2015 Rate Design Application
Cost of Service Methodology Assessment
Workshop - June 19, 2014

Discussion Paper

Strawman Proposal concerning the December 2013 Cost of Service Methodology Review

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1 Background

The three sequential steps employed in the development of BC Hydro rates are: (1) Revenue requirement (**RR**) determination; (2) Cost of Service (**COS**) development; and (3) rate design studies. The RR includes cost of energy, operating and maintenance (**O&M**) expenses, taxes, depreciation and amortization, financing charges and Return on Equity (**ROE**). The COS apportions these costs among BC Hydro's seven customer classes.

Where possible, costs are assigned directly to customer classes. Costs not directly assigned are allocated to customer classes in the following widely-adopted three-step process:

1. Costs are **functionalized** as Generation, Transmission, Distribution or Customer Care
2. Costs by function are **classified** into energy (variable costs that vary with kilowatt-hour provided), demand (fixed costs that vary with kilowatt demand) or customer-related categories
3. The energy, demand and customer categories are **allocated** to the seven classes on the basis of their respective energy use, demands or customer number (or other established allocator base).

BC Hydro requested the COS Methodology Review, which provides an evaluation of BC Hydro's COS methodology, including benchmarking against other utility COS methodologies. The COS Methodology Review makes 18 recommendations. The COS Methodology Review recommendations are listed at pages ES-4 to ES-6 of the Review, a copy of which was circulated to customer stakeholders and British Columbia Utility Commission (**BCUC**) staff as part of the June 3, 2014 invitation to the COS Methodology workshop to be hosted on June 19, 2014.

2 Strawman Proposal

BC Hydro largely concurs with these recommendations, but there are a few recommendations that BC Hydro is evaluating further in terms of whether the recommendation(s) can be feasibly implemented for purposes of the 2015 Rate Design Application (**RDA**). In formulating its strawman proposals for stakeholder input, BC Hydro used the BCUC's 2007 RDA decision and COS-related directions as a starting point, canvassed the relevant business units and reviewed surveys of other North American utility COS methodologies, including:

1. Elenchus survey conducted on behalf of SaskPower in January 2013 entitled "Review of Cost Allocation and Rate Design Methodologies: A Report Prepared by Elenchus Research Associated Inc."[1]
2. Christensen survey conducted on behalf of Manitoba Hydro (**MB Hydro**) in June 2012 entitled "Review of Cost-of-Service Methods of Manitoba Hydro".[2]

Throughout this document BC Hydro uses the word "proposal" and similar expressions to describe its current 'strawman' thinking. The use of those terms should not be construed as BC Hydro's final view on the particular point; instead they allow BC Hydro to avoid the numerous and cumbersome use of qualifying words (e.g., "for the purposes of this workshop…"). BC Hydro is committed to hearing and giving consideration to the views of customer stakeholders on all in-scope elements of the 2015 RDA well in advance of finalizing its proposals for the purpose of that application.

This strawman proposal should be read in conjunction with the June 19, 2014 COS workshop slide-deck presentation, which contains additional information.

In the sections below, the COS Methodology Review recommendations are presented by topic, followed by BC Hydro's proposal on each recommendation for stakeholder

[1] Refer to Nova Scotia Power Inc.'s 2013 Cost of Service Study - Application (Exhibit N-1, Appendix H) which can be found on the Nova Scotia Utility and Review Board website (http://uarb.novascotia.ca/fmi/iwp/cgi?-db=UARBv12&-loadframes) under Case M05473.

[2] Copy available at http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_13_4.pdf.

input. BC Hydro re-ordered and numbered the COS Methodology Review recommendations for purposes of this strawman response. Among other things, BCUC staff in written COS-related comments dated May 30, 2014, emphasized the usefulness of Revenue-to-Cost (**R/C**) ratio sensitivity analysis. Where BC Hydro is seeking stakeholder views on proceeding with a particular proposal, as opposed to commenting on proposal options, BC Hydro provided the R/C ratio analysis, and in all such cases the alternatives do not have a material effect on the applicable R/C ratio. Refer to BC Hydro's responses to Recommendations #1, #10, #11 to #12 and #14.

3 Functionalization

Recommendation #1	**Demand Side Management (DSM) Functionalization**
	We recommend that BC Hydro consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service.

Background

Currently, BC Hydro uses a 90 per cent Generation/10 per cent Transmission functionalization as a result of Directive 6 in the BCUC's 2007 RDA Decision.

BC Hydro's Response

After considering Recommendation #1, BC Hydro proposes to functionalize DSM as 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution:

- The majority of surveyed utilities functionalize DSM as 100 per cent Generation
- DSM savings occur primarily in respect of Generation costs. Based on analysis done as part of the F2012/F2013 DSM plan, DSM has some Transmission- and Distribution-related deferral benefits, primarily on the regional Transmission system along with Distribution substations. However, these benefits are smaller and relatively less certain than DSM's ability to defer more expensive Generation related investments

- BC Hydro is concerned that functionalizing DSM costs based on the relative proportions of Generation and Transmission plant in service will result in more than 70 per cent of DSM being classified as demand-related[3] (this occurs because Generation is classified as both energy and demand, while Transmission is currently classified 100 per cent demand). This is inconsistent with the fact that DSM is primarily acquired for energy savings (current DSM target: 7,800 gigawatt hours per year in F2021), although DSM is relied on for the associated capacity savings (1,400 megawatts (**MW**) in F2021).

The DSM deferral balance is considered part of rate base. Therefore, BC Hydro proposes to functionalize a share of financing and ROE costs in the COS Study (**COSS**) as DSM related.

The proposed DSM functionalization results in about a 40 per cent energy/58 per cent demand/2 per cent customer DSM classification if the F2013 Fully Allocated Cost of Service (**FACOS**) study[4] assumptions for Generation, Transmission and Distribution are applied, and about a 54 per cent energy/44 per cent demand/2 per cent customer DSM classification if a load factor method (discussed below in BC Hydro's response to Recommendation #2) is instead applied when classifying Generation hydro resource costs. The proposed DSM functionalization R/C ratio analysis is set out in Table 1.

[3] Based on F2013 FACOS study assumptions for Generation and Transmission classification. The 2013 FACOS study was filed with the BCUC on February 6, 2014; a copy is found at the BC Hydro 2015 RDA website.

[4] F2013 FACOS Generation classification is 45 per cent energy/55 per cent demand per 2007 RDA Direction 5. A load factor approach would result in a Generation classification of about 60 per cent energy/40 per cent demand. Refer to BC Hydro's response to Recommendation #2.

Table 1 DSM Functionalization R/C Ratio Analysis

Customer Class	F2013 R/C Ratio Base (%)	DSM (90/5/5) (Current Generation Classification) (%)	DSM (90/5/5) Sensitivity (using Generation Classification Load Factor Approach) (%)
Residential	89.82	89.77	90.88
Small General Service (**SGS**) Under 35 kW	126.71	126.64	126.1
Medium General Service (**MGS**) < 150 kW	120.79	120.81	120.4
Large General Service (**LGS**) > 150 kW	102.12	102.13	101.3
Irrigation	86.62	86.32	82.3
Street Lighting	115.66	115.56	117.4
Transmission	104.36	104.55	102.6

Stakeholder Input (BC Hydro Response to Recommendation #1)

BC Hydro seeks customer stakeholder views (with reasons) on proceeding with functionalizing DSM as 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution for the COSS.

4 Generation Classification

Recommendations #2 to #5	Generation Classification
	#2 We recommend that BC Hydro consider using either a System Load Factor method or a Plant Capacity Factor method to classify hydro costs, excluding water rental costs. #3 We recommend that BC Hydro continue to classify peaking thermal plant costs as demand-related and also classify associated O&M costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of generation. #4 We recommend that BC Hydro modify the classification of Independent Power Producer (**IPP**) and other purchased power obligations to reflect either fixed versus variable payment obligations or capacity versus energy usage. #5 We recommend that BC Hydro continue using the split between demand related and energy related generation revenue requirements excluding subsidiary net income

Recommendation #2

Background

BC Hydro proposed a 50 per cent energy/50 per cent demand Generation classification for the 2007 RDA. 2007 RDA Direction 5 provided for a 45 per cent energy/55 per cent demand Generation classification on the basis that at the time, future Resource Smart additions such as Revelstoke Unit 5, Mica Unit 5 and Unit 6, were predominantly capacity-related (BCUC 2007 RDA decision, page 91).

The Generation function accounts for the largest share of BC Hydro's F2016 RR, and received a lot of scrutiny in the 2007 RDA. In general, classifying more Generation costs as energy-related results in higher overall cost responsibility for high load factor[5] customers such as Transmission service customers, while assigning lower cost responsibility to the Residential and other lower load-factor customer classes.

BC Hydro's Response

BC Hydro accepts Recommendation #2.

BC Hydro examined a variety of methods to classify Generation hydro costs and there are pros and cons with each approach. Using a load factor method (Option 1), the energy portion of Generation cost would be equal to the system load factor while the Generation demand portion would equal: one minus the system load factor. BC Hydro would estimate the system load factor for F2016 based on the most recent load forecast, and makes the following observations:

- The calculation is stable and transparent, and the approach recognizes that the system is built to serve domestic load
- Many other hydroelectric jurisdictions use load factor methods to classify hydroelectric generation capital and O&M costs including Avista, MB Hydro, Newfoundland Power and PacifiCorp.

5 Hourly energy demand is relatively constant throughout the year.

A load factor approach results in about a 60 per cent energy/40 per cent demand Generation hydro classification.

A capacity factor approach either for the entire system or a plant-by-plant basis may also be appropriate (Option 2):

- A capacity factor approach will account for system reserve margins and total system operation (serving domestic load, trade, and managing variable water conditions)
- A capacity factor approach, based on historical averages, will likely be unstable because the operation of the hydroelectric units across multiple years is largely tied to system inflows, which can be highly variable. In high inflow years, BC Hydro may be forced to operate the system to a higher capacity factor to avoid spills.

The capacity factor approach could be supplemented by weighting the capacity factors for major hydroelectric plants by the book value of the facilities (Option 3). The value of each generating facility is an important driver of cost because facilities with higher book values will incur higher capital-related costs such as financing charges, depreciation, and return on equity relative to facilities with lower book value. As an example, in F2013 G.M.Shrum Generating Station (**GS**) had higher installed capacity and annual energy production than Revelstoke GS, but had less than 50 per cent of Revelstoke GS's book value. This fact should be accounted for if a plant-by-plant capacity factor approach is adopted.

Stakeholder Input (BC Hydro Response to Recommendation #2)

BC Hydro seeks customer stakeholder input (with reasons) as to whether Options 1, 2 or 3 should be adopted for the COSS. Refer to Table 2.

Table 2 Four Generation Classification Options

Methodology	Pros	Cons
Option 1: Load Factor The system load factor could be calculated using the before-DSM Load Forecast including system losses. This implies that about 60% of hydroelectric generation would be classified as energy-related with the balance (40%) demand-related.	*Consistent with many other primarily hydroelectric utilities including Avista, Newfoundland Power and MB Hydro (prior to 2005). *Simple to calculate, transparent.	*Does not account for the fact that hydroelectric generation is optimized over a three to five-year operational timeframe to serve both domestic load and maximize trade benefits. *Implies that IPPs, net imports and hydroelectric generation should be treated with a load factor approach because all these sources serve load. If confirmed, this may overestimate the demand contribution of these resources.
Option 2: Capacity Factor An average capacity factor for the entire hydroelectric system could be calculated to indicate the percent of costs classified as energy. This would result in classification of around 50% energy and 50% demand.	*A capacity factor approach recognizes that the hydroelectric system is optimized to serve both domestic load and to maximize trade benefits. *The BCUC directed BC Hydro in 2007 to treat Powerex trade income the same as other Generation costs, so recognition of trade benefits in calculating the hydroelectric demand/energy split provides a tie-in to how Powerex net income is ultimately treated. *Accounts for system reserve margins.	*This may not be stable – capacity factor can vary year-to-year. *Using nameplate in the capacity factor calculation may not be appropriate because some units are not capable of achieving nameplate capacity. BC Hydro believes using the dependable capacity of the units would be a reasonable approach as this would be consistent with the leading options for classifying IPP costs.
Option 3: Capacity Factor by plant, weighted by book value. This would result in classification of around 45% energy and 55% demand.	Connects the operation of the system with the capital costs incurred. These capital costs (taxes, financing, depreciation, ROE) are a significant driver of rate increases.	This may be less stable year over year than using an overall system capacity factor. Individual plant operations are influenced by a variety of variables including inflows, maintenance requirements, environmental consideration, etc. Using this method may cause BC Hydro to use a different method for O&M classification, which adds an additional step in the COS methodology.

Recommendation #3

Background

In the 2007 RDA BC Hydro proposed and the BCUC accepted to classify BC Hydro thermal plants as 100 per cent demand-related.

BC Hydro Response

BC Hydro considered Recommendation #3. BC Hydro proposes that Burrard GS continue to be classified as demand-related, while Fort Nelson GS and Prince Rupert GS should be classified as both energy and demand-related. Fort Nelson GS is largely used to serve base load while Prince Rupert GS is often operated during times of transmission outages, which can occur outside of the winter season. BC Hydro proposes to explore directly classifying the O&M expenses from BC Hydro owned thermal facilities.

Stakeholder Input (BC Hydro Response to Recommendation #3)

BC Hydro seeks customer stakeholder views on classifying Burrard GS as 100 per cent demand-related, and Fort Nelson GS and Prince Rupert GS as a combination of energy and demand-related.

Recommendation #4

Background

In the 2007 RDA BC Hydro proposed classifying IPPs as 100 per cent energy-related on the basis on the fact that the primary purpose of entering into contracts with IPPs is the procurement of additional energy. The BCUC accepted IPP classification as 100 per cent energy-related for purposes of the 2007 RDA but Direction 8 required BC Hydro to prepare a study examining and quantifying the capacity benefits associated with IPP contracts.

BC Hydro Response

After considering Recommendation #4, BC Hydro agrees that the 2007 RDA approach of classifying all IPP purchases as energy-related should be revisited. BC Hydro examined a variety of options to classify IPP expenses and has identified two leading options that it seeks stakeholder comment on. Both of the leading options link the demand portion of the IPP cost to the capacity benefits ($) of the IPP portfolio in long term planning. Specifically, the capacity and firm energy benefits are estimated based on the capacity (MW) and firm energy (GWh) contributions to the Integrated Resource Plan (**IRP**). These benefits are converted to $ using the capacity and energy prices in the Clean Power Call (**CPC**) (i.e., $34/kW-year and $124/MWh, 2009$ for capacity and energy respectively). A sensitivity analysis, using the upper end of the current Long-Run Marginal Cost (**LRMC**) for simplicity (i.e., $55/kW-year and $100/MWh 2013$), is also provided.

The two approaches are:

Option 1: Value of energy and capacity. The relative portion of IPP costs allocated to demand is based on the relative portion of capacity benefits over the sum of firm energy and capacity benefits from the IPP portfolio.

Option 2: Value of Capacity. The relative portion of IPP costs allocated to demand is based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs.

These approaches give the following classification results for different types of IPP resources:

Table 3 IPP Classification Results

% Classification to Demand	F2017	F2017	F2016	F2016
	Value of: Energy and Capacity (CPC) (%)	Value of: Energy and Capacity (Current LRMC) (%)	Value of: Capacity (CPC) (%)	Value of: Capacity (Current LRMC) (%)
	Option 1		Option 2	
Alcan	9	16	9	14
Storage Hydro	3	5	5	8
Island Generation (**ICG**)	3	7	17	27
McMahon	3	7	8	12
Wind	2	5	3	5
Biomass & Waste Heat	3	7	5	8
Run of River	2	3	1	2
All IPPs	3	5	4	7

BC Hydro also considered three other options:

Option 3: Contract structure. Determine if any fixed contractual payments, which do not vary with energy production, are made to the IPP and treat these as demand-related. The balance of the IPP contract cost would be treated as energy-related.

- With the exception of a handful of customized EPAs, all IPP contracts are paid based on energy production. The contract structures for the customized EPAs were often set up with considerations other than an intention to differentiate capacity and energy benefits. On the other hand, there are IPPs with high capacity contribution such as biomass projects that are paid based on energy production.

Option 4: Resource contribution. The relative portion of IPP costs allocated to demand is based on the percentage of the IPP's installed capacity that contributes to the IRP Base Resource Plan.

- This approach does not yield reasonable results. For example, dependable resources (such as some biomass projects) could have almost 100 per cent of their installed capacity included in the IRP Base Resource Plan. According to this approach, these biomass resources would be classified 100 per cent demand despite the fact that they provide significant amounts of energy.

Option 5: Load factor. If a system load factor method is used to classify hydroelectric costs, the same method could be applied to IPPs since both IPPs and the hydroelectric system primarily serve domestic load.

- Since the system load factor is approximately 60 per cent, this approach would result in approximately 40 per cent of IPP-related costs being classified as demand. This method will over-estimate the demand contribution of IPP resources and the results would be inconsistent with the IPP planning assumptions BC Hydro used in the IRP.

Table 4 summarizes the pros and cons for the various methods.

Table 4 Five IPP Classification Options

	Pros	Cons
Option 1 Value Approach – Energy and Capacity	Direct linkage between split of energy and capacity benefits and split of energy and demand costs.	Given the low capacity price relative to energy price used in the calculation and the high firm energy capability from dispatchable facilities like ICG, the % demand portion for dependable resources such as biomass and ICG are only slightly higher than intermittent resources. The result is sensitive to future changes in the energy and capacity LRMCs.
Option 2 Value Approach - Capacity	Direct linkage between capacity benefits and demand costs. Better captures the capacity benefits of dependable resources by resulting in a higher allocation of demand cost relative to Option 1.	The result is sensitive to future change in capacity LRMC.
Option 3 Contract Structure	Approach could be used for some IPP contracts that have take-or-pay components or fixed costs that do not vary with energy production.	Most IPP contract payments are based on energy production only. Contract structure had other considerations and does not necessarily reflect benefits between energy and capacity.
Option 4 Resource Contribution	Simple to calculate.	For resource types with high capacity contribution to the IRP, such as thermal projects, almost all of the cost will be allocated to demand even though the energy contribution is significant.
Option 5 Load Factor	Simple to calculate. Potentially appropriate if a load factor method is used for hydroelectric classification.	Inconsistent with hydroelectric classification if another method, besides load factor, is used for hydroelectric classification. Will over-estimate the capacity contribution of IPPs.

Stakeholder Input (BC Hydro Response to Recommendation #3)

BC Hydro seeks customer stakeholder views on classifying IPP purchases. Do you agree that Options 1 or 2 are better than Options 3, 4 and 5? If so, should BC Hydro pursue Option 1 or Option 2?

Recommendation #5

Background

The BCUC in the 2007 RDA (Directives 7 and 10) determined that classification of Powerex trade income should follow overall Generation classification.

BC Hydro Response

BC Hydro accepts Recommendation #5. BC Hydro proposes to continue with the approach approved by the BCUC in the 2007 RDA (Directives 7 and 10) whereby the classification of Powerex trade income follows overall Generation classification.

Stakeholder Input (BC Hydro Response to Recommendation #5)

BC Hydro seeks customer stakeholder views (with reasons) on continuing with the approach approved by the BCUC per 2007 RDA Directives 7 and 10 for the COSS.

5 Transmission Classification

Recommendation #6	Transmission Classification
	For transmission assets that are primarily used to transmit power from generation resources to the network transmission systems, we believe it is most appropriate for the costs of these resources to be classified and allocated in the same manner as costs for the generation resources. For backbone or network transmission, we recommend BC Hydro's use of the current Demand Only method for classification should continue to be used.

Background

In the 2007 RDA BC Hydro proposed and the BCUC accepted classifying Transmission as 100 per cent demand-related.

BC Hydro's Response

BC Hydro accepts Recommendation #6. BC Hydro agrees that the Transmission system should continue to be classified as 100 per cent demand-related because serving peak loads remains the primary planning consideration for capital expenditures on the transmission system. The vast majority of utilities with similar characteristics to

BC Hydro classify the Transmission function as 100 per cent demand-related. The length of Transmission radials, driven by the location of generation, is of secondary importance, while the amount of energy carried through Transmission lines is not a cost factor.

The RR includes an adjustment for Generation-related Transmission assets (**GRTA**) where $43.3 million in Generation-related costs is subtracted from the Transmission RR. By Letter No. L-92-07, the BCUC accepted that a fixed charge of $43.3 million was appropriate for GRTA costs.

Stakeholder Input (BC Hydro Response to Recommendation #6)

BC Hydro seeks customer stakeholder views on continuing to classify Transmission as 100 per cent demand-related. BC Hydro asks whether stakeholders wish to revisit (with reasons) the GRTA fixed charge of $43.3 million as the basis for GRTA costs.

6 Distribution and Customer Care Classifications

Recommendation #7#10	**Distribution and Customer Care Classification**
	#7 We recommend BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available. #8 We recommend BC Hydro consider classifying distribution substation costs as 100 per cent demand-related costs and costs for services and meters as 100 per cent customer-related costs. #9 We recommend BC Hydro review and revise the Distribution System Study to be more consistent with the theoretical foundation of the minimum system method and zero-intercept method as described in the 1992 NARUC Manual, prior to its use by BC Hydro. As an alternative, we recommend BC Hydro consider classifying distribution substation, lines, and transformer costs as all demand-related and services and meter costs as all customer-related. #10 We recommend that BC Hydro classify most, if not all, customer care costs as customer-related.

Recommendations #7 to #9

Background

As part of the 2007 RDA BC Hydro proposed a 75 per cent demand/25 per cent customer classification for Distribution. BCUC 2007 RDA Direction #4 mandated a 65 per cent demand/35 per cent customer Distribution classification. Both splits are comparable to those used by other utilities. BCUC 2007 RDA Direction 4 mandated BC Hydro to conduct Minimum System and Zero Intercept analysis. The 2010 study entitled "Electric Distribution System, Cost of Service Study" circulated to BCUC staff and customer stakeholders as part of the June 3, 2014 cover letter (that invited stakeholders to the June 19, 2014 COS Methodology workshop) addresses this part of Direction 4.

BC Hydro Response

The COS Methodology Review confirmed that Distribution costs should be classified as a combination of demand and customer-related factors. BC Hydro accepts the recommendations for Distribution classification for the reasons described in that part of the June 3, 2014 cover letter where BC Hydro discussed its views on Minimum system and Zero intercept analysis:

- The jurisdictional review in the COS Methodology Assessment shows that many other utilities classify and allocate Distribution assets based on more high-level classification assumptions to separate demand and customer-related distribution costs rather than relying on Minimum System or Zero Intercept analyses
- Given the number of assumptions necessary to prepare these analyses and the substantial data limitations encountered, including the use of replacement cost information in an embedded COS and the complexity of the Distribution system, BC Hydro believes there is significant uncertainty around the results.

BC Hydro proposes instead to first categorize Distribution costs (e.g., substations, primary, secondary, transformers, meters) and then classify the categories as either entirely demand or customer-related in the 2015 RDA. Generally, the closer the Distribution assets are to the Transmission system and further away from the customers, the classification of these assets will be similar to the classification of Transmission assets. The closer the Distribution assets are to the customer connections, the costs are classified as customer-related. For example, most surveyed utilities classify substations as 100 per cent demand-related and many utilities classify meter asset costs as 100 per cent customer-related.

Stakeholder Input (BC Hydro's Response to Recommendations #7 to #9)

BC Hydro seeks customer stakeholder views on the proposed approach of categorizing Distribution costs, and exploring direct assignment of Distribution assets to customer classes on a feeder-by-feeder basis. This proposed method would identify each customer class load on a sample of Distribution feeders along with the costs of those feeders. BC Hydro will report back on direct assignment as part of the proposed October 7, 2014 COSS workshop.

Recommendation #10

Background

BCUC 2007 RDA Direction 4 mandated a 65 per cent demand/35 per cent customer for Customer Care classification.

BC Hydro Response

BC Hydro accepts Recommendation #10. Customer Care costs should be classified 100 per cent as customer-related rather than the current 65 per cent demand/ 35 per cent customer classification directed by the BCUC in 2007. A 100 per cent customer classification is consistent with how other utilities treat Customer Care costs. Customer Care costs do not vary with demand.

The proposed Customer Care classification R/C ratio analysis is set out in Table 5.

Table 5 Customer Care Classification R/C Analysis

Customer Class	F2013 R/C Base (%)	Customer Care 100% Customer (%)
Residential	89.8	88.6
SGS Under 35 kW	126.7	127.1
MGS < 150 kW	120.8	124.1
LGS > 150 kW	102.1	104.8
Irrigation	86.6	92.0
Street Lighting	115.7	114.6
Transmission	104.4	104.1

Stakeholder Input (BC Hydro's Response to Recommendation #10)

BC Hydro seeks customer stakeholder views on its proposal to classify Customer Care costs as 100 per cent customer-related for purposes of the COSS.

7 Generation Allocation

Recommendation #11 to #13	**Generation Allocation**
	#11-#12 For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the CP demands in the months when the thermal plants are primarily used. For allocating demand-related hydro costs, we recommend BC Hydro first analyze how hydro units are designed or being used to serve peak loads throughout the year. To the extent that the hydro plants are designed or used to meet peak loads throughout the entire year, then a 12 coincident peak (**CP**) method is appropriate. If the hydro plants are primarily designed or used to help meet peak loads during only a few months of the year, then methods such as 3CP or 4CP would be more appropriate. #13 As an alternative approach for hydro costs, we recommend BC Hydro consider using the Average and Excess method for allocating demand-related hydro costs.

Recommendations #11 and #12

Background

The BCUC through 2007 RDA Direction 3 mandated a 4CP[6] allocation of Generation demand-related costs on the basis of evidence that the winter peak occurred in each of the months from November through January in recent years and that the February peak is often close to the annul peak (2007 RDA decision, page 82). The BCUC noted that further investigation may be worthwhile.

Using multiple peaks results in more costs being allocated to high load factor customers than would use of a single peak.

BC Hydro Response

BC Hydro considered Recommendations #11 and #12. Consistent with Recommendations #11 and #12, BC Hydro proposes to continue with a 4CP allocator as a reasonable method of allocating hydroelectric Generation demand costs:

- A 12CP allocator is not appropriate given that BC Hydro does not have a flat load shape over the year. The peaks between April and September are relatively flat
- Since all four of the winter months of November, December, January and February are relevant to the winter peak, BC Hydro believes a 4CP allocator is more appropriate than 1CP, 2CP or 3CP allocators. Using a 3CP allocator is problematic, as there is no basis for choosing November through January as opposed to choosing December through February. BC Hydro notes that this past winter's peak occurred in December 2013 and that February's 2014 peak was higher than January's 2014 peak
- BC Hydro remains a winter-peaking utility and does not have a significant summer peak.

[6] CP demand is a customer's or customer class's demand at the time of BC Hydro's system peak demand.

Refer to slides 55 to 57 of the June 19, 2014 COS Methodology workshop slide-deck presentation for additional information.

Generally, all BC Hydro hydroelectric units are planned and operated such that they will be available to meet the winter system peak, which has historically occurred in November, December, January or February. There are only a few hydroelectric units that are primarily operated during the winter. Most are operated year-round, depending on maintenance requirements and stream-flow considerations. The hydroelectric system can be thought of as generally providing both energy and capacity.

Refer to Table 6 for 1CP, 2CP, 4CP and 12CP R/C ratio analysis.

Table 6 CP R/C Ratio Analysis

Customer Class	F2013 R/C Ratio (Based on 4CP) (%)	1CP (%)	2CP (%)	12CP (%)
Residential	89.8	88.5	88.7	95.1
SGS	126.7	127.3	126.5	121.2
MGS	120.8	121.6	121.6	116.2
LGS	102.1	103.3	102.5	96.4
Irrigation	86.6	86.6	86.6	68.0
Street Lighting	115.7	117.1	116.5	131.0
Transmission	104.4	106.5	107.5	99.2

Recommendation #13

BC Hydro considered Recommendation #13 and questions whether the Average & Excess (**A&E**) allocation method would be an appropriate allocation method. The A&E method is described in the COS Methodology Review on page 4-2. Under the A&E method BC Hydro would use load research information to calculate the difference between a rate class's peak demand and average demand for each hour of the year. This "Excess Demand" would then be used to allocate the demand-related costs. The A&E method has not been substantially adopted by other utilities and BC Hydro would need to consider whether non-coincident peak (**NCP**)[7] demands from each rate class or system coincident demands should be used in the calculation.

Given that BC Hydro's Generation and Transmission planning is largely based on the system coincident peak and the fact that no utilities in the jurisdictional review use the A&E method, BC Hydro believes a 4CP approach is preferable.

Stakeholder Input (BC Hydro's Response to Recommendations #11 to #13)

BC Hydro seeks customer stakeholder views on its proposal to continue to use a Generation demand-related 4CP allocator.

8 Transmission Allocation

Recommendations #14 and #15	Transmission Allocation
	#14 When selecting an allocation method, consideration should be given as to how these transmission assets are designed and used and BC Hydro's load patterns. It may be appropriate to sub-functionalize these transmission costs between areas, such as the southern interior and other areas, using different types of allocation factors for each. Based on testimony related to the 2007 RDA, it appears that summer loads are of most importance to that portion of the BC Hydro system while loads during other times of the year may be of more importance for other parts of the system. #15 For transmission/sub transmission assets that essentially serve as a radial high voltage distribution system, we recommend that the Demand Only method for classification should continue to be used and consideration should be given to using one NCP as the demand allocator.

Recommendation #14

Background

The BCUC through 2007 RDA Direction 3 mandated a 4CP allocation of Transmission costs for the reasons outlined above in respect of Generation demand-related allocation.

[7] NCP demand is a customer's or customer class's maximum demand, regardless of when the BC Hydro system peak occurs.

BC Hydro Response

BC Hydro considered Recommendation #14. Consistent with Recommendation #14, BC Hydro proposes to continue with the 4CP allocator approach as it remains a reasonable method to allocate Transmission costs:

- Transmission planning continues to be largely driven by winter-peaking loads. The winter peak has historically occurred in November, December, January or February, which indicates that 4CP is more appropriate than 1CP, 2CP or 12CP. Refer to the discussion above in respect of Generation allocation Recommendations #11 and #12
- Transmission planning analysis is applied to various parts of BC Hydro system and is not only restricted to a system wide perspective. Study scenarios of study areas are created as part of the planning process to consider the impact of peak loads on the bulk and various regional transmission systems
- Some transmission assets are constrained by their summer capacity ratings, but these generally represent a small portion of the overall transmission system and summer peak loads are not a significant driver of capital investment on the transmission system.

Refer to slides 60 to 63 of the June 19, 2014 COS Methodology workshop slide-deck presentation for additional information. Refer to Table 6 for 1CP, 2CP, 4CP and 12CP R/C ratio analysis.

Stakeholder Input (BC Hydro’s Response to Recommendation #14)

BC Hydro seeks customer stakeholder views (with reasons) on continuing to use a Transmission 4CP allocator.

Recommendation #15

BC Hydro will investigate whether it can identify individual loads on radial Transmission lines and the corresponding asset values (either book value or replacement value) of those lines. BC Hydro believes this approach would be consistent with its investigation of Distribution system and whether direct assignment of assets, on a feeder by feeder basis to customer classes, is feasible. BC Hydro would report back to customer stakeholders at the proposed October 7, 2014 COSS workshop.

9 Distribution Allocation

Recommendation #16	**Distribution Allocation**
	We recommend if possible that BC Hydro consider using more direct assignment of Distribution costs (e.g., transformers, services, and meters) based on fixed asset records, or consider using the weighted number of customers when calculating the allocation factors for transformer, services, and meter costs.

BC Hydro Response

After considering Recommendation #16, BC Hydro proposes to investigate the feasibility of the suggested approach and report back to customer stakeholders at the October 7, 2014 COSS workshop.

10 R/C Ratios and Range of Reasonableness

Recommendations #17 and #18	**R/C Ratios and Range of Reasonableness**
	#17 We recommend BC Hydro consider adopting a range of reasonableness for customer class R/C ratios, with the goal of making changes in rate levels gradually over a several year period consistent with this and other ratemaking objectives when customer classes are outside of the target R/C range. #18 We recommend BC Hydro consider more explicitly developing a policy for how rapidly customer classes should be moved towards this range of reasonableness for R/C ratios with consideration also given to other ratemaking goals and objectives and the current legal limit on rebalancing (i.e., no more than two percentage points per year compared to the R/C ratio for that class immediately before the increase).

Recommendation #17

Background

BC Hydro proposed a 90 per cent-110 per cent range of reasonableness in the 2007 RDA, but the BCUC decided that a 95 per cent-105 per cent range of reasonableness was more appropriate. At the 8 May 2014 workshop BC Hydro proposed to continue with the BCUC-directed range of reasonableness of 95 per cent-105 per cent. To date, no customer providing written comments advocated adopting unity (all R/C ratios equal one). Most written comments supported a 95 per cent-105 per cent range of reasonableness, while some comments urged BC Hydro to narrow the range of reasonableness, with one comment proposing 97.5 per cent-102.5 per cent reasonableness range.

BC Hydro Response

BC Hydro considered Recommendation #17. Consistent with Recommendation #17, BC Hydro agrees a range of reasonableness is an appropriate way to deal with the inherent uncertainty in COS analysis, and that in particular 95 per cent-105 per cent is reasonable:

- Assumptions are made during the analysis and the results are sensitive to the particular methodologies selected, and therefore adopting unity is not realistic. Fully distributed costing (cost attribution methods) cannot identify with certainty the true cost to provide services in view of common costs. A range of reasonableness provides flexibility and allows other rate design considerations to be given appropriate weight
- Most other surveyed utilities use ranges of reasonableness of either 90 per cent to 110 per cent or 95 per cent to 105 per cent in their COS analysis as reflecting the fair allocation of costs to customer classes instead of trying to achieve unity

- Of the utilities that adopt a 100 per cent target R/C ratio, there are still significant deviations from unity. This may indicate that the setting of a 100 per cent target R/C ratio may be more a theoretical objective in these jurisdictions
- Relative to the 2007 RDA, BC Hydro has more accurate load research information and this provides a basis for narrowing of the range of reasonableness to 95 per cent to 105 per cent. For example, BC Hydro now develops class load shapes using a larger sample size of hourly loads (45,000 accounts compared to 1,200 accounts). Further, stakeholders to date have not expressed concerns with the proposed 95 per cent to 105 per cent range being too narrow.

Stakeholder Input (BC Hydro Response to Recommendation #17)

BC Hydro seeks further customer stakeholder input (with reasons) on a range of reasonableness of 95 per cent to 105 per cent.

Recommendation #18

BC Hydro will make a proposal for stakeholder input in response to Recommendation #18 as part of the proposed October 7, 2014 COSS workshop after: the cost re-distribution effects, if any, of COS methodology changes including consideration of customer engagement feed-back on this strawman proposal; engagement with the B.C. Government; and face-to-face meetings with customers. The proposal will include consideration of annual rebalancing filings submitted to BCUC for two to three years after 2015 RDA and then a new COS is done which drives another set of annual rebalancing submissions. This could lead to a more efficient and effective review process