BC hydro

2015 Rate Design Application

June 19, 2014 Workshop No. 2

Cost of Service (COS) Methodology

BC Hydro Summary and Consideration of Participant Feedback

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This memo documents customer stakeholder feedback concerning BC Hydro's June 19, 2014 Workshop No. 2 (COS methodology) and BC Hydro's consideration of this input. The workshop was held in Vancouver, B.C. with customers also being provided an opportunity to listen into the discussions remotely through a webinar. Copies of the workshop invitation and presentation slides can be found on the BC Hydro regulatory website at http://www.bchydro.com/about/planning_regulatory/2015-rate-design.html. Customer input was received during the workshop as well as through feedback forms and written comments submitted during a subsequent 45-day comment period, which began with the posting of draft Workshop No. 2 notes on July 10, 2014.

The memo is structured as follows: the main body includes a summary of comments, grouped by topic themes, along with BC Hydro's consideration of input. **Attachment 1** includes the Workshop No. 2 notes which provide a more detailed description of issues (including questions and answers). **Attachment 2** contains the feedback forms and written comments received during the written comment period. **Attachment 3** is a marginal COS-related jurisdictional information memorandum prepared by the COS consultants. **Attachment 4** contains additional independent power producer (**IPP**) contract information, as requested by several workshop participants. **Attachment 5** contains updated, approved revenue-to-cost (**R/C**) ratios in the United States.

1 Marginal and Embedded COS

1.1 Issue

One step in COS analysis is to determine if there are costs which can be directly assigned to a particular customer class. Direct assignment of costs is typically limited to only those costs that are clearly caused by only a single customer class. An example of direct cost is BC Hydro owned street lighting.

However, most utility investments serve many different customer classes which use the utility facilities differently, and direct assignment of costs is not possible. Most utilities use an embedded COS that breaks down the complexities of all non-direct assignment costs by function and classification of cost causation. An embedded COS analysis begins with the development of the utility's revenue requirement (**RR**), based on historic or projected accounting cost and usage patterns.

Another approach for assigning utility costs is through a marginal COS, which assigns costs based on the additional cost incurred to provide an increment of a good or service (i.e., kilowatt hour (**kWh**), kilowatt (**kW**) and customer), or the savings from a small decrement. Insofar as forecast costs are different than embedded costs, marginal COS results need to be adjusted either up or down to ensure that rates overall will recover no more than what the RR dictates. A number of different methodologies have been developed to adjust marginal COS results so that the embedded RR is not missed or exceeded.

In the case of BC Hydro, the RR to be used in the COS, whether embedded or marginal, will be BC Hydro's F2016 RR, the most current approved BC Hydro RR available for purposes of the 2015 RDA (approved pursuant to British Columbia Utilities Commission (**BCUC or Commission**) Order No. G-48-14 - refer to the May 8, 2014 Workshop No. 1 consideration memo, page 5, at the BC Hydro 2015 RDA website). Were a marginal COS analysis to be completed, it is highly unlikely that the results of the unadjusted marginal COS analysis would equal the approved BC Hydro RR, thus resulting in additional complexity and controversy over how adjustments would be made to reconcile a marginal COS with the BC Hydro RR. This topic is discussed further below under 'BC Hydro Consideration'.

At the conclusion of this Workshop No. 2 topic, BC Hydro stated that it intended to prepare an embedded COS:

- With the exception of one participant, stakeholders who commented at Workshop No. 1 (Introductory 2015 RDA issues) or as part of the related written process, or at Workshop No. 2, agreed with BC Hydro's suggestion to prepare an embedded COS
- The Commission in its 2007 RDA decision found that BC Hydro should prepare its COS on an embedded basis. The Commission concluded there has been no widespread adoption of marginal COS methods, and through 2007 RDA[1] Directions 2 through 10, 12 and 14 directed BC Hydro to continue using the embedded COS approach.
- All Canadian and most U.S. Pacific Northwest utilities use embedded approaches for COS purposes. In some of these jurisdictions, marginal COS studies are used to inform rate design rather than allocation of the RR.

1.2 Participant Comments

With the exception of Canadian Office & Professional Employees Union Local 378 (**COPE 378**), stakeholders who addressed this topic at Workshop No. 1, Workshop No. 2 or in subsequent written comments agreed with BC Hydro's suggestion to prepare an embedded COS. Association of Major Power Consumers of British Columbia (**AMPC**) stated that virtually no jurisdictions use marginal COS for cost allocation purposes (as opposed to rate design purposes). Refer also to the Workshop No. 1 consideration memo and related feed-back forms.

At Workshop No. 2, COPE 378 commented that an embedded COS requires more assumptions than a marginal COS. COPE 378's expert, Dr. Marvin Shaffer, in written comments dated July 29, 2014 (refer to Attachment 2 to this memo) stated

1 In the Matter of British Columbia Hydro and Power Authority: 2007 Rate Design Application, Phase 1, Decision, October 26, 2007 (**2007 RDA Decision**), pages 206 to 208.

that it was too early for BC Hydro to dismiss the marginal COS approach. Dr. Shaffer requested that BC Hydro: (1) set out the rationale for, and advantages and disadvantages of, marginal COS relative to an embedded approach; (2) present estimates of what the marginal COS would be by BC Hydro customer class; and (3) describe how marginal COS would be implemented in a manner consistent with the overall embedded RR approach.

1.3 BC Hydro Consideration

Consistent with participant feedback received (with one exception), BC Hydro will prepare an embedded COS. BC Hydro is of the view that there is ample basis to continue to design rate structures with marginal cost pricing while allocating its RR on the basis of embedded costs.

In response to COPE 378's Workshop No. 2-related comments, BC Hydro and the COS consultants undertook additional jurisdictional research summarized here and described in more detail in the memo found at Attachment 3. The six states that adopted marginal COS for cost allocation purposes - California,[2] Oregon,[3] Nevada,[4] Maine,[5] Montana[6] and Massachusetts[7] - did so in the late 1970s and early 1980s. No jurisdiction has adopted marginal COS for RR allocation purposes since the

2 Adopted in 1976 through California Public Utilities Commission (**CPUC**) Decision No. 85559.

3 Adopted in 1974 through Oregon Public Utility Commission decision *Re Portland General Electric Company*, 8 P.U.R. 4th 393 (1974).

4 Effective in 1982, Nevada Administrative Code, Chapter 704.660 (Regulation of Public Utilities) requires the Nevada Public Utilities Commission to consider a utility's marginal COS to each customer class in determining the revenue required from that class.

5 Adopted starting in 1985 through Maine Public Utilities Commission decision *Re Central Maine Power Company*, 69 P.U.R. 4th (1985).

6 Montana is a jurisdiction that places partial reliance on marginal COS for cost allocation purposes. Refer to *Re Montana Power Co.*, Docket No. 80.4.2 (Department of Public Service Regulation, 1982), and *In the Matter of NorthWestern Energy's Application for Approval for Authority to Establish Increased Natural Gas Delivery Service Rates and Implement Allocated Cost of Service in Rate Design Proposals*, Department of Public Service Regulation Docket No. D2009.9.129 (referred to in Attachment 3).

7 Massachusetts requires both embedded and marginal COS studies; refer to 220 Commonwealth of Massachusetts Regulation 30.06 which requires that electric public utilities prepare both marginal and embedded COS.

Commission's 2007 RDA decision. At least one jurisdiction - Illinois Commerce Commission - reverted back to the traditional method of embedded costs.[8]

BC Hydro provides item (1) of the information requested by Dr. Shaffer in this section. The rationale advanced for marginal COS relates to economic efficiency. The theory appears to be that if marginal cost pricing in rate structure design leads to efficiency, the same result must occur if applied to the allocation of RR. However, the real debate over the years associated with marginal COS has not revolved around the underlying economic theory, but whether or not there are any efficiency-related benefits of using marginal COS for RR allocation purposes. From a practical application and implementation perspective, it is BC Hydro's view that there has been no documented evidence that marginal COS for RR allocation purposes results in any meaningful gain in economic efficiency as part of the rate setting process. Additionally, there would be a need to reconcile the resulting class revenues determined on a marginal COS basis with the utility or class revenue requirements identified on an embedded RR basis: (1) to prevent either over or under recovery of the RR; and (2) to recognize the impacts of rate change caps or floors for customer classes. This reconciliation process would cause significant dilution and variation from any potentially meaningful class revenue responsibilities or pricing signals that might reflect 'true' marginal costs.

Other issues to be considered include:

- Although some have argued that marginal COS more fairly apportions costs among customers, there is little documentation of this actually occurring, particularly for utilities with significant existing generation and other infrastructure investments

[8] Compare Illinois Commerce Commission in 1989-1990 (*Re Commonwealth Edison Co*., 117 P.U.R. 4th 107 (1990) and Illinois Commerce Commission decision in 2001/2003 rejecting Commonwealth Edison Co.'s proposal to use a marginal COS approach; Order No. 01-0423, beginning at page 134.

- Marginal COS often leads to class revenue allocations varying significantly over short periods of time, unlike embedded costs which tend to change more gradually. (Embedded costs are by definition average costs; average costs change less dramatically than marginal costs). Some jurisdictions found that marginal COS lead to disruptive swings in allocated RR for various classes, and as a result applied constraints to marginal COS results to moderate resulting rate changes through caps or floors on the actual movement toward a class' marginal COS levels.[9] BC Hydro is a good example of how marginal costs can change significantly in a short period of time. As recently as 2010, BC Hydro's marginal generation costs were greater than $130 per megawatt hour (**/MWh**) ($F2013). The B.C. Government introduced changes to how BC Hydro is to plan for self-sufficiency in early 2012.[10] This change, coupled with other changes, resulted in a lower marginal generation energy cost which is now between $85/MWh to $100/MWh ($F2013). This type of variability is a significant concern that may prevent stable allocation of cost.

At Workshop No. 2, COPE 378 critiqued the embedded COS approach because of the assumptions and judgment required. In BC Hydro's view, both embedded COS and marginal COS require a large number of assumptions. The nature of fixed costs incurred to serve multiple customer classes requires allocation and therefore judgment regardless of whether the costs are viewed on an embedded or marginal basis. Seattle City Light, which is referenced by Dr. Shaffer in his July 29, 2014 written comments, functionalizes its RR into a number of cost categories such as energy, various distribution services and customer service, and separates marginal costs into seven major categories, two of which are further separated into

9 The CPUC introduced rate floors (minimum rates) and rate caps (maximum rates) as part of Decision No. 91107; BC Hydro understands that these limitations have lessened as a result of Assembly Bill 327 in 2013.

10 Electricity Self-Sufficiency Regulation amendment, B.C. Reg. 16/2012, Order in Council No. 036 (deposited February 3, 2012), which changed planning from critical water conditions to average water conditions.

subgroups.[11] The embedded COS RR is based on actual accounting cost information that is relatively easily obtained and relatively non-controversial. BC Hydro notes that since the embedded COS allocation methodology is based on the same information used to determine BC Hydro's overall RR, there exists a familiarity with the type and level of costs included in its embedded COS.

There is no generally agreed-to methodology for marginal COS as the following examples illustrate:

- Long-Run Marginal Cost (**LRMC**) - One of the recurring debates is whether marginal COS should reflect short-term or long-term costs. For marginal customer-related distribution costs, there are debates over using the full cost of rebuilding a distribution system or using only the cost of connecting additional customers to the existing utility system. Other controversial LRMC issues include development and details of utility resource plans (load forecast for each customer class, condition of assets, capital plans) and the appropriateness of replacement cost adjustments. Embedded COS does not require long-term planning assumptions because the costs are known with greater certainty.
- Revenue reconciliation – In contrast to embedded COS where allocated costs are equal to the overall RR, adjustments to marginal costs are almost always required to force projected revenues under marginal COS to equal the public utility commission-set RR. In response to item (3) requested by Dr. Shaffer, BC Hydro notes there are three methods that are most frequently used to reconcile marginal COS results with the RR that is to be allocated:[12] (i) qualitative inverse elasticity method (also referred to as 'Ramsey Pricing')

[11] Seattle City Light, Adopted Cost of Service and Cost Allocation Report, 2007-2008 (December 2006), pages 3, 31; copy available at http://www.seattle.gov/light/news/issues/rateproc/Docs/Adopted%20COSACAR%202007-2008%20FINAL.pdf.

[12] Two of these methods (inverse elasticity and EPMC) are canvassed in Dr. Shaffer's evidence submitted in the 2007 RDA. Refer to Exhibit C6-5 in the Commission 2007 RDA proceeding (available at http://www.bcuc.com/Documents/Proceedings/2007/DOC_15489_C6-5_BCOAPO_Evidence.pdf), pages 4 to 6.

where the customer classes with the highest price elasticity are set closest to marginal COS result, and those with lower price elasticity are set farther from marginal COS results; (ii) quantitatively-derived inverse elasticity method (given the difficulty in measuring customer class price elasticity levels accurately, this method has been used less frequently than the other two); and (iii) equal proportion method (sometimes referred to as the 'equal percentage marginal cost' or **EPMC**) where each customer classes' marginal COS results are adjusted by the same percentage to achieve the overall embedded COS revenue requirement. In all cases, rates paid by customers are only reflective of marginal costs by coincidence or through rate design.

After discussion with its COS consultants, BC Hydro does not believe it can provide item (2) requested by Dr. Shaffer. It would be an extensive and time-consuming analytical exercise for BC Hydro to complete a full marginal COS analysis. BC Hydro is not aware of any 'short cuts' that would provide BC Hydro with meaningful marginal COS estimates other than to complete a full marginal COS analysis.

BC Hydro notes that there was 2007 RDA testimony that under the EPMC methodology, the Transmission service customer class would see a large increase in rates because they have high load factors and are using proportionately more energy, and that at the time, the marginal cost of energy was considerably higher than the embedded cost (2007 RDA Decision, page 61). There was no testimony on the subject of transmission, distribution or customer marginal costs.

2 Functionalization: Demand Side Management (DSM)

Step 1 in the embedded COS approach is functionalizing the RR into either Generation, Transmission, Distribution or Customer Care.

2.1 Issue

At Workshop No. 2 BC Hydro identified DSM as the one functionalization issue, and proposed modifying Commission 2007 RDA Direction 6 from functionalizing DSM-related costs as 90 per cent Generation and 10 per cent Transmission to functionalizing DSM-related costs as 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution (option 1). Many jurisdictions surveyed functionalize DSM as 100 per cent Generation. While BC Hydro DSM initiatives are primarily energy-focused and are primarily undertaken to defer Generation resources, BC Hydro DSM initiatives have some Transmission and Distribution deferral benefits.

2.2 Participant Comments

Most stakeholders commenting on this topic agreed that the proposed functionalization of DSM costs was reasonable as a default position, but requested more information on how DSM impacts Generation, Transmission and Distribution, and on DSM costs broken down by customer class.

Commission staff, AMPC and BC Sustainable Energy Association & Sierra Club of British Columbia (**BCSEA**) suggested that BC Hydro explore directly allocating DSM costs to customer classes that receive DSM incentives or direct financial benefits from DSM measures (option 2). Under this approach, costs incurred to deliver a particular DSM measure would be directly allocated to the class targeted by the measure. For example, the cost of a DSM program such as the Residential Fridge Buyback Program would be directly allocated to the Residential customer class. In contrast, Progress Energy Canada Ltd. (**PECL**) noted that DSM initiatives are undertaken to reduce overall energy consumption.

2.3 BC Hydro Consideration

BC Hydro agrees with PECL's comment, and is concerned that option 2 fails to recognize that all customer classes benefit from DSM energy and related capacity savings.

BC Hydro examined option 2 further. BC Hydro updated its jurisdictional assessment, and understands that Manitoba Hydro directly assigns DSM costs[13]. BC Hydro also examined the costs and benefits of different DSM initiatives (conservation rate structures, codes and standards, and DSM programs) over the F2008 to F2016 period.[14] As illustrated by Table 1, under option 2 there would be a mismatch between the benefits and costs of different DSM initiatives. Table 1 shows the present value (**PV**) of costs and benefits for each of the DSM initiative categories in $F2013 dollars by customer class.

[13] BC Hydro understands that Manitoba recovers approximately $30 million in DSM costs each year as compared to approximately $100 million recovered by BC Hydro.

[14] A multi-year period was selected to smooth out the year over year fluctuations in DSM expenditures and variability in BC Hydro's reference prices.

Table 1 PV of Costs and Benefits for each of the DSM Initiative Categories in F2013 Dollars by Customer Class

F08-F16	Utility PV (F2013 $million)		
	Benefits ($ million)	Costs ($ million)	NPV ($ milliion)
Codes and Standards			
Residential	1,691	5	1,686
Commercial	517	2	516
Industrial	61	0.2	61
Rate Structures			
Residential	920	44	877
Commercial & Industrial Distribution	1,170	68	1,101
Industrial Transmission	232	3	228
Programs			
Residential Sector	565	228	337
Commercial & Industrial Distribution	831	436	395
Industrial Transmission	1,157	291	976
Total DSM	7,367	1,199	6,168
Residential	3,177 (43%)	279 (23%)	
Commercial & Industrial Distribution	2,740 (37%)	626 (52%)	
Industrial Transmission	1,450 (20%)	295 (25%)	

There are numerous examples of a mismatch between benefits and costs such as:

- The PV cost of Residential codes and standard initiatives is about $5 million but the benefits that accrue to all ratepayers exceed $1.6 billion
- Residential program expenditures are around $228 million, while the benefits that accrue to all ratepayers exceed $565 million
- Transmission voltage customer program expenditures are around $300 million, while the benefits that accrue to all ratepayers exceed $1.1 billion

- The Thermo-Mechanical Pulp Program announced in July 2014 has a cost of $100 million and corresponding PV benefits of $265 million over a 15-year period. Given its recent launch, this program has not been included in the Table 1 values shown above.

For the above reasons, BC Hydro's preferred approach is option 1 - functionalize DSM as 90 per cent Generation, 5 per cent, Transmission, and 5 per cent Distribution. Allocation of the final 10 per cent between Transmission and Distribution will not materially impact the R/C ratios set out in the Workshop No. 2 Discussion Paper. As part of the October 7, 2014 workshop BC Hydro will test this preferred option against the direct assignment alternative (option 2) discussed above.

2.4 Assumptions used in the above analysis

- Commercial General Service costs have not been split into the SGS, MGS, LGS, Irrigation, or street lighting rate classes. This would require extensive investigation and analysis of past DSM incentives and numerous assumptions would be required to conduct such an analysis.
- Portfolio level DSM costs were allocated to programs and rates, but not to codes and standards, based on the allocation method directed by the Commission (F05/06 RRA, Directive 61, attached) – allocation of costs according to the proportion of savings for a given initiative on March 31, 2018
- Benefits were derived by valuing the energy and capacity savings from DSM initiatives at BC Hydro's long-run marginal cost (LRMC) at the time of investment. Energy values ranged from $92/MWh to $132/MWh between F2008 and F2012, and BC Hydro's LRMC as presented in the 2013 Integrated Resource Plan (**IRP**) for timeframes after F2012. Generation capacity values ranged from $34/kW-year to $56/kW-year (nominal) from F2008-F2012; followed by BC Hydro's avoided generation capacity values as per the

2013 IRP after F2012. T&D capacity benefits were valued at approximately $12/kW-year (F2011$).

3 Classification: BC Hydro Hydroelectric Generation

Step 2 of the embedded COS approach is classification: what causes the cost to be incurred? In embedded COS analyses, utilities divide costs, according to causality, into three components: (1) energy (variable costs that vary with the kWh); (2) demand (fixed costs that vary with kW demand); and (3) customer (costs directly related to the number of customers).

3.1 Issue

A number of classification issues were discussed, with the first being Generation and the energy/demand split. BC Hydro proposed revisiting the reasoning behind 2007 RDA Direction 5, which found Generation should be classified as 45 per cent energy/55 per cent demand on the basis that at the time, contemplated Resource Smart Generation additions such as Revelstoke Unit 5 were largely capacity resources. BC Hydro identified three options:

- Option 1: load factor, resulting in an energy classification estimated at 60 per cent and demand classification estimated at 40 per cent
- Option 2: capacity factor, resulting in an energy classification estimated at 50 per cent and demand classification estimated at 50 per cent
- Option 3: capacity factor weighted by book value of major hydroelectric plants, resulting in an energy classification estimated at 45 per cent and demand classification estimated at 55 per cent

BC Hydro noted that option 1 has jurisdictional support.

3.2 Participant Comments

Many participants favoured option 1. British Columbia Old Age Pensioners Organization (**BCOAPO**), PECL and BCSEA commented on the instability associated with options 2 and 3. AMPC favoured option 3 as a default but asked why BC Hydro would not perform a plant-specific capacity factor analysis. Commission staff similarly asked if BC Hydro could evaluate use of the five largest hydroelectric facilities. Commission staff also advanced that BC Hydro should for COS purposes generally and Generation classification in particular reference the Manitoba Hydro and Hydro Quebec approach as these two utilities have similar characteristics to BC Hydro. Consumers Association of British Columbia (**CEC**) took the position that all three options should be further analyzed.

3.3 BC Hydro Consideration

As part of the October 7, 2014 COS workshop, BC Hydro will: (1) provide a list of its hydroelectric generation facilities, with the firm energy and dependable capacity contributions; (2) carry forward options 1 and 3 for analysis, including R/C ratio impact. Option 3 is a variation on option 2 supplemented by weighting the capacity factors for major hydroelectric plants by the book value of the facilities. 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; and (3) indicate BC Hydro’s preferred option.

4 Classification: BC Hydro Thermal Generation

4.1 Issue

BC Hydro has three thermal generating stations in its Generation fleet. BC Hydro proposed that Burrard generating station continue to be classified as demand-related, while Fort Nelson generating station and Prince Rupert generating station should be classified as both energy and demand-related. Fort Nelson generating station is largely used to serve base load while Prince Rupert generating station is often operated during times of transmission outages, which can occur outside of the winter season. BC Hydro proposes to explore directly classifying the operating and maintenance (**O&M**) expenses from BC Hydro owned thermal facilities.

4.2 Participant Comments

Most participants agreed with BC Hydro's proposed approach. BCOAPO requested additional information on how the energy/demand split for Fort Nelson generating station and Prince Rupert generating station would be determined, and stated that it disagreed with classifying all thermal Generation O&M costs as demand-related. Commission staff requested additional information on how Burrard generating station is actually used, and what its role will be given the limitations imposed over 'the term of the 2015 RDA'.

COPE 378 disagreed with BC Hydro's proposal. COPE 378 noted that historically Burrard generating station was used to firm up energy, and stated that there should be discussion of how costs associated with B.C. Government imposed limitations on Burrard generating station should be allocated.

4.3 BC Hydro Consideration

In response to Commission staff, BC Hydro provides the following additional information on its expectations for the role of Burrard generating station during the 'term of the 2015 RDA', which for COS purposes is F2016:

- BC Hydro expects that Burrard generating station will be used to provide voltage support for the transmission system (which itself is classified as 100% demand), per section 13 of *Clean Energy Act* and the B.C. Government's

November 26, 2013 announcement that Burrard generating station generating capability will be retired.[15]

- BC Hydro is not counting on Burrard generating station for capacity in F2016. In that year, capacity from the plant is removed from the IRP's Load Resource Balance.
- Burrard generating station is not currently relied on, and will not be relied on, for firm energy, and therefore characterizing some part of Burrard generating station cost as energy-related is not appropriate.

For the above reasons, BC Hydro believes Burrard generation station should be classified as 100 per cent demand. As part of the October 7, 2014 COS workshop, BC Hydro will provide additional information on the energy/demand split for Fort Nelson generating station and Prince Rupert generating station and on thermal Generation O&M cost treatment.

5 Classification: IPP Contracts

5.1 Issue

In response to 2007 RDA Direction 8, BC Hydro set out five options for classifying IPP contracts:

- Option 1: Value of energy and capacity
- Option 2: Value of capacity
- Option 3: Contract structure
- Option 4: Resource contribution
- Option 5: Load factor

[15] http://www.newsroom.gov.bc.ca/downloads/Presentation.pdf; refer to slide 21.

BC Hydro indicated it preferred either option 1 or option 2. Options 3 to 5 do not yield reasonable results. In particular, they tend to over-estimate the demand contribution of IPP resources.

5.2 Participant Comments

Participants agreed with modifying the current COS approach of classifying IPP contracts as 100 per cent energy. Most participants favoured either option 1 or option 2. PECL stated that while none of the options is completely satisfactory, option 2 is marginally superior due to the direct link between capacity benefits and demand costs. CEC favour option 1 but was uncertain about the merits of option 1 as compared to option 2.

Commission staff urged BC Hydro during Workshop No. 2 to reduce the number of options going forward for analysis, and questioned option 5 in particular. AMPC questioned why IPP costs should not be classified in the same way as BC Hydro Generation, given that IPPs are considered to displace BC Hydro Generation. During Workshop No. 2 COPE 378 and Catalyst Paper observed that IPP contractual arrangements are relevant (option 3), and that BC Hydro should check how many contracts have fixed payments which do not vary with energy production. BC Hydro agreed to investigate this issue and report back to stakeholders.

5.3 BC Hydro Consideration

BC Hydro agrees with Commission staff that the number of options carried forward should be reduced. For purposes of the October 7, 2014 workshop, BC Hydro will carry forward: (1) option 2 (there is not much difference between option 1 and option 2, but option 2 yields more reasonable results). Refer to the Workshop No. 2 discussion guide, Table 4. Option 1 results in a demand portion for dependable resources such as the biomass and natural gas-fired Island Generation contracts that is only slightly higher than intermittent run-of-river and wind resource contracts; (2) option 5 as a response to AMPC's comment that there should be a link between

Generation and IPP contract classification, which could occur through the load factor approach.

BC Hydro conducted further investigation of its IPP contracts. The results are set out in Attachment 4 to this memo. BC Hydro concludes that option 3 and in particular classifying IPP contracts on the basis of the fixed and variable components of the contracts will produce counter intuitive results.

6 Classification: Powerex Corp. (Powerex) Net Income

6.1 Issue

BC Hydro proposed continuing with 2007 RDA Direction 7 - classification of Powerex net income should follow overall Generation classification.

6.2 Participant Comments

Virtually all participants who commented on this topic agreed with the proposed approach. However, COPE 378 commented that the proposed approach is arbitrary, and suggested that Powerex net income-related revenue could be used to reduce RR 'equi-proportionately' across all customer classes.

6.3 BC Hydro Consideration

BC Hydro continues to believe that Powerex Net Income should be functionalized to Generation and classified the same as all Generation costs.

It is not clear how COPE 378 proposes to apply Powerex Net Income 'equi-proportionately' across all customers. Allocating net income using each customer class' share of energy sales would be akin to classifying Powerex Net Income as 100 per cent energy related, which fails to recognize the fact that the heritage hydroelectric assets have both energy and demand components that contribute to the Powerex Net Income. Similarly, using each customer class' share of revenue to allocate Powerex net income may be distortionary because much of that revenue pays for BC Hydro's transmission and distribution costs, which are not correlated to Powerex Net Income.

7 Classification: Transmission

7.1 Issue

BC Hydro proposed continuing with the Commission's 2007 RDA decision that Transmission should be classified as 100 per cent demand-related because serving peak loads remains the primary planning consideration for capital expenditures on the transmission system. BC Hydro noted that the length of Transmission radials, driven by the location of generation, is of secondary importance. BC Hydro asked whether the RR adjustment for Generation-related Transmission assets (**GRTA**), where $43.3 million in Generation-related costs is subtracted from the Transmission RR, should be revisited.

7.2 Participant Comments

Virtually all participants who commented on this topic agreed with the proposed approach. Several participants asked that $43.3 million for GRTA costs be revisited as part of the 2015 RDA.

AMPC stated that Transmission should continue to be classified as 100 per cent demand, but that a portion of the Transmission system should be considered as used for serving IPPs, forming the basis of new system access rate charged to IPPs. CEC suggested that other options should be examined as Transmission supports both energy and demand delivery. COPE 378 suggested that if some Transmission-related expenditures are made to reduce losses, they would be energy-related and therefore some classification of less than 100 per cent demand may be appropriate.

7.3 BC Hydro Consideration

BC Hydro will classify Transmission as 100 per cent demand-related for its embedded COS. In BC Hydro's view, the amount of energy carried through Transmission lines is not a cost factor. The vast majority of utilities with similar characteristics to BC Hydro, including Manitoba Hydro, classify Transmission as 100 per cent demand-related. BC Hydro will also examine the GRTA cost outcome of $43.3 million as part of the 2015 RDA.

AMPC first raised its IPP-related comment at Workshop No. 1. BC Hydro addressed this issue in its Workshop No. 1 consideration memo. In summary, BC Hydro does not believe an IPP class is appropriate for the COS for the following two main reasons. First, IPPs are Open Access Transmission Tariff (**OATT**) customers, and charging them network upgrade costs would require amending the OATT. Second, BC Hydro considers the cost of network upgrades as a bid evaluation adjustment when evaluating which IPPs are lowest cost. It is not feasible to amend 21 active F2006 Call electricity contracts and 24 active 2009 Clean Power Call contracts to attempt to pass on network upgrade costs. Refer to the consideration memo concerning Workshop No. 1 at BC Hydro's 2015 RDA website for greater detail.

8 Classification: Distribution

8.1 Issue

2007 RDA Direction 4 mandated a 65 per cent demand/35 per cent customer Distribution classification, and directed BC Hydro to conduct Minimum System and Zero Intercept analysis. Prior to Workshop No. 2, BC Hydro circulated a 2010 study entitled "Electric Distribution System, Cost of Service Study" to Commission staff and customer stakeholders for comment. In BC Hydro's view, the 2010 study addresses that portion of Direction 4 requiring Minimum System and Zero Intercept analysis.

Based on the COS consultants advice, BC Hydro does not believe that either the Minimum System or Zero Intercept approach should be used. BC Hydro proposed instead to explore two options: 1) classify Distribution costs (e.g., substations, primary, secondary, transformers, meters) as either entirely demand or customer-related in the 2015 RDA or 2) direct assign Distribution assets (e.g., primary system and transformers) to customer classes.

8.2 Participant Comments

Virtually all participants agreed with BC Hydro's suggestion not to do further Minimum System/Zero Intercept analysis for the Distribution system and to instead explore direct assignment approaches for the Distribution primary system in particular. BCSEA and AMPC noted that Minimum System/Zero Intercept analysis is complicated and is not determinative in practice.

BCOAPO stated that while it is reasonable to classify substations as 100 per cent demand-related and meters and services as 100 per cent customer-related, for "other parts of the distribution network (i.e., primary lines, transformers, and the remaining secondary lines) there is both a customer and demand component and any decision to treat them as 100 per cent one and 0 per cent the other will be totally arbitrary". Commission staff noted that substations and primary distribution make up about two thirds of Distribution costs, and asked whether BC Hydro is considering whether direct assignment of these component costs is reasonable. COPE 378 commented that it was difficult for it to comment at this time because the results of BC Hydro's proposed approach are unclear.

8.3 BC Hydro Consideration

To alleviate BCOAPO's concern, BC Hydro believes a direct assignment approach is appropriate where possible. Since Workshop No. 2, BC Hydro has compiled a variety of data on the Distribution system including: (1) asset related information; (2)

load information; and (3) cost information. BC Hydro will present this data and the results of its suggested approach at the October 7, 2014 workshop.

9 Classification: Smart Meter Infrastructure (SMI)

9.1 Issue

The historical treatment of metering costs has been to functionalize them as Distribution-related, with costs classified as 65 per cent demand-related (allocated by each customer class's non-coincident peak demand) and 35 per cent customer-related (allocated by each customer class's number of customers on the system).

For discussion purposes, BC Hydro set out two bookends for SMI classification:

1. 100 per cent customer-related. Rationales include that the meters are already being capitalized and the regulatory account largely includes costs associated with operationalizing the meters (option 1)
2. 100 per cent energy-related. Rationales include recognition of the purpose for undertaking SMI, which includes reduction in energy losses (option 2)

BC Hydro committed to undertaking jurisdictional research on the classification and allocation of SMI-related costs, and to share the results at the October 7, 2014 workshop.

9.2 Participant Comments

Stakeholder feedback indicates diverse opinions on the treatment of SMI costs. AMPC stated that option 1 is the only approach consistent with standard utility practice, as metering costs are a function of the number of customers and unrelated to energy or demand. PECL commented that there should be no SMI cost allocated to industrial customers since industrial customers do not materially benefit from SMI. CEC suggested that while SMI appeared to be more consistent with option 1 (cost related to a customer), energy classification should still be examined. COPE 378 took the position that SMI costs should be allocated based on system benefit and is therefore both customer- and energy-related. BCOAPO similarly stated that SMI costs are likely some combination of customer- and energy-related. In terms of allocation, BCOAPO recommended directly assigning costs to customer classes based on the quantity and cost of the meters. Commission staff commented that option 2 seemed extreme, and asked whether some amount of the classification as energy-related could be justified. BCSEA has not yet taken a position on this issue.

9.3 BC Hydro Consideration

BC Hydro agrees with AMPC's and Commission staff's comments that option 2 is extreme, and this option will not be carried forward for further analysis.

Option 1 will be carried forward for further analysis as metering is usually classified as a customer cost because metering is directly related to the number of customers. In addition, option 1 has jurisdictional support, including the Ontario Energy Board, Georgia Power Company and Florida Light & Power Company.

Based on stakeholder feedback that BC Hydro should further consider an option in which some portion of SMI-related costs are classified as energy and for purposes of illustrating impacts, BC Hydro will develop an alternative option for the October 7, 2014 workshop.

Regarding allocation, meter costs do vary in relationship to the size of the meter. However, the costs associated with SMI also include many system-wide costs that can be better correlated with total number of customers.

10 Classification/Allocation: Customer Care

10.1 Issue

BC Hydro proposed that Customer Care costs be classified 100 per cent as customer-related rather than the current 65 per cent demand/35 per cent customer classification mandated by Commission 2007 RDA Direction 4.

BC Hydro indicated that it intended to continue allocating Customer Care-related costs on a weighted basis with 90 per cent of the weight based on the number of bills issued to customers and 10 per cent based on revenue.

10.2 Participant Comments

With the exception of COPE 378, all participants agreed with BC Hydro's classification proposal. COPE 378 opposes BC Hydro's approach, stating that it did not agree that all Customer Care costs do not vary with demand or amount of use.

Some participants such as BCOAPO requested further information concerning Customer Care cost allocation and in particular whether a weighted customer and/or direct assignment approach was being contemplated. CEC commented that the 10 per cent revenue justification is not clear.

10.3 BC Hydro Consideration

BC Hydro will classify Customer Care costs as 100 per cent as customer-related. A 100 per cent customer classification is consistent with how other utilities treat Customer Care costs. BC Hydro agrees with AMPC's comment that Customer Care costs do not vary with demand.

At the October 7, 2014 workshop, BC Hydro will provide additional detail on Customer Care cost allocation for consideration.

11 Allocation: BC Hydroelectric Generation Demand and Transmission

Step 3 of the embedded COS approach is allocation: how much of the total costs should each customer class pay? The allocation of energy costs is straightforward: energy costs are allocated on energy consumption. There may be competing methods proposed for allocation of demand costs.

11.1 Issue

BC Hydro proposed continuing with 2007 RDA Direction 3, which mandates a 4 Coincident Peak (**CP**) allocation of Generation demand-related and Transmission costs on the basis 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 annual peak. The Commission noted that further investigation may be worthwhile. In response, BC Hydro examined 12CP, 3CP and 2CP, and canvassed the Average & Excess (**A&E**) allocation method.

BC Hydro committed, as part of the October 7, 2014 workshop, to set out its views on the treatment of radial lines and whether radial lines should be treated differently from other Transmission assets for COS purposes.

11.2 Participant Comments

Most participants commented that based on the data BC Hydro has provided to date, the use of 4CP as an allocator appears appropriate. No stakeholder supported the A&E allocation method, with AMPC and PECL noting that A&E allocation methodology is rarely used and appears to be unduly complex. AMPC, COPE 378 and CEC suggested a probability weighting for 4CP (4CP does not have to be evenly distributed over the four winter months but could be based on the three or four highest demands within the most likely two months of December and January). BCOAPO supported use of 4CP, with two comments: BCOAPO sought clarification that demand-related BC Hydro thermal generation and IPP costs would also be allocated using 4CP; and suggested that subjecting BC Hydro data to the three tests employed by the Federal Energy Regulatory Commission (**FERC**) could be useful as a check on the use of 4CP.

11.3 BC Hydro Consideration

BC Hydro will not investigate the A&E allocation methodology any further. BC Hydro will advance 4CP as its preferred option, with two 4CP probability weightings, and 3CP as additional options carried forward for analysis at the October 7, 2014 workshop. BC Hydro confirms that 4CP would be the allocator for Generation-related demand, including BC Hydro thermal assets, IPP-related demand and Transmission.

In response to BCOAPO, BC Hydro evaluated its data of 31 years of monthly peaks using the three FERC tests, which are described in Table 2.

Table 2 FERC Test Descriptions

Test	Methodology	Interpretation
1. On and Off Peak Test (**FERC 1**)	Average of monthly peaks during On-Peak period/Annual peak vs. Average of monthly peaks during off-peak period/Annual peak	A difference of 19 percentage point or less is characteristic of a 12CP system.
2. Low to Annual Peak Test (**FERC 2**)	Lowest monthly peak/Annual peak	66% or higher is characteristic of a 12CP system.
3. Average to Annual Peak Test (**FERC 3**)	Average of 12 monthly peaks/Annual peak	81% or higher is characteristic of a 12CP system.

The results are set out in Table 3.

Table 3 Results of Applying FERC Tests

31 Years	FERC 1 (%)	FERC 2 (%)	FERC 3 (%)
4CP	48	13	35
12CP	52	87	65

BC Hydro arrives at no obvious conclusion using the FERC tests. BC Hydro notes the Commission's observation in the 2007 RDA Decision, pages 81 to 82 that the

FERC tests are at most a guide, and that an examination of the circumstances of the particular utility is preferred.

12 COS Miscellaneous Issue: Dual Fuel Interruptible Service (E-Plus)

12.1 Issue

At Workshop No. 2, BC Hydro stated that it considered the language in 2007 RDA Direction 14 as ambiguous, and thus set out two options:

- Option 1: remove E-Plus customers from the 4CP calculation on the assumption they would have been interrupted during peak times in the winter; or
- Option 2: continue to include E-Plus customers in the 4CP calculation

BC Hydro favours option 2 because E-Plus loads are included in BC Hydro's electric load forecast and planning assumptions, and there is no operational ability to interrupt E-Plus customers.

12.2 Participant Comments

All participants commenting on this topic agreed with option 2.

12.3 BC Hydro Consideration

E-Plus option 1, which would result in E-Plus customers not being assigned very much Generation or Transmission demand costs because they would be considered interruptible, is not reasonable because BC Hydro does not have the ability to interrupt E-Plus customers during the four winter months. BC Hydro will proceed with option 2 for COS purposes.

13 COS Range of Reasonableness

13.1 Issue

At Workshop No. 1, BC Hydro proposed to use a 95 per cent to 105 per cent R/C ratio range of reasonableness on the basis that the Commission directed this as part of the 2007 RDA, and many utilities use a 95 per cent to 105 per cent range of reasonableness. BC Hydro introduced additional jurisdictional evidence concerning R/C ratios and ranges of reasonableness as part of Workshop No. 2, and consequently sought further feedback on the proposed 95 per cent to 105 per cent range of reasonableness.

13.2 Participant Comments

Most participants providing written comments repeated their positions communicated to BC Hydro as part of the Workshop No. 1 process. AMPC continued to indicate that competitive considerations make it essential that the R/C ratio for industrial customers remains within a tight tolerance of 1 per cent, or as close to 100 per cent (unity) as the forecast rate design will allow. AMPC requested that BC Hydro update the jurisdictional assessment conducted by the COS consultants to reflect final approved R/C ratios. PECL made similar comments, stating that it preferred either unity or a narrower range of +/- 2.5 per cent.

BCOAPO stated that due to the number of COS-related assumptions, either a 95 per cent to 105 per cent, or a 90 per cent to 110 per cent, R/C ratio range of reasonableness would be appropriate. CEC disagreed with BC Hydro's proposed 95 per cent to 105 per cent R/C ratio range of reasonableness, and appeared to advocate for unity as the overall goal.

13.3 BC Hydro Consideration

In response to AMPC's request, BC Hydro's COS consultants provided BC Hydro with a memo containing updated, approved R/C ratios. Refer to Attachment 4.

BC Hydro plans to propose a 95 per cent to 105 per cent R/C ratio range of reasonableness as part of its 2015 RDA. BC Hydro expects SMI-related information will further improve confidence in COS results relative to BC Hydro's 2007 RDA proposed R/C ratio range of reasonableness of 90 per cent to 110 per cent. The proposed 95 per cent to 105 per cent R/C ratio range of reasonableness is subject to a request that AMPC provide BC Hydro with jurisdictional evidence of tighter ranges for industrial customers. The R/C ratio for Manitoba's transmission voltage customers (greater than 100 kilovolts (**kV**)) is 100 per cent. Hydro Quebec's transmission service customers have a R/C ratio of 116 per cent, but rate rebalancing is prohibited by statute.

Table 4 Manitoba Hydro and Hydro Quebec R/C Ratios

Manitoba Hydro (%)		Hydro Quebec (%)	
Residential	99	Residential	84
General Service (**GS**) Non-Demand	108	GS Includes: GS small (non-demand) < 65 kW GS medium (demand-metered) > 50 kW GS large (demand-metered) > 5,000 kW	125
GS Demand	104		
GS Medium	100		
GS 0-30 kV	93		
GS 30-100 kV	97		
GS > 100 kV (Large industrial customers)	100	Large Industrial customers	116

- Manitoba Hydro's R/C ratios come from its 2013 COS. The Manitoba Public Utilities Board delayed regulatory review of Manitoba Hydro's COS study, with no date set for review.
- The Hydro Quebec R/C ratios are from its 2014 COS. Hydro Quebec has fewer rate classes than Manitoba Hydro or BC Hydro. Rate rebalancing has been suspended since 1997 through provincial legislation. Section 52.1 of the Act respecting Hydro Quebec's regulator, the Régie, states that "the Régie shall not modify the rates applicable to a class of consumers in order to alleviate the cross-subsidization of rates applicable to classes of consumers".

In BC Hydro's view, unity is not appropriate because as noted by BCOAPO, there are a number of assumptions underpinning COS (there is data uncertainty); the jurisdictional analysis conducted by BC Hydro to date and shared with participants indicates that ranges of reasonableness are more prevalent as compared to utilities that adopt unity as a goal; and the fact that even those jurisdictions that adopt unity as an aspirational goal have wide customer class R/C ratios (indicating it is not a realistic goal). BC Hydro also notes that unity is a moving target, which the range of reasonableness is intended to represent. This is because the actual COS assumptions can change year over year. For example, in the 2007 RDA BC Hydro proposed the use of 12CP to allocate demand charges associated with Generation and Transmission. This would have the effect of shifting costs away from the Residential class, thus reducing that class's total cost burden, and increasing its R/C ratio without requiring more revenue from the class. Since BC Hydro was directed by the Commission in the 2007 RDA to use a 4CP allocator, the Residential R/C ratio is lower than it might have been.

2015 Rate Design Application

June 19, 2014 Workshop No. 2
Cost of Service (COS) Methodology

BC Hydro Summary and Consideration of Participant Feedback

Attachment 1

Workshop No. 2 Notes

BC Hydro Rate Design Workshop – Cost of Service Methodology Assessment

SUMMARY 19 JUNE 2014 9 AM TO 12.45 P.M. BCUC Utilities Commission 1125 Howe Street, Vancouver, 12th Floor

TYPE OF MEETING	2015 RDA Workshop No. 2, 19 June 2014
FACILITATOR	Anne Wilson, BC Hydro
PARTICIPANTS	ARC Resources Ltd., Association of Major Power Consumers of British Columbia (AMPC), B.C. Ministry of Energy and Mines, British Columbia Pensioners' and Seniors' Organization (BCPSO), BC Sustainable Energy Association and Sierra Club of Canada, BC Chapter (BCSEA), British Columbia Utilities Commission (BCUC) staff, Canadian Association of Petroleum Producers, Canadian Manufacturers & Exporters Canada, Canadian Natural Resources Ltd., Canadian Office and Professional Employees Local Union 378 (COPE 378), Catalyst Paper, Commercial Energy Consumers Association of British Columbia (CEC), City of New Westminster, CLEAResult Consulting, Encana Corporation, FortisBC Inc., Linda Dong Associates, Manitoba Hydro, Shell Canada, Midgard Consulting Inc., Sun Peaks Resorts, Teck Resources Limited, Weisberg Law Corporation, West Fraser Mills
BC HYDRO ATTENDEES AND CONSULTANTS	Gordon Doyle, Justin Miedema, Dani Ryan, Craig Godsoe, Fred James, Bryan Hobkirk Richard Cuthbert of Cuthbert Consulting, Inc.
AGENDA	1. Introduction 2. Presentation: Background and Stakeholder Cost of Service (COS)-related comments from RDA Workshop No. 1 3. Presentation: Consultant report jurisdictional review 4. Presentation: Consultant report COS methodology recommendations and BCH responses 5. Closing comments & workshop adjourned

MEETING MINUTES

ABBREVIATIONS	AMPC……Association of Major Power Consumers of British Columbia BCH …… BC Hydro BCPSO….British Columbia Pensioner's and Seniors' Organization BCSEA…..BC Sustainable Energy Association and Sierra Club of Canada, BC Chapter COPE 378… Canadian Office and Professional Employees Local Union 378 BCUC……British Columbia Utilities Commission	CEABC……Clean Energy BC CEC……… Commercial Energy Consumers Association of British Columbia COS ……..Cost of Service CP…………Coincident Peak DSM …… Demand Side Management IPP …….. Independent Power Producer MW……….Megawatt PACA…….Participant Assistance/Cost Awards RR…………Revenue Requirement Revenue-to-Cost ratio … R/C ratio RDA……..Rate Design Application SMI………Smart Meter Infrastructure

1. *Introductions*

Gordon Doyle opened the meeting by re-capping the status of BCH's request to the BCUC concerning the applicability of Participant Assistance/Cost Awards (PACA) to pre-application workshops. BCH will be providing funding, and will be guided by the BCUC's PACA guidelines and materials submitted by BCPSO as part of its Workshop No. 1 written feed-back. A letter should issue shortly.

Anne Wilson emphasized there are two ways for stakeholders to provide feed-back: (1) comments and questions at the workshop itself; and (2) written comments through the feed-back form or otherwise after Workshop No. 2, within a 45 day comment period starting with the positing of Workshop #2 notes [Note: posted Thursday, 10 July 2014]. It was noted that the discussion paper provided for this workshop, "Discussion Paper – Strawman Proposal concerning the December 2013 Cost of Service Methodology Review" provides more detail with respect to BC Hydro's response to the consultant

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recommendations, BC Hydro's proposed COS methodology approach and the input sought from customer stakeholders.

2. Presentation: COS Stakeholder Comments from Workshop #1 and Background

Justin Miedema outlined the COS-related participant comments received in respect of Workshop No. 1. The following questions and issues will be addressed as part of the Workshop No. 1 stakeholder engagement summary:

(1) Creation of an Independent Power Producer (IPP) class of customers for COS;
(2) Providing R/C ratios for Non-Integrated Area and Fort Nelson service area.

All Fully Allocated Cost of Service studies filed with the BCUC since the 2007 RDA have been posted on BCH's 2015 RDA website.

BCH will proceed with an embedded COS. The BCUC in the 2007 RDA decided BCH should continue with an embedded COS; no jurisdiction has adopted marginal COS since the BCUC's 2007 RDA; and all participants providing Workshop No. 1-related written feed-back agreed BC Hydro should proceed with an embedded COS.

Justin reviewed COS methodology, including the current functionalization of the Revenue Requirement (RR) and the BCUC 2007 RDA directives relevant to COS classification and allocation.

	FEEDBACK	RESPONSE
1.	**COPE 378** will be pursuing marginal COS as part of the 2015 RDA. A review of Manitoba Hydro's COS consultant [Note: refer to footnote 2 in BC Hydro's Strawman Proposal] leads to the conclusion that embedded COS requires a large number of assumptions; and COPE 378 maintain that marginal COS aligns with the Bonbright efficiency criterion.	Manitoba Hydro's consultant did not recommend that Manitoba Hydro adopt marginal COS, and Manitoba Hydro continues to use embedded COS. Manitoba Hydro builds for export, which are sold into the competitive market; Manitoba Hydro uses incremental cost and revenue for export sales and exports are considered a separate class in their COS study. Marginal COS also requires assumptions and is particularly difficult for allocating Distribution costs.
2.	**AMPC** stated that it is against a marginal COS. No Canadian jurisdiction uses marginal costs to allocate costs to customer classes. Marginal pricing could be helpful for extension test purposes.	
3.	**BCUC staff** commented that BCH should directly assign costs to customer classes whenever possible as this avoids some of the arbitrariness of COS functionalization and classification. **AMPC** supported this, and requested more information on regulatory account recoveries (why 100% Generation)?	BCH will be examining regulatory accounts as part of the draft COS as part of the proposed 7 October 2014 COS workshop.
4.	**AMPC** commented that Customer Care costs should be classified as 100% customer. The BCUC's 2007 RDA decision to classify Customer Care costs as 65% demand and 35% customer is incorrect.	BCH agrees with AMPC's observation, and will propose classifying Customer Care costs as 100% customer, which aligns with how other electric utilities classify Customer Care costs.
5.	**AMPC/Catalyst** asked how the 4 Coincident Peak (CP) is calculated – is it the highest demand in each of the four winter months? Smart meter infrastructure (SMI) may enable better load profile	Each customer class' share of peak demand in each of the four winter months (November, December, January, February) is calculated and then averaged.

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Workshop – Cost of Service Methodology Assessment

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	(15 minutes vs. 1 hour). **Catalyst** noted that transmission voltage demand charges are based on 30 minutes.	A 1 hour peak is used.
6.	**BCUC staff** asked whether load is based on actual sales, and is it weather adjusted (cold/warm days vs. average)?	The load forecast is based on actual sales. Both the energy and peak load forecasts are weather normalized. The energy load forecast is based on a 10-year rolling average; peak is based on more recent history.

3. Presentation: Consultant Jurisdictional Assessment

Richard Cuthbert reviewed the jurisdictional assessment, which examined 9 Canadian and U.S. utilities in 10 jurisdictions with similar characteristics (e.g., winter peaking, except Idaho Power which is dual peaking; and hydroelectric based). Only two smaller jurisdictions – Portland General Electric and Seattle City Light – use marginal COS.

	FEEDBACK	RESPONSE
1.	**AMPC** stated it understands why winter peaking/hydroelectric-based would be useful criteria for Generation and Transmission, but questioned if this was relevant for Distribution classification. **AMPC** recommended broadening the utilities surveyed for Distribution purposes, such as FortisAlberta. **CEABC** asked how many utilities surveyed have Generation assets located far from load, as this could impact Transmission. **CLEAResult** indicated that of the utilities surveyed by the consultant, Manitoba Hydro was most comparable; Bonneville Power Administration has only Generation and Transmission, and not Distribution; Portland General Electric has only Distribution; Puget Sound does not have many industrial customers; and Seattle City Light is urban with City council as regulator.	No utility has all of BCH's characteristics, but (i) many have some; and (ii) jurisdictional assessment is only one input into BC Hydro's proposed COS methodology. BCH augmented the list of utilities reviewed by the consultant; for example, BC Hydro looked at Alberta Electric System Operator (2007), and other utilities which completed fairly recent COS such as FortisBC, Nova Scotia Power and SaskPower. BC Hydro is open to examining other jurisdictions. Manitoba Hydro, Newfoundland Power and Hydro Quebec are examples of utilities surveyed that have Generation located far from load.
2.	**BCUC staff** stated that the take away is for BCH to indicate which jurisdictions it thinks are most comparable. BCUC staff indicated that Transmission classification is not a real issue, and that the focus should be on Generation and Distribution classification. Regarding Distribution, the issue is BC Hydro's proposed categorization approach vs. Zero Intercept/Minimum System.	BCH thinks Manitoba Hydro and Hydro Quebec Distribution are most relevant for Generation classification, and agrees with BCUC staff's observation on Transmission as utilities usually classify Transmission as demand. Jurisdictional assessment indicates that not many utilities currently use Zero Intercept/Minimum System.
3.	**CLEAResult** asked if other utilities distinguish between IPP resources by generation technology. **COPE 378** observed that IPP contractual arrangements are relevant, and BC Hydro should check how many contracts have fixed payments which do not vary with energy production. IPPs are an example of why BC Hydro should not rely on jurisdictional assessment alone.	Yes; an example is Nova Scotia Power regarding biomass and wind. Nova Scotia Power ran into the same problem with intermittent IPP wind resources such as BC Hydro has - adopting Generation classification approaches such as capacity factor result in a large IPP demand classification when such resources provide little dependable capacity. BCH agrees with COPE 378's observation, and will describe its approach to IPP classification later in the presentation.

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4.	**AMPC** suggested that the table on slide 31 showing target and actual R/C ratios should be expanded to show approved R/C ratios by major customer class. AMPC stated it was rare for industrials to depart much from 100% (unity). **CEC** asked if the goal for R/C ratios was purely cost causation, and stated that while unity may be a good goal, other considerations must be brought to bear on how quickly a customer class gets to unity. **COPE 378** commented that R/C ratios are policy/political, while the rest of COS is methodological.	BCH agrees with AMPC's suggestion for slide 31 and will provide this information as part of the 7 October 2014 COS workshop. Industrials can be both above and below 100%. [Note: Manitoba Hydro's transmission voltage (greater than 107 kV) R/C ratio is 103.7%[1]; Hydro Quebec's response to Nova Scotia's 2003 survey showed that transmission voltage customers were at R/C ratio of 115%(note the Province of Quebec ruled out rebalancing)]. BC Hydro welcomes any AMPC evidence on the topic of industrial R/C ratios. A 95% to 105% range of reasonableness is the range most commonly adopted by other Canadian utilities – examples include ATCO Power, Manitoba Hydro, New Brunswick Power, Nova Scotia Power and SaskPower. A range of reasonableness of 95%-105% reflects that unity as a goal is not advisable due to the assumptions with inherent margins of error (e.g., judgment, load and forecasting) underpinning COS.

4. *Presentation: Consultant recommendations and BC Hydro responses*

Richard Cuthbert described each of the consultant's 18 recommendations, and **Justin Miedema and Dani Ryan** outlined BC Hydro's analysis and proposal with respect to each of the 18 recommendations.

	FEEDBACK	RESPONSE
1.	**BCUC staff** questioned whether Demand Side Management (DSM) costs could be directly assigned to customer classes. **BCSEA** asked if direct assignment would address equity concerns.	BCH will explore direct assignment of DSM costs for purposes of the 7 October COS workshop, but notes most utilities functionalize DSM as Generation as DSM is largely aimed at avoiding Generation costs. BCH does not believe that direct assignment in and of itself addresses equity issues. Equity arises at the time of DSM program design – BCH does not base DSM programs solely on least cost. The 2013 approved Integrated Resource Plan (tables 9-3 and 9-4) shows BCH plans to spend about the same on Industrial and Commercial customer DSM programs over the next 8 years, and less on Residential given that more Residential savings are expected through rate structures and codes and standards.
2.	**BCUC staff** asked if Burrard Generating Station (Burrard) was used for emergency backup and system support, why should it be classified 100% demand?	Burrard's use as an emergency resource would likely occur during winter peaks (e.g., Peace River icing).
3.	**BCUC staff** suggested that BCH should be more explicit on IPP classification options – are we down to Options 1, 2 and 5? **BCUC staff and Catalyst** expressed concern with Option 1, which does not seem sensible for thermal IPPs such as Island Generation (ICG) as it results in a low demand classification (3% to 7% - see slide 42). **BCUC**	BCH's lead option for IPP classification is Option 2. Option 2 provides higher demand classification for thermal IPPs which is more in line with planning reliance on these IPPs, and is thus more reasonable than Option 1. BCH agrees Options 3 and 4 should be rejected. While alignment with Generation classification is attractive

[1] Before methodology changes from their 2012 Cost of Service Review

	staff noted that the load factor approach's (Option 5) virtue seems to be simplicity if it is also chosen for Generation. Contract structure and resource contribution (Options 3 and 4) have many downsides. **CLEAResult** noted that the ICG contract is not just fixed cost; there are fuel costs. CLEAResult requested an IPP contract overview as part of COS.	from a simplicity point of view, one of the two leading options for Generation classification – capacity factor – will not work for intermittent IPPs; wind would be given a 70% demand, 30% energy classification when wind delivers little dependable capacity.
4.	**AMPC** asked how Generation Related Transmission Assets (GRTA) is defined – is it radial only, and if not, why is it different than radial? AMPC asked BCH to check if GRTA includes IPP costs.	The $43.3m GRTA adjustment that functionalizes a portion of transmission costs as generation includes transmission lines along with some substation assets. At this time, BC Hydro understands the transmission lines are generally radial and that no IPP related costs are included in the GRTA adjustment. A more detailed analysis will be completed prior to the 7 October 2014 workshop.
5.	**BCUC staff** asked if the Average and Excess (A&E) method could be applied to Distribution classification and allocation? **BCPSO** asked if Distribution feeders are used by more than one customer class, how would BCH split costs among classes?	A&E is not commonly used by electric utilities, and even then it is only used for Generation. It is not an alternative for Distribution. BCH would use customer classes' pro rata share of load, likely using peak hour. BCH has good load information by customer class. The issue is the assigning of value/cost.
6.	**AMPC** suggested that 1CP for Generation demand and Transmission allocation is too unstable. AMPC noted that 80% of demand occurs in two months – December and January. A 2CP approach is reasonable, as is a 4CP approach which is weighted toward two months - December and January. **COPE 378** offered that December and January could be broken into semi-months as opposed to using a 'two day cold snap' which would lead to distortions.	If November is excluded, the record peak set on 29 November 2006 (10,113 MW) is missed. BC Hydro noted that last year, the peak in February was higher than January. BCH agrees with AMPC on its 1CP observation – and BCH rules out 1CP and 12CP. 3CP is problematic – which of November or February are dropped? 4CP, 4CP with the suggested variation and 2CP seem to be the alternatives to move forward into the COS.
7.	**BCUC staff** observed that Distribution direct assign is preferable to using a Non Coincident Peak allocator. Distribution primary is where most of the $ are, and so BCH should focus on this area, and perhaps the remaining Distribution components are not as much of a worry.	BC Hydro agrees but notes that transformers account for 23% of distribution cost while the primary system accounts for about 65% of cost (see Table 2 from the Electric Distribution system Cost of Service Study prepared by Arnie Reimer Consulting Group). Focusing on the primary system and transformers will cover about 88% of distribution cost[2].
8.	**AMPC** commented that one of the two SMI functionalization book-ends, which is all energy, is not reasonable. SMI are meters and reduce meter costs. Energy savings (theft loss reduction) are a small part of SMI benefits, and in any even theft detection is a metering function. Theft should not be confused with losses; a utility plans on losses not on theft.	Theft detection is a way of reducing losses. BCH is leaning toward the other bookend, which is classifying SMI as a customer cost as it substantially relates to metering. The Ontario Energy Board's recommended treatment of SMI is consistent with classifying SMI as a meter with allocation to customer. BCH will undertake additional jurisdictional SMI COS analysis for the 7 October workshop.

[2] BC Hydro acknowledges these percentages have changed given the increased investment in metering related to SMI. However, a focus on the primary system and transformers will still capture a significant portion of overall distribution cost.

BC Hydro Rate Design Workshop – Cost of Service Methodology Assessment

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9.	**BCUC staff** questioned why E+ Option 1 (treat as true interruptible rate and remove from 4CP calculation) is under consideration. **BCPSO** understood that E+ could not really be interrupted.	E+ Option 1 results from 2007 RDA BCUC Direction 14. However, BCH does not agree with this direction and is in favour of E+ Option 2 (continue to include E+ in 4CP calculation). BCPSO is correct, and this supports Option 2.
5. Closing Comments		
Anne Wilson thanked everyone for making the time to participate in the workshop and reiterated that the 45 day written comment period which starts with the posting of Workshop #2 notes. Meeting adjourned at 12.45 pm.		

2015 Rate Design Application

June 19, 2014 Workshop No. 2
Cost of Service (COS) Methodology

BC Hydro Summary and Consideration of Participant Feedback

Attachment 2

Feedback Forms and Written Comments

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

18 RECOMMENDATIONS FROM THE COS METHODOLOGY REVIEW, BC HYDRO'S RESPONSES TO THE RECOMMENDATIONS AND PROPOSALS, AND COMMISSION STAFF'S COMMENTS

	RECOMMENDATIONS	BC HYDRO'S RESPONSES & PROPOSALS IN WORKSHOP	CURRENT COMMISSION DECISION DATED OCTOBER 26, 2007	STAFF COMMENTS
1	DSM costs functionalization: · Based on relative proportions of BC Hydro's generation plant in service to transmission plant in service	· Functionalize DSM as 90 % Generation, 5 % Transmission and 5 % Distribution · Functionalize a share of financing and ROE costs in the COS Study as DSM related	Directive 6: · 90% to generation and 10 % to transmission · Portion functionalized to generation be allocated to the customer classes in the same proportions that the total generation revenue requirement is allocated to the customer classes	· If it is reasonable to assume that DSM will provide more resources than the IPP EPA renewals, then would BC Hydro's proposed functionalization of DSM costs (which includes 5% to Distribution) create a disproportionate impact on the residential and commercial class rates? · Although there are issues with direct allocation to each rate class, does BC Hydro consider that it may be less arbitrary than the straw man proposal? · Has BC Hydro included Power Smart operating costs or other related OM&A costs in Generation and Transmission?
2.	Classification of hydro costs excluding water rental costs:	Three options are proposed: · Option 1 is a load	Directive 5: · For hydro plant a 55% demand and 45 %	· Would Classification based on a capacity factor approach be more theoretically valid? Also, want to see

	· Use either a System Load Factor method or a Plant Capacity Factor method	factor method where the energy portion of Generation cost would be equal to the system load factor while Generation demand portion would equal one minus the system load factor; this would result in 40% demand and 60% energy · Option 2 is a capacity factor approach (entire system or plant-by-plant) which will account for system reserve margins and total system operation · Option 3 is capacity factor approach supplemented by weighting the capacity factors for major hydroelectric plants by the book value of the facilities	energy split · This split is subject to a detailed analysis in its next FACOS or rate design filing	more detail on the calculations of the load and capacity factors (and the weighting factors for option 3). · The current range seems to vary between 40% and 60% on demand or energy split. To the extent that BCH can evaluate the individual use of the largest 5 or so hydro plants would it help narrow the range of classification between energy and demand? · A discussion on what Quebec and Manitoba do with their Hydro resources (and why) may be informative.
3.	Classification of peaking thermal plant costs excluding fuel costs · Demand related	BC Hydro looks at the three thermal plants individually: · Burrard GS – 100% demand related	Accepted the proposed 100% demand related classification.	· For Burrard, how is the plant actually used now, and what are the limitations on its role likely to be over the term of the RDA?

		· Fort Nelson GS – used to serve base load; classify as both energy and demand-related · Prince Rupert GS – often operated during times of transmission outages which can occur outside the winter season; classify as both energy and demand-related · Directly classifying the O&M		
4.	Classification of IPP and other purchased power obligations to reflect either fixed versus variable payment obligations or capacity versus energy usage	Two leading options plus 3 others: · Allocation to demand based on the relative portion of capacity benefits over the sum of firm energy and capacity benefits from the IPP portfolio. · Allocation to demand based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs. · Any fixed contractual payments that do not	Directive 8: · Accepted BC Hydro's allocation of 100% energy-related. BC Hydro was directed to examine and quantify the capacity benefits associated with IPP contracts.	· Is the load factor approach sufficiently informative to be included as an option?

		vary with energy production (currently no such contract in place) · Based on the percentage of the IPPs's installed capacity that contributes to the IRP Base Resource Plan (some biomass resources would be classified as 100% demand) · Load factor – similar to hydroelectric cost classification (this would be 40:60 and over-estimate the demand contribution of IPP)		
5.	Classification of the Powerex subsidiary net income should be consistent with the aggregate classification and allocation results for generation resources	BC Hydro accepts the recommendation	Directive 7: Shall be allocated to customer classes in the same proportions that the total generation revenue requirement is allocated Directive 10: The revenue requirement related to the Trade Income deferral be treated in the same manner as Powerex Net Income	

6.	Classification and allocation of transmission assets · For transmission assets that are primarily used to transmit power from generation resources to the network transmission systems, they should be classified and allocated in the same manner as costs for the generation resources · For backbone or network transmission, recommend the use of the current Demand Only method for classification	BC Hydro accepts the recommendations	Transmission is 100% demand related.	
7.	Distribution System Cost · More detailed sub-functionalization of distribution system costs to the degree data to support this is available	BC Hydro has fulfilled the studies requirement and believes there is significant uncertainty from those results. BC Hydro proposes: · 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	Directive 4: · Determines that an allocation of the total distribution revenue requirement, from primary to meters and including related customer care costs and directly assigned street lighting on a 65% demand, 35% customer basis · BC Hydro directed to conduct both a minimum system and zero intercept analysis for the next FACOS or rate	· Substations and primary distribution make up about 2/3 of distribution costs. Is BCH planning to investigate this and consider direct assignment where reasonable?

			design filing	
8.	Distribution System Cost · Classifying distribution substation costs as 100% demand-related costs and costs for services and meters as 100% customer-related costs	· Same as No. 7	· Same as No. 7	· On slide 70, BC Hydro discussed 'bookending' the SMI costs as either 100% customer-related or 100% energy-related; the latter option was disputed. While 100% energy-related seems extreme, could some amount of Classification as energy-related be justifiable? · Referencing the most recently approved IRP on assumptions regarding SMI's energy benefits may be useful. · Are there reasons as to why meters not directly assigned or allocated entirely to customer? Do most Canadian utilities classify meters to customer-related?
9.	Distribution System Study · Review and revise the study to be more consistent with the theoretical foundation of the minimum system method and zero-intercept method · Alternatively classifying distribution substation, lines, and transformer costs as all demand-related and services and meter costs as all customer-related	· Same as No. 7	· Same as No. 7	· In the Workshop, BCH downplays the value of the minimum system and zero-intercept studies' results. Perhaps there could be more discussion of the underlying issue that the distribution system has attributes that benefit all customers as well as peak-demand design. To what extent should these common benefits be shared equally?
10.	Customer Care	BC Hydro accepts the	· Same as No. 7	

	· Classify most if not all customer care costs as customer-related	recommendation		
11.	Generation Allocation of Peaking Thermal Plant · For demand related costs use an allocator that reflects the classes' contributions to the CP demands in the months when the thermal plants are primarily used	BC Hydro proposes to continue with a 4 CP allocator	Directive 3: · The allocation of transmission and demand-related generation costs should be based on a 4 CP	
12.	Generation Allocation of hydro costs · For demand related costs, analyze how hydro units are designed or being used to serve peak loads throughout the year · 12 CP · 4 CP · 3 CP	BC Hydro proposes to continue with a 4 CP allocator	· As #11 above	
13.	As an alternative approach for hydro costs, consider Average and Excess method for allocating demand-related hydro costs	BC Hydro prefers a 4 CP	· As #11 above	
14.	Transmission allocation · How transmission assets are designed and used, and the load patterns are considerations in selecting an allocation method. May be appropriate to	BC Hydro proposes to continue with the 4 CP allocator approach	· As #11 above	

	sub-functionalize these transmission costs between areas.			
15.	Transmission allocation · Where the service area is a radial high voltage distribution system, the Demand Only method for classification should continue, and consideration should be given to using one NCP as the demand allocator	BC Hydro will investigate whether it can identify individual loads on radial Transmission lines and the corresponding asset values.	· As #11 above	
16	Distribution allocation · Using more direct assignment of Distribution costs 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 will investigate the feasibility of the suggested approach.		
17	R/C Ratios and Range of Reasonableness · Consider adopting a range of reasonableness · With the goal of making changes in rate levels gradually	BC Hydro proposed 95% - 105% in the May 8, 2014 Workshop	Commission Decision (p. 71) · denied BC Hydro's proposed range of reasonableness of 90% to 110%. · Considered 95% to 105% to be more appropriate	· Can BCH relate the proposed narrow range of reasonableness in relation to the COSS assumptions and methodology? A commentary on what parts of the costs can be directly allocated and the confidence level in the Classification and Allocation assumptions used for the various cost categories would be useful.
18.	R/C Ratios and Range of Reasonableness	BC Hydro will make a proposal.		

	• Explicitly developing a policy for how rapidly customer classes should be moved towards the range of reasonableness.			

2015 RDA – June 19, 2014 COS Workshop Feedback Form

Name/Organization: Richard Stout AMPC

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Demand Side Management (DSM) Functionalization					
Recommendation - #1 **BC Hydro should consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service.** **BC Hydro's Response** BC Hydro proposes to functionalize DSM as 90% Generation, 5% Transmission and 5% Distribution (the proposed DSM functionalization results in about a 40% energy/58% demand/2% Customer DSM classification based on F2013 Fully Allocated Cost of Service (**FACOS**) study assumptions). The proposed DSM functionalization Revenue/Cost (**R/C**) ratio is set out in Table 1, page 4 of the Strawman Proposal. The DSM deferral balance is considered part of rate base and therefore BC Hydro proposes to functionalize a share of financing and Return on Equity costs in the COS Study (**COSS**) as DSM-related.	☐	☐	☐	Not sure	As a default 90% Generation 5% transmission and 5% distribution does not appear unreasonable but we need more information on DSM costs by project and customer class. Why should DSM program costs (and energy savings) not be assigned directly to the class that participates in each program? Does BC Hydro have the information to do this? What would the results look like? What portion of each DSM program is considered to conserve energy and demand?

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder input (with reasons) on functionalizing DSM as 90% Generation, 5% Transmission and 5% Distribution.					
Generation Classification					
Recommendation #2 **BC Hydro should consider using either a System Load Factor method or a Plant Capacity Factor method to classify hydro costs, excluding water rental costs.** **BC Hydro's Response** BC Hydro examined three options to classify Generation hydro costs. Refer to Table 2, page 6 in the Strawman Proposal for analysis.					
Option 1: load factor method – the energy portion of Generation costs would be equal to the system load factor while the Generation demand portion would equal to 1 minus the system load factor. Implies that 60% of hydroelectric generation would be classified as energy, 40% demand related.		☐	Disagree	☐	
Option 2: spare capacity factor approach for either the entire system or on a plant by plant basis may also be appropriate. This is around 50% energy/50% demand.		☐	Disagree	☐	How would BCH perform a plant-specific capacity factor analysis? What would the R/C impact be?

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Option 3: Capacity factor approach supplemented by weighting the capacity factors for major hydroelectric plants by the book value of the facilities. This is around 45% energy/ 55% demand. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) as to whether option 1, 2 or 3 should be adopted for the COSS.	☐	Maybe	☐	☐	Why has a fixed and variable cost as used for peaking units not been considered? What would the demand/energy split look like? As a default the capacity factor weighted by cost has merit.
<u>Recommendation #3</u> **BC Hydro should continue to classify peaking thermal plant costs as demand-related and also classify associated Operations & Maintenance (O&M) costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of generation.** **BC Hydro Response** BC Hydro proposes Burrard Generating Station (**GS**) continue to be classified as demand-related, while Fort Nelson GS and Prince Rupert GS should be treated as a combination of energy and demand related. BC Hydro proposes to explore directly classifying the O&M expenses from BC Hydro owned thermal facilities as demand related.	☐	Agree	☐	☐	A modified fixed/variable approach that seems incomplete.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views (with reasons) on classifying Burrard GS as 100% demand, and Fort Nelson GS and Prince Rupert GS as a combination of energy and demand-related.					
<u>Recommendation #4</u> **BC Hydro should 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.** **BC Hydro Response** BC Hydro considered five options and proposes two leading options for consideration. The impact of each leading option option is presented in Table 3, page 8 , and all five options are discussed in Table 4, page 10 of the Strawman Proposal. **Option 1:** Value approach – 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	☐	☐	☐	☐	Need more information. Why would the IPP costs not be classified in the same proportions as BC Hydro's own hydro generation that the IPPs are considered to displace?
Option 2: Value approach – 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.	☐	☐	☐	☐	

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views on classifying IPP purchases and whether Option 1, Option 2 or an alternative option should be pursued.					
Recommendation #5 **BC Hydro should continue using the split between demand related and energy related generation revenue requirements excluding subsidiary net income.** **BC Hydro Response** BC Hydro proposes to continue with the approach approved by the British Columbia Utilities Commission (**BCUC**) in the 2007 Rate Design Application (**RDA**) (Directives 7 and 10) whereby the classification of Powerex trade income follows overall Generation classification. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on continuing with the approach approved by the BCUC per the 2007 RDA Directives 7 and 10 for the COSS.	☐	Agreed	☐	☐	This is a reasonable and well tested approach.
Transmission Classification					
Recommendation #6 **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**					

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
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.** **BC Hydro's Response** BC Hydro agrees that the Transmission system should continue to be classified as 100% 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% demand-related. The Revenue Requirement 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 L-92-07 the BCUC accepted that a fixed charge of $43.3 million was appropriate for GRTA costs.					
Stakeholder Input BC Hydro seeks stakeholder views on continuing to classify Transmission as 100% demand related. BC Hydro asks whether stakeholders wish to revisit (with reasons) the GRTA Generation-related fixed charge of $43.3 million as the basis for GRTA costs.					Transmission should continue to be classified as 100% demand related. A portion of the transmission system costs should be considered used for serving IPPs and form the basis of a new system access rate charged to IPPs.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution and Customer Care Classifications					
<u>Recommendations #7-9</u> **#7 BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available.** **#8 BC Hydro consider classifying distribution substation costs as 100 percent demand-related costs and costs for services and meters as 100 percent customer-related costs.** **#9 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.**					
BC Hydro Response BC Hydro accepts the recommendations for Distribution classification for the reasons described in that part of the 3 June 2014 cover letter where BC Hydro discussed its views on Minimum system and Zero intercept analysis. BC Hydro proposes instead to first categorize Distribution costs (e.g., substations, primary,	☐	Agree	☐		Distribution costs are demand or customer related. The minimum intercept approach is an

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
secondary, transformers, meters) and then classify the categories as either entirely demand- or customer-related in the 2015 RDA. **Stakeholder Input (BC Hydro's response to Recommendations #7-#9)** BC Hydro seeks 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 7 October 2014 COSS workshop.					academic exercise that generally lacks good data and is not determinative in practice. It should be abandoned. We would like to see the results of a direct allocation study by feeders and understand the impact of "accidents of geography" on this approach and its implications for postage stamp rates and extension policy in general.
<u>Recommendation #10</u> **BC Hydro classify customer care costs as customer-related.** **BC Hydro Response** Customer Care costs should be classified 100% as customer-related rather than the current 65% demand/35% customer classification directed by the BCUC in 2007. A 100% 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, page 14 of the Strawman Proposal.	☐	Agree	☐	☐	We oppose the 2007 BCUC decision on this particular allocation and can see no supportable basis for it. Customer care is 100% customer related and BC Hydro should return to this sound approach. Demand has no discernable connection to customer care cost causation. Any proportion of demand allocation lacks support.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views (with reasons) on classifying Customer Care as 100% customer for purpose of the COSS.		Agree			Customer care costs are driven directly by the number of customers cared for, and are not a function of energy consumption or demand. Customer care costs need to be treated as 100% customer related.
Generation Allocation					
<u>Recommendations #11-#12</u> **For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the coincident peak (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 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 3 CP or 4 CP would be more appropriate.** **BC Hydro Response** BC Hydro proposes to continue with a 4-CP allocator as a reasonable method of allocating hydroelectric Generation demand costs: · A 12-CP allocator is not appropriate given	☐	Agree	☐	☐	BC is winter peaking with the most likely peak occurrence in December/January rather than November or February. A 3CP or 4CP allocator for Hydraulic generation is the most

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
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 4 CP is more appropriate than 1 CP, 2 CP or 3 CP. 3-CP is problematic as there is no basis for choosing November-January as opposed to December-February · BC Hydro remains a winter peaking utility and does not have a significant summer peak. Refer to Table 6, page 16 of the Strawman Proposal for 1 CP, 2 CP, 4 CP and 12 CP R/C ratio analysis.					appropriate. Some further investigation of CP determination is also appropriate based on the probability function over the winter period. In other words 3CP and 4CP does not have to be evenly distributed over four months but could be based on the three or four highest demands within the most likely two months.
<u>**Recommendation #13**</u> **As an alternative approach for hydro costs, we recommend BC Hydro consider using the Average and Excess method for allocating demand-related hydro costs.** **BC Hydro Response** Given that BC Hydro's Generaton and Transmission planning is largely based on the system CP and no utilities reviewed use the Average & Excess allocation method, BC Hydro believes a 4CP approach is preferable. Additional discussion is found on page 16 of the Strawman Proposal. **Stakeholder Input - Recommendations**	☐	Agree	☐	☐	The average and excess allocation methodology is rarely used and is not appropriate for a winter peaking utility that plans generation and transmission systems on a CP basis.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
#11-13 BC Hydro seeks stakeholder views on continuing to use Generation demand-related 4-CP allocator.					
Transmission Allocation					
<u>Recommendation #14</u> **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.** **BC Hydro Response** BC Hydro proposes to continue with the 4-CP allocator approach as it remains a reasonable method to allocate Transmission costs. Additional discussion is found on page 17 of the Strawman Proposal. Refer to Table 6, page 16 for 1CP, 2CP 4CP and 12CP R/C ratio analysis.	☐	Agree	☐	☐	Transmission allocators should reflect the planning considerations that determine transmission need. The bulk or backbone system and connections to generators are planned to meet system coincident peak demand (along with expected IPP output) and therefore should continue to be allocated on a CP basis similar to generation. Radial transmission lines that connect load customers to the bulk transmission (to the first node "upstream") are typically sized on

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views (with reasons) on continuing to use Transmission 4-CP allocator.					non-coincident peak demand. Consideration should be given to identifying load-serving radial elements and allocating them on a NCP basis.
<u>Recommendation #15</u> **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 1 non-coincident peak (NCP) as the demand allocator.** **BC Hydro response** 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 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.		Agree			See comments above. NCP would be the better allocator for transmission (and distribution) assets identified as load-related radial feeders.

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution Allocation					
Recommendation - #16 **BC Hydro consider if possible 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** BC Hydro proposes to investigate the feasibility of the suggested approach and report back to customer stakeholders at the 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					Direct assignment of transformers, service drops and meters better reflects cost causation where a single customer is involved, but should not be entertained for elements of the system that serve multiple customers.

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
R/C Ratios and Range of Reasonableness					
<u>Recommendation #17</u> **BC Hydro should 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**. **BC Hydro Response** 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%-105% is reasonable. See page 19 of the Strawman Proposal document for additional discussion.	☐	Agree in part	Disagree in part	☐	While 95%-105% is a reasonable starting point for <u>overall</u> rate design in the longer run, in practice <u>target</u> ranges differ significantly by rate class in the time-frame of a typical RDA. Industrial rates are commonly **designed** to be within the 99-101% range, commercial rates are commonly designed to be in the 110-120% range and residential rates in the 90-100% range. These are more appropriate targets for BC Hydro in this proceeding than a “one size fits all” R/C target band. When long periods between rate design applications occur, R/C may drift outside these design ranges. Competitive market pressures generally ensure that Industrial rates are kept within a tighter tolerance than other rate classes. The higher R/C targets for commercial (and lighting services) and lower R/C targets for residential classes are common and practically

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks further stakeholder input (with reasons) on a range of reasonableness of 95% - 105%.					universal for regulated utilities.These R/C range differences appear to reflect historical municipal agreements, taxation considerations, competitive pressures on larger customers, and political reality. The 2% annual limitation on upward changes in R/C ratios did not anticipate the length of elapsed time and drift that has occurred since the last comprehensive rate design and “rebalancing”. Ideally the period between full RDA’s and R/C adjustments should be less than 5 years.

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>**Recommendation #18**</u> **BC Hydro should 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).** **BC Hydro Response** BC Hydro will make a proposal for stakeholder input in response to Recommendation #18 as part of the proposed 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					See comments above. The 2% annual limit applies only to ***increases*** in R/C ratios and not to decreases. The rate of correction should reflect the degree of departure from more typical R/Cs for the class affected and the time that has elapsed since the last R/C ratio adjustments. Industrial transmission customers are experiencing severe competitive pressures at an unusually high R/C of 107% compared to a more normal appropriate ratio of 99-101%. Given the size of industrial customer bills this is a lot of money being extracted to subsidize residential bills.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Other					
<u>Customer Care Cost Allocation</u> **How to allocate Customer Care-related costs in COSS.** **BC Hydro Proposal** BC Hydro proposes to continue allocating Customer Care-related costs on a weighted basis with: · 90% of the weight based on the number of bills issued to customers · 10% based on revenue A more detailed analysis has been completed for the various categories of customer care cost and the preliminary results support an overall 90% / 10% weighting factor. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on its proposal to continue allocating Customer Care related costs on a weighted basis, with 90% based number of bills issued to customers and 10% based on revenue.	☐	?	☐	**?**	This seems inconsistent with recommendation #10 that customer care costs be allocated by the number of customers. If this is a sub-category of customer care for billing production costs then 100% on the number of bills produced would seem to the appropriate allocator. It is hard to believe that even 10% of the billing costs are a function of revenues without a strong supporting study, and not just the “preliminary results” of a “detailed analysis”. A bill for $10,000 should not cost significantly more to produce than a bill for $10.

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Smart Metering & Infrastructure Program (SMI)</u> **BCUC staff asked BC Hydro to identify developments since the 2007 RDA and specifically referenced SMI** **Possible Bookends**: 1.Treat SMI costs as 100% customer-related · Consistent with historical treatment for meter-related costs · Energy savings not readily quantifiable at this early stage in SMI 2.Treat SMI costs as 100% energy-related · SMI was installed primarily for energy-saving benefit					Option 1 is the only approach that is consistent with standard utility practice. Metering costs are universally allocated as customer costs, being the classic example of costs that are a function of the number of customers and are not a function of energy or demand. For example, refer to BCUC Recommendation #8 … "costs for services and meters (should be classified) as 100% customer-related costs." This is therefore not a "bookend" issue where a spectrum of reasonable approaches might exist. All metering systems including electro-mechanical devices can be assumed to save energy by allowing tariffs to be based on energy consumption and to deter theft. This is not to be confused with the clear distinction between a customer related and an energy related cost. A metering system such as SMI must be in place for all customers in a class, even for customers that may consume no energy for extended periods."

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input: BC Hydro seeks stakeholder input (with reasons) on the treatment of SMI-related costs in the COSS.					
<u>E-Plus Customers</u> **BCUC Directive #14 from the 2007 RDA stated:** ***"Include interruptible service to E-Plus customers as a separate class in its future COS and calculate costs of providing service as though BC Hydro has the ability to interrupt the class for the four winter months"*** **BC Hydro Proposal** Two options proposed: **Option 1:** Remove E-Plus customers from the 4 CP calculation on the assumption they would have been interrupted during those peak times in the winter	☐	☐	Disagree	☐	This would be a deliberate distortion of the FACOSS that should be strenuously avoided. Cost of service studies provide a reference whereby cross-subsidies can at least be identified if not entirely avoided. Distorting the reference would hide the cross-subsidy and remove any possibility of correcting it.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Option 2: Continue to include E-Plus customers in the 4 CP calculation BC Hydro favours Option 2. These loads are in BC Hydro's load forecast and planning. However there is no operational ability to interrupt - true Interruptibility would be expensive and administratively complex. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on the two proposed options for E-Plus customers.	☐	Agree	☐	☐	There is no ability to interrupt E-plus customers and their cost of service is therefore no different than other residential customers. The E-plus should be terminated as a rate option that would help improve the R/C ratio for residentials as a whole.

CONSENT TO USE PERSONAL INFORMATION

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

Signature:____ Date: ______________________

Thank you for your comments.

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

You can return completed feedback forms by:

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

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

Email: bchydroregulatorygroup@bchydro.com

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2015 RDA – June 19, 2014 COS Workshop Feedback Form

Name/Organization:
BC Sustainable Energy Association & Sierra Club of BC; 22 August 2014

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Demand Side Management (DSM) Functionalization					
Recommendation - #1 **BC Hydro should consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service.** **BC Hydro's Response** BC Hydro proposes to functionalize DSM as 90% Generation, 5% Transmission and 5% Distribution (the proposed DSM functionalization results in about a 40% energy/58% demand/2% Customer DSM classification based on F2013 Fully Allocated Cost of Service (**FACOS**) study assumptions). The proposed DSM functionalization Revenue/Cost (**R/C**) ratio is set out in Table 1, page 4 of the Strawman Proposal. The DSM deferral balance is considered part of rate base and therefore BC Hydro proposes to functionalize a share of financing and Return on Equity costs in the COS Study (**COSS**) as DSM-related.	☐	X☐	☐	☐	BCSEA-SCBC's view is that DSM costs should be functionalized in a way that reasonably accurately reflects the proportions of demand and energy costs that are avoided by DSM activities. Further, DSM costs should, where possible, be allocated to the customer class to which they pertain. Costs associated with the DSM deferral balance should be functionalized the same way that the costs of other deferral balances are functionalized.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder input (with reasons) on functionalizing DSM as 90% Generation, 5% Transmission and 5% Distribution.					
Generation Classification					
<u>**Recommendation #2**</u> **BC Hydro should consider using either a System Load Factor method or a Plant Capacity Factor method to classify hydro costs, excluding water rental costs.** **BC Hydro's Response** BC Hydro examined three options to classify Generation hydro costs. Refer to Table 2, page 6 in the Strawman Proposal for analysis.					
Option 1: load factor method – the energy portion of Generation costs would be equal to the system load factor while the Generation demand portion would equal to 1 minus the system load factor. Implies that 60% of hydroelectric generation would be classified as energy, 40% demand related.	☐	X☐	☐	☐	BCSEA-SCBC favour option 1 at this time because of its simplicity and transparency. However, their position may change based on reviewing the input from other stakeholders.
Option 2: spare capacity factor approach for either the entire system or on a plant by plant basis may also be appropriate. This is around 50% energy/50% demand.	☐	☐	☐	☐	

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Option 3: Capacity factor approach supplemented by weighting the capacity factors for major hydroelectric plants by the book value of the facilities. This is around 45% energy/ 55% demand. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) as to whether option 1, 2 or 3 should be adopted for the COSS.	☐	☐	☐	☐	
<u>**Recommendation #3**</u> **BC Hydro should continue to classify peaking thermal plant costs as demand-related and also classify associated Operations & Maintenance (O&M) costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of generation**. **BC Hydro Response** BC Hydro proposes Burrard Generating Station (**GS**) continue to be classified as demand-related, while Fort Nelson GS and Prince Rupert GS should be treated as a combination of energy and demand related. BC Hydro proposes to explore directly classifying the O&M expenses from BC Hydro owned thermal facilities as demand related.	☐	X☐	☐	☐	BC Hydro's proposal seems accurate.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views (with reasons) on classifying Burrard GS as 100% demand, and Fort Nelson GS and Prince Rupert GS as a combination of energy and demand-related.					
Recommendation #4 **BC Hydro should 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.** **BC Hydro Response** BC Hydro considered five options and proposes two leading options for consideration. The impact of each leading option option is presented in Table 3, page 8 , and all five options are discussed in Table 4, page 10 of the Strawman Proposal. **Option 1:** Value approach – 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	☐	☐	☐	☐	BCSEA-SCBC agree with modifying the current 100% energy treatment of IPP costs to a formula that attributes some amount of demand to IPP costs. Using the capacity benefits of the IPP portfolio in the IRP makes sense. Options 3, 4 and 5 are either too complicated or produce odd results. Option 1 (benefits as a percentage of benefits) seems like a more accurate way to determine the proper allocation of IPP costs to demand than Option 2.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Option 2: Value approach – 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. **Stakeholder Input** BC Hydro seeks stakeholder views on classifying IPP purchases and whether Option 1, Option 2 or an alternative option should be pursued.	☐	☐	☐	☐	
Recommendation #5 **BC Hydro should continue using the split between demand related and energy related generation revenue requirements excluding subsidiary net income.** **BC Hydro Response** BC Hydro proposes to continue with the approach approved by the British Columbia Utilities Commission (**BCUC**) in the 2007 Rate Design Application (**RDA**) (Directives 7 and 10) whereby the classification of Powerex trade income follows overall Generation classification. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on continuing with the approach approved by the BCUC per the 2007 RDA Directives 7 and 10 for the COSS.	☐	X☐	☐	☐	

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transmission Classification					
<u>Recommendation #6</u> **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.** **BC Hydro's Response** BC Hydro agrees that the Transmission system should continue to be classified as 100% 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% demand-related. The Revenue Requirement 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 L-92-07 the BCUC accepted that a fixed charge of $43.3 million was appropriate for GRTA costs.					

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views on continuing to classify Transmission as 100% demand related. BC Hydro asks whether stakeholders wish to revisit (with reasons) the GRTA Generation-related fixed charge of $43.3 million as the basis for GRTA costs.		X			BCSEA-SCBC agree with keeping transmission at 100% demand. We don't have enough information to know if the $43-million adjustment for generation-related transmission assets is sufficiently accurate.
Distribution and Customer Care Classifications					
<u>Recommendations #7-9</u> **#7 BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available.** **#8 BC Hydro consider classifying distribution substation costs as 100 percent demand-related costs and costs for services and meters as 100 percent customer-related costs.** **#9 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.**					

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
BC Hydro Response BC Hydro accepts the recommendations for Distribution classification for the reasons described in that part of the 3 June 2014 cover letter where BC Hydro discussed its views on Minimum system and Zero intercept analysis. 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. **Stakeholder Input (BC Hydro's response to Recommendations #7-#9)** BC Hydro seeks 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 7 October 2014 COSS workshop.	☐	☐	☐	☐	BCSEA-SCBC tend not to support the highly complicated and uncertain Minimum System or Zero Intercept approachs. BC Hydro's proposed approach may be a reasonable compromise, if categorizing the Distribution costs is a straightfoward and inexpensive process.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Recommendation #10</u> **BC Hydro classify customer care costs as customer-related.** **BC Hydro Response** Customer Care costs should be classified 100% as customer-related rather than the current 65% demand/35% customer classification directed by the BCUC in 2007. A 100% 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, page 14 of the Strawman Proposal. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on classifying Customer Care as 100% customer for purpose of the COSS.	☐	☐X	☐	☐	BCSEA-SCBC agree with classifying customer care costs as 100% customer related. This seems like the most accurate approach.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation Allocation					
<u>Recommendations #11-#12</u> **For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the coincident peak (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 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 3 CP or 4 CP would be more appropriate.** **BC Hydro Response** BC Hydro proposes to continue with a 4-CP allocator as a reasonable method of allocating hydroelectric Generation demand costs: • A 12-CP 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	☐	X☐	☐	☐	A 4 coincident peak approach is reasonable.

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February are relevant to the winter peak, BC Hydro believes 4 CP is more appropriate than 1 CP, 2 CP or 3 CP. 3-CP is problematic as there is no basis for choosing November-January as opposed to December-February • BC Hydro remains a winter peaking utility and does not have a significant summer peak. Refer to Table 6, page 16 of the Strawman Proposal for 1 CP, 2 CP, 4 CP and 12 CP R/C ratio analysis.					
Recommendation #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.** **BC Hydro Response** Given that BC Hydro's Generaton and Transmission planning is largely based on the system CP and no utilities reviewed use the Average & Excess allocation method, BC Hydro believes a 4CP approach is preferable. Additional discussion is found on page 16 of the Strawman Proposal. **Stakeholder Input - Recommendations #11-13** BC Hydro seeks stakeholder views on continuing to use Generation demand-related 4-CP allocator.	☐	☐X	☐	☐	We agree with BC Hydro that the A&E approaches don't seem better than the 4 CP approach. As above, we support the 4 CP approach for Generation.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transmission Allocation					
Recommendation #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.** **BC Hydro Response** BC Hydro proposes to continue with the 4-CP allocator approach as it remains a reasonable method to allocate Transmission costs. Additional discussion is found on page 17 of the Strawman Proposal. Refer to Table 6, page 16 for 1CP, 2CP 4CP and 12CP R/C ratio analysis. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on continuing to use Transmission 4-CP allocator.	☐	☐	☐	☐	We are satisfied with the 4 CP approach for Transmission costs, subject to hearing the views of other stakeholders.

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Recommendation #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 1 non-coincident peak (NCP) as the demand allocator.** **BC Hydro response** 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 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

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Distribution Allocation					
<u>Recommendation - #16</u> **BC Hydro consider if possible 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** BC Hydro proposes to investigate the feasibility of the suggested approach and report back to customer stakeholders at the 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

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R/C Ratios and Range of Reasonableness					
<u>**Recommendation #17**</u> **BC Hydro should 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**. **BC Hydro Response** 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%-105% is reasonable. See page 19 of the Strawman Proposal document for additional discussion.	☐	☐	☐	☐	The "range of reasonableness" should be treated as a different issue than the formula or mechanism for bringing customer classes' R/C ratios into the range of reasonableness. BCSEA-SCBC generally favour a mechanism that moves customer class R/C ratios into the range of reasonableness as quickly as possible given the statutory and bill impact constraints. BCSEA-SCBC have previously supported a R/C objective of 100%. A 10% range (95 to 105%) of reasonableness should be considered the maximum acceptable. The governing principle should be sending the proper price signal, with modifications as necessary to deal with legal constraints and bill impacts. All the work being done on COS methodology becomes moot if (a) the range of reasonableness is too broad and/or (b) customer classes' R/C ratios are not brought within the range of

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Stakeholder Input BC Hydro seeks further stakeholder input (with reasons) on a range of reasonableness of 95% - 105%.					reasonableness anyway. A practical priority is to re-balance the current allocations, which are more than 10% out of balance in some instances.
<u>Recommendation #18</u> **BC Hydro should 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).** **BC Hydro Response** BC Hydro will make a proposal for stakeholder input in response to Recommendation #18 as part of the proposed 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Other					
<u>**Customer Care Cost Allocation**</u> **How to allocate Customer Care-related costs in COSS.** **BC Hydro Proposal** BC Hydro proposes to continue allocating Customer Care-related costs on a weighted basis with: • 90% of the weight based on the number of bills issued to customers • 10% based on revenue A more detailed analysis has been completed for the various categories of customer care cost and the preliminary results support an overall 90% / 10% weighting factor. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on its proposal to continue allocating Customer Care related costs on a weighted basis, with 90% based number of bills issued to customers and 10% based on revenue.	☐	X☐	☐	☐	We support the 90/10 allocation of customer care costs if that is what is is supported by the empircal study.

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<u>Smart Metering & Infrastructure Program (SMI)</u> **BCUC staff asked BC Hydro to identify developments since the 2007 RDA and specifically referenced SMI** **Possible Bookends**: 1.Treat SMI costs as 100% customer-related • Consistent with historical treatment for meter-related costs • Energy savings not readily quantifiable at this early stage in SMI 2.Treat SMI costs as 100% energy-related • SMI was installed primarily for energy-saving benefit **Stakeholder Input:** BC Hydro seeks stakeholder input (with reasons) on the treatment of SMI-related costs in the COSS.					We look forward to hearing the views of other stakeholders on the treatment for SMI costs. We don't have fixed position yet.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>E-Plus Customers</u> **BCUC Directive #14 from the 2007 RDA stated:** ***"Include interruptible service to E-Plus customers as a separate class in its future COS and calculate costs of providing service as though BC Hydro has the ability to interrupt the class for the four winter months"*** **BC Hydro Proposal** Two options proposed:					
Option 1: Remove E-Plus customers from the 4 CP calculation on the assumption they would have been interrupted during those peak times in the winter	☐	☐	X☐	☐	Disagree.
Option 2: Continue to include E-Plus customers in the 4 CP calculation BC Hydro favours Option 2. These loads are in BC Hydro's load forecast and planning. However there is no operational ability to interrupt - true Interruptibility would be expensive and administratively complex. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on the two proposed options for E-Plus customers.	☐	X☐	☐	☐	Agree. BCSEA-SCBC understand that E-Plus customers have never had a call on the interruptible feature of their rate, and BC Hydro deems this feature effectively unusable.

CONSENT TO USE PERSONAL INFORMATION

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

Signature:___________ __________________ Date: ______ 22 August 2014 _________

Thank you for your comments.

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

You can return completed feedback forms by:

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

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

Email: bchydroregulatorygroup@bchydro.com

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

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2015 RDA – June 19, 2014 COS Workshop Feedback Form

Name/Organization:

TOPIC	**Strongly Agree**	**Agree**	**Disagree**	**N/A**	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Demand Side Management (DSM) Functionalization					
<u>Recommendation - #1</u> **BC Hydro should consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service.** **BC Hydro's Response** BC Hydro proposes to functionalize DSM as 90% Generation, 5% Transmission and 5% Distribution (the proposed DSM functionalization results in about a 40% energy/58% demand/2% Customer DSM classification based on F2013 Fully Allocated Cost of Service (**FACOS**) study assumptions). The proposed DSM functionalization Revenue/Cost (**R/C**) ratio is set out in Table 1, page 4 of the Strawman Proposal. The DSM deferral balance is considered part of rate base and therefore BC Hydro proposes to functionalize a share of financing and Return on Equity costs in the COS Study (**COSS**) as DSM-related.	☐	☒	☐	☐	However, BC Hydro should examine other options

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder input (with reasons) on functionalizing DSM as 90% Generation, 5% Transmission and 5% Distribution.					BC Hydro should look at DSM delivery of Energy and Capacity and the related acquisition costs reduction to Energy and Capacity
Generation Classification					
Recommendation #2 **BC Hydro should consider using either a System Load Factor method or a Plant Capacity Factor method to classify hydro costs, excluding water rental costs.** **BC Hydro's Response** BC Hydro examined three options to classify Generation hydro costs. Refer to Table 2, page 6 in the Strawman Proposal for analysis.					
Option 1: load factor method – the energy portion of Generation costs would be equal to the system load factor while the Generation demand portion would equal to 1 minus the system load factor. Implies that 60% of hydroelectric generation would be classified as energy, 40% demand related.	☐	☒	☐	☐	All options should be examined
Option 2: spare capacity factor approach for either the entire system or on a plant by plant basis may also be appropriate. This is around 50% energy/50% demand.	☐	☐	☒	☐	Not sure how spare capacity factor is relevant to the whole

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Option 3: Capacity factor approach supplemented by weighting the capacity factors for major hydroelectric plants by the book value of the facilities. This is around 45% energy/ 55% demand. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) as to whether option 1, 2 or 3 should be adopted for the COSS.	☐	☐	☒	☐	Not sure why the book values and capacity factors are the relevant combination
<u>**Recommendation #3**</u> **BC Hydro should continue to classify peaking thermal plant costs as demand-related and also classify associated Operations & Maintenance (O&M) costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of generation.** **BC Hydro Response** BC Hydro proposes Burrard Generating Station (**GS**) continue to be classified as demand-related, while Fort Nelson GS and Prince Rupert GS should be treated as a combination of energy and demand related. BC Hydro proposes to explore directly classifying the O&M expenses from BC Hydro owned thermal facilities as demand related.	☐	☒	☐	☐	However the O&M cost are likely not all for demand and would support some energy

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Stakeholder Input BC Hydro seeks stakeholder views (with reasons) on classifying Burrard GS as 100% demand, and Fort Nelson GS and Prince Rupert GS as a combination of energy and demand-related.					BC Hydro should examine options
<u>Recommendation #4</u> **BC Hydro should 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.** **BC Hydro Response** BC Hydro considered five options and proposes two leading options for consideration. The impact of each leading option option is presented in Table 3, page 8 , and all five options are discussed in Table 4, page 10 of the Strawman Proposal. **Option 1:** Value approach – 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	☐	☒	☐	☐	Uncertain at this time about the merits of capacity benefits/energy & capacity benefits

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Option 2: Value approach – 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. **Stakeholder Input** BC Hydro seeks stakeholder views on classifying IPP purchases and whether Option 1, Option 2 or an alternative option should be pursued.	☐	☒	☐	☐	Uncertain about merits of capacity benefits/IPP costs Possibly BC Hydro should look at IPP capacity cost as a proportion of IPP costs
<u>**Recommendation #5**</u> **BC Hydro should continue using the split between demand related and energy related generation revenue requirements excluding subsidiary net income.** **BC Hydro Response** BC Hydro proposes to continue with the approach approved by the British Columbia Utilities Commission (**BCUC**) in the 2007 Rate Design Application (**RDA**) (Directives 7 and 10) whereby the classification of Powerex trade income follows overall Generation classification. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on continuing with the approach approved by the BCUC per the 2007 RDA Directives 7 and 10 for the COSS.	☐	☒	☐	☐	However, BC Hydro should examine options The trade income value should be looked at in terms of the capabilities generating the value

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Transmission Classification					
<u>Recommendation #6</u> **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.** **BC Hydro's Response** BC Hydro agrees that the Transmission system should continue to be classified as 100% 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% demand-related. The Revenue Requirement 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 L-92-07 the BCUC accepted that a fixed charge of $43.3 million was appropriate for GRTA costs.		þ			

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views on continuing to classify Transmission as 100% demand related. BC Hydro asks whether stakeholders wish to revisit (with reasons) the GRTA Generation-related fixed charge of $43.3 million as the basis for GRTA costs.					Transmission supports both energy and demand delivery. Options might be examined. Yes, GRTA should be examined
Distribution and Customer Care Classifications					
<u>Recommendations #7-9</u> **#7 BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available.** **#8 BC Hydro consider classifying distribution substation costs as 100 percent demand-related costs and costs for services and meters as 100 percent customer-related costs.** **#9 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.**		þ þ þ			

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
BC Hydro Response BC Hydro accepts the recommendations for Distribution classification for the reasons described in that part of the 3 June 2014 cover letter where BC Hydro discussed its views on Minimum system and Zero intercept analysis. 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. **Stakeholder Input (BC Hydro's response to Recommendations #7-#9)** BC Hydro seeks 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 7 October 2014 COSS workshop.	☐	☒	☐	☐	Alternatives that are not 100% demand should be examined BC Hydro could do feeder by feeder analysis or look at class use proportion of whole system as alternatives

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Recommendation #10 **BC Hydro classify customer care costs as customer-related.** **BC Hydro Response** Customer Care costs should be classified 100% as customer-related rather than the current 65% demand/35% customer classification directed by the BCUC in 2007. A 100% 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, page 14 of the Strawman Proposal. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on classifying Customer Care as 100% customer for purpose of the COSS.	☐	☒	☐	☐	This appears to be logical Customer Care is a service and is most likely proportional to customer account, with possible value per customer differences based on different service levels and requirements

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation Allocation					
<u>Recommendations #11-#12</u> **For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the coincident peak (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 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 3 CP or 4 CP would be more appropriate.** **BC Hydro Response** BC Hydro proposes to continue with a 4-CP allocator as a reasonable method of allocating hydroelectric Generation demand costs: · A 12-CP 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	☐	þ	☐	☐	Agree that 12 CP not appropriate

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
February are relevant to the winter peak, BC Hydro believes 4 CP is more appropriate than 1 CP, 2 CP or 3 CP. 3-CP is problematic as there is no basis for choosing November-January as opposed to December-February · BC Hydro remains a winter peaking utility and does not have a significant summer peak. Refer to Table 6, page 16 of the Strawman Proposal for 1 CP, 2 CP, 4 CP and 12 CP R/C ratio analysis.					Possibly BC Hydro could look at probability weighting of the 4 CP scenarios
<u>**Recommendation #13**</u> **As an alternative approach for hydro costs, we recommend BC Hydro consider using the Average and Excess method for allocating demand-related hydro costs.** **BC Hydro Response** Given that BC Hydro's Generaton and Transmission planning is largely based on the system CP and no utilities reviewed use the Average & Excess allocation method, BC Hydro believes a 4CP approach is preferable. Additional discussion is found on page 16 of the Strawman Proposal. **Stakeholder Input - Recommendations #11-13** BC Hydro seeks stakeholder views on continuing to use Generation demand-related 4-CP allocator.	☐	þ	☐	☐	The 4 CP approach appears to be a logical basis

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transmission Allocation					
<u>Recommendation #14</u> **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.** **BC Hydro Response** BC Hydro proposes to continue with the 4-CP allocator approach as it remains a reasonable method to allocate Transmission costs. Additional discussion is found on page 17 of the Strawman Proposal. Refer to Table 6, page 16 for 1CP, 2CP 4CP and 12CP R/C ratio analysis. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on continuing to use Transmission 4-CP allocator.	☐	þ	☐	☐	Certainly the Peak drives the costs at the margin 4 CP is relevant Transmission is necessary to deliver energy

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Recommendation #15</u> **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 1 non-coincident peak (NCP) as the demand allocator.** **BC Hydro response** 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 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					This seems to be a relevant option analysis

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution Allocation					
<u>Recommendation - #16</u> **BC Hydro consider if possible 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** BC Hydro proposes to investigate the feasibility of the suggested approach and report back to customer stakeholders at the 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					This appears to be reasonable

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
R/C Ratios and Range of Reasonableness					
Recommendation #17 **BC Hydro should 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**. **BC Hydro Response** 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%-105% is reasonable. See page 19 of the Strawman Proposal document for additional discussion. **Stakeholder Input** BC Hydro seeks further stakeholder input (with reasons) on a range of reasonableness of 95% - 105%.	☐	☐	þ	☐	BC Hydro needs to focus on the separate steps of triggering rebalancing toward unity and avoiding retrigger after rebalancing achieved until range of reasonableness is subsequently breached. Different R of R maybe relevant by class

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Recommendation #18</u> **BC Hydro should 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).** **BC Hydro Response** BC Hydro will make a proposal for stakeholder input in response to Recommendation #18 as part of the proposed 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.		þ			Yes Alternative approaches should be examined and relevant decision criteria discussed

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Other					
<u>Customer Care Cost Allocation</u> **How to allocate Customer Care-related costs in COSS.** **BC Hydro Proposal** BC Hydro proposes to continue allocating Customer Care-related costs on a weighted basis with: · 90% of the weight based on the number of bills issued to customers · 10% based on revenue A more detailed analysis has been completed for the various categories of customer care cost and the preliminary results support an overall 90% / 10% weighting factor. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on its proposal to continue allocating Customer Care related costs on a weighted basis, with 90% based number of bills issued to customers and 10% based on revenue.	☐	þ	☐	☐	Alternatives may be relevant to examine 10% revenue justification is not clear Possibly weighting by type of account would reflect different levels of customer care service investment

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Smart Metering & Infrastructure Program (SMI) **BCUC staff asked BC Hydro to identify developments since the 2007 RDA and specifically referenced SMI** **Possible Bookends**: 1.Treat SMI costs as 100% customer-related · Consistent with historical treatment for meter-related costs · Energy savings not readily quantifiable at this early stage in SMI 2.Treat SMI costs as 100% energy-related · SMI was installed primarily for energy-saving benefit **Stakeholder Input:** BC Hydro seeks stakeholder input (with reasons) on the treatment of SMI-related costs in the COSS.		þ			This is more consistent with the cost related to a customer This alternative should be examined though it would be more challenging to implement on an ongoing basis as the benefit results change

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>E-Plus Customers</u> **BCUC Directive #14 from the 2007 RDA stated:** ***"Include interruptible service to E-Plus customers as a separate class in its future COS and calculate costs of providing service as though BC Hydro has the ability to interrupt the class for the four winter months"*** **BC Hydro Proposal** Two options proposed:					
Option 1: Remove E-Plus customers from the 4 CP calculation on the assumption they would have been interrupted during those peak times in the winter	☐	☐	☐	☐	This option should be examined
Option 2: Continue to include E-Plus customers in the 4 CP calculation	☐	þ	☐	☐	The E-Plus customers should be moving to normalization as the justification for the class is weak to non-existent
BC Hydro favours Option 2. These loads are in BC Hydro's load forecast and planning. However there is no operational ability to interrupt - true Interruptibility would be expensive and administratively complex. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on the two proposed options for E-Plus customers.		þ			

CONSENT TO USE PERSONAL INFORMATION

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

Signature:_______________________________________ Date: ______________________

Thank you for your comments.

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

You can return completed feedback forms by:

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

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

Email: bchydroregulatorygroup@bchydro.com

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

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

2015 RDA – June 19, 2014 COS Workshop Feedback Form

Name/Organization:

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Demand Side Management (DSM) Functionalization					
Recommendation - #1 **BC Hydro should consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service.** **BC Hydro's Response** BC Hydro proposes to functionalize DSM as 90% Generation, 5% Transmission and 5% Distribution (the proposed DSM functionalization results in about a 40% energy/58% demand/2% Customer DSM classification based on F2013 Fully Allocated Cost of Service (**FACOS**) study assumptions). The proposed DSM functionalization Revenue/Cost (**R/C**) ratio is set out in Table 1, page 4 of the Strawman Proposal. The DSM deferral balance is considered part of rate base and therefore BC Hydro proposes to functionalize a share of financing and Return on Equity costs in the COS Study (**COSS**) as DSM-related.	☐	x	☐	☐	

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder input (with reasons) on functionalizing DSM as 90% Generation, 5% Transmission and 5% Distribution.					***We believe that rates should be based on marginal costs, modified as required for total approved revenue recovery in a manner that maintains as much as possible efficient price signals and allocates heritage asset benefits in accordance with explicit policy objectives and criteria. This is preferable for promoting efficient energy use and equity than the in many respects arbitrary and largely irrelevant allocation of embedded costs.*** ***However if it is decided to allocate costs on an embedded cost basis there should be clear and consistent principles guiding the allocation process.*** ***We believe causal responsibility for or benefit from the expenditure is most appropriate. In the case of DSM this would require allocating costs based on the impacts it is expected to have on generation and transmission service as opposed to the proportions of plant in service.***
Generation Classification					
<u>**Recommendation #2**</u> **BC Hydro should consider using either a System Load Factor method or a Plant Capacity Factor method to classify hydro costs, excluding water rental costs.** **BC Hydro's Response** BC Hydro examined three options to classify Generation hydro costs. Refer to Table 2,					

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page 6 in the Strawman Proposal for analysis. **Option 1:** load factor method – the energy portion of Generation costs would be equal to the system load factor while the Generation demand portion would equal to 1 minus the system load factor. Implies that 60% of hydroelectric generation would be classified as energy, 40% demand related.	☐	x	☐	☐	
Option 2: spare capacity factor approach for either the entire system or on a plant by plant basis may also be appropriate. This is around 50% energy/50% demand.	☐	☐	x	☐	
Option 3: Capacity factor approach supplemented by weighting the capacity factors for major hydroelectric plants by the book value of the facilities. This is around 45% energy/ 55% demand. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) as to whether option 1, 2 or 3 should be adopted for the COSS.	☐	☐	x	☐	***An arbitrary allocation of this nature would not be required with a marginal cost approach. A logical approach for this embedded cost allocation however would be to consider how the assets are used – in other words the load factor they serve.***
<u>Recommendation #3</u> **BC Hydro should continue to classify peaking thermal plant costs as demand-related and also classify associated Operations & Maintenance (O&M) costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of**					

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
generation. **BC Hydro Response** BC Hydro proposes Burrard Generating Station (**GS**) continue to be classified as demand-related, while Fort Nelson GS and Prince Rupert GS should be treated as a combination of energy and demand related. BC Hydro proposes to explore directly classifying the O&M expenses from BC Hydro owned thermal facilities as demand related.	☐	☐	x	☐	
Stakeholder Input BC Hydro seeks stakeholder views (with reasons) on classifying Burrard GS as 100% demand, and Fort Nelson GS and Prince Rupert GS as a combination of energy and demand-related.					***The allocation of Burrard costs raises a more fundamental issue. Historically Burrard was used to firm up BC Hydro's energy capability. A significant portion of its costs were incurred for energy not just demand purposes.*** ***Burrard is not now used to firm up energy only because of government policy and legislation. The question arises (as was raised in the industrial rate review) how should one recover costs imposed by government.*** ***Allocating all of the costs of Burrard to demand ignores the energy value foregone as a result of government policy intervention. It thereby imposes the cost of government policy disproportionately to some customer groups over others. That does not seem fair.*** ***Some explicit discussion and direction on the allocation of government imposed costs is required.***

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Recommendation #4</u> **BC Hydro should 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.** **BC Hydro Response** BC Hydro considered five options and proposes two leading options for consideration. The impact of each leading option is presented in Table 3, page 8 , and all five options are discussed in Table 4, page 10 of the Strawman Proposal. **Option 1:** Value approach – 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	☐	x	☐	☐	***Subject to the Comments in the related Stakeholder Input Section found below.***
Option 2: Value approach – 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. **Stakeholder Input** BC Hydro seeks stakeholder views on classifying IPP purchases and whether Option 1, Option 2 or an alternative option should be pursued.	☐	☐	x	☐	***Again, an arbitrary allocation of this nature would not be required with the marginal cost approach. However, to allocate the embedded costs that have been incurred, a consistent allocation principle is required. As with DSM we would suggest allocating benefits on the***

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					basis of the relative benefits it is expected to have. If this results in excessive costs being allocated to energy (or capacity) – costs that would not have been incurred except for government direction, the allocation of those excess costs should be considered along with the broader question of the allocation of govt-imposed costs.
<u>Recommendation #5</u> **BC Hydro should continue using the split between demand related and energy related generation revenue requirements excluding subsidiary net income.** **BC Hydro Response** BC Hydro proposes to continue with the approach approved by the British Columbia Utilities Commission (**BCUC**) in the 2007 Rate Design Application (**RDA**) (Directives 7 and 10) whereby the classification of Powerex trade income follows overall Generation classification. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on continuing with the approach approved by the BCUC per the 2007 RDA Directives 7 and 10 for the COSS.	☐	☐	x	☐	***It is not clear what allocation principle this is intended to serve. It is fundamentally arbitrary. One could equally argue that these revenues should simply be used to reduce revenue requirements equi-proportionately across all customer groups.***
Transmission Classification					
<u>Recommendation #6</u> **For transmission assets that are primarily used to transmit power from generation**					

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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.** **BC Hydro's Response** BC Hydro agrees that the Transmission system should continue to be classified as 100% 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% demand-related. The Revenue Requirement 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 L-92-07 the BCUC accepted that a fixed charge of $43.3 million was appropriate for GRTA costs.					
Stakeholder Input BC Hydro seeks stakeholder views on continuing to classify Transmission as 100% demand related. BC Hydro asks whether stakeholders wish to		**X** **(Subject to Comment)**			***To the extent the transmission is developed solely to meet demand this would seem appropriate. However, some transmission expenditures may be made to reduce losses and therefore relate to energy costs. That***

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revisit (with reasons) the GRTA Generation-related fixed charge of $43.3 million as the basis for GRTA costs.					***would suggest something less than 100% may be more appropriate.***
Distribution and Customer Care Classifications					
Recommendations #7-9 **#7 BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available.** **#8 BC Hydro consider classifying distribution substation costs as 100 percent demand-related costs and costs for services and meters as 100 percent customer-related costs.** **#9 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.**			x		
BC Hydro Response BC Hydro accepts the recommendations for Distribution classification for the reasons described in that part of the 3 June 2014 cover letter where BC Hydro discussed its views on					

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Minimum system and Zero intercept analysis. 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. **Stakeholder Input (BC Hydro's response to Recommendations #7-#9)** BC Hydro seeks 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 7 October 2014 COSS workshop.	☐	☐	x	☐	***It is difficult for COPE to indicate its agreement or not to this as it deals with many issues where the result of your proposed review is unclear. The primary issue for COPE is the recommended classification of smart meters.*** ***We are not convinced that all meter costs should be classified as customer related. The costs of smart meters serve system objectives (and govt mandate). We are also not convinced that service costs should all be considered customer-related without regard to the size of the customer.***

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Recommendation #10 **BC Hydro classify customer care costs as customer-related.** **BC Hydro Response** Customer Care costs should be classified 100% as customer-related rather than the current 65% demand/35% customer classification directed by the BCUC in 2007. A 100% 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, page 14 of the Strawman Proposal. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on classifying Customer Care as 100% customer for purpose of the COSS.	☐	☐	x	☐	***We do not agree that all customer care costs do not vary with demand or amount of use. As a result, we do not support this proposed change.***

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation Allocation					
<u>Recommendations #11-#12</u> **For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the coincident peak (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 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 3 CP or 4 CP would be more appropriate.** **BC Hydro Response** BC Hydro proposes to continue with a 4-CP allocator as a reasonable method of allocating hydroelectric Generation demand costs: · A 12-CP 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	☐	x	☐	☐	***COPE supports a 4 CP allocator but does not take a position on whether the four months proposed should form the 4-CP or whether those 4 CP should be bi-monthly during the December/January time period as was discussed at the workshop.***

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February are relevant to the winter peak, BC Hydro believes 4 CP is more appropriate than 1 CP, 2 CP or 3 CP. 3-CP is problematic as there is no basis for choosing November-January as opposed to December-February · BC Hydro remains a winter peaking utility and does not have a significant summer peak. Refer to Table 6, page 16 of the Strawman Proposal for 1 CP, 2 CP, 4 CP and 12 CP R/C ratio analysis.					
<u>Recommendation #13</u> **As an alternative approach for hydro costs, we recommend BC Hydro consider using the Average and Excess method for allocating demand-related hydro costs.** **BC Hydro Response** Given that BC Hydro's Generation and Transmission planning is largely based on the system CP and no utilities reviewed use the Average & Excess allocation method, BC Hydro believes a 4CP approach is preferable. Additional discussion is found on page 16 of the Strawman Proposal. **Stakeholder Input - Recommendations #11-13** BC Hydro seeks stakeholder views on continuing to use Generation demand-related 4-CP allocator.	☐	x	☐	☐	***COPE supports continuing with the current 4-CP allocator for Generation and Transmission planning purposes***

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transmission Allocation					
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TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Recommendation #15</u> **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 1 non-coincident peak (NCP) as the demand allocator.** **BC Hydro response** 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 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

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Distribution Allocation					
<u>Recommendation - #16</u> **BC Hydro consider if possible 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** BC Hydro proposes to investigate the feasibility of the suggested approach and report back to customer stakeholders at the 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
R/C Ratios and Range of Reasonableness					
<u>Recommendation #17</u> **BC Hydro should 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**. **BC Hydro Response** 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%-105% is reasonable. See page 19 of the Strawman Proposal document for additional discussion. **Stakeholder Input** BC Hydro seeks further stakeholder input (with reasons) on a range of reasonableness of 95% - 105%.	☐	☐	x	☐	***We believe that in many respects the allocation of embedded costs is arbitrary and therefore it is misleading to focus on a single revenue recovery percentage and would be inappropriate to base rate adjustments on it. The narrower the 'reasonableness' band the more unreasonable would this be.*** ***An alternative approach we think warrants consideration is to calculate for each customer class a range of R/C percentages based on a range of plausible or justifiable alternative allocation assumptions akin to the "margin of error" in statistical calculations.***

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
					Then, disproportionate rate adjustments by customer class could be considered if the entire R/C range for the customer class fell significantly (e.g. more than 5%) below or above 100%.
<u>Recommendation #18</u> **BC Hydro should 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).** **BC Hydro Response** BC Hydro will make a proposal for stakeholder input in response to Recommendation #18 as part of the proposed 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Other					
<u>Customer Care Cost Allocation</u> **How to allocate Customer Care-related costs in COSS.** **BC Hydro Proposal** BC Hydro proposes to continue allocating Customer Care-related costs on a weighted basis with: · 90% of the weight based on the number of bills issued to customers · 10% based on revenue A more detailed analysis has been completed for the various categories of customer care cost and the preliminary results support an overall 90% / 10% weighting factor. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on its proposal to continue allocating Customer Care related costs on a weighted basis, with 90% based number of bills issued to customers and 10% based on revenue.	☐	☐	☐	x	

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Smart Metering & Infrastructure Program (SMI)</u> **BCUC staff asked BC Hydro to identify developments since the 2007 RDA and specifically referenced SMI** **Possible Bookends**: 1.Treat SMI costs as 100% customer-related · Consistent with historical treatment for meter-related costs · Energy savings not readily quantifiable at this early stage in SMI 2.Treat SMI costs as 100% energy-related · SMI was installed primarily for energy-saving benefit **Stakeholder Input:** BC Hydro seeks stakeholder input (with reasons) on the treatment of SMI-related costs in the COSS.					***These costs should be allocated based on the reasons smart meters were installed in the manner and time frame that they were, and the benefits they are expected to have.*** ***The way in which this was pitched to ratepayers and voters was not the same as in the past: purely a meter-related benefit, but a systemic one – one that would improve service to all by allowing the utility to more readily identify and address outages, curb energy theft (particularly from grow ops), identify conservation opportunities, etc. This means the cost benefit is both customer and energy and spans more than one rate class as well.***

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>E-Plus Customers</u> **BCUC Directive #14 from the 2007 RDA stated:** ***"Include interruptible service to E-Plus customers as a separate class in its future COS and calculate costs of providing service as though BC Hydro has the ability to interrupt the class for the four winter months"*** **BC Hydro Proposal** Two options proposed:					
Option 1: Remove E-Plus customers from the 4 CP calculation on the assumption they would have been interrupted during those peak times in the winter	☐	☐	x	☐	
Option 2: Continue to include E-Plus customers in the 4 CP calculation	☐	x	☐	☐	
BC Hydro favours Option 2. These loads are in BC Hydro's load forecast and planning. However there is no operational ability to interrupt - true Interruptibility would be expensive and administratively complex. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on the two proposed options for E-Plus customers.					***It does not make sense to the Union to remove these customers from the 4-CP calculation on that basis because they have yet to be interrupted. The assumption should be that they will be on the system.***

CONSENT TO USE PERSONAL INFORMATION

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

Signature: ___Leigha Worth______________ Date: ___Aug 21, 2014____________

Thank you for your comments.

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

You can return completed feedback forms by:

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

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

Email: bchydroregulatorygroup@bchydro.com

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

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

M S A.

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Telephone: (604) 787-1620

MEMORANDUM

To: **Jim Quail, Leigha Worth**
From: **Marvin Shaffer**
Date: **July 29, 2014**
Re: **Marginal vs Embedded Costs of Service**

In its June 19 cost-of-service workshop presentation, BC Hydro stated that it planned to maintain its embedded as opposed to marginal cost-of-service approach to allocating revenue requirements among different classes of customers. It stated that there is no widespread adoption of a marginal cost-of-service approach; the embedded approach is used by almost all Canadian and Northwest utilities.

As I stated in my comments on the first workshop, I think it is premature of BC Hydro to reject out of hand the marginal cost-of-service approach. For reasons set out below I think at a minimum BC Hydro should present estimates of what the marginal costs of service by customer class would be and the BCUC panel should be presented with information on the rationale for a marginal cost-of-service approach, how it could be implemented in a manner consistent with the overall embedded cost revenue requirement, and what its advantages and disadvantages would be relative to the embedded approach.

Contrary to BC Hydro's assertions, the Leidos review of cost of service methodology in other comparable utilities indicated that a marginal cost approach is used by two Northwest utilities: Seattle City Light and Portland General Electric. Three other utilities (of the 10 Leidos considered) used some marginal cost considerations in its cost-of-service analysis.

While it is correct to state that embedded cost-of-service is the predominant methodology used to allocate revenue requirements, it is not correct to suggest that the marginal cost approach or marginal cost considerations are not used by utilities similar at least in some respects to BC Hydro. And those that use the marginal cost approach (even some that don't) recognize the advantages it has.

In a recent report, Seattle City Light noted that a marginal cost of service approach was first adopted in the 1970's when (as is currently the case for B.C.) "the Northwest enjoyed low average rates but faced very high costs for new resources". It stated it was very important then to better signal the cost consequences of growing demands for electricity with marginal cost-based rates. Their marginal cost approach also proved important during later periods when the system was in significant surplus. It encouraged more efficient utilization of the system capability. Seattle City Light stated that the marginal cost approach has been used for every rate change since 1980 and has been very advantageous.[1]

Portland General Electric also notes the advantages of its marginal cost of service approach, particularly with growing interest in customer distributed-generation and other demand response initiatives. It states that it is important in developing more economically efficient rates, thereby enabling customers to make financial decisions consistent with the most economic use of PGE's facilities and services.[2]

Both of these utilities take the position that the starting point in developing rates is to calculate economically efficient (marginal cost-based) rates. Then those rates can be modified, in as least distorting a way as possible, to meet total revenue requirements and explicit policy objectives and constraints.

The embedded cost approach is almost exactly opposite. It takes as the starting point universally recognized economically inefficient historic average as opposed marginal costs. Historic costs do not signal the consequences of decisions to increase or decrease electricity consumption today and in the future. They do not provide consumers the information they need to make economically efficient choices. To some extent this is mitigated by two tier rate structures, but those raise difficult issues in every rate class and in any event do not address the problem with major new loads where decisions are based on average, not second tier or marginal rates.

The upcoming BC Hydro RDA affords an opportunity to consider whether it is timely to reconsider the basic methodology for developing rates. There are numerous reasons why the status quo is problematic for BC Hydro and its customers.

1. There is a marked divergence between embedded (historic average) and marginal costs, particularly for energy. Basing rates on embedded costs consequently causes the greatest distortions (relative to economically efficient marginal cost-based rates) for those customer classes that consume proportionately more energy than capacity (transmission and distribution) and customer services. In other words the distortion is greatest for large industrial customers where most evidence suggests the elasticity of demand is greatest.

   This is undermining BC Hydro's conservation efforts by encouraging inefficient demands for electricity.

   It is distorting the allocation of revenues requirements by customer class,

[1] Seattle City Light, ***Adopted Cost of Service and Cost Allocation Report 2013-14*** (http://www.seattle.gov/light/rates/docs/cosacar_2013-2014.pdf), p. 45.
[2] Portland General Electric, ***Marginal Cost of Service Testimony***, February, 2014 (http://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/filings/docketed_filings/UE-283/docs/Exhibit_1300.pdf), p.2.

suggesting for example that residential customers should be paying relatively more, when the relative cost consequences of their electricity consumption (the marginal costs associated with their consumption relative to other customer classes) suggests they should be paying relatively less.

It is increasing the cost of DSM programs and distorting the economics and allocation of DSM program funding.

2. A major challenge in the structuring of rates is how to allocate the benefits of low cost heritage supply among different customers. With embedded cost-based rates the allocation of those benefits is simply the result of embedded cost-of-service calculations, something that requires numerous assumptions and judgments, many of which are questionable at best. With marginal cost-based rates, the allocation of those benefits is policy driven. It can be implemented in accordance with explicit, transparent objectives and criteria, and as well in a manner which serves to minimize economically inefficient demands for electricity.

There is already inconsistency in the application of embedded versus marginal cost principles in the setting of rates and service terms and conditions. Tariff Supplement #6 for example calls for some or all of new connection costs to be based on marginal costs. The non-integrated area rates are based more on marginal than embedded costs. These issues will have to be reviewed in the upcoming hearing. It is timely for the broader issue of marginal versus embedded costs to be considered as well so that a more consistent, efficient and equitable set of principles and approach can be applied.

2015 RDA – June 19, 2014 COS Workshop Feedback Form

Name/Organization: Progress Energy Canada Ltd.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Demand Side Management (DSM) Functionalization					
<u>**Recommendation - #1**</u> **BC Hydro should consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service.** **BC Hydro's Response** BC Hydro proposes to functionalize DSM as 90% Generation, 5% Transmission and 5% Distribution (the proposed DSM functionalization results in about a 40% energy/58% demand/2% Customer DSM classification based on F2013 Fully Allocated Cost of Service (**FACOS**) study assumptions). The proposed DSM functionalization Revenue/Cost (**R/C**) ratio is set out in Table 1, page 4 of the Strawman Proposal. The DSM deferral balance is considered part of rate base and therefore BC Hydro proposes to functionalize a share of financing and Return on Equity costs in the COS Study (**COSS**) as DSM-related.	☐	þ	☐	☐	This is a reasonable approach to allocating DSM benefits, since the existing BC Hydro DSM program is primarily focused upon reducing overall energy consumption.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder input (with reasons) on functionalizing DSM as 90% Generation, 5% Transmission and 5% Distribution.					
Generation Classification					
<u>Recommendation #2</u> **BC Hydro should consider using either a System Load Factor method or a Plant Capacity Factor method to classify hydro costs, excluding water rental costs.** **BC Hydro's Response** BC Hydro examined three options to classify Generation hydro costs. Refer to Table 2, page 6 in the Strawman Proposal for analysis.					
Option 1: load factor method – the energy portion of Generation costs would be equal to the system load factor while the Generation demand portion would equal to 1 minus the system load factor. Implies that 60% of hydroelectric generation would be classified as energy, 40% demand related.	☐	þ	☐	☐	Most stable option being considered, less potential for year to year rate adjustments.
Option 2: spare capacity factor approach for either the entire system or on a plant by plant basis may also be appropriate. This is around 50% energy/50% demand.	☐	☐	þ	☐	Unstable rate calculation basis depending upon market conditions and provincial hydrology

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Option 3: Capacity factor approach supplemented by weighting the capacity factors for major hydroelectric plants by the book value of the facilities. This is around 45% energy/ 55% demand. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) as to whether option 1, 2 or 3 should be adopted for the COSS.	☐	☐	þ	☐	Unstable rate calculation basis depending upon market conditions and local basin hydrology
<u>**Recommendation #3**</u> **BC Hydro should continue to classify peaking thermal plant costs as demand-related and also classify associated Operations & Maintenance (O&M) costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of generation.** **BC Hydro Response** BC Hydro proposes Burrard Generating Station (**GS**) continue to be classified as demand-related, while Fort Nelson GS and Prince Rupert GS should be treated as a combination of energy and demand related. BC Hydro proposes to explore directly classifying the O&M expenses from BC Hydro owned thermal facilities as demand related.	☐	þ	☐	☐	This proposal aligns well with the actual utilization of Burrard GS as presently understood. No strong opinion on the Ft Nelson and Prince Rupert GS allocation, except to note that BC Hydro's proposed allocation of costs for these facilities does not seem unreasonable.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views (with reasons) on classifying Burrard GS as 100% demand, and Fort Nelson GS and Prince Rupert GS as a combination of energy and demand-related.					
Recommendation #4 **BC Hydro should 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.** **BC Hydro Response** BC Hydro considered five options and proposes two leading options for consideration. The impact of each leading option option is presented in Table 3, page 8 , and all five options are discussed in Table 4, page 10 of the Strawman Proposal. **Option 1:** Value approach – 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	☐	☐	þ	☐	None of the proposed options provide a completely satisfactory allocation of the costs for the entire IPP portfolio. Options 1 and 2 are the least problematic alternatives, and Option 2 appears to be the marginally superior of these two options due to the direct linkage between capacity benefits and demand costs.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Option 2: Value approach – 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. **Stakeholder Input** BC Hydro seeks stakeholder views on classifying IPP purchases and whether Option 1, Option 2 or an alternative option should be pursued.	☐	þ	☐	☐	None of the proposed options provide a completely satisfactory allocation of the costs for the entire IPP portfolio. Options 1 and 2 are the least problematic alternatives, and Option 2 appears to be the marginally superior of these two options due to the direct linkage between capacity benefits and demand costs.
<u>**Recommendation #5**</u> **BC Hydro should continue using the split between demand related and energy related generation revenue requirements excluding subsidiary net income.** **BC Hydro Response** BC Hydro proposes to continue with the approach approved by the British Columbia Utilities Commission (**BCUC**) in the 2007 Rate Design Application (**RDA**) (Directives 7 and 10) whereby the classification of Powerex trade income follows overall Generation classification. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on continuing with the approach approved by the BCUC per the 2007 RDA Directives 7 and 10 for the COSS.	☐	þ	☐	☐	The proposed approach is consistent with Directives 7 and 10 issued as part of the BCUC's 2007 BC Hydro RDA decision on October 26, 2007, and there is no compelling information available to suggest a better approach to allocating Powerex trade income.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transmission Classification					
<u>**Recommendation #6**</u> **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.** **BC Hydro's Response** BC Hydro agrees that the Transmission system should continue to be classified as 100% 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% demand-related. The Revenue Requirement 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 L-92-07 the BCUC accepted that a fixed charge of $43.3 million was appropriate for GRTA costs.					

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Stakeholder Input BC Hydro seeks stakeholder views on continuing to classify Transmission as 100% demand related. BC Hydro asks whether stakeholders wish to revisit (with reasons) the GRTA Generation-related fixed charge of $43.3 million as the basis for GRTA costs.					
Distribution and Customer Care Classifications					
<u>Recommendations #7-9</u> **#7 BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available.** **#8 BC Hydro consider classifying distribution substation costs as 100 percent demand-related costs and costs for services and meters as 100 percent customer-related costs.** **#9 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.**					

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
BC Hydro Response BC Hydro accepts the recommendations for Distribution classification for the reasons described in that part of the 3 June 2014 cover letter where BC Hydro discussed its views on Minimum system and Zero intercept analysis. 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. **Stakeholder Input (BC Hydro's response to Recommendations #7-#9)** BC Hydro seeks 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 7 October 2014 COSS workshop.	☐	☐	☐	þ	PECL's major loads will not be connected via the distribution system, so these factors are not material to PECL's BC operations.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Recommendation #10</u> **BC Hydro classify customer care costs as customer-related.** **BC Hydro Response** Customer Care costs should be classified 100% as customer-related rather than the current 65% demand/35% customer classification directed by the BCUC in 2007. A 100% 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, page 14 of the Strawman Proposal. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on classifying Customer Care as 100% customer for purpose of the COSS.	☐	þ	☐	☐	This is an appropriate allocation approach for Customer Care costs. Any different approach would potentially lead to misallocation of these costs.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation Allocation					
<u>Recommendations #11-#12</u> **For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the coincident peak (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 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 3 CP or 4 CP would be more appropriate.** **BC Hydro Response** BC Hydro proposes to continue with a 4-CP allocator as a reasonable method of allocating hydroelectric Generation demand costs: · A 12-CP 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	☐	þ	☐	☐	4CP allocation is not unreasonable given the historical range of actual system peak dates experienced in BC Hydro's service area. Sub-functional allocation would diverge from BC Hydro's postage stamp approach to ratemaking, and no information has been provided to demonstrate that the interior transmission system is unduly constrained during the summer season.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
February are relevant to the winter peak, BC Hydro believes 4 CP is more appropriate than 1 CP, 2 CP or 3 CP. 3-CP is problematic as there is no basis for choosing November-January as opposed to December-February · BC Hydro remains a winter peaking utility and does not have a significant summer peak. Refer to Table 6, page 16 of the Strawman Proposal for 1 CP, 2 CP, 4 CP and 12 CP R/C ratio analysis.					
<u>Recommendation #13</u> **As an alternative approach for hydro costs, we recommend BC Hydro consider using the Average and Excess method for allocating demand-related hydro costs.** **BC Hydro Response** Given that BC Hydro's Generaton and Transmission planning is largely based on the system CP and no utilities reviewed use the Average & Excess allocation method, BC Hydro believes a 4CP approach is preferable. Additional discussion is found on page 16 of the Strawman Proposal. **Stakeholder Input - Recommendations #11-13** BC Hydro seeks stakeholder views on continuing to use Generation demand-related 4-CP allocator.	☐	þ	☐	☐	The A&E allocation methodology is untested and appears to be an unduly complex approach to allocating demand costs.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transmission Allocation					
<u>Recommendation #14</u> **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.** **BC Hydro Response** BC Hydro proposes to continue with the 4-CP allocator approach as it remains a reasonable method to allocate Transmission costs. Additional discussion is found on page 17 of the Strawman Proposal. Refer to Table 6, page 16 for 1CP, 2CP 4CP and 12CP R/C ratio analysis. **Stakeholder Input** BC Hydro seeks stakeholder views (with reasons) on continuing to use Transmission 4-CP allocator.	☐	þ	☐	☐	4CP allocation is not unreasonable given the historical range of actual system peak dates experienced in BC Hydro's service area. Sub-functional allocation would diverge from BC Hydro's postage stamp approach to ratemaking, and no information has been provided to demonstrate that the interior transmission system is unduly constrained during the summer season.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>**Recommendation #15**</u> **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 1 non-coincident peak (NCP) as the demand allocator.** **BC Hydro response** 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 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution Allocation					
Recommendation - #16 **BC Hydro consider if possible 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** BC Hydro proposes to investigate the feasibility of the suggested approach and report back to customer stakeholders at the 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
R/C Ratios and Range of Reasonableness					
<u>Recommendation #17</u> **BC Hydro should 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**. **BC Hydro Response** 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%-105% is reasonable. See page 19 of the Strawman Proposal document for additional discussion. **Stakeholder Input** BC Hydro seeks further stakeholder input (with reasons) on a range of reasonableness of 95% - 105%.	☐	þ	☐	☐	PECL would prefer a target of unity for COS allocations for each customer class, but recognizes that this is an ideal target and a range is likely necessary. However, PECL's preference would be to utilize the narrowest practical range, e.g.; +/- 2.5% is better than +/- 5%.

TOPIC	Strongly Agree	Agree	Disagree	N/A	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Recommendation #18</u> **BC Hydro should 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).** **BC Hydro Response** BC Hydro will make a proposal for stakeholder input in response to Recommendation #18 as part of the proposed 7 October 2014 COSS workshop. **Stakeholder Input** No response required at this time.					

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Other					
Customer Care Cost Allocation **How to allocate Customer Care-related costs in COSS.** **BC Hydro Proposal** BC Hydro proposes to continue allocating Customer Care-related costs on a weighted basis with: · 90% of the weight based on the number of bills issued to customers · 10% based on revenue A more detailed analysis has been completed for the various categories of customer care cost and the preliminary results support an overall 90% / 10% weighting factor. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on its proposal to continue allocating Customer Care related costs on a weighted basis, with 90% based number of bills issued to customers and 10% based on revenue.	☐	☐	☐	☐	PECL would be interested in reviewing the more detailed analysis to help determine its position on this item.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>Smart Metering & Infrastructure Program (SMI)</u> **BCUC staff asked BC Hydro to identify developments since the 2007 RDA and specifically referenced SMI** **Possible Bookends**: 1.Treat SMI costs as 100% customer-related · Consistent with historical treatment for meter-related costs · Energy savings not readily quantifiable at this early stage in SMI 2.Treat SMI costs as 100% energy-related · SMI was installed primarily for energy-saving benefit **Stakeholder Input:** BC Hydro seeks stakeholder input (with reasons) on the treatment of SMI-related costs in the COSS.					SMI costs should not be applicable to industrial rate classes, since industrial customers do not benefit materially from this program. The least objectionable proposed bookend is to to treat SMI costs as 100% Customer-related.

TOPIC	Strongly Agree	Agree	Disagree	N/A	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
<u>E-Plus Customers</u> **BCUC Directive #14 from the 2007 RDA stated:** ***“Include interruptible service to E-Plus customers as a separate class in its future COS and calculate costs of providing service as though BC Hydro has the ability to interrupt the class for the four winter months”*** **BC Hydro Proposal** Two options proposed:					
Option 1: Remove E-Plus customers from the 4 CP calculation on the assumption they would have been interrupted during those peak times in the winter	þ	☐	☐	☐	The E-Plus rate should be eliminated if there is no operational ability to interrupt these loads.
Option 2: Continue to include E-Plus customers in the 4 CP calculation	☐	☐	þ	☐	See comment above
BC Hydro favours Option 2. These loads are in BC Hydro’s load forecast and planning. However there is no operational ability to interrupt - true Interruptibility would be expensive and administratively complex. **Stakeholder Input** BC Hydro seeks stakeholder input (with reasons) on the two proposed options for E-Plus customers.					

CONSENT TO USE PERSONAL INFORMATION

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

Signature:____ Date: __________________________

Thank you for your comments.

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

You can return completed feedback forms by:

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

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

Email: bchydroregulatorygroup@bchydro.com

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

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

2015 Rate Design Application

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BC Hydro Summary and Consideration of Participant Feedback

Attachment 3

Marginal COS-related Jurisdictional Information Memorandum

NewGen Strategies & Solutions
4528 Trails End
Lapeer, MI 48446
Phone: (810) 479-0873

Memorandum

To: Craig Godsoe

Cc: Justin Miedema, Dani Ryan, and Richard Cuthbert

From: Laurie Tomczyk

Date: July 10, 2014

Re: Final Approved Revenue to Cost Ratios for U.S. Facilities in Jurisdictional Review

Background

Most electric rate case filing and studies included in the jurisdictional review portion of the BC Hydro Cost of Service Methodology Review Report that was finalized in December 2013 (2013 COS Report) were still in progress at the time they were reviewed. Therefore, revenue to cost ratios (R/C ratios) based on proposed rates rather than final approved rates were reported in the 2013 COS Report for those electric utilities whose rate case filings or studies were still in progress. Per the request of BC Hydro, the purpose of this memorandum is to report the final approved R/C ratios for the U.S. utilities included in the jurisdictional review portion of the 2013 COS Report.

Summary of Results

The following table presents a summary of the results from our review of the final R/C ratios for the U.S. utilities included in the jurisdictional review portion of the 2013 COS Report. The table indicates whether changes were made to the utilities' original proposed revenue requirements or COS analyses before the final rates were approved, and also shows the range of R/C ratios associated with the final approved rates.

Utility	Changes Made to Revenue Requirement	Changes Made to COS Analysis	Range of R/C Ratios Based on Final Approved Rates
Avista Corporation -Idaho	Yes	No	0.94 – 1.12
Avista Corporation -Washington	Yes	No	0.89 – 1.30
Bonneville Power Administration	No	Yes	NA
Idaho Power Company-Idaho	Yes	No	0.63 – 2.37
Portland General Electric	Yes	No	0.50 – 1.04
Puget Sound Energy	Yes	Yes	0.88 – 1.04
Seattle City Light	NA	NA	1.0

Memorandum

As shown in the above table, the revenue requirements for five of the utilities changed from those in their original rate case applications as part of the final rate approval process. Based on the information we found, only one of those utilities updated their COS analysis to include the new revenue requirement before the rates were finalized. Therefore, we estimated the COS results based on the final approved revenue requirements for these utilities as discussed below for purposes of calculating the R/C ratios for their final approved rates. More detailed information is provided below for each of the utilities.

Avista Corporation-Idaho

In Case No. AVU-E-12-08 before the Idaho Public Utilities Commission, Avista Corporation-Idaho utilized the results of the electric COS study as a "guide" in spreading the overall proposed revenue increase to its electric service schedules in its original application filed with the Idaho Public Utilities Commission.

The final revenue requirement and rates approved by the Idaho Public Utilities Commission were part of a stipulation of settlement. The allowed revenue increase in the stipulation of settlement was lower than the proposed increase in the original application filed with the Idaho Public Utilities Commission. For settlement purposes, the parties agreed to use a pro rata allocation of the allowed revenue increase from the settlement agreement based on the Avista Corporation-Idaho's original pro rata allocation of the overall proposed revenue increase between customer classes, while not agreeing on any particular COS methodology.

In Table 1 of the attachment to this memorandum, the R/C ratios for Avista Corporation-Idaho are shown for revenues from rates in effect at the time of the original rate case application, revenues from proposed rates in their original application, and revenues from the final rates approved by the Idaho Public Utilities Commission. It should be noted, however, that the final approved revenue requirement differed from the original proposed revenue requirement, but the COS analysis was not updated with the new revenue requirement before the case was finalized. Therefore, we used a pro rata allocation of the final approved revenue requirement based on the utility's original COS results to estimate final COS results for purposes of calculating the R/C ratios based on the final approved rates in the attached Table 1.

Avista Corporation-Washington

In Docket No. UE-120436 before the Washington Utilities and Transportation Commission, Avista Corporation-Washington spread their proposed general base rate increase to the rate schedules on a uniform percentage basis in its original application.

The final revenue requirement and rates approved by the Washington Utilities and Transportation Commission were part of a stipulation of settlement. The allowed revenue increase in the settlement agreement was lower than the proposed increase in the original filing. For settlement purposes, the parties agreed to a uniform percentage of revenue increase for each class for purposes of spreading the revised electric revenue requirement. The COS methodology was not addressed in the settlement agreement or final order.

In Table 2 of the attachment to this memorandum, the R/C ratios for Avista Corporation-Washington are shown for revenues from rates in effect at the time of the original rate case application, revenues from proposed rates in their original application, and revenues from final rates approved by the Washington

Utilities and Transportation Commission. It should be noted, however, that the final approved revenue requirement differed from the original proposed revenue requirement, but the COS analysis was not updated with the new revenue requirement before the case was finalized. Therefore, we used a pro rata allocation of the final approved revenue requirement based on the utility's original COS results to estimate final COS results for purposes of calculating the R/C ratios based on the final approved rates in the attached Table 2.

Bonneville Power Administration

In the Bonneville Power Administration's BP-14 rate case, the original proposed revenue requirement did not change before the rates were finalized, but the final rates differed from those originally proposed. The methodology used by Bonneville Power to allocate costs to customer classes and design rates is governed by the Northwest Power Act, the Transmission System Act, and the Flood Control Act. The process is very complex and intermingles both COS and rate design processes. Therefore, R/C ratios are not readily identified. In general, however, the Bonneville Power Administration's rates are to be consistent with COS principles and comply with statutory rate directives.

Idaho Power Company-Idaho

In Case No. IPC-E-11-08 before the Idaho Public Utilities Commission, Idaho Power-Idaho stated that they generally advocate movement towards COS results. However, in its original application filed with the Idaho Public Utilities Commission, Idaho Power-Idaho stated that a pure COS approach would result in substantial increases to Irrigation Service, Traffic Control Lighting Service, and their four special contract customers. In order to mitigate the magnitude of the rate increase to those customer classes that would be necessary to bring them to COS levels, Idaho Power-Idaho proposed to cap the percentage increase to those customer classes at one and one-half times the overall average requested increase. As proposed, Dusk to Dawn Lighting and Municipal Street Lighting received neither a decrease nor an increase in rates. The existing rates for these classes were resulting in revenues that significantly exceeded COS levels.

The final revenue requirement and rates approved by the Idaho Public Utilities Commission were part of a stipulation of settlement. The signing parties agreed that the revised annual revenue requirement would be recovered by increasing the rates for each customer class and special contract customers by a uniform percentage instead of using the Idaho Power-Idaho's original proposal. The parties also agreed that the proposed COS study was not binding on the signing parties in future cases.

In Table 3 of the attachment to this memorandum, the R/C ratios for Idaho Power-Idaho are shown for revenues from rates in effect at the time of the original rate case application, revenues from proposed rates in their original application, and revenues from final rates approved by the Idaho Public Utilities Commission. It should be noted, however, that the final approved revenue requirement differed from the original proposed revenue requirement, and the COS analysis was not updated with the new revenue requirement before the case was finalized. Therefore, we used a pro rata allocation of the final approved revenue requirement based on the utility's original COS results to estimate final COS results for purposes of calculating the R/C ratios based on the final approved rates in the attached Table 3.

Memorandum

Portland General Electric

In Case No. IPC-E-11-08 before the Public Utility Commission of the State of Oregon, Portland General Electric used the results of their marginal COS study to spread the proposed revenue requirement in their original application, except as follows:

- Limited the rate increase to two times the average increase for Optional Time of Day and Irrigation classes, and further limited the subsidy to no more than 9.5 cents per kWh.
- For the major rate schedules, including Residential and Non-Residential/General Service classes, limited the increase to 1.25 times the average increase. This was done because of the significant changes in marginal cost estimation and rate spread proposed in this case. Furthermore, increases to the major rate schedules were limited to single digits in percent terms.
- Did not give any rate schedule a decrease.
- Employed the Customer Impact Offset (CIO) after spreading the revenue requirements in order to temper the rate impacts to certain schedules. The CIO is the method by which Portland General Electric limits price increases to certain rate schedules. The CIO then recovers from other customers the allocated costs that would otherwise be paid under those schedules. When allocating the CIO, Portland General Electric did not propose any surcharges for Residential, Small General Service, and Medium General Service schedules because for these schedules they proposed increases that were above the average increase.

The final revenue requirement and rates approved by the Public Utility Commission of the State of Oregon were part of three partial stipulations of settlement. The signing parties agreed that, except as noted below, it was appropriate to spread costs to the individual rate schedules using Portland General Electric's filed marginal cost study and the rate design principles contained in Portland General Electric's original filing in this docket. The exception was that no customer schedule should receive an average rate increase greater than 17 percent. The parties also agreed to certain changes to the marginal cost methodology.

In Table 4 of the attachment to this memorandum, the R/C ratios for Portland General Electric are shown for revenues from rates in effect at the time of the original rate case application, revenues from proposed rates in their original application, and revenues from final rates approved by the Public Utility Commission of the State of Oregon. It should be noted, however, that the final approved revenue requirement and COS methodology differed from the original proposed revenue requirement, but the updated marginal COS analysis with the new revenue requirement and methodology changes was not readily available. Therefore, we used a pro rata allocation of the final approved revenue requirement based on the utility's original COS results to estimate final COS results for purposes of calculating the R/C ratios based on the final approved rates in the attached Table 4.

Memorandum

Puget Sound Energy

In Docket No. UE-11148 before the Washington Utilities and Transportation Commission, Puget Sound Energy's indicated the proposal in its original application was "guided" by the results of the original COS study and continued movement towards parity, while also considering the relative impact on different classes of customers. Based upon the parity percentages shown in Puget Sound Energy's original COS study and the desire to move towards full parity (a parity percentage of 100 percent) in a gradual manner, Puget Sound Energy proposed the following with two exceptions:

- Apply an adjusted average rate increase to retail classes within five percent of full parity. The adjusted average electric rate increase is the average electric rate increase after accounting for the effect of above-average or below-average increases to certain classes.
- Apply a rate increase that is 75 percent of the adjusted average to the class that was more than five percent above full parity (Secondary Voltage Greater > 50 kW but <= 350 kW Schedules).
- Apply an increase that is 125 percent of the average to the one retail class that was five percent or more below full parity (Choice/Retail Wheeling).

The two exceptions were as follows:

- Campus rates are tied to rates in the High Voltage Schedule, such that the rate increase for that schedule is not independently determined. The Campus production and transmission charges are linked to those found in the High Voltage Schedule and distribution charges are based on customer-specific information. This results in a calculated rate spread amount for this class, rather than a rate spread based on a class-specific COS and rate spread analysis.
- The Firm Resale/Special Contract class were allocated an amount that would move it to full parity so that there is not a cross-jurisdictional subsidy.

The final revenue requirement and rates approved by the Washington Utilities and Transportation Commission were a part of a multiparty stipulation of settlement. The agreed upon approach for spreading the approved increase to each of the customer classes was as follows:

- Campus customer rates were determined in accordance with the calculated rate methodology, in which campus rates for power supply (generation and transmission) were set equal to High Voltage customer charges (adjusted for power factor and losses). In addition, delivery-related charges were derived based on customer specific costs of Puget Sound Energy distribution facilities used to provide delivery services directly to each Campus customer.
- The revenue requirement increase for all other rate schedules is equal to the Proposed Revenue Increase Percent multiplied by the revenue at current rates. In deriving the Proposed Revenue Increase Percent, the settling parties agree to the following rate spread metrics:
    - o With two exceptions as follows, apply a rate increase equal to 100 percent of the uniform percentage increase.

Memorandum

- o For the Secondary Voltage Greater > 50 kW but <= 350 kW Schedules, apply a percentage increase equal to 75 percent of the uniform percentage increase assigned to the other rate schedules.
- o For the Firm Resale and Special Contract Classes, apply an increase equal to the class revenue deficiency as determined in Puget Sound Energy's COS model provided with the final compliance filing in the proceeding.

In Table 5 of the attachment to this memorandum, the R/C ratios for Puget Sound Energy are shown for revenues from rates in effect at the time of the original rate case application, revenues from proposed rates in their original application, and revenues from final rates approved by the Washington Utilities and Transportation Commission. These R/C ratios based on revenues from final approved rates were determined using the results of Puget Sound Energy's revised COS model included in the final compliance filings in this proceeding.

Seattle City Light

For purposes of the jurisdictional review, we used their 2013-2014 Adopted Cost of Service and Cost Allocation Report and 2013-2014 Adopted Rate Design Report. Seattle City Light's rates and associated COS and rate design reports are approved by Seattle's Mayor and the City Council, and the rates are set every two years as a part of a biennial budget process. The rates in Seattle City Light's 2013-2014 Adopted Rate Design Report are consistent with the class revenue targets detailed in their 2013-2014 Adopted Cost of Service and Cost Allocation Report, so the R/C ratios for all classes are equal to 1.0 based on the adopted rates.

In Table 6 of the attachment to this memorandum, the R/C ratios for Seattle City Light are shown based on revenues from rates effective before adoption of the 2013-2014 rates and revenues at adopted rates.

ATTACHMENT

Table 1: Avista Corporation-Idaho Revenue to Cost Ratios

Basis of Revenue to Cost Ratios	System Total	Residential	General Service	Large General Service	Extra Large General Service	Extra Large Service CP	Pumping Service	Street & Area Lights
Revenues from Rates in Effect at Time of Orig. Rate Case Application	0.96	0.89	1.07	1.00	0.96	1.01	0.93	0.86
Revenues from Proposed Rates In Original Application	1.00	0.94	1.11	1.04	0.99	1.04	0.99	0.90
Revenues from Final Approved Rates	1.00	0.94	1.12	1.04	0.99	1.04	0.98	0.90

Table 2: Avista Corporation-Washington Revenue to Cost Ratios

Basis of Revenue to Cost Ratios	System Total	Residential	General Service	Large General Service	Extra Large General Service	Pumping Service	Street & Area Lights
Revenues from Rates in Effect at Time of Original Rate Case Application	0.92	0.81	1.19	1.06	0.87	0.88	0.90
Revenues from Proposed Rates In Original Application	1.00	0.89	1.30	1.15	0.94	0.96	0.98
Revenues from Final Approved Rates	1.00	0.89	1.30	1.15	0.94	0.96	0.98

Table 3: Idaho Power Company-Idaho Revenue to Cost Ratios

Basis of Revenue to Cost Ratios	System Total	Residential	Small General Service	Large General Service	Dusk/Dawn Lighting	Large Power Service	Irrigation Service	Unmetered Service	Municipal Lighting	Traffic Lighting
Revenues from Rates in Effect at Time of Original Rate Case Application	0.91	0.94	0.89	0.95	2.16	0.90	0.81	0.93	1.32	0.57
Revenues from Proposed Rates In Original Application	1.00	1.03	1.02	1.02	2.16	1.03	0.93	1.03	1.32	0.66
Revenues from Final Approved Rates	1.00	1.04	0.97	1.05	2.37	0.99	0.89	1.02	1.45	0.63

Table 4: Portland General Electric Revenue to Cost Ratios

Basis of Revenue to Cost Ratios	System Total	Residential	Outdoor Area Lighting	General Service <30kW	Opt. Time-of-Day G.S. >30kW	Irrigation & Drain Pump <30kW	Irrigation & Drain Pump >30kW	General Service 31-200 kW	General Service& Direct Access 201-	Schedule 89 & Direct Access >	Street & Highway Lighting	Traffic Signals
Revenues from Rates in Effect at Time of Original Rate Case Application	0.94	0.91	0.84	0.90	0.94	0.47	0.41	0.96	1.02	1.06	0.97	1.02
Revenues from Proposed Rates In Original Application	1.00	0.99	0.97	0.99	1.01	0.55	0.48	1.02	1.03	1.04	1.01	1.02
Revenues from Final Approved Rates	1.00	0.99	0.87	0.97	0.99	0.57	0.50	1.02	1.04	1.03	1.02	1.02

Table 5: Puget Sound Energy Revenue to Cost Ratios

Basis of Revenue to Cost Ratios	System Total	Residential	Secondary Voltage (kW< 50)	Secondary Voltage (kW > 50 & < 350)	Secondary Voltage (kW > 350)	Primary Voltage	Campus	High Voltage	Choice / Retail Wheeling	Lighting	Firm Resale / Special Contract
Revenues from Rates in Effect at Time of Original Rate Case Application	0.92	0.90	0.95	0.98	0.96	0.96	0.87	0.92	0.81	0.87	0.67
Revenues from Proposed Rates In Original Application	1.00	0.98	1.03	1.05	1.04	1.04	0.94	0.99	0.90	0.95	1.00
Revenues from Final Approved Rates	1.00	0.98	1.03	1.06	1.04	1.04	0.94	1.00	0.88	0.93	1.00

Table 6: Seattle City Light Revenue to Cost Ratios

Basis of Revenue to Cost Ratios	System Total	Residential	Small General Service	Medium General Service	Large General Service	High Demand	Lights
Revenues from Rates in Effect Before Adoption of 2013-2014 Rates	0.95	0.94	0.95	0.95	0.96	0.94	0.96
Revenues from Final Adopted Rates	1.00	1.00	1.00	1.00	1.00	1.00	1.00

BC hydro

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Attachment 4

Additional IPP Contract Information

As of April 1, 2014, BC Hydro had 86 Electricity Purchase Agreements (**EPAs**) with IPPs whose projects are in-service and a further 41 EPAs for IPP projects under development.[1]

IPP Contracts with Fixed Cost Component

The following are the IPP EPAs with fixed cost components: Alcan, Island Generation, Northwest Energy and McMahon. Each of these is described below.

Rio Tinto Alcan

The 2007 Alcan EPA includes a monthly capacity payment, which represents about 5 per cent of the total costs associated with the Alcan EPA. The payment relates to 'Incremental Scheduling Capacity' that BC Hydro can utilize.[2] Thus for the 2007 Alcan EPA, the capacity related payments are a relatively small portion of overall EPA cost.

Island Generation

BC Hydro typically acquires energy from Island Generation on an as needed basis. The contract structure provides Island Generation with capital cost recovery and includes a number of take or pay provisions.

Typically, Island Generation is run when the energy that it provides is economic compared to other supply sources and to the marginal value of generation from the BC Hydro system. Unless it is needed to meet Vancouver Island or other domestic system load, Island Generation is curtailed when it is uneconomic to run. Examples of when Island Generation may be curtailed include: (a) when electricity market prices are

1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/independent-power-producers-currently-supplying-power-to-bc-hydro.pdf; and https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/independent-power-producers-with-projects-currently-in-development.pdf.

2 More information on the payment can be found on page 3-29 of the BC Hydro/Alcan 2007 Electricity Purchase Agreement Report, filed as Exhibit B-2 as part of the BCUC's proceeding concerning the BC Hydro/Alcan 2007 EPA; copy available at http://www.bcuc.com/ApplicationView.aspx?ApplicationId=160.

low due to an abundance of hydroelectric generation in the Pacific Northwest; and (b) when BC Hydro system storage is approaching full, leading to an elevated risk of system spill and a lower marginal value of generation. For example, in F2014 Island Generation was run intermittently between November 2013 and February 2014 and largely curtailed outside of these months.

The terms of the contract with Island Generation specify that BC Hydro pays for fuel and fuel transportation and an electricity rate to Island Generation when the plant is ready and capable of delivering energy whether or not the energy is actually delivered. In F2016, approximately 20 per cent of the $59 million of IPP costs related to Island Generation is associated with energy generated by the plant while the remaining costs are associated with it being available on standby, i.e., to provide capacity on an as needed basis.

Northwest Energy and McMahon

For both of these EPAs there is a direct connection between energy production and contract cost. McMahon can be considered base loaded as it operates year round providing both firm energy and capacity to support the BC Hydro system. Other than about three months in a year when the plant is dispatched off (typically May thru July), Northwest Energy also operates as a base loaded facility.

Discussion on a Fixed/Variable Approach

Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results:

- In the case of Alcan, a relatively small portion of the EPA is directly related to capacity which would suggest perhaps 95 per cent classification to energy and 5 per cent to demand. This capacity classification appears low relative to the capacity benefits the EPA brings to the domestic system and more specifically the northwest coastal region of the province (close to 200 megawatts (MW) of dependable capacity). BC Hydro's proposed IPP classification option 2 (weighted with LRMC prices) suggests the Alcan EPA would be classified 86 per cent energy and 14 per cent demand.

- The approach also fails for Island Generation because the plant typically operates in the winter and the take or pay provisions take effect when the plant is not in operation during the other months of the year. A fixed/variable approach would suggest that perhaps 20 per cent of Island Generation's costs be classified as energy and the remaining 80 per cent as demand. This approach would be problematic because it would not be appropriate to assign demand-related costs from Island Generation (which occur outside of the winter period) to customer classes based on their winter usage patterns (e.g., 4CP). Furthermore, 20 per cent energy classification to Island Generation fails to account for the fact that more than 2,000 gigawatt hours of firm energy from the plant is included in BC Hydro's load/resource balance for planning purposes. For these reasons, BC Hydro does not believe a fixed/variable approach is workable for the Island Generation EPA. BC Hydro's proposed IPP classification option 2 (weighted with LRMC prices) suggests that Island Generation would be classified 73 per cent energy and 27 per cent demand.
- A fixed or variable approach for Northwest Energy and McMahon would suggest very high energy classification, which would fail to recognize the significant capacity benefits these plants bring to the system as these two EPAs contribute about 170 MW of dependable capacity to BC Hydro's load/resource balance. BC Hydro's proposed IPP classification option 2 (weighted with LRMC prices) suggests that McMahon would be classified 88 per cent energy and 12 per cent demand.

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Attachment 5

Updated, Approved R/C Ratios in the United States

NewGen Strategies & Solutions

4528 Trails End
Lapeer, MI 48446
Phone: (810) 479-0873

Memorandum

To: Craig Godsoe

Cc: Justin Miedema, Dani Ryan, and Richard Cuthbert

From: Laurie Tomczyk

Date: August 12, 2014

Re: Jurisdictional Usage of Electric Utility Marginal Cost of Service Studies in the United States

Background

Per the request of BC Hydro, the purpose of this memorandum is to report on the jurisdictional usage of marginal electric utility cost of service studies (MCOSS) in the U.S. for allocation of revenue requirements to customer classes. As a starting point, NewGen Strategies & Solutions, LLC, (NewGen) obtained the results of two past surveys that addressed jurisdictional MCOSS usage in the U.S. One survey was done by the National Economic Research Associates, Inc. in 1990[1], and the other was done on behalf of the Nevada Resorts Association in 2006[2]. For those states in which either or both of the surveys indicated that MCOSS were used to allocate revenue requirements to customer classes, NewGen researched the current status of MCOSS usage in that jurisdiction by reviewing the associated commission's rules and regulations and a few recent selected electric utility rate case filings in that jurisdiction. If additional information was needed, then associated commission staff were contacted by NewGen. In addition, a limited web search was performed to determine if any jurisdictions have recently adopted the use of electric utility MCOSS for allocation of revenue requirements to customer classes. The results of the 1990 and 2006 surveys and NewGen's additional research are shown in the attachment to this memorandum.

While marginal costs can be used for both revenue requirement allocation and rate design, the focus of this effort was on the use of MCOSS for revenue requirement allocation. Also, MCOSS can be developed for production, transmission, distribution, and/or customer functions, with the use of MCOSS for generation, transmission, time of use, and/or energy efficiency rate design being the most common. For this effort, the focus was on the use of MCOSS for allocation of, at a minimum, functionalized distribution revenue requirements.

[1] "The Role and Nature of Marginal and Avoided Costs in Ratemaking: A Survey," NERA Working Paper, February 1992.

[2] "Electric Utility Cost of Service Study Methodology by State", Nevada Resorts Association Working Paper, September 2006.

Memorandum

Craig Godsoe
August 12, 2014
Page 2

Jurisdictions Using MCOSS for Allocation of Revenue Requirements

Based on our review, the jurisdictions in the U.S. currently using MCOSS for allocation of electric utility revenue requirements to customer classes are as follows:

- **California** - In 1974, an act of the California legislature directed the California Public Utilities Commission to investigate marginal cost pricing as one of six alternatives to existing rate structures. In 1976, the California Public Utilities Commission decided to follow the marginal cost approach, but made no decisions as to how it would be applied. Several subsequent decisions addressed the types of marginal costs and methodologies.[3]
- **Maine –** The Maine Public Utilities Commission started considering MCOSS in 1977, but it was not until 1985 that the Maine Public Utilities Commission clearly began requiring MCOSS be submitted in rate design cases. By the end of the 1980s, the Maine Public Utilities Commission had moved to making its rate design approvals with heavy weight placed upon marginal cost studies. [4][5]
- **Massachusetts –** The Massachusetts Department of Public Utilities' rate design precedent since the mid-1980's has been to apply the concepts of marginal cost pricing in setting the rates of Massachusetts electric and gas utilities, to promote proper energy consumption decisions[6]. 220 CMR 30.06 requires that, "Nine months from the effective date of 220 CMR 30.00, each electric utility company shall file with the Department a minimum of two cost of service studies. One study must be based on historical embedded costs and the other on marginal costs.
- **Montana** – The Montana Public Service Commission first adopted marginal cost principles was in the 1980s. ARM § 38.5.176 states that, "The public service commission currently recognizes allocated cost of service based on marginal cost principles."
- **Nevada** – Effective beginning in 1982, NAC 704.660 required the Nevada Public Utilities Commission to consider a utility's marginal (incremental) cost of service to each class of customer in determining the revenue required from that class.[7] Also effective beginning in 1982, NAC

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[3] Conkling, R.L. (1999). Marginal Cost Pricing for Utilities: A Digest of the California Experience. *Contemporary Economic Policy, Western Economic Association International, Volume 17*.

[4] J. Rausch (on behalf of the Maine Public Utilities Commission), personal communication, August 1, 2014.

[5] In the 1977 Electric Rate Reform Act, the Commission was required to order electric public utilities to submit proposals for the development and implementation of, "rates which reflect marginal costs of services at different voltages, times of day or seasons of the year". As an initial response, the Commission stated in its Order dated September 11, 1985 (Docket No. 80-66) that, "State law does not require the adoption of a marginal cost methodology". Rather, it appeared the Commission viewed the Electric Rate Reform Act of 1977 as requiring it to consider a margin[5]al cost methodology (that is, to consider rate design proposals that are based on marginal costs). In that Order, the Commission went on to state that "Accordingly to the extent possible rates for electricity should reflect the utility's marginal cost of service." The Commission went on to state that "Our endorsement of marginal cost-based rates does not mean that embedded costs serve no purpose." The only marginal cost study submitted to date in that proceeding was one produced by on behalf of CMP and submitted to FERC in accordance with PURPA requirements. In a separate proceeding and Order dated January 10, 1985, the Commission ordered that, "that Bangor Hydro-Electric shall file a marginal cost study as part of its next general rate case or no later than June 1, 1985." Bangor Hydro had not provided a marginal cost study in that case up to that date.

[6] C.R. Goodwin on behalf of Western Massachusetts Electric Company. (2010). Expert Witness Testimony. Commonwealth of the Massachusetts Department of Public Utilities, Case No. DPU 10-70.

[7] See NAC 704.660.

704.662 required that the rates charged by a utility for supplying electricity to customers of a particular class must reflect the marginal (incremental) cost of serving that class, including any seasonal or hourly differences in the cost of the service, except in a few specified circumstances.

- **Oregon** – Since approximately 1973, the Oregon Public Utility Commission has used marginal costs as one of the principal factors for spreading revenue requirements among customer classes.[8] Several subsequent decisions addressed types of marginal costs and methodologies.

The two utilities in the jurisdictional survey that use primarily MCOSS in allocating revenue requirements to customer classes are Seattle City Light and Portland General Electric. Seattle City Light has used a marginal COS framework since 1980. Portland General Electric uses MCOSS per the Oregon Public Utility Commission's requirements adopted in 1974.

Recent Jurisdictional Decisions Regarding MCOSS Issues

As discussed above, it has been more than 25 years since any jurisdiction in the U.S. has adopted the use of MCOSS for allocation of electric utility revenue requirements. However, some recent rulings involving the use of MCOSS for allocating electric utility revenue requirements were identified during the course of the study as follows:

- **Illinois** – In its 2001 rate case, ComEd proposed the use of a MCOSS for allocating revenue requirements, the resulting Commission decision required the continued use of embedded cost of service studies.

- **Massachusetts –** In its 2010 rate case, Western Massachusetts Electric Company notes that MCOSS had more relevance prior to restructuring as the cost of incremental generation capacity is of a much greater magnitude than the distribution component of service. Given the reduced relevance with restructuring, as well as the fact the MCOSS study has a limited role in establishing rate design, the Company stated that it may be appropriate for the Department to reevaluate the need to file a MCOSS as part of a distribution rate case. The Department's final decision in this case did not address the need to file a MCOSS study. In its 2009 rate case, National Grid filed both full embedded and marginal COS studies, but the "fundamental purpose of the MCOSS was to provide information that would be useful in rate design."

- **Montana –** Even though ARM § 38.5.176 states that, "The public service commission currently recognizes allocated cost of service based on marginal cost principles.", the Montana Public Service Commission has recently allowed the use of embedded cost studies such as in Docket No. D2009.9.129 in the matter of NorthWestern Energy's Application for Approval for Authority to Establish Increased Natural Gas and Electric Delivery Service.

- **New York –** In its 2009 rate case, New York State Electric & Gas Corporation proposed using a MCOSS study for allocating revenue requirements. However, the settlement agreement approved by the Commission avoided detailed resolution of the MCOSS issues raised at the

[8] M. Cody (on behalf of Pacific Gas and Electric) and J. Miedema (on behalf of BC Hydro), personal communication, July 24, 2014.

hearings in that proceeding, primarily by providing that the revenue increases be allocated to each service classification on the basis of an equal percentage of delivery revenues.

- **North Dakota –** In Otter Tail Power's 2008 rate case filing, it was proposed that an embedded cost of service study be used to determine the revenue requirements for the major customer classes for purposes of rate design, but then the results of a MCOSS be used to apportion the revenue requirements between rate schedules within the major customer classes. While marginal cost information was used in certain instances to design the rates approved by the Commission as part of a settlement agreement, it was specified that the settlement agreement did not establish any principle or precedent for any future proceeding.
- **South Dakota –** In Otter Tail Power's 2008 rate case filing, it was proposed that an embedded cost of service study be used to determine the revenue requirements for the major customer classes for purposes of rate design, but then the results of a MCOSS be used to apportion the revenue requirements between rate schedules within the major customer classes. While marginal cost information was used in certain instances to design the rates approved by the Commission as part of a settlement agreement, it was specified that the settlement agreement did not establish any principle or precedent for any future proceeding.

The conclusion based on the rulings discussed above is that recent proposals in the U.S. to expand the use of MCOSS for allocating revenue requirements were either not approved by the associated commissions or the associated settlement agreements approved by the commissions did not establish any principles or precedents for future proceedings.

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Use of Marginal Cost of Service Studies (MCOSS) in the U.S. for Allocation of Electric Utility Revenue Requirements

Line	State	1990 Survey (10)	2006 Survey (11)	Current	Comments
1	CALIFORNIA	√	√	√	In 1974, an act of the California legislature directed the California Public Utilities Commission to investigate marginal cost pricing as one of six alternatives to existing rate structures. In 1976, the California Public Utilities Commission decided to follow the marginal cost approach, but made no decisions as to how it would be applied. Several subsequent decisions addressed the types of marginal costs and methodologies.
2	HAWAII		√		Marginal COS not required by state statutes or Commission rules. Based on a brief review of recent selected filings, it appears that IOUs and cooperative are using embedded COS.
3	IDAHO		(1)		Two Idaho utilities in jurisdictional review used embedded COS analyses, with one using marginal weighting factors to allocate production and transmission costs.
4	ILLINOIS	√			IAC 285.5110 requires "at least" an embedded COS study. ComEd proposed marginal COS in 2001, but resulting Commission decision required use of embedded COS. Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.
5	LOUISIANA		√		Neither state statutes or Commission rules address COS methodology. Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.
6	MAINE	√	√	√	In the 1977 Electric Rate Reform Act, the Commission was required to order electric public utilities to submit proposals for the development and implementation of "Rates which reflect marginal costs of services at different voltages, times of day or seasons of the year". However, it was not until 1985 when the Commission had clearly begun requiring marginal cost studies be submitted in rate design cases. By the end of the 1980s, the Commission had moved to making its rate design approvals with heavy weight placed upon marginal cost studies.
7	MARYLAND		(2)		Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.
8	MASSACHUSETTS		√ (3)	√	Department of Public Utiliites rate design precedent since the mid -1980's has been to apply the concepts of marginal cost pricing in setting the rates of Massachusetts electric and gas utilities, to promote proper energy consumption decisions. 220 CMR 30.06 requires that , "Nine months from the effective date of 220 CMR 30.00, each electric utility company shall file with the Department a minimum of two COS studies. (a) One study must be based on historical embedded costs; (b) the other, on marginal costs. In its 2010 rate case, Western Massachusetts Electric Company notes that the MCOSS had more relevance prior to restructuring as the cost of incremental generation capacity is of a much greater magnitude than the distribution component of service. Given the reduced relevance with restructuring, as well as the fact the marginal COS study has a limited role in establishing rate design, the Company believes it may be appropriate for the Department to reevaluate the need to file a MCOSS as part of a distribution rate case. The Department's final decision in this case did not address the need to file a MCOSS. In its 2009 rate case, National Grid filed both full embedded and marginal COS studies, but the "fundamental purpose of this study was to provide information that would be useful in rate design."
9	MONTANA	√	√	√	Commission adoption of marginal cost principles was in the 1980s. ARM § 38.5.176 states that, "The public service commission currently recognizes allocated COS based on marginal cost principles." However, the Commission has recently allowed the use of embedded cost studies such as in Docket No. D2009.9.129 in the matter of NorthWestern Energy's Application for Approval for Authority to Establish Increased Natural Gas and Electric Delivery Service.
10	NEVADA	√	√	√	Effective beginning in 1982, NAC 704.660 required the Commission to consider a utility's marginal (incremental) COS to each class of customer in determining the revenue required from that class. Also effective beginning in 1982, NAC 704.662 requires that the rates charged by a utility for supplying electricity to customers of a particular class must reflect the marginal (incremental) cost of serving that class, including any seasonal or hourly differences in the cost of the service, except in a few specified circumstances.
11	NEW HAMPSHIRE		(4)		Part Puc 1604.01(a)(7) requires that a the utility's most recent cost of service study be included in a rate case filing, but does not specify embedded or marginal. Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.
12	NEW MEXICO	√			NMAC 17.9.530.13.A requires that a proposed COS be included in rate filings by investor owned utilities. Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.
13	NEW YORK				In 2009 rate case, New York State Electric & Gas Corporation proposed using a MCOSS. However, the settlement agreement approved by the Commission in this proceeding avoided detailed resolution of the the MCOSS issues raised at the hearings, primarily by providing that the revenue increases be allocated to each service classification on the basis of an equal percentage of delivery revenues.
14	NORTH DAKOTA		(5)		NDCC 40-05 does not contain any requirements regarding the inclusion of COS studies in rate case filings. The Commission decided in 1981 to rely on embedded rather than marginal cost studies. In Otter Tail Power's 2008 rate case filing, it was proposed that an embedded COS study be used to determine the revenue requirements for the major customer classes for purposes of rate design, but then the results of a MCOSS be used to apportion the revenue requirements between rate shedules within the major customer classes. While marginal cost information was used in certain instances to design the rates approved by the Commission as part of a settlement agreement, it was specified that the settlement agreement did not establish any principle or precedent for any future proceeding.
15	OREGON		√	√	Since 1974, the Commission has used marginal costs as one of the principal factors for spreading revenue requirement among customer classes. Several subsequent decisions addressed types of marginal costs and methodologies.
16	PENNSYLVANIA		√ (6)		Marginal COS not required by statutes or PUC admin rules. Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.
17	RHODE ISLAND		(7)		Part 2 of the Commission Rules require filing of COS schedules, but the type is not specified. Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.
18	SOUTH DAKOTA				In Otter Tail Power's 2008 rate case filing, it was proposed that an embedded COS study be used to determine the revenue requirements for the major customer classes for purposes of rate design, but then the results of a MCOSS be used to apportion the revenue requirements between rate schedules within the major customer classes. While marginal cost information was used in certain instances to design the rates approved by the Commission as part of a settlement agreement, it was specified that the settlement agreement did not establish any principle or precedent for any future proceeding.
19	UTAH		√ (8)		Rules R746-700-21 and R746-700-22 require filing of COS schedules, but the type is not specified. Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.

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Use of Marginal Cost of Service Studies (MCOSS) in the U.S. for Allocation of Electric Utility Revenue Requirements

Line	State	1990 Survey (10)	2006 Survey (11)	Current	Comments
20	VERMONT		√		30 V.S.A. § 218 and Vermont Public Service Board Rule 2.000 do not specify the type of COS study to be filed. Based on a brief review of recent selected filings, it appears that IOUs are using embedded COS.
21	WASHINGTON		√ (9)		Seattle City Light has used a marginal COS framework since 1980; WAC 480-07-510 (6) requires a regulated, or investor-owned utility to file with the Commission "any cost studies it performed or relied on to prepare its filing" in any general rate proceeding, but does not identify a preferred methodology. Two Washington IOUs in jurisdictional review used embedded COS analyses.

(1) No standard. Accepts both studies.
(2) No standard used.
(3) Both COS studies are required.
(4) No mandated methodology. Embedded is used for the COS and the marginal is used for rate design. Not vertically integrated, so use of marginal COS is not relied on as much. Commission prefers the combination of embedded and marginal.
(5) Embedded is generally used, but there is no standard.
(6) Marginal COS study using three methods: peak responsibility, average and excess on non-coincident demand basis and company preferred (recent case - locational marginal pricing and voltage peak were used).
(7) It has been a while since a rate case with COS study for a electric utility has been done. Nobody in the office knows, but staff thought that it would be a combination of embedded and marginal COS. The marginal COS study would not be allowed as the only methodology.
(8) A combination of marginal and embedded COS may be used for rate design.
(9) Prefers utilities to submit both embedded and marginal.
(10) "The Role and Nature of Marginal and Avoided Costs in Ratemaking: A Survey," NERA Working Paper, February 1992.
(11) "Electric Utility Cost of Service Study Methodology by State", Nevada Resorts Association Working Paper, September 2006.