that all customers benefit from encouraging prompt payment of bills, which in turn reduces costs to electric utilities. The per cent charge and the $30 threshold have been in place since their inception. The Late Payment charge is in line with, or lower than most other jurisdictions.[516] The proposed return payment charge is in line with actual costs.

588. The CEC notes that BC Hydro has generally proposed rates and standard charges on the basis of average costs regardless of the specific costs for an individual customer.[517] BC Hydro acknowledges that given the development of online capabilities there could be situations in which further differentiation in pricing could be beneficial such as in the case of returned payments.

589. The CEC agrees that it is reasonable to create charges based on average costs and submits that the above changes are all appropriate.

590. The BCUC also provided interim approval for Minimum Reconnection Charge[518] (to be set at the proposed rate of $30/meter) and other proposed charges including the Manual Reconnection performed on overtime (to be set at $280/meter); the manual reconnection at the point of connection because of refused access charge (to be set at $700/meter); and removal of the manual reconnection requiring a call charge; on an interim basis effective December 1, 2015.[519]

591. The CEC expects that the Final Approvals for these charges would occur during this application.

592. The CEC has reviewed the evidence with respect to the above and finds the charges to be appropriate.

593. The CEC recommends Final Approval of these charges and disposition of the Minimum Reconnection deferral account which collected the difference between the reconnection

[512] Exhibit B-5, CEC 1.85.2
[513] Exhibit B-5, CEC 2.115.2
[514] Exhibit B-23, CEC 2.115.1
[515] Exhibit B-23, CEC 2.114.2
[516] Exhibit B-1, page 8-12
[517] Exhibit B-23, CEC 2.113.1
[518] Order G-175-15, dated November 3, 2015
[519] BC Hydro Final Argument page 117

charges collected at the interim rate and the reconnection charges that would have been collected had they been billed at the current rate, in the period December 1, 2015 through March 31, 2016, for recovery in rates in F2017.[520]

594. BC Hydro also updates Minimum connection charges as follows:

Table 8-2 Summary of Proposed Standard Charges

	Current Charge ($)	Proposed Charge ($)
100A Overhead	463	799
200A Overhead	496	838
400A Overhead	798	Remove
100A Underground	605	957
200A Underground	855	1270
First Meter	92	181
Additional Meter	23	46
Call back Charge	194	368

[521]

595. The charge increases are significant.

596. Several of the cost elements are reviewed in BCUC IR 1.119 to 1.124 series. The basis for these calculations include a loaded SLR (standard labour rate) of $143.57. BC Hydro stated that the loaded standard labour rate (SLR) has increased from $65.08 in the 2007 RDA to $143.57 in the 2015 RDA due to "A change in loading methodology on distribution work."[522] Some minor work could be performed by a Meter Technician at lower cost.[523]

597. BC Hydro does not update its charges year over year as it does with its electric service rates, and as such when fees and charges are updated the increase can be substantial in large part because of the time period between updates. To mitigate the magnitude of increases going forward BC Hydro is proposing more frequent updates to the fees and charges with BC Hydro RRA filings.[524]

598. The CEC submits that the costing is appropriate and it is also appropriate for BC Hydro to update the fees and charges more frequently.

(ii) Security Deposits

599. BC Hydro proposes changes to its tariff language related to Security *Deposits* as outlined in its Final Argument at pages 71 to 73.

[520] BC Hydro Final Argument page 117
[521] BC Hydro Final Argument page 68
[522] Exhibit B-5, BCUC 1.120.2
[523] Exhibit B-23, BCOAPO 2.289.3.1
[524] Exhibit B-23, 2.5.2

600. These are intended to:

(a) to allow BC Hydro to charge a new security deposit or increase an existing security deposit if actual consumption is found to be significantly higher than the consumption that is estimated when the account was created; and

(b) facilitate greater flexibility in the amount that is assessed.

601. The CEC submits that it is valuable for BC Hydro to have improved flexibility in managing its security deposits and that it is beneficial for ratepayers as a whole to have improved collections.

602. BC Hydro will determine the amount of security based on factors such as energy consumption and the customer's account and credit history. BC Hydro intends to develop a business practice regarding security deposits that is consistent with the approved Terms and Conditions. Factors that BC Hydro is considering to determine the amount of security deposit required include:

- Estimated consumption at the premises;
- Actual consumption at the premises;
- Account holder's credit score and payment history;
- Type of the premises (apartments versus single homes);
- Account holder's ID validation result; and
- Type of account holder (renter versus owner).[525]

603. The CEC notes that customers in apartments who are assessed as requiring a security deposit will have a maximum charge of $50.[526] The CEC submits this should not be too onerous for low income and lower use customers.

604. The CEC recommends Commission approval of the changes to the Terms and Conditions relating to Security Deposits.

(iii) Miscellaneous Amendments

605. BC Hydro proposes the elimination of the Collection Charge[527] of the DataPlus Service Charge which are no longer relevant.[528] In any case the DataPlus service charge is recovering less than 1/3 of the cost of providing service.[529]

606. BC Hydro proposes two additional amendments. The first amendment addresses application procedures and allows application either online, by telephone or in-person.

607. The CEC submits this is appropriate and should be approved.

608. BC Hydro also proposes the following amendment.

[525] Exhibit B-23, BCOAPO 2.292.1
[526] BC Hydro Final Argument page 73
[527] Exhibit B-1, page 8-17
[528] Exhibit B-1, page 8-18
[529] Exhibit B-23, BCOAPO 2.290.1

> *"Where a Customer Terminates Service to a Premises and that Person, or a co-occupant, representative or agent of that Person, applies for Service to the same Premises within 12 months of such Termination on the same Rate Schedule as previously applied, and regardless of whether Disconnection occurred, the applicant will pay the ~~greatest~~ sum of:*
>
> 1. *The greater of the Minimum Reconnection Charge, as set out in section 11.3 (Minimum Reconnection Charges), or BC Hydro's estimated cost to restore Service; and*
>
> 2. *The sum of the minimum charges the Customer would have paid between the time of Termination and the time that Service is restored, under this section."*

[530]

609. The CEC submits that the terms are reasonable, and recommends Commission approval.

(iv) Low Income Terms and Conditions

610. BC Hydro outlines its views with respect to BCOAPO's Low Income Terms and Conditions at a high level in its Final Argument at pages 76-78, but will provide its Submissions with respect to BCOAPO's proposals on October 11, 2016. BC Hydro believes that the BCUC does not have jurisdiction to approve low income rates per se and provides a legal argument at pages 78 to 108 of its Final Argument.

611. The CEC has provided its comments with respect to Low Income Terms and Conditions in Section 2 'Low Income' of these Submissions.

(v) Commission Endorsement of Proper Forums

612. BC Hydro also seeks Commission endorsement of its proposed review of Standard Charges between rate design applications, such that:

- Revenue Requirement Applications (RRAs) are the appropriate forum for updating existing Standard Charges to reflect current costs; and

[530] BC Hydro Final Argument page 74

- Fundamental changes to Standard Charges, the introduction of new Standard Charges and/or major changes to the terms and conditions related to Standard Charges are preferably filed with and examined through Rate Design Applications(RDAs).[531]

613. BC Hydro will review the costs of the Standard Charges in future RRAs and seek approval to update them to reflect its costs. Any material changes to the cost methodology of the Standard Charges would be addressed in future RDAs.[532]

614. The CEC agrees with BC Hydro's assessment of the appropriate forums and recommends that the Commission provide its endorsement as requested by BC Hydro.

615. The CEC recommends that the Commission approve BC Hydro's proposed Terms and Conditions as filed in its Application.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

David Craig

David Craig, Consultant for the Commercial Energy Consumers Association of British Columbia

Christopher P. Weafer, Counsel for the Commercial Energy Consumers Association of British Columbia

[531] BC Hydro Final Argument page 66
[532] Exhibit B-5, BCUC 1.118.1