British Columbia Utilities Commission

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ORDER NUMBER
G-47-16

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
2015 Rate Design Application

BEFORE:
D. M. Morton, Commissioner/Panel Chair
D. A. Cote, Commissioner
K. A. Keilty, Commissioner

on April 11, 2016

ORDER

WHEREAS:

A. On September 24, 2015, British Columbia Hydro and Power Authority (BC Hydro) filed its 2015 Rate Design Application (Application);

B. A procedural conference was held on January 19, 2016, by the British Columbia Utilities Commission (Commission) to hear procedural matters on the Application;

C. By Order G-12-16 dated February 1, 2016, the Commission established the regulatory timetable for the review of the Application, which included a negotiated settlement process (NSP) for its cost of service study and rate class segmentation, to take place on March 7 and 8, 2016;

D. On February 24, 2016, the Commission issued a letter to all parties (Exhibit A-21) appointing Ms. Liisa O'Hara as the facilitator for the NSP along with the establishment of roles for several Commission staff;

E. The NSP was held in Vancouver, BC on March 7 and 8, 2016, and an agreement was reached on issues raised on the second day. The final negotiated settlement agreement (NSA) was circulated to participants on March 24, 2016;

F. The following registered interveners, along with Commission staff, participated in the NSP:

- BC Hydro;
- Association of Major Power Customers;
- British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, BC Poverty Reduction Coalition, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and Tenant Resource & Advisory Centre;
- BC Sustainable Energy Association (BCSEA) and the Sierra Club of BC;

…/2

- Commercial Energy Consumers Association of BC;
- FortisBC Energy Inc. and FortisBC Inc.;
- Movement of United Professionals (MoveUP); formerly the Canadian Office and Professional Employees' Union, Local 378 (COPE378);
- Non-Integrated Areas Ratepayers Group; and
- Zone II Ratepayers Group;

G. Letters of support for the NSA have been received from all participants of the NSP;

H. On March 31, 2016, the NSP Facilitator filed the NSA and supporting documents with the Commission; and

I. The Commission has reviewed the NSA package and considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, the British Columbia Utilities Commission approves the Negotiated Settlement Agreement for British Columbia Hydro and Power Authority pertaining to its F2016 cost of service study and rate class segmentation as issued on March 31, 2016, and attached as Appendix A to this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 11th day of April 2016.

BY ORDER

Original signed by:

D. M. Morton
Commissioner/Panel Chair

Attachment

LIISA A. O'HARA
Consultant
c/o BC Utilities Commission
900 Howe Street, Vancouver, BC
V6Z 2N3

VIA E-MAIL

March 31, 2016

British Columbia Utilities Commission
6th Floor - 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Laurel Ross
Acting Commission Secretary

Dear Ms. Ross:

Re: British Columbia Hydro and Power Authority (BC Hydro)
2015 Rate Design Application
Negotiated Settlement Agreement
Re: F2016 Cost of Service Study

Enclosed with this letter is the proposed Negotiated Settlement Agreement (Agreement) for BC Hydro's F2016 Cost of Service Study. Also enclosed are Letters of Acceptance or Support received from the participants in the Negotiated Settlement Process (NSP).

On February 24, 2016, the Chair of the Commission appointed me to act as the facilitator of the NSP (Exhibit A-21). Participants in the NSP met on March 7 and 8, 2016 and reached an agreement at the end of the second day. During the following two weeks the Agreement was drafted and refined. The final Agreement was circulated to the participants on March 24, 2016 with a request for Letters of Acceptance or dissent due on March 30, 2016.

Since the Agreement was circulated on March 24, it has been brought to my attention that on page 3 of the Settlement Agreement, the Order issuing the Decision on BC Hydro's 2007 RDA is identified incorrectly as Order G-103-07. The proper Order is G-130-07. This reference was for context only and has no bearing on the substance of the Agreement. Rather than change the Agreement, I note the error and the proper reference here as an erratum.

The Agreement is now public and is being submitted to the non-participating registered Interveners and the Commission Panel for review. If non-participating registered Interveners have any comments, these should be received by the Commission within five business days.

In conclusion, I wish to thank all participants and BC Hydro for their willingness to co-operate and make every effort to find a path towards reaching this Agreement.

Yours truly,

Liisa A. O'Hara
NSP Facilitator

Attachments

British Columbia Hydro and Power Authority (BC HYDRO)

2015 Rate Design Application
British Columbia Utilities Commission (Commission) Project No. 3698781

NEGOTIATED SETTLEMENT AGREEMENT
REGARDING THE
F2016 COST OF SERVICE STUDY

Introduction

Participants (listed below) in the negotiated settlement process (NSP) met on March 7 and 8, 2016 for the purpose of negotiating a settlement of the F2016 Cost of Service Study (COSS) proposed in BC Hydro's 2015 Rate Design Application (2015 RDA) in accordance with Commission Order G-12-16. The NSP discussions were facilitated by a third party, Ms. Liisa O'Hara, appointed by the Commission (Facilitator).

Commission Staff participated separately in the roles of:

1. Active Participant - providing representation to ratepayer groups not actively participating in the review of the COSS;
2. Advisor - providing technical and factual support to the discussions; and
3. Observers - monitoring the NSP to ensure that it is fair and open, and providing procedural information and technical assistance to the Commission Panel.

The Commission Panel did not participate in the NSP.

Participants in the NSP for the F2016 COSS were representatives for:

- Commission staff (Commission Staff),
- BC Hydro
- Association of Major Power Customers (AMPC)
- British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, BC Poverty Reduction Coalition, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and Tenant Resource & Advisory Centre, (BCOAPO)
- BC Sustainable Energy Association (BCSEA) and the Sierra Club of BC (SCBC)
- Commercial Energy Consumers Association of BC
- FortisBC Energy Inc. and Fortis BC Inc. (collectively FortisBC)
- Movement of United Professionals (MoveUP); formerly the Canadian Office and Professional Employees' Union, Local 378 (COPE378)
- Non-Integrated Areas Ratepayers Group (NIARG)
- Zone II Ratepayers Group (ZoneIIRPG)

The British Columbia Ministry of Energy and Mines (MEM) attended the NSP as an observer and did not actively participate. All of those in attendance at the NSP, including participants, observers, the Advisor and the Facilitator, signed a copy of the Confidentiality Agreement appended to the February 2012 *Commission's Negotiated Settlement Process - Policy, Procedures and Guidelines*.

After completion of the negotiations, BC Hydro prepared a document for this Negotiated Settlement Agreement (NSA) titled "Cost of Service (COS) Model Changes as part of 2015 RDA. The document identified changes to the COSS resulting both from changes to the COSS as agreed to in the NSP and corrections for errors that were discovered during the revision to the COSS. That document is attached as Appendix B. In addition, the updated COSS is attached as Appendix C.

Issues for Negotiation

On February 11, 2016, prior to the NSP discussions, the Commission Panel issued a letter (Ex. A-18) that requested comments from interveners on the specific issues regarding the F2016 COSS that they wished to address. After receiving the intervener comments, Commission Staff acting in the role of Advisor circulated an Issues Summary on March 2, 2016 containing a list of issues to be addressed in the negotiations, including a summary of each issue as identified by each intervener.

At the beginning of the NSP, the Facilitator asked for, and received, agreement from the NSP participants that parts of the F2016 COSS that no one raised as an issue before or during the NSP would be presumed to be accepted by the NSP participants for the purposes of achieving a settlement.

Also at the beginning of the NSP the Facilitator asked the participants for suggestions on the most efficient order in which to address the issues. Those suggestions led to the issues being addressed in a different order than the Issues Summary, and the issues are presented here in the order in which they were addressed.

In the responses to the Commission Panel letter (Ex. A-18) there were four potential issues that one or more participants put forward that were either general in nature or applied to the Zone 1B and Zone II/Non-Integrated Areas. These were:

- The F2016 COSS changes relative to the 2007 RDA Decision
- Rate design and COSS principles
- The appropriateness of cost allocations as they apply to the Non-Integrated Areas (NIAs)
- COSS energy supply costs, specifically line loss and NIA diesel costs

These were identified during the NSP as either issues that would be better covered in one or more of the specific issues that follow, or as requests for clarification from BC Hydro rather than a dispute requiring resolution. BC Hydro's clarifications appeared to satisfy the parties, and these topics were not pursued further during the NSP. Consequently, they are not included in this NSA.

In the end, all the issues set out in the Issues Summary, and all other F2016 COSS issues raised in the course of the NSP, were addressed and resolved by agreement of the participants as described below.

<u>Context</u>

The last time BC Hydro filed a COSS for Commission approval was in 2007. This led to the Commission's Decision and Order G-103-07 (2007 RDA Decision).

On July 14, 2015 the Province issued Order in Council (OIC) 405, which directed that in setting BC Hydro's rates for F2017 through F2019, the BCUC must not set rates for BC Hydro for the purpose of changing the revenue-cost (R/C) ratio for a class of customer. The OIC removed much of the contention from the COSS, a key output of which is R/C ratios; parties noted that consequently the COSS would result in no rebalancing of rates between rate classes over that time period, although it could have an intra-class rate impact.

BC Hydro has committed to filing a new COSS and Rate Design Application in F2019. BC Hydro will use F2018 actuals as a basis for its F2019 RDA, and will precede it with a robust engagement process starting around the summer of 2017, using F2017 data as the initial basis of its analysis and consultation until F2018 data becomes available. Parties agreed at the outset of the negotiations that, regardless of positions taken in this NSP or the resolution of issues in this NSP, all cost of service issues would be open for discussion in the F2019 COSS and RDA, and the resolution of issues in this NSP would not establish a precedent or be used to justify approaches taken in the F2019 COSS and RDA (or to devalue alternative approaches).

A summary table of all Cost of Service (COS) issues addressed in the 2015 RDA, whether included for discussion in the NSP or not, is attached as Appendix A. The table compares the 2007 RDA Decision COS methodology to BC Hydro's 2015 RDA COS proposed methodology and to the 2016 NSA accepted methodology. With the exception of the classification of Heritage Hydro generation costs, the COS NSA resulted in no changes to BC Hydro's 2015 RDA COS methodology as proposed in Exhibit B-1.

Except where otherwise indicated, this document uses the COSS specialized terminology used by BC Hydro in the Application. Examples include: functionalization, sub-functionalization, classification, allocation, generation, transmission, distribution, customer costs, energy, demand, capacity, load factor, and capacity factor.

1.0 <u>Marginal Cost Study</u>

<u>References:</u>

Ex. B-1, pp. 3-6 and 3-7;
Ex. B-1, App. C-2A, p. 170 of 439 and pages 269 to 276 of 439
Ex. B-1, App. C-2B, Attachment 4 (pages 179 to 186 of 205)
Ex. C4-6
Ex. C12-5

<u>Issue:</u>

BC Hydro proposes an embedded cost COS approach to allocating its revenue requirement. BC Hydro does not support the use of a marginal COSS for allocating its revenue requirement, (Ex. B-1, pp. 3-5 to 3-7). MoveUP (formerly Cope 378) noted in response to Ex. A-18 that it "…intends to pursue an agreement that BC Hydro present modelling based on the Marginal Cost of Service in the next RDA even if it intends to continue with an application based on the current embedded COS." (Ex. C4-6)

Discussion:

BC Hydro states in its Application that most utilities use an embedded COS approach. It also notes that marginal COSS results in a revenue requirement that is different from the utility's approved revenue requirement, requiring adjustments to ensure that rates recover no more than the approved revenue requirement, thus varying from and diluting any price signals that would reflect "true" marginal costs. Prior to the NSP, AMPC indicated that it supported BC Hydro's proposal to continue to use an embedded cost of service for revenue requirement allocation purposes, and, consistent with the 2007 RDA Decision, believed it to be appropriate to continue to use this approach because marginal cost should not be relevant to rate design. (Ex. C12-5)

Several parties to the negotiations were concerned that the development of a marginal COSS is expensive, requires considerable judgment that would be open to debate, and would provide limited value. BC Hydro also noted that although almost all Canadian and Pacific Northwest utilities use embedded cost approaches, these jurisdictions use marginal costs to inform rate design rather than as a basis for their cost of service studies. It was also noted that BC Hydro uses Long–Run Marginal Cost (LRMC) to set Tier 2 rates and provide a price signal. In response it was argued that there might be value in using marginal cost information in specific areas and that there should be an attempt to identify any such areas.

Settlement:

MoveUp and BC Hydro will engage prior to the F2019 COSS and RDA to identify if there are specific areas where there might be value using marginal cost information.

2.0 Heritage Hydro Classification

References:

Ex. B-1, pp. 3-23 to 3-25
Ex. B-1, COS Methodology Review (App. C-2A, pp. 40 and 85 of 439);
Ex. B-1, Workshop 2 Discussion Paper (App. C-2A), pp 245-248 of 439;
Ex. B-1, Workshop 4 Discussion Guide (App. C-2B), pp. 62 and 65-67 of 205;
Ex. B-1 Workshop 4 Consideration Memo (App. C-2B), pp. 89-92 of 205;
Ex. B-5, BCUC IR 1.25.3 to 1.25.7; AMPC IR 1.3.1 -1.3.11
BCOAPO IR 1.37.2 - In its response, BC Hydro provides tables that show the energy, demand-related costs and total generation costs allocated to each rate class under the three hydroelectric classification options, which are described in section 4 of the Workshop 4 discussion guide (pages 65 to 67 of 205, Appendix C-2B, Exhibit B-1)

Issue:

BC Hydro is proposing a System Load Factor approach, adjusted for IPP energy and demand since it is classifying IPPs separately, to classify its Heritage Hydro generation. This results in a 55% energy/45% demand split. BC Hydro also put forward two alternative options:

- Capacity Factor approach weighted by book value (leading to a 45% energy/55% demand split)
- Use of BC Hydro's historic (pre-2007) classification of Heritage Hydro of a 50% energy/50% demand split.

It does not oppose adoption of any of the three classification methods. (Ex. B-1, pp. 3-23 to 3-25)

Discussion:

The 2007 RDA Direction 5 read as follows:

> *"For purposes of this Application the Commission Panel finds a 55 percent demand 45 percent energy split using the demand (head) approach is reasonable absent a detailed study and BC Hydro is directed to recalculate the FACOS [fully allocated cost of service] accordingly, as directed in Commission Order No. G-111-07.*
>
> *Further, BC Hydro is directed to include a detailed analysis of this issue as part of its next FACOS or rate design filing."*

Two participants raised the Heritage Hydro classification method as an issue for the NSP. Another party identified the Classification of Heritage Hydro as it applies to the NIA as an issue.

BC Hydro notes in its Workshop 4 Consideration Memo (App. C-2B, p. 89 of 205) that the classification of Heritage Hydro is one of the larger impact issues. The impact relative to some other COSS methodology changes is shown in the response to Fortis IR 1.2.1.

BC Hydro is proposing a System Load Factor approach, adjusted for IPP demand since it is classifying IPPs separately, to classify its Heritage Hydro generation. This results in a 55% energy/45% demand split. In the Application, BC Hydro provided a table outlining the three different options and the pros and cons of each (Ex. B-1, App. C-2A, p. 248 of 439). It notes that many utilities use a Load Factor approach, but acknowledges that such an approach doesn't account for how generation is being used for trade purposes. At the same time, BC Hydro acknowledges that a Load Factor approach doesn't account for recent expenditures on capacity, and recent additions to the Heritage Hydro system have been capacity additions.

Some parties support BC Hydro's proposed Load Factor approach; one noted that while there is no inter-class impact there would be an intra-class impact for some rate classes due to a change in the percentage of costs classified as energy-related versus demand-related. Other parties support a Capacity Factor approach weighted by book value that classifies Heritage Hydro costs 45% to energy and 55% to demand. These parties submit that such an approach is consistent with 2007 RDA Direction 5, and it continues to be the most appropriate classification mechanism for these generation costs given that capacity needs drive the design of Heritage Hydro resources making the approach more cost driven. However, the results of the Capacity

Factor approach may be unstable from year to year as capacity factors vary with water flows and new investments are made in individual generating stations.

Settlement:

As parties could not reach consensus on a methodology for classifying Heritage Hydro, parties agree to default to the energy and demand classification established in the 2007 RDA Decision (i.e. 45% energy and 55% demand) on the basis that this agreeement will not be used as a precedent or justification for a classification approach in the F2019 COSS and RDA.

3.0 Heritage Thermal Classification

References:

Ex. B-1, pp. 3-25 and 3=26
Ex. B-1, pages 87 to 90 of 439 (review of classification methods in other jurisdictions)
Ex. B-1, App. C-2A, p. 299 of 439, and 282 to 284 of 439
Ex. B-1, App C-2B, pp. 68-70 and 93 of 205
Ex. B-5, AMPC IR 1.5.1 to 1.5.3 (the latter describes how each of the three plants is used)
Ex. B-5, BCOAPO IRs 1.38.1 and 138.2.

Issue:

BC Hydro proposes different classification treatments, described below, for each of the Fort Nelson Generating plant (FNG), the Prince Rupert Generating plant (PRG) and Burrard Thermal plant (Burrard). One of the participants stated that Prince Rupert and Fort Nelson generating stations should be allocated as 45% energy /55% demand, and using a Capacity Factor approach instead of using a Load Factor approach.

Discussion:

BC Hydro proposes using a Load Factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generating costs, resulting in a 74% energy/26% demand split. For PRG, BC Hydro uses a System Load Factor approach with no adjustment for IPP supply to classify PRG's O&M and capital generation costs, resulting in a 60% energy/40% demand classification. For Burrard Thermal BC Hydro is proposing to classify O&M and capital costs as 100% demand. Fuel cost for all thermal generation will continue to be classified as 100 % energy related.

BC Hydro notes that the classification method selected for the three Heritage thermal plants does not change the COS R/C ratios when reported to one decimal place. (App. C-2B - Workshop 4 Consideration Memo, p. 13)

In the response to BCOAPO IR 1.38.1 BC Hydro confirms that all O&M, Depreciation, Tax and Finance charges associated with Thermal Generation were classified on the same basis as Heritage Hydro Generation. BC Hydro says the impact on the F2016 COSS results is negligible and it did not include the additional calculations in the F2016 COSS model in the interest of simplicity. In response to BCOAPO 1.38.2, BC Hydro provides a table showing the dollar impact resulting from its classification of Heritage Thermal costs.

Settlement:

Parties agree with the classification of Burrard Thermal's capital and operating costs as 100% demand related and fuel costs as 100% energy related. With regard to the Fort Nelson and Prince Rupert thermal plants, parties agree that the impact of the classification percentages is low and consequently accept the classification percentages proposed in the Application: that is, 74% energy/26% demand for FNG and 60% energy /40% demand for PRG. Participants did not reach consensus on a methodology for the classification of the Fort Nelson and Prince Rupert plants.

4.0 Classification of IPP costs

References:

Ex. B-1, section 3.7.3, p. 3-26
Ex. B-1, App. C-2A, Workshop 2 Consideration Memo, section 4 and Attachment 4
Ex. B-1, App.C-2B, pp. 83-84 of 205
Ex. B1-5, Responses to IRs: AMPC 1.4.1 to 1.4.7)
AMPC submission (Ex. C12-5, p. 3) and AMPC March 16 Comments (Ex, B-1, App. C-2C, p. 62 of 79)
BCOAPO submission (Ex. C2-6)

Issue:

BC Hydro's preferred option for classifying IPPs is the 'Value of Capacity' option, which results in a 93% energy and 7% demand classification. (Ex. B-1, p. 3-26) Some parties disputed BC Hydro's classification and felt much or all of it should be classified as demand.

Discussion:

Direction 6 of the 2007 RDA Decision directed BC Hydro to prepare a study for its next FACOS or rate design filing that examines and quantifies the capacity benefits associated with IPP contracts. In response to Direction 6, it undertook an 'EPA-by-EPA analysis' and developed five options (See section 4 of Workshop 2 Consideration Memo at App. C-2A).

Of the options developed, BC Hydro's preferred option for is the 'Value of Capacity' option, which results in a 93 % energy and 7 % demand classification. (Ex. B-1, p. 3-26) BC Hydro says in Section 5.2 of the Workshop 2 Consideration Memo that most participants favoured either a value of energy and capacity option or a value of capacity option (Ex. B-1, App. C-2A, pp. 284-285 of 439). BC Hydro's response to BCUC IR 1.27.1 shows the equations used to calculate the 'value of capacity' and, for various types of IPP contracts, the percentage of IPP costs classified as demand. BC Hydro provides details on the IPP contracts with fixed cost components in Attachment 4 to the Workshop 2 Consideration Memo (Ex. B-1, App. C-2A).

Discussion largely focused on the reasons why BC Hydro engages in IPP contracts and whether the chosen classification option properly reflected original cost causation. During this discussion, one participant suggested that while a principled approach based on the IPP contract structure could theoretically justify a 100% demand allocation, a more practical way to reflect what caused BC Hydro to enter into IPP contracts would be to use the same Heritage Hydro classification (45% energy and 55% demand) as a proxy for IPPs.

Settlement:

Parties accept the 93% energy/7% demand classification as proposed by BC Hydro, but not necessarily the principles behind the percentages.

In the information BC Hydro provides for the F2019 COSS, it will include high-level overviews of:

- the policy context underpinning the procurement of fixed-price take-and-pay IPP contracts (both with and without fixed cost components); and
- standard IPP contract structure(s) (e.g., why structured as take-and-pay on a MW/h basis instead of fixed monthly payments over the contract term, cancellation provisions, etc.).

BC Hydro will also discuss the energy and capacity attributable to the generation displaced by the IPP take-and-pay contracts.

5.0 Functionalization of Information Technology (IT) Costs

References:

Ex. B-1, p. 3-18 to 3-19
Ex. B-5, Responses to AMPC IRs 1.6.1 to 1.6.6; CEC IR 1.21.1
Ex. C-12-5

Issue:

BC Hydro proposes to treat IT costs as a corporate expense, functionalizing according to the "main beneficiary of the services", based on Corporate OM&A, which is functionalized proportionate to the functionalization of O&M by business unit. BC Hydro doesn't have a detailed "bottom-up" functionalization study, which some parties argued it should do in order to directly and more accurately assign IT costs to all significant users of IT services.

Discussion:

BC Hydro indicated that it would be difficult ("administratively complex and time-consuming") to do a 'bottom-up' functionalization study of IT costs (Ex. B-1, p. 3-17 to 3-19, and Response to CEC IR 1.21.1).

One party argued that a study that directly and more accurately assigns IT costs to all significant users of IT services including and specifically identifying metering, billing, customer service, and distribution operations and planning is necessary and should be conducted to inform a F2019 COSS.

The issue is explored in BC Hydro's responses to AMPC IRs 1.6.1 to 1.6.6, which generally address the functionalization of IT costs. The response to AMPC IR 1.6.2 shows what functionalized costs would be if based on total Corporate costs.

Settlement:

The parties agree to functionalize IT costs as proposed in the Application. BC Hydro agrees to repeat a high-level bottom-up cost analysis for its F2019 COSS and RDA, similar to that used for the F2016 COSS, although it does not agree that it will necessarily adopt the results of that subsequent study.

6.0 Functionalization of Regulatory Accounts and Classification of Deferral Accounts

References:

Ex. B-1, section 3.6.7, pp. 3-20 to 3-22
Ex. B-1, App. C-2B, Workshop 4 Discussion Guide, Section 3, pp. 64-65 of 205.
Ex. B-5, Response to BCOAPO IRs 1.36.1 and 1.36.2

Issue:

Annual Revenue Requirement amounts related to current amortization of deferral and regulatory account balances have previously been included in current OM&A amounts and not analyzed individually to determine the appropriate functionalization and classification. In the 2015 RDA, BC Hydro has broken these amounts out and applied a functionalization rationale to each regulatory account amount individually to follow the treatment of underlying assets. This has resulted in small adjustments to how these amounts are functionalized. The classification of deferral account amounts was similarly refined to reflect the classification associated with Cost of Energy instead of Heritage Hydro.

Discussion:

BC Hydro explained that the largest adjustment occurred as a result of changing the functionalization of the Rate Smoothing Account to align with total Revenue Requirement functionalization instead of current OM&A functionalization. No parties opposed the proposed treatment of Deferral and Regulatory Account amounts.

Settlement:

Parties accept the percentages for functionalization of Regulatory Accounts and for classification of Deferral Accounts as proposed in BC Hydro's application, but not necessarily the principles behind the percentages. As requested by the parties, BC Hydro agrees to re-examine this issue for the F2019 COSS and RDA.

BC Hydro also agreed to provide a table or tables showing the treatment of each of the Regulatory and Deferral Accounts whose functionalization or classification changed in the F2016 COSS, in order to provide more clarity. Regulatory and Deferral Accounts whose treatment did not change are not included. The table is provided below.

Account	Proposed Change to	Proposed
Heritage & Non-Heritage Deferral	Classification	Cost of Energy as per F2016 RRA: - 92% energy

Accounts		- 8% demand (previously Heritage Hydro classification)
PCB Remediation Regulatory Account	Functionalization	As per F2016 RRA: - 2% Generation - 55% Transmission - 43% Distribution (previously proportionate to functionalized Corporate O&M)
First Nations Regulatory Account	Functionalization	As per F2016 RRA: - 45% Generation - 55% Transmission (previously 100% Transmission)
Interest on Deferral & Regulatory Accounts	Functionalization	Functionalized as per associated Deferral or Regulatory Account. In F2016: - 72% Generation - 7% Transmission - 21% Distribution (previously proportionate to functionalized total annual finance charges in revenue requirement)
Rate Smoothing Regulatory Account	Functionalization	Functionalized proportionate to total revenue requirement functionalization. In F2016: - 60% Generation - 17% Transmission - 22% Distribution - 1% Customer Care (previously proportionate to functionalized Corporate O&M)

7.0 Sub-Functionalization and Classification of Distribution Costs

References:

Ex. B-1, section 3.6.3, p. 3-14
Ex. B-1, App. C-2A, pp. 256-257 of 439, and pp. 288-290 of 439
Ex. B-1, App. C-2B, pp. 72-74 of 205, and pp. 98-104 of 205
Ex. B-5, Responses to BCOAPO IRs 1.40.5; 1. 45.1; 1.47.1-2 and BCUC 1.29.1 and 1.29.2

Issue:

In the F016 COSS, BC Hydro sub-functionalized the distribution system into: primary system, transformers, secondary services, and meters, and then classified each of the sub-functionalized components separately. While parties generally were supportive of the sub-functionalization, some were opposed to the classification applied to some of the sub-functionalized assets.

Discussion:

In the F2016 COSS, BC Hydro has sub-functionalized the distribution system into: primary system, transformers, secondary services, and meters based on the advice of its COS consultants and in response to the Commission's comment in the 2007 RDA that BC Hydro should update its study of its distribution system. Customer care costs were treated separately and are included in this NSA as a separate issue.

BC Hydro's classification of the sub-functionalized distribution assets is as follows: (1) Meters: 100% customer; (2) Secondary and Services: 50% demand and 50% customer; (3) Direct Assignment of Transformers: 50% demand and 50% customer; (4) Substations and Primary: 100% demand. This results in overall Distribution classification before substations as 71% demand and 29% customer, and overall with substations (which are classified as 100% demand) as 73% demand and 27% customer.

One party took issue with the classification methodologies used by BC Hydro. Although it agreed with the sub-functionalization of distribution, it submitted that the classification methodologies do not provide a classification that is soundly grounded in the cost causation for the distribution sub-functions. In that party's view, the cost causation for the distribution system sub-functions of meters, secondary & services, transformers and primary is, at least in significant part, driven by the standards for electrical service to homes based on the quantity of amps provided for in the standard service. The BC Hydro distribution system standards then must deliver adequate capacity to enable the requirements of a standard service to be met. In its view, the standard service and the related distribution system costs caused by these design standards are largely independent of customer demand.

No other party offered an alternative proposal to BC Hydro's for the classification of distribution assets.

Settlement:

Parties agree with sub-functionalization of the distribution assets. Parties agree to accept the classification percentages used by BC Hydro in the F2016 COSS on the basis that the NSA will not be used as a precedent or justification for a classification approach in the F2019 COSS and RDA. Parties also agree that the classification of distribution assets will be comprehensively examined in the F2019 COSS and RDA.

For the F2019 COSS and RDA, BC Hydro will also review the related OM&A and Depreciation costs, by looking at the gross book value of the underlying assets to further sub-functionalize the OM&A and depreciation subject to the data being available.

8.0 Functionalization of Demand Side Management (DSM) Costs

References:

Ex. B-1, pp. 3-19 and 3-20;
Ex, B-1, Workshop 2 Consideration Memo (App C-2A), section 2.3 (pp. 10-13);
Workshop 4 Consideration Memo (App. C-2B), section 1.1 (pp. 5-70)
Ex. B-5, Responses to IRs: BCUC 1.23.2; CEC 1.23.1 to 1.23.5;

Issue:

Functionalization of DSM costs as 90% Generation, 5% Transmission and 5% Distribution

Discussion:

Direction 6 of the 2007 RDA Decision said:

> "…the Commission Panel finds that the functionalization of all revenue requirement related to demand-side management 90 percent to generation and 10 percent to transmission is appropriate. It also finds it appropriate that the portion functionalized to generation is allocated to the customer classes in the same proportions that the total generation revenue requirement is allocated to the customer classes…."

BC Hydro in the F2016 COSS proposes functionalizing DSM as 90% generation, 5% transmission and 5% distribution. BC Hydro looked at direct assignment of DSM costs but did not pursue it because it could not find a direct correlation between the benefits and costs of different DSM initiatives. (Ex. B-1, pp. 3-19 and 3-20). In its response to CEC IR 1.23.5, BC Hydro indicates that it arrived at a DSM functionalization of 90% Generation, 5% Transmission and 5% Distribution based on, among other things, an adjusted system load factor of 55%. BC Hydro further discusses direct assignment in Workshop 2 Consideration Memo section 2.3, and the rationale behind its functionalization proposal in Workshop 4 Consideration Memo section 1.1.

One party indicated that although BC Hydro's proposed functionalization of 90% generation/5%transmission and 5% distribution is an improvement over the prior split of 90% generation and 10% transmission, a higher weighting on generation would be appropriate because this better reflects the generation displacement focus and justification of utility funded DSM. (Ex. C12-5)

Settlement:

Parties support the BC Hydro proposal (90% generation/5% transmission/5% distribution), subject to BC Hydro revisiting the functionalization between generation, transmission, and distribution in the F2019 COSS and RDA.

9.0 Classification of DSM Costs

References:

Ex. B-1, Section 3.7.4, pp. 3-26 and 3-27
Ex. B-5, Responses to IRs: BCOAPO 1. 39.1 and 1.39.2.2

Issue:

BC Hydro proposes to continue classifying the part of DSM functionalized to generation (90%) in the same way as overall generation costs. Some participants questioned whether that was an appropriate classification. Parties also raised questions regarding the classification of the DSM costs functionalized to distribution.

Discussion:

BC Hydro proposes to continue classifying the part of DSM costs functionalized to generation (90%) in the same way as overall generation costs because DSM expenditures are primarily incurred to avoid generation costs. In its response to BCOAPO 1.39.1, BC Hydro notes that the proposed classification methodology for Generation-related DSM costs was not reflected in the

F2016-COS model, and BC Hydro has filed a revised series of COS Schedules as attachment 1 to the response.

In IR 1.39.2.2 (Ex. B-5), BCOAPO asks why it wouldn't be more appropriate to classify Generation-related DSM using the same percentages for demand and energy as proposed for IPPs. BC Hydro responds that this would underestimate the demand-related benefits of DSM and has revised its treatment to 76% energy and 24% demand the same as overall generation demand, and notes that it has filed revised COS schedules. (Overall generation demand and energy proportions change depending on the classification of all other generation-related costs including Heritage Hydro, therefore 76% energy/24% demand is not a fixed split for this portion of DSM costs.)

One participant indicated that it accepts the amount classified as generation, but thinks that the Distribution-related DSM, which is classified about 25% customer, should be classified as 100% demand related and pro-rated by other demand-related costs identified for distribution. BC Hydro confirmed that the order of magnitude on this issue is very small; the 25% represents about $1 million.

Settlement:

Parties agree to accept BC Hydro's classification of DSM costs, subject to revisiting the allocation of distribution-related costs in the F2019 COSS and RDA.

10.0 Classification of Generation-Related Transmission Assets

References:

Ex. B-1, p. 3-13
Ex. B-5, Responses to BCOAPO 1.31.1 and 1.31.2

Issue:

A participant raised the issue of how Generation-Related Transmission Assets (GRTAs) are classified.

Discussion:

BC Hydro has functionalized $43.3 million of transmission costs to generation as costs incurred to connect Heritage Generation assets to the transmission grid, and has classified them the same as Heritage Hydro.

A participant requested clarification on the classification of GRTAs and suggested that GRTAs should be classified based on the classification percentage using the same percentages as Heritage Hydro. BC Hydro confirmed that it classifies GRTAs in that manner.

Settlement:

Parties accept BC Hydro's classification of GRTAs on the same basis as Heritage Hydro.

11.0 Classification of Smart Meter Infrastructure (SMI) Costs

References:

Ex. B-1, section 3.7.8, pp. 3-29 to 30
Ex. B-1, App. C-2A, pp. 290-291 of 439 (Workshop 2 Consideration Memo)
Ex. B-1, App. C-2B, pp. 94-98 of 205 (Workshop 4 Consideration Memo)
Ex. B-5, Responses to IRs: BCUC 1.18.2; CEC 1.12.3, 1.12.4, 1.12.8.

Issue:

BC Hydro's proposed F2016 COSS classification of SMI costs is 100% customer-related.

Discussion:

BC Hydro proposes to classify those costs identified as SMI costs as 100% customer-related. It reviewed several other options but settled on 100% customer-related, and submits that that approach has "overwhelming jurisdictional support". BC Hydro also states that classification of SMI does not have a significant impact on R/C ratios and that it can revisit the issue in its F2019 COSS and RDA once the distribution system has feeder-by-feeder metering expected in 2016. (Ex. B-1, p. 3-30) BC Hydro evaluated 5 options; the description and impact of those options is shown in App. C-2B, Workshop 4 Consideration Memo, pp. 14-18.

The rationale for adopting a 100% customer classification was discussed with some parties putting forward the view that nothing much has changed between analogue and smart meters in terms of cost causation. Another party put forward the view that there are system-wide benefits to SMI (such as quick identification of outages and theft reduction) that should be considered, but indicated it was willing to accept BC Hydro's classification as long as the reasoning is not something that will be relied on in the F2019 COSS and RDA.

Settlement:

Parties accept the classification of SMI costs as 100% customer-related on the condition that BC Hydro agrees that the issue can be revisited in the F2019 COSS and RDA and it agrees to investigate other SMI benefits in advance of the F2019 COSS. Not all parties endorse the reasoning for the agreed-upon classification.

12.0 Classification and Allocation of Customer Care Costs

References:

Ex. B-1, pp 3-30 and 3-34
Ex. B-1, App. C-2A, p. 292 of 439
Ex. B-1, App. C-2B, pp. 74-76 of 205 and p. 109 of 205
Ex. B-5, BCUC 1.32.1

Issue:

Classification and allocation of Customer Care Costs

Discussion:

BC Hydro proposes to classify Customer Care costs as 100% customer-related. It says that customer care costs do not vary with demand and a 100% customer classification is consistent with how other utilities treat Customer Care costs.

BC Hydro currently allocates Customer Care costs to rate classes based 90% on number of customers, and 10% by revenue per rate class. The 10% allocated by revenue is an acknowledgement that the larger accounts require a different level of attention.

A 'bottom-up' approach to allocating customer care costs was discussed, BC Hydro acknowledges that a bottom-up approach would be possible, but that its analysis indicates the result would be largely the same. BC Hydro did a more detailed analysis and the results of its proposed weighted allocator method align closely with those based on a more detailed bottom-up approach (Ex. B-1, App. C-2B, pp. 74-76 of 205). It prefers the weighted allocator method because it yields a similar result to the bottom-up method but is easier to calculate.

Settlement:

Parties accept BC Hydro's approach to classifying and allocating Customer Care Costs for the 2015 RDA. BC Hydro will repeat its bottom-up study for comparison to the weighted allocator method in the F2019 COSS and RDA.

13.0 Generation Demand and Transmission Allocation and Derivation of 4CP and 1NCP allocators

References:

Ex. B-1, Sections 3.8.3 an 3.8.4 pp. 3-32 to 3-34
Ex. B-1, App. C-2A, pp. 221-229 of 439 (COS Methodology Review Presentation, slides 55-63) and pp. 258-263 of 439 (Workshop 2 Discussion Guide, Sections 7 and 8)
Ex. B-1, App. C-2B, pp. 26- 31 of 205 (Workshop 4 slide deck, slides 26 to 31) and p. 85 of 205
Ex. B-5, Responses to IRs: BCOAPO 1.43.1-2, 1.52.1 to 1.53.1.2; Fortis 1.10.1

Issue:

Two issues were conjoined and discussed together in the NSP: (1) BC Hydro's proposal to use a 4 Coincident Peak (CP) method to allocate Generation Demand and Transmission, and (2) the actual derivation of the 4CP allocator. Although the 1CP allocator was included as a potential topic in the responses to Ex. A-18, parties to the NSP did not raise it as an issue and the discussion did not focus on it.

Discussion:

BC Hydro's F2016 COSS allocates Generation Demand and Transmission using a 4CP approach, which is consistent with the 2007 RDA Direction 3. BC Hydro submits that sensitivities provided at Workshop 4 (3CP, variations on 4CP) produced little difference in the results. (Ex. B-1, pp. 3-32 and 3-33).

BC Hydro's preferred option for calculating 4CP is to use a 5-year average of 4 monthly peaks for November through February (App. C-2B, workshop 4 Slide Deck Slide 29), using data from the five most recent preceding years. To clarify how it approaches the 4CP calculation, BC Hydro first calculates for each year the average of the 4 monthly peaks, and then it averages the peaks for the five years. To calculate a rate class's 4CP allocation, BC Hydro calculated the allocation for the rate class as the five year average of the sum of that rate class's demand at each winter month's peak divided by the sum of all rate classes' demand during those same hours (Ex. B-1, p. 3-32).

Regarding the 1NCP allocator, BC Hydro's proposed methodology for assigning Distribution demand-related costs is based on average rate class profiles for five years. For each year of data, each rate class is assigned a 1NCP percentage allocator based on its annual peak load as a proportion of the sum of all the rate classes' annual peak loads (Ex. B-1, p.3-33).

In the responses to Exhibit A-18 (Commission February 11, 2016 letter requesting submissions), one participant raised the issue of whether 4CP was an appropriate allocator to use. Another party said that it expects to raise the derivation of the 4CP and 1NCP allocators, although discussion largely focused on the derivation of 4CP. The two issues - Generation demand and transmission allocation and the derivation of 4CP and 1NCP allocators - were determined to have sufficient overlap that parties decided to discuss them together.

The participant raising the issue of whether 4CP is an appropriate allocator to use submitted that the cost causation for the generation and transmission demand is more closely aligned with the system design peak related to the coldest period in the preceding 10 years, and that BC Hydro must ensure that it has adequate capacity to meet this peak and therefore must invest in the cost of the facilities which enable BC Hydro to deliver the required demand.

Regarding the issue of the calculation of the 4CP allocator, one party stated that it understood that the 2007 RDA COSS used an average of the monthly coincident peaks of the 4 winter peak months from the preceding year and questioned whether it was appropriate to move to the five year average approach described above. BC Hydro provided a draft table showing the difference in the R/C ratios between using a single year to calculate the 4 CP for each year from F2010 to F2014, and a 5-year average based on the same five years. It showed that, for every rate class, the R/C ratios based on a 4CP calculated from a 5-year average fall within the range of R/C ratios based on the single-year 4CP calculated from each of the previous 5 years. The Table also established that there is little difference between using the one-year 4CP based on F2014 (consistent with the 2007 RDA Decision) versus that calculated using a 5-year average (F2010-F2014). BC Hydro also noted that F2014 was an unusual year and that the peaks were not representative of normal system demand.

Settlement:

While not all parties supported BC Hydro's proposal to use a 4CP allocator calculated on a 5-year average for the F2016 COSS, the parties accepted the approach on the understanding that the CP allocation issues including the manner in which each of the CP allocators are determined would be comprehensively examined in the F2019 COSS and RDA proceeding.

14.0 Customer Segmentation and Street Lighting

References:

Ex. B-1, pp. 4-2 to 4-27

Issue:

By Order G-12-16 and the attached Reasons for Decision, the Commission Panel ordered a negotiated settlement process (NSP) to be used to address issues related to the COSS, rate class segmentation and BC Hydro's proposal to split the Street Lighting Class into customer-owned Street Lighting and BC Hydro-owned Street Lighting. None of the parties raised either customer segmentation or BC Hydro's street lighting proposal as an issue in the responses to Ex. A-18.

Discussion:

Customer Segmentation: With the exception of the Street Lighting class, BC Hydro proposes to keep the current customer segmentation so that the customer classes remain the same. BC Hydro has committed to looking at the possibility of an Extra-Large General Service class in Module 2 of the 2015 RDA.

Street Lighting: BC Hydro is proposing to split the street lighting class into two classes – BC Hydro-owned street lighting and non-BC Hydro-owned street lighting.

Parties briefly discussed the customer segmentation and the street lighting proposal.

Settlement:

Parties accept the BC Hydro proposals to keep all customer classes except the street lighting class as they are currently, and to look at the possibility of an Extra-Large General Service class in Module 2.

Parties also accept the BC Hydro proposal to split the Street Lighting class into two classes, and note that the subject of the pole contact charge will be reviewed in Module 2.

<u>Appendix A</u>

<u>Summary of Material COS Methodology Topics by 2007 RDA Decision, BC Hydro 2015 RDA COS Proposals, and March 2016 NSA</u>

Cost	**F2007 RDA Decision**	**2015 RDA – BCH proposed**	**2015 RDA – March 2016 NSA**
Heritage Hydro: Classification	55% demand-related 45% energy-related	45% demand-related 55% energy-related	55% demand-related 45% energy-related
Heritage Thermal: Classification	Capital Generation costs & OMA 100% demand-related Fuel costs 100% energy	Treatment of capital generation costs & OMA varies by plant as described on page 3-25 of Exhibit B-1 Fuel costs 100% energy	
DSM: Functionalization	90% Generation 10% Transmission	90% generation 5% transmission 5% distribution	
DSM: Classification	Generation portion classified the same as all generation assets (57% demand-related, 43% energy-related)	Generation portion classified the same as overall generation	
IPP purchases: Classification	100% energy-related	7% demand-related 93% energy-related	
Distribution: Classification	35% customer-related 65% demand-related	Sub-functionalization method with the following classifications: • Substations – 100% demand-related; • Primary system – 100% demand-related; • Transformers – 50% customer-related / 50% demand-related; • Secondary system – 100% demand-related; • Services – 100% customer-related; • Meters – 100% customer-related Aggregate classification of about 73% demand-related, 27% customer-related	
Customer Care: Classification	35% customer-related 65% demand-related	100% customer-related	
IT costs: Functionalization	100% Generation	30% Generation 30% Transmission 30% Distribution 10% Customer Care Values based on F2016 RRA	
IPP capital lease	100% Customer Care	100% Generation	

costs: Functionalization		
ERP costs: Functionalization	100% Customer Care	100% Generation
Corporate Tax: Functionalization	61% Generation 0% Transmission (since BCTC was separate at the time) 39% Distribution	21% Generation 65% Transmission 30% Distribution Values based on F2016 RRA
Corporate Depreciation: Functionalization	60% Generation 0% Transmission (since BCTC was separate at the time) 40% Distribution	21% Generation 65% Transmission 14% Distribution Values based on F2016 RRA
Regulatory Accounts: Functionalization	100% Generation	See the Regulatory account section or BC Hydro's response to BCUC IR 1.24.3 for more detail
Deferral Accounts: Classification	As Heritage Hydro: 55% demand-related 45% energy-related	As Cost of Energy: 92% energy-related 8% demand-related Values based on F2016 RRA
SMI-related costs: Classification	Metering related distribution assets classified the same as other distribution (65% demand-related, 35% customer) Costs associated with regulatory account functionalized to generation and classified the same as generation assets (57% demand-related, 43% customer-related)	Both the metering related distribution assets and costs associated with the SMI regulatory account are 100% customer-related
Generation demand-related costs: Allocation	4 CP – single year	4 CP – 5 year average
Distribution demand costs: Allocation	NCP – single year	NCP – 5 year average
Metering costs: Allocation	# of customers	Weighted metering allocator

Appendix B

Cost of Service (COS) Model Changes as part of 2015 RDA

September 24, 2015

COS Model filed as Appendix E in 2015 RDA

November 17, 2015

COS Model re-filed as attachment to response to BCOAPO 1.39.1 with the following changes:

- Schedule 3.2: Correction to Distribution Sub-Functionalization
- Schedule 2.0: Correction to DSM Amortization Classification of Generation portion

March 24, 2016

COS Model re-filed as attachment to NSA with the following changes:

- Schedule 2.0: Revised Classification of Heritage Hydro
    - 2015 RDA proposed classification was 45% Demand-related and 55% Energy-related
    - NSP agreed-upon classification is 55% Demand-related and 45% Energy-related
    - Result is shift of $114.0M from Energy- to Demand-Related and $15.7M between rate classes
- Schedule 2.0: Inclusion of Thermal Generation classification by plant
    - Impact is negligible but not previously separately shown, now included for transparency
- Schedule 2.0: Correction to Classification of Deferral Account amounts
    - Proposed and accepted methodology is classification with total Cost of Energy
    - Previously classified mistakenly as Heritage Hydro
    - Result is shift of $37.1M from Energy- to Demand-related and $3.9M between rate classes
- Schedule 5.1: Correction to calculation of NCP allocators
    - 5-year average was weighted incorrectly
    - Result is shift of $0.2M between rate classes
    - Schedule is expanded to show the single-year inputs to the 5-year average calculation (see table below)

COS Model Schedule 4.0

Rate Class	Generation Costs	Transmission Costs	Distribution Costs	Customer Care Costs	Total Cost	Total Revenue	Revenue - Cost ($ million)	Revenue:Cost Ratios	R/C Ratios last filed (in response to BCOAPO IR 1.39.1)	R/C Ratio change from last filed
Residential	1,004.43	364.26	617.89	69.16	2,055.74	1,917.57	-138.2	93.3%	94.0%	-0.7%
GS Under 35 kW	184.62	57.35	118.43	7.55	367.95	411.82	43.9	111.9%	112.0%	-0.1%
MGS < 150 kW	168.79	51.19	85.68	2.06	307.72	360.50	52.8	117.2%	117.1%	0.0%
LGS > 150 kW	527.56	146.31	149.77	2.04	825.68	836.14	10.5	101.3%	100.8%	0.5%
Irrigation	2.79	0.00	4.05	0.06	6.90	6.04	-0.9	87.6%	84.8%	2.8%
Street Lighting BCH	3.19	1.56	6.71	0.41	11.88	20.61	8.7	173.6%	175.9%	-2.3%
Street Lighting Cust	9.36	3.15	4.05	0.40	16.96	17.77	0.8	104.8%	105.3%	-0.5%
Transmission	694.56	170.62	0.00	1.69	866.87	889.32	22.4	102.6%	101.3%	1.3%
Total	2,595.30	794.44	986.59	83.37	4,459.70	4,459.79	0.1	100.0%		

COS Model Schedule 5.1

Demand Allocators

Rate Class	4 CP	NCP w/o T	NCP w/o Prim
Residential	45.85%	56.57%	58.36%
GS Under 35 kW	7.22%	10.62%	10.95%
MGS < 150 kW	6.44%	8.56%	22.57%
LGS > 150 kW	18.42%	23.15%	6.98%
Irrigation	0.00%	0.43%	0.44%
Street Lighting BCH	0.20%	0.22%	0.23%
Street Lighting Cust	0.40%	0.45%	0.46%
Transmission	21.48%	0.00%	0.00%
Total	100.00%	100.00%	100.00%

Rate Class 4CP	F10	F11	F12	F13	F14	5-Yr Avg
Residential	45.61%	46.88%	47.59%	45.66%	43.51%	45.85%
GS Under 35 kW	7.00%	7.01%	6.66%	7.03%	8.39%	7.22%
MGS < 150 kW	6.15%	6.27%	6.61%	6.52%	6.67%	6.44%
LGS > 150 kW	19.13%	17.97%	17.00%	18.28%	19.70%	18.42%
Irrigation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Street Lighting BCH	0.19%	0.21%	0.21%	0.22%	0.14%	0.20%
Street Lighting Cust	0.38%	0.43%	0.43%	0.45%	0.29%	0.40%
Transmission	21.53%	21.24%	21.49%	21.83%	21.30%	21.48%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Rate Class NCP w/o T	F10	F11	F12	F13	F14	5-Yr Avg
Residential	57.58%	55.78%	57.70%	54.50%	57.30%	56.57%
GS Under 35 kW	10.45%	11.17%	10.92%	10.37%	10.17%	10.62%
MGS < 150 kW	7.98%	8.62%	9.02%	9.13%	8.06%	8.56%
LGS > 150 kW	22.82%	23.31%	21.35%	24.84%	23.42%	23.15%
Irrigation	0.52%	0.45%	0.36%	0.44%	0.39%	0.43%
Street Lighting BCH	0.21%	0.22%	0.21%	0.24%	0.22%	0.22%
Street Lighting Cust	0.43%	0.45%	0.43%	0.48%	0.45%	0.45%
Transmission	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

<u>Appendix C</u>

Addendum to COS NSA: F2016 Cost of Service – Forecast Cost

See following pages

F2016 Cost of Service - Forecast Cost

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Note: All costs are in $ X 1 million unless otherwise noted.

F2016 Cost of Service - Planned Cost

	F2016 Forecast Revenue Requirement	Generation	Transmission	Distribution	Customer Care
Cost of Energy					
IPPs and Long-term Purchases commitment	1,134.72	1,134.72	0.00	0.00	0.00
Domestic Transmission (Non-Heritage)	0.00	0.00	0.00	0.00	0.00
NIA Generation	34.30	34.30	0.00	0.00	0.00
Gas Transportation	12.10	12.10	0.00	0.00	0.00
Water Rentals	391.90	391.90	0.00	0.00	0.00
Market Purchases	56.60	56.60	0.00	0.00	0.00
Natural gas for thermal generation	26.90	26.90	0.00	0.00	0.00
Domestic Transmission (Heritage)	25.70	0.00	25.70	0.00	0.00
Non-treaty storage agreement	-19.80	-19.80	0.00	0.00	0.00
Other and Surplus Sales	-116.30	-116.30	0.00	0.00	0.00
Net purchases (sales) from Powerex	4.80	4.80	0.00	0.00	0.00
Heritage Deferral Account Recoveries	17.74	17.74	0.00	0.00	0.00
Non-Heritage Deferral Account Recoveries	104.82	104.82	0.00	0.00	0.00
Total	1,673.49	1,647.79	25.70	0.00	0.00
O M & A Expenses					
Generation	314.05	235.48	33.36	34.04	11.16
Transmission	237.96	19.31	218.64	0.00	0.00
Distribution	223.09	0.00	0.00	223.09	0.00
Customer Care	73.16	0.00	0.00	0.00	73.16
Corp Service	95.70	-7.19	43.64	39.47	19.78
Total	943.96	247.61	295.64	296.61	104.10
Depreciation & Amortization					
Generation	332.40	332.40	0.00	0.00	0.00
Transmission	182.97	0.00	182.97	0.00	0.00
Distribution	224.81	0.00	0.00	224.81	0.00
Customer Care	0.00	0.00	0.00	0.00	0.00
Corporate Services	30.06	13.50	7.43	9.13	0.00
Total	770.23	345.90	190.40	233.93	0.00
Taxes					
Generation	43.07	43.07	0.00	0.00	0.00
Transmission	131.96	0.00	131.96	0.00	0.00
Distribution	27.59	0.00	0.00	27.59	0.00
Customer Care	0.00	0.00	0.00	0.00	0.00
Corporate	15.76	3.35	10.26	2.15	0.00
Total	218.38	46.42	142.23	29.73	0.00
Finance Charges					
Generation	304.68	304.68	0.00	0.00	0.00
Transmission	231.13	0.00	231.13	0.00	0.00
Distribution	184.92	0.00	0.00	184.92	0.00
Customer Care	0.00	0.00	0.00	0.00	0.00
Interest on Regulatory Accounts	-61.74	-44.30	-4.32	-12.99	-0.13
Regulatory Account Recoveries	-26.24	-11.09	-8.42	-6.73	0.00
Total	632.75	249.29	218.39	165.20	-0.13
Allowed Net Income					
Generation	275.56	275.56	0.00	0.00	0.00
Transmission	207.27	0.00	207.27	0.00	0.00
Distribution	169.02	0.00	0.00	169.02	0.00
Customer Care	0.00	0.00	0.00	0.00	0.00
Total	651.85	275.56	207.27	169.02	0.00
Miscellaneous Revenues					
Non Tariff Revenue (Functionalized)	-112.08	-3.07	-39.19	-51.09	-18.73
Corporate Miscellaneous Revenue	-11.18	-0.31	-3.91	-5.10	-1.87
Total	-123.26	-3.38	-43.10	-56.19	-20.60
Deferral Accounts, Revenue Offsets & Other					
Subsidiary Net Income	-14.69	-14.69	0.00	0.00	0.00
Other Utility Revenue	-16.50	-16.50	0.00	0.00	0.00
Deferral Rider Revenue	-222.99	-222.99	0.00	0.00	0.00
Intersegment revenues	-53.51	-3.00	-50.51	0.00	0.00
Internal Allocations (GRTA, SDA)	0.00	43.30	-191.57	148.27	0.00
Total	-307.69	-213.88	-242.08	148.27	0.00
Total Revenue Requirement	**4,459.70**	**2,595.30**	**794.44**	**986.59**	**83.37**

Classification of Generation Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Energy Related	Demand Costs	Energy Costs	Comments
Cost of Energy						
IPPs and Long-term Purchases commitment	1,134.72	7.40%	92.60%	83.97	1,050.76	
Domestic Transmission (Non-Heritage)	-	0.00%	100.00%	-	-	
NIA Generation	34.30	0.00%	100.00%	-	34.30	
Gas Transportation	12.10	0.00%	100.00%	-	12.10	
Water Rentals	391.90	10.00%	90.00%	39.19	352.71	*Based on Water Rental Rate*
Market Purchases	56.60	0.00%	100.00%	-	56.60	
Natural gas for thermal generation	26.90	0.00%	100.00%	-	26.90	
Domestic Transmission (Heritage)	-	100.00%	0.00%	-	-	
Non-treaty storage agreement	(19.80)	0.00%	100.00%	0.0	(19.80)	
Other and Surplus Sales	(116.30)	0.00%	100.00%	-	(116.30)	
Net purchases (sales) from Powerex	4.80	0.00%	100.00%	-	4.80	
Heritage Deferral Account Recoveries	17.74	8.07%	91.93%	1.43	16.31	
Non-Heritage Deferral Account Recoveries	104.82	8.07%	91.93%	8.46	96.36	
Total	1,647.79	8.07%	91.93%	133.06	1,514.73	
O M & A Expenses						
Generation	215.05	55.00%	45.00%	118.28	96.77	
Burrard	6.24	26.00%	74.00%	1.62	4.62	
Fort Nelson	13.36	40.00%	60.00%	5.34	8.02	
Prince Rupert	0.83	100.00%	0.00%	0.83	-	
Thermal Generation	20.43	38.17%	61.83%	7.80	12.63	
Transmission	19.31	55.00%	45.00%	10.62	8.69	
Distribution	-	55.00%	45.00%	-	-	
Customer Care	-	55.00%	45.00%	-	-	
Corp Service	(7.19)	55.00%	45.00%	(3.95)	(3.23)	
Total	247.61			132.75	114.86	
					-	
Depreciation & Amortization					-	
Amort on March 2014 Assets	220.83	55.00%	45.00%	121.46	99.37	
Amortization on Additions	36.59	55.00%	45.00%	20.13	16.47	
DSM Amortization	74.98	28.93%	71.07%	21.69	53.29	
Generation	332.40	55.00%	45.00%	163.27	169.13	
Transmission	-	55.00%	45.00%	-	-	
Distribution	-	55.00%	45.00%	-	-	
Customer Care	-	55.00%	45.00%	-	-	
Corporate Services	13.50	55.00%	45.00%	7.42	6.07	
Total	345.90			170.70	175.20	
					-	
Taxes					-	
Generation	43.07	55.00%	45.00%	23.69	19.38	
Transmission	-	55.00%	45.00%	-	-	
Distribution	-	55.00%	45.00%	-	-	
Customer Care	-	55.00%	45.00%	-	-	
Corporate	3.35	55.00%	45.00%	1.84	1.51	
Total	46.42			25.53	20.89	
					-	
Finance Charges					-	
Generation	304.68	55.00%	45.00%	167.57	137.11	
Transmission	-	55.00%	45.00%	-	-	
Distribution	-	55.00%	45.00%	-	-	
Customer Care	-	55.00%	45.00%	-	-	
Interest on Deferral Accounts	(23.79)	8.07%	91.93%	(1.92)	(21.87)	
Interest on Regulatory Accounts	(20.50)	55.00%	45.00%	(11.28)	(9.23)	
Regulatory Account Recoveries	(11.09)	55.00%	45.00%	(6.10)	(4.99)	
Total	249.29			148.27	101.01	
					-	
Allowed Net Income					-	
Generation	275.56	55.00%	45.00%	151.56	124.00	
Transmission	-	55.00%	0.00%	-	-	
Distribution	-	55.00%	0.00%	-	-	
Customer Care	-	55.00%	0.00%	-	-	
Total	275.56			151.56	124.00	
					-	
Miscellaneous Revenues					-	
Non Tariff Revenue (Functionalized)	(3.07)	55.00%	45.00%	(1.69)	(1.38)	
Corporate Miscellaneous Revenue	(0.31)	55.00%	45.00%	(0.17)	(0.14)	
Total	(3.38)			(1.86)	(1.52)	
					-	
Deferral Accounts, Revenue Offsets & Other					-	
Subsidiary Net Income	(14.69)	28.93%	71.07%	(4.25)	(10.44)	*Total costs before subsidiary income*
Other Utility Revenue	(16.50)	55.00%	45.00%	(9.07)	(7.42)	
Deferral Rider Revenue	(222.99)	8.07%	91.93%	(18.01)	(204.99)	
Intersegment revenues	(3.00)	55.00%	45.00%	(1.65)	(1.35)	
Internal Allocations (GRTA, SDA)	43.30	55.00%	45.00%	23.82	19.49	
Total	(213.88)			(9.17)	(204.72)	
Total Generation Costs	**2,595.30**	**28.93%**	**71.07%**	**750.84**	**1844.46**	

Classification of Transmission Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Demand Costs
Cost of Energy			
IPPs and Long-term Purchases commitment	-	100.00%	-
Domestic Transmission (Non-Heritage)	-	100.00%	-
NIA Generation	-	100.00%	-
Gas Transportation	-	100.00%	-
Water Rentals	-	100.00%	-
Market Purchases	-	100.00%	-
Natural gas for thermal generation	-	100.00%	-
Domestic Transmission (Heritage)	25.70	100.00%	25.70
Other and Surplus Sales	-		-
Total	25.70		25.70
O M & A Expenses			
Generation	33.36	100.00%	33.36
Transmission	218.64	100.00%	218.64
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Corp Service	43.64	100.00%	43.64
Total	295.64		295.64
Depreciation & Amortization			
Generation	-	100.00%	-
Transmission	182.97	100.00%	182.97
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Corporate Services	7.43	100.00%	7.43
Total	190.40		190.40
Taxes			
Generation	-	100.00%	-
Transmission	131.96	100.00%	131.96
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Corporate	10.26	100.00%	10.26
Total	142.23		142.23
Finance Charges			
Generation	-	100.00%	-
Transmission	231.13	100.00%	231.13
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Interest on Regulatory Accounts	(4.32)	100.00%	(4.32)
Regulatory Account Recoveries	(8.42)	100.00%	(8.42)
Total	218.39		218.39
Allowed Net Income			
Generation	-	100.00%	-
Transmission	207.27	100.00%	207.27
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Total	207.27		207.27
Miscellaneous Revenues			
Non Tariff Revenue (Functionalized)	(39.19)	100.00%	(39.19)
Corporate Miscellaneous Revenue	(3.91)	100.00%	(3.91)
Total	(43.10)		(43.10)
Deferral Accounts, Revenue Offsets & Other			
Subsidiary Net Income	-	100.00%	-
Other Utility Revenue	-	100.00%	-
Deferral Rider Revenue	-	100.00%	-
Intersegment revenues	(50.51)	100.00%	(50.51)
Internal Allocations (GRTA, SDA)	(191.57)	100.00%	(191.57)
Total	(242.08)		(242.08)
Total Transmission Costs	794.44		794.44

Classification of Distribution Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Customer Related	SMI Energy Related	Streetlighting Costs (Direct Assigned)	Demand Costs	Customer Costs
Cost of Energy							
IPPs and Long-term Purchases commitment	-					-	-
Domestic Transmission (Non-Heritage)	-					-	-
NIA Generation	-					-	-
Gas Transportation	-					-	-
Water Rentals	-					-	-
Market Purchases	-					-	-
Natural gas for thermal generation	-					-	-
Domestic Transmission (Heritage)	-					-	-
Non-treaty storage agreement	-					-	-
Other and Surplus Sales	-					-	-
Net purchases (sales) from Powerex	-					-	-
Heritage Deferral Account Recoveries	-					-	-
Non-Heritage Deferral Account Recoveries	-					-	-
Total	-				-	-	-
O M & A Expenses							
Generation	34.04	71%	29%			24.17	9.87
Transmission	-	71%	29%			-	-
Distribution	191.77	71%	29%		1.23	135.28	55.25
Customer Care	-	71%	29%			-	-
Corp Service	39.47	71%	29%			28.03	11.45
Total	296.61				1.23	187.47	107.90
Depreciation & Amortization							
Generation	-	71%	29%			-	-
Transmission	-	71%	29%			-	-
Distribution	224.81	71%	29%		1.16	158.79	64.86
Customer Care	-	71%	29%			-	-
Corporate Services	9.13	71%	29%			6.48	2.65
Total	233.93				1.16	165.27	67.50
Taxes							
Generation	-	71%	29%			-	-
Transmission	-	71%	29%			-	-
Distribution	27.59	71%	29%		0.16	19.47	7.95
Customer Care	-	71%	29%			-	-
Corporate	2.15	71%	29%			1.52	0.62
Total	29.73				0.16	21.00	8.58
Finance Charges							
Generation	-	71%	29%			-	-
Transmission	-	71%	29%			-	-
Distribution	184.92	71%	29%		1.08	130.53	53.32
Customer Care	-	71%	29%			-	-
Interest on Regulatory Accounts	(12.99)	71%	29%			(9.22)	(3.77)
Regulatory Account Recoveries	(6.73)	71%	29%			(4.78)	(1.95)
Total	165.20				1.08	116.53	47.60
Allowed Net Income							
Generation	-	71%	29%			-	-
Transmission	-	71%	29%			-	-
Distribution	169.02	71%	29%		0.98	119.31	48.73
Customer Care	-	71%	29%			-	-
Total	169.02				0.98	119.31	48.73
Miscellaneous Revenues							
Non Tariff Revenue (Functionalized)	(51.09)	71%	29%			(36.27)	(14.82)
Corporate Miscellaneous Revenue	(5.10)	71%	29%			(3.62)	(1.48)
Total	(56.19)				-	(39.89)	(16.29)
Deferral Accounts, Revenue Offsets & Other							
Subsidiary Net Income	-	71%	29%			-	-
Other Utility Revenue	-	71%	29%			-	-
Deferral Rider Revenue	-	71%	29%			-	-
Intersegment revenues	-	71%	29%			-	-
Internal Allocations (GRTA, SDA)	148.27	100%	0%			148.27	-
Total	148.27				-	148.27	-
Total Distribution Costs	**986.59**	**72.8%**	**26.8%**		**4.61**	**717.96**	**264.01**

Classification of Customer Care Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Customer Related	Demand Costs	Customer Costs
Cost of Energy					
IPPs and Long-term Purchases commitment	-	0%	100%	-	-
Domestic Transmission (Non-Heritage)	-	0%	100%	-	-
NIA Generation	-	0%	100%	-	-
Gas Transportation	-	0%	100%	-	-
Water Rentals	-	0%	100%	-	-
Market Purchases	-	0%	100%	-	-
Natural gas for thermal generation	-	0%	100%	-	-
Domestic Transmission (Heritage)	-	0%	100%	-	-
Other and Surplus Sales	-	0%	100%	-	-
Total	-			-	-
O M & A Expenses					
Generation	11.16	0%	100%	-	11.16
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	73.16	0%	100%	-	73.16
Corp Service	19.78	0%	100%	-	19.78
Total	104.10			-	104.10
Depreciation & Amortization					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	-	0%	100%	-	-
Corporate Services	-	0%	100%	-	-
Total	-			-	-
Taxes					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	-	0%	100%	-	-
Corporate	-	0%	100%	-	-
Total	-			-	-
Finance Charges					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	(0.00)	0%	100%	-	(0.00)
Interest on Regulatory Accounts	(0.13)	0%	100%	-	(0.13)
Regulatory Account Recoveries	0.00	0%	100%	-	0.00
Total	(0.13)			-	(0.13)
Allowed Net Income					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	(0.00)	0%	100%	-	(0.00)
Total	(0.00)			-	(0.00)
Miscellaneous Revenues					
Non Tariff Revenue (Functionalized)	(18.73)	0%	100%	-	(18.73)
Corporate Miscellaneous Revenue	(1.87)	0%	100%	-	(1.87)
Total	(20.60)			-	(20.60)
Deferral Accounts, Revenue Offsets & Other					
Subsidiary Net Income	-	0%	100%	-	-
Other Utility Revenue	-	0%	100%	-	-
Deferral Rider Revenue	-	0%	100%	-	-
Intersegment revenues	-	0%	100%	-	-
Internal Allocations (GRTA, SDA)	-	0%	100%	-	-
Total	-			-	-
Total Customer Care Costs	83.37			-	83.37

Allocation of Generation Costs

(Classified Costs from Schedule 2.0)

Cost Classification	Generation Demand	Generation Demand-Related Costs	Generation Energy	Generation Energy Related Costs
Allocation Basis	4 CP Demand including losses (Sched 5.1)	750.84	Energy Including Loss (Sched 5.0)	1,844.46
Residential	45.85%	344.27	35.79%	660.16
GS Under 35 kW	7.22%	54.20	7.07%	130.41
MGS < 150 kW	6.44%	48.38	6.53%	120.42
LGS > 150 kW	18.42%	138.28	21.11%	389.28
Irrigation	0.00%	0.00	0.15%	2.79
Street Lighting BCH	0.20%	1.48	0.09%	1.71
Street Lighting Cust	0.40%	2.98	0.35%	6.38
Transmission	21.48%	161.26	28.91%	533.31
Total	100.0%	750.84	100.0%	1,844.46

Allocation of Transmission Costs

(Classified Costs from Schedule 2.1)

Cost Classification	Transmission Demand	Demand Related Costs (Sched 2.1)
Allocation Basis	4 CP demand including losses (Sched 5.1)	794.44
Residential	45.85%	364.26
GS Under 35 kW	7.22%	57.35
MGS < 150 kW	6.44%	51.19
LGS > 150 kW	18.42%	146.31
Irrigation	0.00%	0.00
Street Lighting BCH	0.20%	1.56
Street Lighting Cust	0.40%	3.15
Transmission	21.48%	170.62
Total	100.0%	794.44

Allocation of Distribution Costs
(Classified Costs from Schedule 2.2)

Cost Classification	Distribution Demand Related	Distribution Demand-Related	Distribution Secondary Demand Related	Distribution Secondary Demand-Related	Distribution Transformer Related	Distribution Transformer Related	Distribution Customer Related	Distribution Customer Related	Distribution Metering Related	Distribution Metering Related	Street Light Customer	Street Light Customer Related
Allocation Basis	NCP (Sched 5.1)	585.70	NCP w/o Primary (Sched 5.1)	61.30	Transformer Allocator (Sched 5.4)	141.91	Customer Count (Sched 5.2)	75.60	Metering Allocator (Sched 5.2)	117.45	Street Light Direct Assignment	4.61
Residential	56.57%	331.34	58.36%	35.78	65.51%	92.97	88.87%	67.19	77.15%	90.62	0.00%	0.00
GS Under 35 kW	10.62%	62.18	10.95%	6.71	16.80%	23.85	9.19%	6.95	15.96%	18.74	0.00%	0.00
MGS < 150 kW	8.56%	50.15	22.57%	13.84	10.74%	15.25	0.94%	0.71	4.89%	5.74	0.00%	0.00
LGS > 150 kW	23.15%	135.58	6.98%	4.28	5.41%	7.67	0.33%	0.25	1.69%	1.99	0.00%	0.00
Irrigation	0.43%	2.52	0.44%	0.27	0.54%	0.76	0.18%	0.13	0.31%	0.36	0.00%	0.00
Street Lighting BCH	0.22%	1.30	0.23%	0.14	0.33%	0.47	0.25%	0.19	0.00%	0.00	100.00%	4.61
Street Lighting Cust	0.45%	2.62	0.46%	0.28	0.67%	0.95	0.25%	0.19	0.00%	0.00	100.00%	0.00
Transmission	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00
Total	100.0%	585.70	100.0%	61.30	100.0%	141.91	100.0%	75.60	100.0%	117.45	200.0%	4.61

Allocation of Customer Care Costs
(Classified Costs from Schedule 2.3)

Cost Classification	Customer Care Demand	Customer Care Demand Related Costs	Customer Care Customer	Customer Care Customer Related Costs
Allocation Basis	NCP Sched 5.1	0.00	Blended Customer Count & Revenue Sched 5.3	83.37
Residential	56.57%	0.00	82.96%	69.16
GS Under 35 kW	10.62%	0.00	9.06%	7.55
MGS < 150 kW	8.56%	0.00	2.47%	2.06
LGS > 150 kW	23.15%	0.00	2.45%	2.04
Irrigation	0.43%	0.00	0.07%	0.06
Street Lighting BCH	0.22%	0.00	0.49%	0.41
Street Lighting Cust	0.45%	0.00	0.49%	0.40
Transmission	0.00%	0.00	2.02%	1.69
Total	100.0%	0.00	100.0%	83.37

Summary of Costs by Functions and Revenue to Cost Ratios

Rate Class	Generation Costs	Transmission Costs	Distribution Costs	Customer Care Costs	Total Cost	Total Revenue	Revenue - Cost ($ million)	Revenue:Cost Ratios
Residential	1,004.43	364.26	617.89	69.16	2,055.74	1,917.57	-138.2	93.3%
GS Under 35 kW	184.62	57.35	118.43	7.55	367.95	411.82	43.9	111.9%
MGS < 150 kW	168.79	51.19	85.68	2.06	307.72	360.50	52.8	117.2%
LGS > 150 kW	527.56	146.31	149.77	2.04	825.68	836.14	10.5	101.3%
Irrigation	2.79	0.00	4.05	0.06	6.90	6.04	-0.9	87.6%
Street Lighting BCH	3.19	1.56	6.71	0.41	11.88	20.61	8.7	173.6%
Street Lighting Cust	9.36	3.15	4.05	0.40	16.96	17.77	0.8	104.8%
Transmission	694.56	170.62	0.00	1.69	866.87	889.32	22.4	102.6%
Total	2,595.30	794.44	986.59	83.37	4,459.70	4,459.79	0.1	100.0%

Summary of Costs by Classification

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

Addendum to COS NSA

Percent of Costs by Allocator

Rate Class	Generation Energy (kWh)	Generation & Transmission Demand (4CP)	Distribution Demand (NCP)	Customer (Various)
Residential	32%	34%	20%	13%
GS Under 35 kW	35%	30%	22%	12%
MGS < 150 kW	39%	32%	23%	5%
LGS > 150 kW	47%	34%	17%	1%
Irrigation	40%	0%	46%	14%
Street Lighting BCH	14%	26%	14%	46%
Street Lighting Cust	38%	36%	20%	6%
Transmission	62%	38%	0%	0%
Total	41%	35%	16%	8%

Addendum to COS NSA

Energy Allocators

Rate Class	Energy @ Customer Meter	Distribution Loss Factor	Energy @ Transmission Interface	Transmission Loss Factor	Energy @ Generation Interface	Energy by Rate Class	Energy at Generator Allocation Factor
	(MWh)		(MWh)		(MWh)		
Residential	18,742,647	6.00%	19,867,206	6.00%	21,059,238	21,059,238	35.79%
GS Under 35 kW	3,702,548	6.00%	3,924,701	6.00%	4,160,183	4,160,183	7.07%
MGS < 150 kW Primary	87,191	3.44%	90,191	6.00%	95,602		
MGS < 150 kW Secondary	3,333,608	6.00%	3,533,624	6.00%	3,745,642		
MGS						3,841,244	6.53%
LGS > 150 kW Primary	7,118,064	3.44%	7,362,925	6.00%	7,804,701		
LGS > 150 kW Secondary	4,105,904	6.00%	4,352,258	6.00%	4,613,394		
LGS						12,418,095	21.11%
Irrigation	79,206	6.00%	83,958	6.00%	88,995	88,995	0.15%
Street Lighting BCH	48,676	6.00%	51,597	6.00%	54,692	54,692	0.09%
Street Lighting Cust	181,143	6.00%	192,011	6.00%	203,532	203,532	0.35%
Transmission	16,049,484	0.00%	16,049,484	6.00%	17,012,453	17,012,453	28.91%
Total	53,448,470		55,507,955		58,838,432	58,838,432	100.00%

Demand Allocators

Rate Class	4 CP	NCP w/o T	NCP w/o Prim
Residential	45.85%	56.57%	58.36%
GS Under 35 kW	7.22%	10.62%	10.95%
MGS < 150 kW	6.44%	8.56%	22.57%
LGS > 150 kW	18.42%	23.15%	6.98%
Irrigation	0.00%	0.43%	0.44%
Street Lighting BCH	0.20%	0.22%	0.23%
Street Lighting Cust	0.40%	0.45%	0.46%
Transmission	21.48%	0.00%	0.00%
Total	100.00%	100.00%	100.00%

Rate Class 4CP	F10	F11	F12	F13	F14	5-Yr Avg
Residential	45.61%	46.88%	47.59%	45.66%	43.51%	45.85%
GS Under 35 kW	7.00%	7.01%	6.66%	7.03%	8.39%	7.22%
MGS < 150 kW	6.15%	6.27%	6.61%	6.52%	6.67%	6.44%
LGS > 150 kW	19.13%	17.97%	17.00%	18.28%	19.70%	18.42%
Irrigation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Street Lighting BCH	0.19%	0.21%	0.21%	0.22%	0.14%	0.20%
Street Lighting Cust	0.38%	0.43%	0.43%	0.45%	0.29%	0.40%
Transmission	21.53%	21.24%	21.49%	21.83%	21.30%	21.48%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Rate Class NCP w/o T	F10	F11	F12	F13	F14	5-Yr Avg
Residential	57.58%	55.78%	57.70%	54.50%	57.30%	56.57%
GS Under 35 kW	10.45%	11.17%	10.92%	10.37%	10.17%	10.62%
MGS < 150 kW	7.98%	8.62%	9.02%	9.13%	8.06%	8.56%
LGS > 150 kW	22.82%	23.31%	21.35%	24.84%	23.42%	23.15%
Irrigation	0.52%	0.45%	0.36%	0.44%	0.39%	0.43%
Street Lighting BCH	0.21%	0.22%	0.21%	0.24%	0.22%	0.22%
Street Lighting Cust	0.43%	0.45%	0.43%	0.48%	0.45%	0.45%
Transmission	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Distribution Customer Allocators

Rate Class	Distribution Customer Count	Distribution Customer Allocator	Distribution Meter Weighting	Distribution Metering Allocator
Residential	1,766,045	88.87%	1.00	77.15%
GS Under 35 kW	182,647	9.19%	2.00	15.96%
MGS < 150 kW	18,639	0.94%	6.00	4.89%
LGS > 150 kW	6,466	0.33%	6.00	1.69%
Irrigation	3,534	0.18%	2.00	0.31%
Street Lighting BCH	4,998	0.25%	0.00	0.00%
Street Lighting Cust	4,998	0.25%	0.00	0.00%
Transmission	304	0.00%	0.00	0.00%
Total	1,987,630	100.00%	1.15	100.00%

Customer Care Allocators

Rate Class	Number of Accounts	Annual bills per account	Annual bills per rate class	# of Bills Allocator		Revenue ($millions)	Revenue Allocator		90% # of Bills Allocator	10% Revenue Allocator	Blended Customer Care Allocator
Residential	1,766,045	6	10,596,267	87.40%		$1,918	43.00%		78.7%	4.3%	82.96%
GS Under 35 kW	182,647	6	1,095,883	9.04%		$412	9.23%		8.1%	0.9%	9.06%
MGS < 150 kW	18,639	12	223,665	1.84%		$361	8.08%		1.7%	0.8%	2.47%
LGS > 150 kW	6,466	12	77,590	0.64%		$836	18.75%		0.6%	1.9%	2.45%
Irrigation	3,534	2	7,068	0.06%		$6	0.14%		0.1%	0.0%	0.07%
Street Lighting BCH	4,998	12	59,976	0.49%		$21	0.46%		0.4%	0.0%	0.49%
Street Lighting Cust	4,998	12	59,976	0.49%		$18	0.40%		0.4%	0.0%	0.49%
Transmission	304	12	3,648	0.03%		$889	19.94%		0.0%	2.0%	2.02%
Total	1,987,630		12,124,073	100.00%		4,459.8	100.00%				100.00%

Distribution Transformer Allocators

Rate Class	OH Transformers	UG Transformers	Weighted Allocator
Residential	72.15%	55.79%	65.51%
GS Under 35 kW	17.03%	16.47%	16.80%
MGS < 150 kW	6.90%	16.37%	10.74%
LGS > 150 kW	1.66%	10.89%	5.41%
Irrigation	0.85%	0.07%	0.54%
Street Lighting BCH	0.47%	0.13%	0.33%
Street Lighting Cust	0.94%	0.27%	0.67%
Transmission	0.00%	0.00%	0.00%
Total	59.41%	40.59%	100.00%

* Based on replacement costs

Distribution Classification by Sub-Functionalization

Sub-Function	F14 Year-End Assets	% of assets (excluding Substation)	% of assets without Streetlighting	Demand-related %	Customer-related %	Demand % of Total Costs	Customer % of Total Costs	% of total Demand costs	% of total Customer costs
Primary	2,176.2	55.2%	55.6%	100%	0%	55.6%	0.0%	77.8%	0.0%
Secondary/Services	576.1	14.6%	14.7%	50%	50%	7.4%	7.4%	10.3%	25.7%
Meters	498.0	12.6%	12.7%	0%	100%	0.0%	12.7%	0.0%	44.5%
Transformers	666.8	16.9%	17.0%	50%	50%	8.5%	8.5%	11.9%	29.8%
Substation	629.5								
Streetlighting	22.9	0.58%							
Total	4,569.5	100.0%	100.0%			71.4%	28.6%	100.0%	100.0%

Addendum to COS NSA

Rate Base
(re-calculated with DSM 90-5-5 alternative)

Function		SQ		Preferred	
Generation	Mid-Year Net Assets	6,500.2	42.3%	6,500.2	42.3%
	90% of DSM	851.0		851.0	
Transmission	Mid-Year Net Assets	5,482.1	32.1%	5,482.1	31.8%
	% DSM	94.6		47.3	
Distribution	Mid-Year Net Assets	4,461.8	25.7%	4,461.8	25.9%
	% DSM	-		47.3	
Corporate	Mid-Year Net Assets	776.3		776.3	

William J. Andrews
Barrister & Solicitor
1958 Parkside Lane, North Vancouver, BC, Canada, V7G 1X5
Phone: 604-924-0921, Fax: 604-924-0918, Email: wjandrews@shaw.ca

March 29, 2016

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC, V6Z 2N3
Attn: Ms. Liisa O'Hara, NSP Facilitator
By email: liisao@shaw.ca

Dear Madam:

Re: British Columbia Hydro and Power Authority 2015 Rate Design Application (RDA);
BCUC Project No.3698781;
Negotiated Settlement Agreement regarding the F2016 Cost of Service Study
BC Sustainable Energy Association and Sierra Club BC support letter

I am counsel for the interveners BC Sustainable Energy Association and Sierra Club BC. BCSEA-SCBC participated fully in the negotiated settlement process (NSP) regarding BC Hydro's F2016 Cost of Service Study pursuant to Order G-12-16 and in accordance with the Commission's February 2012 *Negotiated Settlement Process Policy, Procedures and Guidelines*[1]. In person meetings were held on March 7 and 8, 2016 and follow-up communications were conducted by email. A Negotiated Settlement Agreement was concluded. The final text was circulated to the parties on March 24, 2016. I confirm that BCSEA-SCBC support the Agreement. BCSEA-SCBC support a Commission order approving the Agreement.

Yours truly,

William J. Andrews

Barrister & Solicitor

cc. NSP Distribution List by email

[1] Appendix A to Order G-11-12.

British Columbia Utilities Commission

Eileen Cheng
Senior Economist, Rates

Eileen.cheng@bcuc.com
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Sixth Floor, 900 Howe Street
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FAX: (604) 660-1102

Log No. 51126

VIA EMAIL

March 29, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Attention: Mr. Jim Fraser, Consultant/BCUC Staff Advisor
Ms. Liisa O'Hara, BCUC Facilitator

Dear Mr. Fraser and Ms. O'Hara:

Re: British Columbia Hydro and Power Authority
Commission Order G-12-16/Project No. 3698781
2015 Rate Design Application/Cost of Service Study Negotiated Settlement Agreement

I am a British Columbia Utilities Commission (Commission) staff member who acted as an Active Participant to the Negotiated Settlement Proceeding (NSP) established by Commission Order G-12-16 to review the cost of service study and rate class segmentation that formed part of BC Hydro's 2015 Rate Design Application (RDA).

The role of an Active Participant is described in Section IV (iv) of the Commission's NSP Guidelines and further clarified in the Introduction section of the proposed Negotiated Settlement Agreement (NSA).

I am providing this letter to confirm my support of the terms of the proposed NSA and accept its use in informing the 2015 RDA proposals.

Sincerely,

Eileen Cheng
BCUC staff member – Active Participant

EC/cms
cc: parties of the NSP

Linda Dong Associates
Energy Consulting

2491 Hyannis Drive
North Vancouver, BC
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604.417.8877
linda@dongassociates.com

VIA EMAIL

March 29, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street, Box 250
Vancouver, BC
V6Z 2N3

Attention: Ms. Liisa O'Hara, NSP Facilitator
Mr. Jim Fraser, NSP Advisor

Dear Ms. O'Hara and Mr. Fraser:

Re: BC Hydro 2015 Rate Design Application
Project No. 3698781
Negotiated Settlement Agreement regarding the F2016 Cost of Service Study

The Zone II Ratepayers Group confirms its acceptance of the terms of the Negotiated Settlement Agreement regarding the F2016 Cost of Service Study for the BC Hydro 2015 Rate Design Application accompanying your email to the parties to the NSP dated March 24, 2016.

Yours truly,

Linda Dong

Linda Dong
Principal

cc: Parties to the NSP

BULL HOUSSER

Bull, Housser & Tupper LLP
1800 – 510 West Georgia Street
Vancouver, BC V6B 0M3

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Reply Attention of:	Matthew D. Keen
Direct Phone:	604.641.4913
Direct Fax:	604.646.2551
E-Mail:	mdk@bht.com
Our File:	14-3364
Date:	March 30, 2016

VIA COMMISSION E-FILING

British Columbia Utilities Commission
6th Floor – 900 Howe Street
Vancouver, BC V6Z 2V3

Attention: Ms. Liisa O'Hara, NSP Facilitator

Dear Madam:

**Re: British Columbia Hydro and Power Authority (BC Hydro) 2015 Rate Design Application (RDA); BCUC Project No. 3698781
Negotiated Settlement Agreement re F2016 Cost of Service Study
Association of Major Power Customers (AMPC) Support Letter**

We are legal counsel to AMPC in this matter. AMPC actively participated in the negotiated settlement process regarding BC Hydro's F2016 Cost of Service Study. AMPC supports a Commission order approving the Negotiated Settlement Agreement in the form circulated to the parties on March 24, 2016.

Please contact the writer if you have any questions.

Yours truly,

Bull, Housser & Tupper LLP

Matthew D. Keen

BC Hydro
Power smart

Tom A. Loski
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

March 30, 2016

Mr. Jim Fraser
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Fraser:

RE: Project No. 3698781
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2016 Cost of Service Study (COS) Negotiated Settlement Agreement (NSA)

BC Hydro writes to confirm its acceptance of the NSA attached to Mr. Jim Fraser's email dated March 24, 2016, and to provide the following comments.

The Negotiated Settlement Process took place on March 7 and 8, with further communication between participants via email over the following weeks. In BC Hydro's view, the COS NSA represents a reasonable compromise of the issues regarding the F2016 COS Study, and BC Hydro respectfully submits that the Commission should approve it.

BC Hydro thanks all participants for their efforts during these negotiations.

For further information, please contact Gordon Doyle at 604-623-3815 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Tom Loski
Chief Regulatory Officer

dr/af

Copy to: BCUC (Jim Fraser) March 24, 2016 Email Distribution List.

BCPIAC
Public Interest Advocacy Centre
208-1090 W. Pender St, Vancouver BC V6E 2N7 Coast Salish Territory
604.687.3063 fax 604.682.7896 www.bcpiac.com

March 30, 2016

Our file: 7615

VIA EMAIL

Jim Fraser, Facilitator
Consultant to BCUC
BC Utilities Commission
6th Floor 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Fraser:

**Re: BC Hydro and Power Authority 2015 Rate Design Application
March 24, 2016 Negotiated Settlement Agreement regarding the F2016 Cost of Service Study**

BCOAPO confirms its acceptance of the terms of the Negotiated Settlement Agreement dated March 24, 2016 (NSA) regarding the F2016 Cost of Service Study.

The only point we wish to raise about the NSA is regarding the following excerpt on page 13:

> "A participant requested clarification on the classification of GRTAs and suggested that GRTAs should be classified based on the classification percentage using the same percentages as Heritage Hydro. BC Hydro confirmed that it classifies GRTAs in that manner."

BCOAPO was the participant that raised this point, and we wish to clarify that the issue we raised was whether GRTAs should be classified using the percentages for all costs of Heritage Hydro, including Heritage Energy. This was in contrast to BC Hydro's proposal which forms the basis for the NSA and classifies GRTAs based on Heritage Hydro, excluding the cost of Heritage Energy.

Please let me know if you have any questions.

Sincerely,

BC Public Interest Advocacy Centre

Sarah Khan and Erin Pritchard
Staff Lawyers

c. NSP Participants

OWEN • BIRD
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E-mail: cweafer@owenbird.com
Our File: 23841/0131

March 30, 2016

VIA ELECTRONIC MAIL

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

Attention: Mr. Jim Fraser, Facilitator Consultant to BCUC

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority ("BC Hydro") 2015 Rate Design Application, Project No. 3698781
Negotiated Settlement Agreement Regarding F2016 Cost of Service Study

We are counsel for the Commercial Energy Consumers Association of British Columbia ("CEC") and write to advise that the CEC confirms its acceptance of the terms of the Negotiated Settlement Agreement dated March 24, 2016 for the BC Hydro F2016 Cost of Service Study.

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

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb
cc: CEC
cc: BC Hydro
cc: Parties to NSP

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: www.fortisbc.com

March 30, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Liisa O'Hara, BCUC Facilitator
Mr. Jim Fraser, Consultant/BCUC Staff Advisor

Dear Ms. O'Hara and Mr.Fraser:

Re: Project No. 3698781/ BCUC Order No. G-12-16

British Columbia Hydro and Power Authority (BC Hydro) 2015 Rate Design Application Cost of Service Study Negotiated Settlement Process (NSP)

FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC)

On behalf of FortisBC we, the undersigned, participated in the negotiated settlement process (NSP) established by BCUC Order G-12-16 regarding BC Hydro's F2016 Cost of Service Study and conducted in accordance with the Commission's 2012 *Negotiated Settlement Process Policy, Procedures and Guidelines*. We participated in the in-person meetings held on March 7 and 8, 2016 and in the follow-up communications conducted by email. A Negotiated Settlement Agreement (NSA) was reached in this process, the final text of which was circulated to the parties on March 24, 2016. We confirm that FortisBC supports the NSA and recommend that the Commission issue an order approving it.

If further information is required, please contact Dave Perttula at (604) 592-7470 or Corey Sinclair at (250) 469-8038.

Sincerely,

on behalf of FORTISBC

Original signed by: Dave Perttula & Corey Sinclair

cc (email only): BC Hydro
NSP Participants

ALLEVATO QUAIL & WORTH

BARRISTERS AND SOLICITORS

Allevato & Quail Law Corporation
Leigha L. Worth Law Corporation

March 30, 2016

our file 15-070
Leigha Worth
direct: 604-424-8634
lworth@aqwlaw.ca

via email

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Attention: Ms. Liisa O'Hara, BCUC Facilitator
Mr. Jim Fraser, Consultant/BCUC Staff Advisor

Dear Ms. O'Hara and Mr. Fraser:

RE: BC Hydro and Power Authority
Commission Order G-12-16 / Project No. 3698781
2015 BC Hydro Rate Design Application
Cost of Service Study Negotiated Settlement Agreement

Please be advised that I make the following submission on behalf of my client, the Movement of United Professionals, also known as the Canadian Office and Professional Employees Union, Local 378. MoveUP confirms its acceptance of the terms of the proposed Negotiated Settlement Agreement to inform the Utility's 2015 Rate Design Application.

Please do not hesitate to contact the undersigned should you have any questions.

Yours truly,

Leigha Worth
Barrister & Solicitor

cc: parties to the NSP

WEISBERG LAW
CORPORATION

2730 Ailsa Crescent
North Vancouver BC V7K 2B2
Reply to: Fred J. Weisberg
Telephone:(604) 980-4069
Email: fredweislaw@gmail.com

VIA EMAIL

March 29, 2016

British Columbia Utilities Commission
6th Floor 900 Howe Street
Vancouver, BC V6Z 2N3
Attention: Mr. Jim Fraser, Consultant/BCUC Staff Advisor
and Ms. Liisa O'Hara, BCUC Facilitator

Dear Mr. Fraser and Ms. O'Hara:

RE: BC Hydro and Power Authority
2015 Rate Design Application
Non-Integrated Areas Ratepayers Group
Negotiated Settlement Agreement for
F2016 Cost of Service Study

I am legal counsel to our clients, the Heiltsuk Tribal Council, Shearwater Marine Limited and the Gitga'at First Nation, collectively registered as the Non-Integrated Areas Ratepayers Group ("NIARG") in the above-captioned proceeding. NIARG actively participated in the March 7 and 8, 2016 Negotiated Settlement Process ("NSP") regarding BC Hydro's F2016 Cost of Service Study. The NSP negotiations were carried out pursuant to Commission Order G-12-16 and consistent with the Commission's Negotiated Settlement Process Policy, Procedures and Guidelines. Subsequent communications by email resulted in a consensus draft Negotiated Settlement Agreement ("NSA").

NIARG confirms its support for the proposed NSA regarding BC Hydro's 2016 Cost of Service Study and rate class segmentation. NIARG accepts the use of the NSA to inform BC Hydro 2015 Rate Design Application proposals.

Letter to BC Utilities Commission
Non-Integrated Areas Ratepayers Group
Confirmation of Support for COSS NSA
March 29, 2016

Yours truly,

Fred J. Weisberg

Fred J. Weisberg
Barrister & Solicitor
Weisberg Law Corporation
Counsel to the Non-Integrated Areas Ratepayers Group

Addendum to Cost of Service Negotiated Settlement
Dated March 24, 2016

Spreadsheet