2015 Rate Design Application

Module 2

Transmission Extension Policy

BC Hydro Summary and

Consideration of Participant Feedback to Date

Table of Contents

Attachments

BC Hydro is re-commencing its engagement with respect to its terms and conditions governing the interconnection and service of transmission voltage industrial customers pursuant to Tariff Supplement No. 5 (**TS 5**) and Tariff Supplement No. 6 (**TS 6**). This process forms part of Module 2 of BC Hydro's 2015 Rate Design Application (**2015 RDA**) (**Module 2**).

Prior to the formal commencement of Module 2, BC Hydro held a workshop with respect to TS 6 on November 18, 2014 (**Workshop No. 1**). Workshop No. 1 presentation slides are included at Attachment 1.

This memo summarizes BC Hydro's consideration of the stakeholder feedback in 2014. The memo is intended as a resource for stakeholders and interested parties of the status of consultations held in 2014 to support moving forward with these discussions in future workshops. Comments made by stakeholders in Workshop No. 1 are captured in this memo, as are comments made by TSR customers during the May to June 2014 regional sessions. A copy of these archived consultation materials can be found on BC Hydro's website at; https://www.bchydro.com/about/planning_regulatory/2015-rate-design/workshops.html. BC Hydro also considered submissions made as part of the 2013 Industrial Electricity Policy Review (**IEPR**).[1] The memo does not necessarily reflect BC Hydro's current analysis and considerations, which will be developed and reviewed for stakeholder feedback in 2015 RDA Module 2 workshops.

The memo is structured as follows:

- Section 1 provides background with respect to TS 6 and summarizes the legal basis upon which TS 6 will be reviewed and approved. It also confirms the

[1] Copies of the October 2013 IEPR task force final report and November 2013 B.C. Government response are found at BC Hydro's 2015 RDA website under 'Resources' http://www.bchydro.com/about/planning_regulatory/2015-rate-design/resources.html.

scope of the review to be undertaken in Module 2 and provides the high level timelines anticipated for Module 2.

- Section 2 addresses applicability of the eight Bonbright rate design criteria to transmission extension policy and identifies key criteria for consideration.
- Section 3 identifies four categories of contribution models for consideration moving forward based on feedback received on Workshop No. 1, as follows (please refer to the Workshop No. 1 slide deck for a summary of the ten contribution models initially reviewed for participant consideration, at Attachment 1):

  1. Category 1: Status quo (**SQ**) TS 6;
  2. Category 2: Customer pays for System Reinforcement (**SR**) with BC Hydro contribution and the Customer pays for customer transmission line/Basic Transmission Extension (**BTE**);
  3. Category 3: BC Hydro pays for SR and the Customer pays for customer transmission line/BTE; and
  4. Category 4: BC Hydro pays for SR and the Customer pays for customer transmission line/BTE with a utility contribution.

- Section 4 addresses the SQ 150 megavolt amperes (**MVA**) threshold for inclusion of bulk transmission upgrades and generation costs in the definition of SR and four potential options.
- Section 5 addresses how transmission extensions could be treated if:

  (a) there are a number of requests in a region (clustered loads); and

  (b) due to area constraints (geographical, environmental, etc.), it is practical to construct one transmission line (transmission extensions in constrained areas).

- Section 6 addresses security and the risk of BC Hydro recouping its investment in assets constructed to enable interconnection, including discussion of:
  - (a) Whether security should be required and in what amount;
  - (b) When security should be released; and
  - (c) What forms of security should be allowed.
- Section 7 addresses the terms upon which a customer can transfer its transmission line to BC Hydro under TS 6 and discusses alternatives.
- Section 8 discusses options for transition rules to determine when the prior TS 6 will apply and when any new transmission extension tariff will apply.
- Section 9 reviews the draft transmission Interconnection Queue Management business practice.

Attachment 1 provides the slide deck of the 2015 RDA Module 1 Workshop No. 1 from November 18, 2014.

Attachment 2 provides the notes of 2015 RDA Module 1 Workshop No. 1 from November 18, 2014, which offer some detailed description of issues (including a summary of questions and answers from Workshop No. 1).

Attachment 3 contains the feedback forms received during the written comment period.

1 TS 6 Background and Context

1.1 TS 6 Background

TS 6 governs the connection of customers at transmission voltages (60 kilovolts (**kV**) and greater). TS 6 became effective January 21, 1991 pursuant to British Columbia Utilities Commission (**Commission**) Order No. G-4-91 and has not undergone any updates since that time. At the time it was introduced, TS 6 was designed to leave existing customers relatively indifferent to the introduction of new load (i.e., neither better nor worse off). The Commission recognized this effect in 1991 when it referenced the lack of inter-class financial impacts as the primary reason for accepting the negotiated tariff. [2]

TS 6 defines the transmission facilities needed to interconnect a customer for the purposes of assigning responsibility to build, own, operate and finance each class of facilities. The classes of facilities are:

- **Transmission Line** – The transmission line connecting the customer's facility to BC Hydro's system. Customers are responsible to undertake the design, procurement of materials and construction (including securing government agency approval and land acquisition) of the Transmission Line, and are responsible for 100 per cent of the costs and to own, maintain and operate the Transmission Line;
- **BTE** – Additions or alterations to existing BC Hydro facilities, including switches and circuit breakers, necessary to extend up to 90 meters to the customer Transmission Line. The customer is responsible for 100 per cent of design, material and construction costs, but BC Hydro owns, operates and maintains these facilities; and
- **SR –** Additions or alterations to existing BC Hydro facilities required to supply electricity to the customer through the BTE. BC Hydro builds, owns, maintains and operates these facilities but costs are allocated based on a contribution formula set out in TS 6 (discussed below). Alteration or addition to generation or transmission lines 500 kV and greater are not included as SR unless a new load or incremental load exceeds the specified 150 MVA threshold.

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[2] Reasons for Decision, Commission Order No. G-4-91, pages 13-14; copy available at http://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/112793/index.do?r=AAAAAQAGRy00LTkxAQ.

TS 6 employs what is called a ‘revenue-test model’ to allocate cost responsibility for the SR. In general, under a revenue-test tariff new customers pay for the assets that they cause to be built, net of a utility contribution, to account for the incremental revenues generated by the new customer. BC Hydro utilizes TS 6 to determine the extent to which a new customer or load is responsible to pay for a portion of the costs of additions or alterations by assigning cost responsibility between BC Hydro (in this memo, BC Hydro refers to its share of incremental costs arising from the new customer as the **BC Hydro contribution**) and the new customer (referred to as **customer payment**) for SR. To date, no new customer has been assessed a customer payment for SR, although BC Hydro has required customer security.

TS 6 treats load increases differently in distinguishing between new or incremental loads that are in excess of 150 MVA and new or incremental loads that are at or below that threshold. Specifically, customers with loads of 150 MVA or less are not financially responsible for generation costs or 500 kV-and-above transmission costs. The 150 MVA threshold results in customer loads at or below 150 MVA potentially receiving a share of the Heritage resources, while loads above 150 MVA not receiving these benefits.

TS 6 also sets out the terms under which a new customer can elect to transfer the Transmission Line to BC Hydro and under which a customer can receive compensation for costs incurred in constructing the BTE and/or the Transmission Line (if transferred to BC Hydro) if BC Hydro uses these facilities to connect/serve other customers or for a BC Hydro benefit (i.e., referred to as the ‘pioneer rights’ of such customers).[3]

1.2 Legal and Regulatory Context

Since Workshop No. 1, BC Hydro has confirmed that TS 5 will also be in scope for Module 2. While this memo only addresses feedback and considerations in respect

[3] Refer to TS 6 section 10b.

of TS 6, BC Hydro will bring forward for consideration amendments to TS 5 in future workshops.

Section 3 of Direction No. 7 raises jurisdictional issues regarding TS 5 and TS 6. Subsection 3(2) provides that the Commission "must ensure the rates for [BC Hydro] transmission service customers are subject to … the terms and conditions found in Supplements 5 and 6 of [BC Hydro's] tariff". BC Hydro remains of the view that the Commission cannot unilaterally amend TS 5 or TS 6 under its section 58 to 61 *Utilities Commission Act* (***UCA***) rate setting power as a result of this provision. Any changes to TS 5 and TS 6 must be approved by the province of BC. Under the direction of the Lieutenant Governor in Council (**LGIC**), the Commission can be given jurisdiction to review and make recommendations concerning this issue through a section 5 *UCA* inquiry review process.

BC Hydro has confirmed that the LGIC intends to refer consideration of TS 5 and TS 6 to the Commission pursuant to section 5 of the *UCA.* This review will occur as part of the Module 2 regulatory process – i.e., with the Commission's review of TS 5 and TS 6 taking place under section 5 of the *UCA* while the other matters for consideration under Module 2 being filed with the Commission pursuant to sections 58 to 61 of the *UCA.*

The schedule for BC Hydro's Module 2 process is still being confirmed. However, BC Hydro currently expects the following:

- A first workshop to be scheduled for January 2017 – This workshop will pick up from the consultation held in 2014 and will present BC Hydro's views on how the options previously discussed can be refined and will introduce further areas for consideration under TS 6. TS 5 will be introduced for discussion and consideration.

- A second workshop to be scheduled for summer 2017 – The intention is to put forward a preferred direction in this workshop to allow stakeholders to fully consider and comment on BC Hydro's preferred options.
- A third workshop to be scheduled for fall 2017 – This workshop will present the forms of TS 5 and TS 6 that BC Hydro intends to file with the Commission for consideration.
- Filing of BC Hydro's TS 5 and TS 6 is currently scheduled for fall 2017.
- Once TS 5 and TS 6 have been reviewed and approved, BC Hydro will update the terms and conditions of TS 87 and TS 88 (the Indirect Load Interconnection tariffs) and will file them with the Commission for approval.

BC Hydro will update the Module 2 schedule as it gets more refined.

2 Bonbright Rate Design Criteria

2.1 Background

For the purposes of Workshop No. 1, BC Hydro set out the following subset of the eight Bonbright criteria for discussion as to whether they should be the primary criteria for consideration of TS 6 issues:

- 'Fair apportionment of costs among customers' (referred to as **Fairness**): Balancing the interests of existing customers in maintaining postage stamp rate levels with interests of new customers in receiving system access at a predictable and reasonable cost;
- 'Price signals that encourage efficient use and discourage inefficient use' (**Efficiency**): BC Hydro takes a broad view of this criterion in the transmission extension policy context in consideration of new customers requesting the most economical connection facilities and/or taking into account the existing or planned transmission system when considering alternate locations for service;

- 'Rate and bill stability' (**Revenue and Rate impacts**): The rate impact of any changes to TS 6; and
- BC Hydro posed three questions regarding establishment of appropriate rate making criteria:
  - **Question #1 -** In the context of transmission extension policy, BC Hydro noted (on slide 9 of the presentation slide deck) that regulators have traditionally emphasized three Bonbright criteria: (1) Fairness; (2) Efficiency; and (3) Revenue and Rate impacts. We asked stakeholders which of the eight Bonbright criteria were considered most important in the transmission extension policy context, and why.
  - **Question #2 –** We asked whether there were any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions. For example, if 'new customers would receive fair contribution from the utility and that contribution would not place undue upward pressure on rates' is an element of Fairness, what does 'undue upward pressure on rates' mean in quantitative terms?
  - **Question #3 -** In addition to the eight Bonbright criteria, we asked if there were any other objectives which should inform BC Hydro's transmission extension policy.

Question #3 garnered the most attention, with the Association of Major Power Consumers of British Columbia (**AMPC**), Mining Association of British Columbia (**MABC**), Canadian Association of Petroleum Producers (**CAPP**), Commission staff, First Nations Energy and Mining Council (**FNEMC**), Commercial Energy Consumers Association of British Columbia (**CEC**), British Columbia Old Age Pensioners Organization *et al* (**BCOAPO**) and BC Sustainable Energy Association and Sierra Club British Columbia (**BCSEA**) stating that the B.C. Government's and BC Hydro's transmission extension policy objectives should be laid out to, among other things, inform how the Bonbright criterion should be weighted.

2.2 Participant Comments

- **Question #1:** Which of the eight Bonbright criteria were considered most important in the transmission extension policy context, and why?

The majority of participants (AMPC, FNEMC, CAPP and BCOAPO) at Workshop No. 1 stated that Fairness should be the primary Bonbright criterion in the context of transmission extension policy. Fairness was broadly viewed as fairness between new and existing customers and the protection of postage stamp rates (non-discrimination based on end use or industry type). AMPC summarized that “the ideal transmission extension policy will attract new customers without placing an undue burden on existing ratepayers”.

Some stakeholders questioned the Efficiency criterion and suggested that Bonbright’s ‘customer understanding and acceptance/freedom from controversies as to proper interpretation’ is a more important criterion. AMPC believes that “transmission extensions are not made in small increments analogous to distribution additions, [and therefore] efficiency is a less important consideration”, and that efficiency is less a concern if economic development is an overall objective. APMC advanced that “[p]redictability, clarity, stability and customer acceptance are often considered more important than dynamic efficiency considerations”.[4] AMPC also emphasized that “comparisons to the detailed extension policies of other jurisdictions must also be included as this informs measures of fairness, customer acceptance, and stability”. The Commission staff also raised customer understanding and acceptance as an important Bonbright criterion. CAPP is of the view that if costs are fairly apportioned among customers then usage levels among

[4] Economists differentiate between ‘static efficiency’, which is concerned with the most efficient combination of resources at a given point in time and ‘dynamic efficiency’, which is concerned about the development of better technology and working practices which improve the efficiency of production over time.

customer groups will respond accordingly and inefficient levels of consumption will be discouraged.

In general it was agreed that Revenue and Rate impacts was an important objective and several participants noted it to be as important as Fairness. BCOAPO states that minimizing rate impacts on existing customers should be the primary consideration as there are costs "to existing customers now when new load comes online (as compared to when there was a surplus of heritage power, and there was a benefit to all customers when new load came online)". MABC and CAPP, in meetings prior to Workshop No. 1, commented that the rate and bill stability criterion should account for the impact any future change to TS 6 will have on the costs a new customer will bear and is a significant concern as their respective members are making business decisions based on the allocation of costs under the current TS 6. If TS 6 changes such that more costs are borne by the new connecting customer it could change the economics of financing options for the customer's project.

Canadian Office and Employees Union Local No. 378, now called Movement of United Professionals, (**MoveUp**), made the point that consistent principles should be applied to transmission and distribution extension policies, including with respect to whether generation costs ought to be included for new customer cost recovery purposes.

- **Question #2:** Are there any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers would receive fair contribution from the utility and that contribution would not place undue upward pressure on rates' is an element of Fairness, what does 'undue upward pressure on rates' mean in quantitative terms?

The Commission staff commented that before addressing how to measure the Bonbright criteria, it may be useful for BC Hydro to refine what each criterion means.

The Commission staff stated that defining 'undue upward pressure on rates' in precise quantitative terms may be difficult since transmission extension policy may be dependent on customer revenue forecasts that are subject to some uncertainty. Both CAPP and AMPC were also of the view that an acceptability threshold for "undue upward pressure on rates" cannot be usefully considered as a single number. BCOAPO suggested that the most practical approach to ensuring fairness and rate stability is to base the utility contribution on the costs that are reflected in the (current) rates that the new customer will pay.

- **Question #3:** In addition to the eight Bonbright criteria, are there any other objectives which should inform BC Hydro's transmission extension policy?

As noted above, most Workshop No. 1 participants noted the need to understand any specific B.C. Government policy initiatives or overarching objectives to be considered in addition to or as part of the weighting of the Bonbright criteria. For example, AMPC states that "[t]here are many objectives that will inform BC Hydro's transmission extension policy. These include the goals of the shareholder to support economic growth in resource industries, and to maintain competitive rate levels for existing customers. They also include acceptable interpretations of "postage stamp" rates for new areas and industries, the presence or absence of tariff preferences for specific industries, the significance or desirability of preferred end uses, and the willingness to consider least-cost developments where local generation might substitute for transmission reinforcements". CEC recommended that the B.C. Government's economic development plans inform transmission extension policy. BCSEA also saw a need for B.C. Government objectives to inform transmission extension policy, and referred to the "British Columbia's energy objectives" set out in section 2 of the *Clean Energy Act*[5] as a starting point. FNEMC advanced that

[5] S.B.C. 2010, c.22; copy available at https://www.canlii.org/en/bc/laws/stat/sbc-2010-c-22/latest/sbc-2010-c-22.html.

regional economic development, including the need for economic development on First Nations lands, must be considered.

2.3 BC Hydro Consideration

It is common practice for utilities to use the eight Bonbright criteria in the extension policy context. For example, Alberta Electric System Operator (**AESO**) in its 2012 Construction Contribution Policy filing with the Alberta Utilities Commission (**AUC**) used a modified version of the eight Bonbright criteria as the basis for principles informing its transmission contribution policy.[6] In that case, AESO noted that extension policy may not in all cases be able to satisfy all eight criteria simultaneously and therefore primary principles should be identified. AESO suggested prioritizing efficiency, cost causation and what AESO referred to as “maintain intergenerational equity”.

BC Hydro is of the view that overarching transmission extension policy objectives, including B.C. Government objectives, can inform the weighting of the Bonbright criteria.

With respect to the subset of Bonbright criteria set out above, BC Hydro notes the following considerations for establishing their relevance to transmission extension policy discussions going forward:

- **Fairness** is relevant in the transmission extension policy context because the crux of transmission extension policy is to balance what a new customer pays compared to what all existing customers pay through rates. How this criterion is applied as between new and existing customers should be informed by B.C. Government objectives, including with respect to economic development;
- **Customer understanding and acceptance** should inform transmission extension policy and as such BC Hydro will assess the extent to which

[6] AUC, Decision 2012-362: Alberta Electric System Operator – 2012 Contribution Policy, December 28, 2012, page 4.

transmission extension policy options could be applied consistently and transparently, and would be simple to administer and update. BC Hydro will also include jurisdictional assessment where relevant;

- **Rate and Bill Stability** should include the view of what a customer must bear for a new connection. This will be carried forward for discussion. Undue upward pressure on rates could be informed by anticipated customer impacts (such as represented by the change in per cent of new customer projects that would make payments) and the anticipated financial impact of adopting a contribution model as compared to the SQ TS 6, using recent projects for evaluation purposes; and
- **Efficiency** should be carried forward to discussions and evaluation of clustered loads. Stakeholder feedback considered customer understanding and acceptance as being more important that Efficiency, however BC Hydro will seek further input in regards to clustered loads in the transmission extension policy context at future workshops.

3 Utility Contribution Models

3.1 Background

SQ TS 6 is used to determine the maximum contribution BC Hydro will make toward a SR triggered by a new load request. The formula is based on a forecast of projected revenues BC Hydro expects over a period of 7.4 years adjusted for expenses, depreciation and BC Hydro benefits. Both energy and demand revenues are included in the revenue component of the calculation,[7] however the expenses component only includes operating and maintenance expenses for the SR up to but

[7] This is to be contrasted with BC Hydro's current distribution extension policy, which, pursuant to the Commission decision concerning BC Hydro's 2007 Rate Design Application, specifically excludes the incremental cost of energy in distribution extension calculations on the basis of what are now subsections 5(a) and 5(d) of Direction No. 7). Refer to *In the Matter of British Columbia Hydro and Power Authority: 2007 Rate Design Application, Phase -1*, Decision, October 26, 2007, page 186; copy available at http://www.bcuc.com/ApplicationView.aspx?ApplicationId=145.

not including 500 kV transmission upgrade or additions or alterations to generation plant. For loads greater than 150 MVA, BC Hydro would consider operating and maintenance costs for generation and transmission lines greater than 500 kV.

- If the maximum BC Hydro contribution is greater than the estimated SR, then BC Hydro would seek a revenue guarantee from the customer for the amount of the SR; and
- If the maximum BC Hydro contribution is insufficient to cover the costs of the SR, BC Hydro seeks a revenue guarantee for the amount of the maximum contribution and a cash payment for the difference between the SR and the maximum contribution. Since TS 6 was approved, the maximum BC Hydro contribution for projects that proceeded has always been sufficient to cover the cost of the SR and therefore no customer has had to make cash payments towards the SR.

For purposes of Workshop No. 1, BC Hydro reviewed the DCAT CPCN proceeding and IEPR task force submissions, and conducted jurisdictional assessment (AESO; SaskPower; Manitoba Hydro; Hydro One (Ontario); Bonneville Power Authority (**BPA**)) in addition to Energy + Environmental Economics' jurisdictional survey completed for the IEPR task force process.[8] The jurisdictional results were as follows:

- Several utilities provide a utility contribution to extensions/connections (in TS 6 terms, toward the Transmission Line plus BTE): AESO, SaskPower, Hydro One, Hydro Quebec; and
- BC Hydro is the only utility whose transmission extension policy shares the cost of SR (referred to as network upgrades in other jurisdictions) between utility and new customers. In all other jurisdictions surveyed SR costs are rolled into rate

[8] Appendix A to BC Hydro's Round 2 submission to the IEPR task force.

base, whereas for BC Hydro only the portion covered by the utility contribution is rolled into rate base.

BC Hydro sought feedback on four categories of utility contribution options as a refinement of the original ten options reviewed at Workshop No. 1 (refer to slides 38-49 of Attachment 1 for further detail on the ten options):

- Category 1: SQ TS 6;
- Category 2 – Customer pays for SR with utility contribution and the Customer pays for customer Transmission Line/BTE. Category 2 includes the Options 1 to 4 reviewed during Workshop No. 1. BC Hydro advanced at Workshop No. 1 that one of these options should be brought forward for further analysis, favouring Option 3, which is a Transmission cost of service model that provides a contribution based solely on the incremental transmission revenues and most closely aligns to BC Hydro's distribution extension policy ("**Cost of Service Model**");
- Category 3 – Utility pays for SR and the Customer pays for Transmission Line/BTE. This is the Manitoba Hydro model (Option 10). BC Hydro advanced at Workshop No. 1 that Option 10 should be brought forward for further analysis because it is simple; it is similar to the outcome of applying TS 6 in respect of Revenue and Rate impacts, but is more transparent and simple, at least in the context of a single customer extension. A cluster extension variation described in section 5 could be included as a subset; and
- Category 4 – Utility pays for SR; Customer pays for Transmission Line/BTE with a utility contribution. Category 4 includes Options 5, 6, 7, 8 and 9 as presented during Workshop No. 1. A key difference between these Options is that in some cases (SaskPower – Option 8; Hydro Quebec – Option 9) the utility builds and owns the Transmission Line/BTE whereas in others (Hydro One – Option 7) there is optionality around who builds the extension.

Specifically, Option 7 gives the customer the option of building and owning the Transmission Line, of building the Line and transferring it to the utility, or the utility building and owning the Line and then having a true up of costs.

BC Hydro advanced at Workshop No. 1 that Option 9 (Hydro Quebec) should be brought forward for further analysis due to its simplicity and the similarity of the market structure/utility transmission system to BC Hydro's system; however, BC Hydro also believes that the Hydro One model (Option 7) should be brought forward because it gives more optionality as to the obligation for construction of the Line.

3.2 Category 1: SQ TS 6

3.2.1 Participant Comments

There was general stakeholder support to advance SQ TS 6 with a cluster extension option variation as set out on slide 19 of the Workshop No. 1 slide deck (refer to section 5), even if only to serve as the base option to compare other options against. Only AMPC disagreed with carrying forward SQ TS 6. AMPC stated that it could not support any transmission extension policy that "retains the core structure of TS 6, even if some changes or options are included". AMPC notes that TS 6 is based on unrecorded shareholder goals and circumstances of more than 20 years ago that remain obscure and cannot be articulated or explained by BC Hydro today, and that TS 6 "utilizes unique procedures that are inconsistent with the practices of all other utilities surveyed". AMPC referenced its DCAT CPCN submissions in which it pointed to the unfairness of what AMPC labelled "the vastly different contributions assessed by TS 6 for two different groups of customers [mining customers in relation to Northwest Transmission Line-related TS 37, and gas customers under TS 6] who presented comparable incremental costs and revenues to the system".

Other participants expressed strong reservations with SQ TS 6, but supported carrying forward SQ TS 6 for further review. CAPP supported the further analysis of

SQ TS 6, but stated that the jurisdictional assessment provided support for its position that the SQ TS 6 was flawed because in all other jurisdictions reviewed SR costs are borne by the utility (and all ratepayers). BCOAPO states that it is unable to agree with the continuation of SQ TS 6 without further justification of the current contribution formula.

3.2.2 BC Hydro Consideration

BC Hydro agreed with the majority of Workshop No. 1 participants that SQ TS 6 should be carried forward as a comparison point for options analysis. The cluster extension variation could be an option for all four categories of BC Hydro contribution models.

The issues with TS 6 have been catalogued in the IEPR task force proceeding, including but not limited to the 150 MVA threshold as described in section 4 of this memo. In response to BCOAPO's request, BC Hydro is unable to put forward the original justification for the current TS 6 contribution formula, including the basis for an annual revenue multiplier of 7.4 years. The reasoning behind this formula and its variables is not available from BC Hydro's records.

3.3 Category 2: Customer Pays for SR with Utility Contribution; Customer Pays for Transmission Line/BTE

3.3.1 Participant Comments

Some stakeholders support the idea that customers may have to pay something for SR, with no agreement however on how much. Other stakeholders strongly disagreed with customers contributing anything to SR and referred to the jurisdictional assessment for support of this position. In addition, aligning transmission and distribution extension policy for purposes of analyzing Category 1 did not seem to be important, with some stakeholders even objecting to it. For example, CAPP was concerned that BC Hydro proposed to advance the Cost of Service model for further analysis simply because it is closest to BC Hydro's distribution extension policy when this is the least competitive option from a transmission customer perspective. CAPP stated that this concern was amplified by the fact that the jurisdictional review revealed that SR are often borne by the utility with no need for a customer contribution.

CEC raised different concerns with the Cost of Service model, noting that it included only capital and excluded operating and maintenance (**O&M**) costs and taxes. CEC goes on to advance that as O&M and taxes are a real part of costs impacting rates it would be more suitable to consider incorporating all costs or at least demonstrate immateriality. BCSEA supported the Cost of Service Model being advanced for further analysis, noting that the Cost of Service Model results in the highest percentage of new customers where the utility does not cover 100 per cent of the SR costs.

3.3.2 BC Hydro Consideration

Requiring new customers to make a payment toward SR is at odds with other relevant jurisdictions where SR costs are generally not charged to new customers. One partial exception is BPA, where SR (referred to as network upgrades) that have no benefits to other customers on the BPA system are borne by the connecting customer. While recognizing that Options 1 to 4 have little jurisdictional support, in BC Hydro’s view it is too early in the stakeholder process to dismiss all four options on this basis. Accordingly BC Hydro proposes to consider the Cost of Service model as the option within Category 2 for further analysis and comparison.

A possible variation of the Cost of Service model is adoption of BPA’s approach to SR cost assignment to new customers for purposes of analyzing Cost of Service model and possibly the proposed safety valve discussed in section 4. BC Hydro understands that Puget Sound Energy takes a similar approach to BPA.

3.4 Category 3: Utility Pays for SR; Customer Pays for Transmission Line/BTE

3.4.1 Participant Comments

There is general stakeholder agreement to advance Category 3 (Manitoba Hydro model). Several Workshop No. 1 participants supported Category 3 on the basis of simplicity and that the outcome most closely resembles the actual outcome of SQ TS 6 (FNEMC, CAPP). Some participants noted that their support for Category 3 may change depending on potential associated rate impacts and/or whether BC Hydro covering SR cost entirely could reduce the overall interconnection timeline. BCOAPO expressed reservations about Category 3 on the basis that Manitoba Hydro has no cap on the SR for which the utility could be responsible, with resulting concerns about the implications with respect to both Fairness and Revenue and Rate impacts for existing customers. The Commission staff recommended that BC Hydro consider whether time in the queue would be reduced by the time required for a System Impact Study (**SIS**) if BC Hydro adopted Category 3 and covered SR.

3.4.2 BC Hydro Consideration

BC Hydro will carry forward Category 3 for further analysis for the reasons advanced by Workshop No. 1 participants. BC Hydro noted that Manitoba Hydro's extension policy had never been subjected to regulatory review by the Manitoba Public Utilities Board and so the reasons for the adoption of the particular model were not publicly available.

In partial response to BCOAPO, Category 3 could encompass a safety valve (as noted by AMPC and the Commission staff and discussed in section 4 below in more detail) to mitigate the risk of BC Hydro being responsible for extraordinarily high SR costs. However, the rate impacts of adopting Category 3 as compared to SQ TS 6 are not expected to be material given that, practically speaking, the outcomes of the two models are the same . Nevertheless, BC Hydro will conduct financial impact analysis of Category 3 as part of its preparation for the January 2017 workshop.

3.5 Category 4: Utility Pays for SR; Customer Pays for Transmission line/BTE with a Utility Contribution.

3.5.1 Participant Comments

There was uniform agreement among participants that both Option 7 (Hydro One) and Option 9 (Hydro Quebec) merit further analysis. Workshop No. 1 participants highlighted the relative simplicity of Option 9 together with Hydro Quebec being similarly situated to BC Hydro in terms of market structure and transmission system, while Option 7 gives both the customer and the utility options in terms of extension building and ownership.

BCOAPO is concerned with the Category 4 approach, stating that it gives rise to concerns regarding fairness and rate stability as there is no cap on BC Hydro's potential SR cost responsibility and it will also require BC Hydro to make a contribution towards the customer Transmission Line/BTE. BCOAPO is particularly concerned with the potential for upward rate impacts with Option 7, the Hydro One model.

3.5.2 BC Hydro Consideration

BC Hydro will advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the Transmission Line which is different than SQ TS 6.

BC Hydro will also advance Option 7 (Hydro One model) for further analysis as it gives the customer the option of building and owning the Transmission Line, the customer building and transferring ownership of the Transmission Line to the utility, or the utility building and owning the Transmission Line with a 'true up' of costs.[9]

In regards to BCOAPO's concern above, please refer to section 4 of this memo for a discussion of including a safety valve within a Category 4 option under which Commission or Government approval would be required to allocate costs to a new customer to minimize rate impacts to existing customers. BC Hydro notes that if BC Hydro were to contribute to a transmission extension, this would be a new cost to BC Hydro.

BC Hydro has concerns about the SaskPower model (Option 8) pursuant to which connecting customers pay the extension costs associated with connecting to the nearest transmission line based on fixed $/km construction costs; if actual construction costs exceed the fixed $/km construction costs, SaskPower pays for the additional costs. Thus, existing SaskPower ratepayers bear risk of any cost incurred above the fixed fee and the customer over contributes if costs are less than fixed fee. Most jurisdictions use a revenue test/discount cash flow model. As was pointed out by MoveUp at Workshop No. 1, deriving a single $/km number would be difficult in respect of BC Hydro's service area where regional constraints and geography greatly affect interconnection costs. While the SaskPower model has the virtue of simplicity, so does the Manitoba Hydro model (refer to section 3.4).

BC Hydro has concerns about the AESO model (Option 6) as one of AESO guiding principles is intergenerational equity to afford new connecting customers with similar utility contributions as previous customers. This is not one of the guiding principles chosen as being important in rate making for BC Hydro extension policy. The AESO

[9] Hydro One's Transmission Connection Procedures are governed by the Ontario Energy Board's (**OEB**) Transmission System Code (**OEB TSC**; refer to http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Transmission_System_Code.pdf.Section 2.5 of the OEB TSC sets out how the discounted cash flow model is used. Refer to section 6.5.2 of the OEB TSC for the true up intervals.

model also looks at the historic cost[10] of connections and a future load forecast to develop a $/MW offset that are applied to BTE and extension. AESO typically covers SR costs through its rate base. As most of BC Hydro's new loads are resource based, a change in economic conditions, access to financial markets, or commodity prices can suddenly change a proposed project's viability or timing which will significantly affect our load forecast and the associated forecasted costs that makeup the inputs in calculation this Option. Alberta typically has a homogenous load (oil and gas) and relatively similar terrain, BC Hydro load is not homogenous and our terrain varies significantly.

4 150 MVA Threshold

4.1 Background

The definition of "System Reinforcement" contained in section 2 of TS 6 provides that SR do not include any additions or alterations to generation plant and associated transmission, or transmission lines at 500 kV and over, unless the new or incremental load exceeds 150 MVA. BC Hydro cannot find any reference to the 150 MVA threshold in any of the materials filed or the hearing documents concerning the 1990 TS 6 Commission proceeding:

- On September 11, 1990 BC Hydro filed a draft copy of the future TS 6 with the same TS 6 contribution formula described in section 3.1 above but a different definition of SR ("alterations or additions to the physical plant of BC Hydro") which included both transmission and generation assets;
- On December 7, 1990 a new version was submitted which contained the current definition of SR (limited to transmission assets unless load is greater than 150 MVA).

[10] The AESO data set used in calculating the offset includes 69 AESO-era greenfield projects, 18 pre-AESO greenfield projects, and 128 upgrade projects.

The 150 MVA threshold has never been applied to a new load connection that proceeded. It was considered by the Commission in a 2002/2003 application with respect to a proposed aluminum smelter requesting 650 megawatts (**MW**) of load. At that time, the Commission concluded that BC Hydro had correctly applied TS 6 to include generation costs as part of the SR. The proposed project ultimately did not proceed.

The IEPR task force October 2013 Final Report states that "[t]he 150 MVA threshold presents a cost barrier not found in other jurisdictions, and sends a signal that new large electric loads are not supported in British Columbia".[11] A jurisdictional review showed that a threshold of this nature is uncommon, with only one other jurisdiction having an established threshold – Hydro Quebec (50 MW). However, as pointed out by AMPC at Workshop No. 1, the nature of the Hydro Quebec threshold is different. For loads greater than 50 MW the decision to supply the load is made by the Quebec government, but once that decision is made Hydro Quebec does not necessarily treat customers above or below the threshold differently. In particular, no generation costs are charged to customers greater than 50 MW. In Ontario, the utility normally bears the SR costs but there is a provision in the Ontario Energy Board (**OEB**) Transmission System Code (**TSC**) whereby a utility can apply to the OEB to request transmission costs be assigned to new customer. No utility had invoked this provision as of the time of the workshop.

BC Hydro proposed four options with respect to the provision of a threshold for allocation of generation and bulk transmission costs:

1. **SQ** – Maintain the 150 MVA threshold.
2. **Develop New Threshold** – Develop a new threshold for inclusion of generation costs. If a new threshold was created, it would need to be determined whether

[11] *Industrial Electricity Policy Review: Task Force Final Report*, October 31, 2013, page 25; copy available at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/october-2013-industrial-electricity-policy-review-report.pdf.

the threshold should be applied to the total load or just to the incremental load above the threshold.

3. **No Threshold with Safety Valve** - Do not include a threshold in the tariff , but for the exceptional case where a new load would cause a significant rate impact, BC Hydro would have the option to seek Commission (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer (**safety valve**). If this option is pursued, it needs to be determined whether the safety valve should include generation costs or, as with Ontario, it should be confined to transmission costs.

4. **No Threshold and No Safety Valve**

4.2 Participant Comments

Participants representing customers connecting at transmission voltages – AMPC, MABC and CAPP – unanimously opposed the 150 MVA threshold. AMPC's position was that there should be no specific MVA threshold: "A simple MV.A threshold at any level violates Bonbright principles (fairness and predictability in particular), is challenging to apply, and easy to defeat in practice by a determined proponent". AMPC favoured a 'safety valve' approach, necessary "to avoid the roll-in of ***extraordinary*** costs of local extension or system reinforcements necessary to serve a new customer under unusually expensive circumstances. How those circumstances might be identified without impeding desirable economic development requires significant further discussion and development".

CAPP strongly supported the removal of any threshold for triggering the inclusion of costs for additions and alterations to the bulk system and associated new generation. CAPP believed that any threshold would be arbitrary. CAPP stated that it is not correct that only "new" customers cause the incurrence of any higher marginal cost for new supply. "Old" customers who continue to take service are just as responsible for new supply requirements as "new" customers. With respect to the issue of a ‘safety valve’ CAPP was concerned that such an approach might effectively create a new “threshold” while not being explicitly identified as being one. However, CAPP was supportive of further analysis being conducted to see what rate impacts might be associated with new transmission projects of various size

Only FNEMC supported the SQ 150 MVA threshold. CEC stated that “a safety valve is likely the better approach where specific case examples can be examined and suitable rate impact protection can be provided”. CEC believed that both transmission and generation costs should be considered for the safety valve. BCSEA observed that the SQ 150 MVA threshold is problematic due to the all-or-nothing aspect; however, it was not obvious what a preferable alternative might be to balance costs and benefits to existing and potential new customers. BCSEA recommended that BC Hydro give consideration to inclusion of generation costs in the formula for transmission extension customer payments. Whatever the rest of the formula consists of, BCSEA thought there should be a safety valve component, and that the safety valve component should include generation costs.

BCOAPO’s position was that some form of threshold is required. BCOAPO made two observations: (1) Once put into practice “there may not be that much distinction between a “safety valve” and a “threshold” approach since the triggering of the safety valve will likely occur at some threshold value”; and (2) Ontario’s approach whereby the costs included are limited to transmission is a function of the market structure and the fact that generation is not part of the regulated utility. BCOAPO also noted that Ontario’s introduction of a “safety valve” is directly related to the fact that the OEB TSC requires utilities to otherwise pay for all incremental network cost triggered by a new connection.

FNEMC, CEC, BCSEA, BCOAPO opposed the option of ‘no threshold, and no safety valve.’

The Commission staff posed a series of questions for BC Hydro and stakeholder consideration:

- The 150 MVA threshold “promotes most new industrial developments on the one hand but discourages very large new customers that could be a burden to existing customers on the other hand. Have the economic policy drivers changed over time and would option 3 solve the ‘all or nothing nature’ of the 150 MVA threshold?”:
- “If a large new customer were charged for bulk [SR], would they then be exempt from future revenue requirement costs for bulk transmission or generation additions? Could this vintaging create a problem of potential cost allocation difficulty for all other customers?”;
- “If new industrial customers were to be charged the potential cost of future bulk transmission or generation additions to serve them, should BC Hydro also consider streaming future bulk transmission or generation costs to Residential or General Service customers if their growth in a region were the direct cause of a bulk transmission or generation addition?”;
- “If BC Hydro is not aware of any utility charging for generation reinforcement, what is the special circumstance in B.C. for its inclusion? Can the potential for LNG development be such a special circumstance?”; and
- “If most utilities do not charge for bulk transmission [SR], it would be helpful if BC Hydro articulated the need for such policies in B.C. If no customers have ever been charged for bulk transmission reinforcement in BC Hydro’s service area, should the requirement be discarded?”.

4.3 BC Hydro Consideration

There is a fair degree of stakeholder consensus that the SQ 150 MVA threshold is problematic, including in submissions to the 2013 IEPR task force. FNEMC appears to be the only workshop participant strongly favouring the SQ (Option 1) or New Threshold (Option 2). BC Hydro understands the observations raised by AMPC and CAPP that the 150 MVA threshold is both arbitrary and subject to gaming. One reason why gaming risk is an issue in respect of TS 6 is that the consequence of being slightly over the 150 MVA threshold is profound. There is also no jurisdictional support for the 150 MVA threshold where the safety valve is based solely on MVA and results in the new customer paying all incremental costs, inclusive of generation.

Aside from CAPP, there is no stakeholder support for Option 4 (no threshold or safety valve).

There is strongest stakeholder support for Option 3, being the removal of the 150 MVA threshold with a safety valve provision. There is no consensus on the mechanism for implementing the safety valve however. BC Hydro will provide options for implementing a safety valve concept in the January 2017 workshop.

BC Hydro has not found any Canadian jurisdiction that charges new customers for generation reinforcement through extension policies. In addition, at Workshop No. 1 there was no consensus on whether generation costs should be included. The Commission staff questioned if the BC Hydro system is characterized by unique features leading to the inclusion of generation costs. BC Hydro considers the addition of generation isn't so much a question of the uniqueness of BC Hydro's system as it has to do with the size of a new load and if generation will be to the sole benefit of that customer. AMPC noted that attributing generation costs is challenging in practice because generators are planned in aggregate (along with integrating transmission) to meet aggregate load and growth in load – not to serve a specific load – as there are large economies of scale and scope in aggregate planning. However AMPC also noted that with the exception of dedicated local generators that may displace distribution or area transmission reinforcements, the cost of expanded system generation is not normally included by utilities as part of the system expansion costs to be recovered from new customers.

As part of its round 2 submission to the IEPR task force, BC Hydro highlighted two features of its system that are relatively unusual (although not unique) as follows:

- First, as a large service area with relatively long radial lines, attaching new loads can trigger significant costs even before the customer reaches the BC Hydro system. In addition, even the first point of interconnection with the BC Hydro system can be remote and radial, adding to SR costs. There is more potential for large incremental costs when a new customer connects to BC Hydro’s radial system than when a similar customer hooks up to a tightly looped grid in, for example, the U.S. northeast; and
- Second, BC Hydro’s embedded cost of generation is below the long-run marginal cost of new supply. All new customers (residential, commercial, and those taking service at transmission voltage) impose generation-related costs on existing customers in a way that new customers would not in jurisdictions where the average and marginal costs of generation are similar, or where the price relationship is the reverse of BC Hydro’s.

BC Hydro has not found any Canadian jurisdiction that charges new customers for generation reinforcement through extension policies.

5 Clustered Loads and Extensions

5.1 Background

With the growth in the natural gas sector in the Peace Region, BC Hydro has seen a situation arise where multiple customers are requesting new connections within the same geographic area (the Dawson Creek/Chetwynd region). Requiring each customer to build a transmission line to the BC Hydro grid may result in several transmission lines being built in an area where one transmission line with sufficient transfer capacity for all requests would be more feasible on an aggregate basis and would minimize the environmental footprint.

BC Hydro presented the questions set out in sections 5.2 and 5.3 below for consideration and comments.

5.2 Question 1: Clustered Loads

BC Hydro asked the following: When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with:

1. First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect;
2. BC Hydro builds the common transmission extension and charges each customer an upfront payment on a prorated basis; or
3. BC Hydro builds the common transmission extension and treats this as SR which it would apply the utility contribution towards and seek security/payment on a prorated basis?

5.2.1 Participant Comments

As noted by AMPC, the clustering/constrained area options must take into account the underlying BC Hydro contribution option (refer to section 3).

A majority of responses indicate preference for Option 1 “First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect” based on its simplicity and providing the least risk to BC Hydro and ratepayers. A few responses (Commission staff and CEC) suggest a hybrid of all three options, or that all three should be available for consideration depending on the customer project, its economic contribution to the area, and the number, likelihood, and timing of additional customer participation. CEC noted that the ability of future customers to commit should also be a factor, e.g., a group of customers that are willing to commit to taking service together could be treated differently than if the new customers are uncommitted when extensions are being approved/designed.

CAPP noted that in the case of a transmission extension (versus system reinforcement, like DCAT/PRES) there is potentially a greater risk of stranded capital for the utility as new transmission is being built to an area that was previously not served by BC Hydro (and especially if the extension only serves a limited number of new customers). Accordingly, treating an extension as a system reinforcement alone and applying the existing utility contribution could potentially put other ratepayers at risk if loads fail to materialize. CAPP agrees that in these circumstances the customer builds and pays for the extension and receives pioneer right to recoup costs if other customers connect. In the case of reinforcements of an existing transmission system (like DCAT and PRES) the risk of stranded capital due to underutilization of the reinforcement is much lower (as the capacity will be used as load growth in the region continues). Accordingly, these system reinforcements should be treated as a utility cost (and borne by all ratepayers).

BCOAPO was uncertain of what the rationale for the third option would be, unless the extension somehow reinforces the existing system and also benefits existing customers.

A number of Workshop No. 1 participants indicated that there needs to be clear distinctions between and definitions of customer extension and SR for the purpose of developing an approach to clustered loads.

5.2.2 BC Hydro Consideration

Clustered loads have become an issue for BC Hydro in the last five to seven years due to the volume of requests from the Oil & Gas (O&G) sector. Technological advances in gas extraction (fracking) combined with government greenhouse gas (GHG) reduction objectives, and proposed Liquefied Natural Gas (LNG) export has created a demand for electrification in the O&G sector in the south peace region (Dawson/Chetwynd area and north of GMS).

Stakeholders have recognized that clustered loads present a unique challenge for BC Hydro not only in the allocation of capacity and costs but also in the cumulative impacts on BC Hydro planning resources that need to determine the impacts of these loads on the transmission system and associated upgrades. The stakeholders realize that where the new customer is in its project development cycle affects their ability to commit or when they can commit. In general most felt that where there was uncertainty, that BC Hydro and rate payers should not bear the risks of stranded assets and that the first customer connecting should bear the cost of the transmission line but receive pioneer benefits as others connect. Some felt that in those instances where the certainty of future connections was high, a different treatment of costs could be warranted. CAPP and BCOAPO both suggested a hybrid model that would support option 1 as the default but allow BC Hydro, where justified, to use either Option 2 or 3.

The uniqueness of clustered loads may require new provisions in the tariff to allow flexibility in interconnecting these clusters.

5.3 Question 2: Transmission Extensions in Constrained Areas

BC Hydro asked the following: There may be instances where, due to geographical constraints or environmental impacts, for example, only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In such a situation, which option would be preferred:

1. The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity); or
2. Allocate the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line?

5.3.1 Participant Comments

The majority of responses (CEC, BCOAPO, and FNEMC) indicated a preference that the initial customer contributes based on their avoided cost of the line required to service its load (Option 1 above). In addition, CEC and BCOAPO commented that the justification for any BC Hydro contribution to an extension should be subject to review by the Commission.

The Commission highlighted the need to consider the time value of money and/or the depreciated nature of the line to which a new customer will be assessed a contribution and to what extent there is a risk of stranded assets/rate impacts under each option.

APMC did not indicate a preferred option but they did recognize that transmission lines are frequently built with capacity in excess of the forecast load being served. AMPC considers it important to assess the circumstances under which “excess” capacity is allocated as a “system” versus a “local” or “customer” cost and under what circumstances a portion of a customer-related extension might be considered a “system” cost to be borne by all customers.

BCSEA questioned the public interest in grid extensions and suggested that the risk allocation to existing ratepayers would likely require careful consideration and may require significantly different rules and policies than BC Hydro's existing transmission extension policies.

5.3.2 BC Hydro Consideration

Although there was strong support for Option 1, BC Hydro notes AMPC's assertion that the clustering/constrained area options are dependent on the underlying BC Hydro contribution model. BC Hydro will forward all options for further review and analysis.

6 Security

6.1 Background

As discussed in section 1 of this memo, where BC Hydro provides a contribution towards SR, the customer is required to provide a revenue guarantee (security) in the amount of the BC Hydro contribution. BC Hydro currently accepts a broad range of security. The form of security is at BC Hydro's reasonable discretion; however, TS 6 specifies the following 6 options:

- Irrevocable Letter of Credit (**LOC**);
- Contract bond;
- Guarantee by a corporation other than the customer;
- Bank term deposit, to be deposited in trust for BC Hydro;
- Negotiable bearer bond, that is government guaranteed at face value; or
- Prepayment on account.

The most common types of security being provided are LOC and guarantees provided by a parent company (**Parental Guarantees**).

Once a customer plant is in normal operation, BC Hydro conducts an annual review of revenues realized and releases security based this review. Although the calculation of the maximum BC Hydro contribution is based on 7.4 years, the customer has 12 years for the revenue to materialize before BC Hydro will call on the security. To date BC Hydro has never had to draw on security provided.

Almost all utilities in BC Hydro's jurisdictional review require some form of security to manage the risk of stranded assets and most will release the security when a customer's facility reaches its "Commercial Operation Date" or shortly thereafter. The review also highlights that there is no consistent approach in determining how much of the utility contribution is to be covered by the security (for example, Hydro One uses a creditworthiness test to determine the amount of security and SaskPower uses a project risk assessment).

Stakeholders expressed concern with the security provisions. Provision of security can be a financial liability which affects borrowing capacity during a project development. Some customers have indicated this is becoming a barrier to financing when financial markets are constrained. Also, customers have taken issue with supplying security for capacity that they are not using and which is available for BC Hydro to use to serve other customers. In other words, because of the nature of transmission upgrades creating capacity in blocks that may not match the capacity needs of the requested load, customers feel that the security should be prorated based on their needs/usage of the new capacity. Other issues identified regarding the provision of security included the terms of BC Hydro's creditworthiness policies that dictate the maximum amounts that a customer may secure by way of Parental Guarantee, as well as the mechanism for releasing security.

BC Hydro asked four security-related questions in the Workshop No. 1 feedback form:

1. Should security be required, if so for what amount?
2. When should security be released?

3. What forms of security should be allowed?
4. Other comments with respect to security?

As these questions are closely related, they are not separated out for purposes of summarizing participant comments and BC Hydro's consideration.

6.2 Participant Comments

All submissions supported some form of security requirement, with general support for a security requirement based on actual SR costs. Security based on $/kW or historical averages is seen as arbitrary. AMPC considers it premature to review security requirements before establishing how SR cost are to be determined and allocated.

There was general but not unanimous support for the release of security after the risk of stranded resources has been reduced significantly, i.e., after construction and connection, or a short (six to 12 month) period after connection to ensure that [some] revenues from customers are being realized. CAPP notes that releasing security after the risk of stranded resources has been decreased (though not necessarily until the whole amount of the security is recovered through a customer's revenues as under the current TS 6) is jurisdictionally supported. Most other jurisdictions only require security to mitigate stranded investment risk and security is typically only held until the customer reaches its commercial operation date. BCOAPO prefers the option in which security is released based on an assessment of revenue recovered as this provides the most protection for existing ratepayers.

There was general support for a range of security options, with acceptable forms of security to be based on credit risk. BCOAPO emphasized that the current requirement that the form of security must have BC Hydro's prior approval should continue. CAPP urged BC Hydro to maximize the use of Parental Guarantees for customers who are considered financially "low risk", noting that the approach of 'risking' customers is jurisdictionally supported by Hydro One. CAPP voiced concern that LOCs, which need to be posted for extended periods, present competitiveness challenges. The Commission staff noted the feedback from customers in the Workshop No. 1 summary notes indicated that the issue was not how soon the LOC/security was returned but rather the ability of the customers to get the security in the first place. The Commission staff asked to what extent different forms of security provide a potential solution to this problem while still offering a reasonable degree of risk mitigation for other customers.

Finally, CAPP suggested that security be used as a mechanism for transitioning between the old and new tariffs, and proposed that customers wishing to secure load under the terms and conditions of the old tariff provide security up-front. CAPP proposes a framework whereby a customer that wishes to secure load under the terms and conditions of the old tariff, that security be provided up-front and be grandfathered under the old tariff until the load comes online. This issue is addressed in section 7.

6.3 BC Hydro Consideration

As highlighted by BCOAPO, the jurisdictional review indicates that virtually all utilities require security. BC Hydro is of the view that there is merit to consider a number of security alternatives so that customers can choose an option that best accommodates their financial circumstances while providing adequate security to BC Hydro.

Based on the jurisdictional review and feedback from stakeholders, BC Hydro will carry forward for further discussion a review and analysis of the risks and impacts of changing the requirements for reviewing when security should be released. The review will include impacts and benefits for both the new customer and BC Hydro, including an analysis of the risk of BC Hydro bearing the stranded asset risk before a customer's commercial operation versus after.

7 Line Transfer

7.1 Background

Under TS 6 the customer has the option to transfer a Transmission Line to BC Hydro. The transfer is for a nominal amount and the benefit for the customer is that BC Hydro assumes responsibility for the operation and maintenance of the Transmission Line. The transfer is conditional on the Transmission Line being constructed to meet BC Hydro standards, which includes items such as design, materials, construction, access, environmental, right-of-way acquisition, permitting, & consultation. If there are unusually high operation or maintenance costs, BC Hydro can require compensation for these costs.

Under TS 6, BC Hydro has no ability to require a customer to transfer its Transmission Line to it. BC Hydro also cannot reject a line transfer if the terms of TS 6 have otherwise been met. Any line transfers outside of the scope of TS 6 are subject to agreement between the parties.

In Workshop No. 1, BC Hydro asked whether BC Hydro should have the option to reject a request by a customer to transfer its Transmission Line to BC Hydro if there is no existing or potential need to serve other customers or if it will put an unreasonable cost on BC Hydro. Conversely, in situations where there are geographic or other constraints that will limit the number of lines that can be built, BC Hydro may want the right to request that the Transmission Line be transferred to it in order to serve other loads or generators.

7.2 Participant Comments

CEC, FNEMC, BCSEA, BCOAPO, and CAPP generally agreed that BC Hydro should have more discretion on initiating and/or rejecting the Transmission Line transfer. There was disagreement on how much discretion BC Hydro should have; however, most of the feedback suggested that if BC Hydro was requesting a Transmission Line transfer due to system benefits then the customer who built the line should be compensated fairly. BCSEA stated they "tend to think that BC Hydro should have sole discretion to take or reject ownership of transmission extensions. Presumably this would create a transfer of risk to the new customer and away from BC Hydro. If so, this should be taken into account in the transmission extension rules." CEC went further to suggest that Commission arbitrate what fair compensation could be and it would be useful to establish Commission guidelines for fair compensation. CAPP also felt that if BC Hydro is given the right to refuse to take over a Transmission Line, then a similar right should be granted to customers if they do not wish to transfer a line to BC Hydro.

APMC noted that the transfer provisions are dependent on the form of the extension and contribution policy developed and a useful response cannot be provided at this stage. However AMPC did note that utility investment in customer lines or consideration of "customer" related lines as being at least in part a "system" development suggests that automatic line transfers may be desirable in these circumstances.

The Commission stated this provision seems to be entirely to BC Hydro's benefit. The fairness to the transmission customer having built and owned the Transmission Line should be further investigated. The Commission also questioned if there is an issue related to suggestions that BC Hydro construction costs seem to be much higher than transmission customers' costs. If there are benefits to BC Hydro in excess of the depreciated cost of the Transmission Line, should the customers be compensated?

7.3 BC Hydro Consideration

There was consensus among participants that Transmission Line transfer rules need to be revised to give BC Hydro more discretion in rejecting or requiring a Transmission Line transfer and to ensure that if a Transmission Line is transferred customers should receive fair compensation. BC Hydro will carry forward

Transmission Line transfer issues and options for further discussion at the January 2017 workshop**.**

8 Transition Rules

8.1 Background

A need for clear transition rules from the old tariff to a revised tariff is required as customers are making investment decisions on projects based on the existing terms and conditions of TS 6 and years in advance of the project in-service dates. Concern was raised that changes to TS 6 could be less favourable and in some cases affect either the economics of a project (and whether it should proceed) or the choice of energy supply options.

BC Hydro recognized that this was a key issue for new customers; that customers needed some assurance of what rate they would be treated under in order to make their investment decisions. Therefore, BC Hydro presented a strawman transition rule for grandfathering for stakeholder comment in Workshop No. 1:

- Prior to the effective date of a new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro’s satisfaction that their projects are likely to come into service within 24 months of the effective date of the new TS 6 will have the option to continue under the old TS 6. Customers who have not met both conditions on the effective date of the new TS 6 must proceed under the new TS 6.

BC Hydro’s rationale for this transition rule was the view that the Facilities Study Agreement is the appropriate position for apply grandfathering as this is the first point in the connection process after which the customer has been provided scope, cost, and schedule information (SIS report) which they can use in their business cases.

In developing this strawman proposal, BC Hydro recognized that the transition rules need to be consistent with the Bonbright criteria of rate and bill stability and that a time limit needed to be established in which the two tariffs are maintained and managed.

BC Hydro requested comment as to whether participants agree or not with the proposed strawman transition rule, with reasons. BC Hydro noted that it recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under:

1. **System Impact Study (SIS)** – customer has initiated a SIS;
2. **Facilities Study (FS)** - customer has initiated a FS; and
3. **Facilities Agreement (FA)** – customer has an executed FA.

BC Hydro also questioned if other factors should be considered such as: In-service dates, final investment decision date, and permitting approvals.

8.2 Participant Comments

Transition rules were unanimously supported because customers make significant investments (money and time) in BC Hydro interconnection studies and make investment decisions based on those studies and the terms and conditions for interconnection in place when the studies are requested. Customers need certainty as to how costs will be assigned before commencing the interconnection process.

Most of the feedback suggested that a customer with an executed FA should have grandfathered rights because this is the first point at which a customer has made a full commitment to proceed to implementation.

There was almost unanimous agreement that the requirement for the customer's in-service date to be within 24 months of the FA was seen as onerous as some customer projects take longer than that to design, permit and build. Also if the in-service date was dependant on a BC Hydro SR that had an in-service date greater than 24 months, then the customer was being penalized for circumstances beyond their control.

CAPP noted that it understood BC Hydro's desire for a sunset clause for grandfathering purposes, but believed that given the uncertainty regarding the timing for PRES (due to project complexity and scope) that requiring a two-year sunset clause would put the broader PRES project at risk. CAPP suggested a potential alternative to having a set time period for grandfathering could be to have a requirement for customers to post security for the SR based on study estimates.

FNEMC, in principle, supported the strawman transition rule in grandfathering new customers in the interconnection queue should there be any changes to TS 6; therefore aligning with Bonbright's criteria of rate and bill stability.

FNEMC and BCOAPO both noted that in addition to the 24-month rule for the project in-service date, the impact of other contributing factors such as in-service date, customer investment decision dates, permitting approvals, construction schedule, etc. needed more discussion

AMPC also commented they needed to understand what the new extension/contribution policy will be, before appropriate transition rules could be developed.

8.3 BC Hydro Consideration

BC Hydro understands that customers are making significant investments in interconnection studies and advancing their projects and need to know how interconnection costs will be treated during the transition period in order to make their final investment decisions. These investment decisions cannot be deferred until the new tariff is approved.

BC Hydro acknowledges the view of AMPC that contribution policy decisions will determine the extent that transition rules are more or less relevant. Nonetheless, BC Hydro considers that transition rules will provide clarity for when and how long a customer will be governed under the old tariff provisions or when the provisions of the new tariff will become effective.

Most stakeholders agreed that the FA was the appropriate point for customers to reach in order to have the ability to be grandfathered because it is the first point at which a customer has made a commitment to proceed to implementation and which BC Hydro will have provided an refined level estimate (+15/-10%). However, there was considerable disagreement with BC Hydro's proposal that a project's forecasted in-service date must be within 24 months of the FA. BC Hydro will continue to review the need and options for sunset rules that balance BC Hydro's desire to minimize the time in which two tariffs are in effect and the customers' need for cost allocation certainty. BC Hydro will review if changes to queue management rules can be used to address the need for a sunset clause in respect to transition rules.

BC Hydro considers that it is likely most appropriate to further discussion on transition rules once there is more clarity on transmission extension policy and preferred alternatives overall.

9 Queue Management

9.1 Background

As part of the workshop preparation materials, BC Hydro circulated and sought comments on a draft queue management business practice, raising four specific areas for comment:

1. **Staged Approach with Soft Milestones** under which BC Hydro would have discretion on timeframes if others later in the queue are not harmed by extensions to deadlines;
2. **Staged Approach with Hard Milestones** under which there would be strict adherence to timeframes, with definition of what constitutes a material change (changes in load size, point of interconnection, deferral of in-service date by X years, etc..) that would require a customer to lose its current queue position and be moved to the bottom of the queue;
3. **Fast Track Process under which** later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) would be allowed to connect prior to earlier queue customers; and
4. **Open Call/clustered study under which** BC Hydro would initiate a call for projects that want to connect to the BC Hydro transmission system when there is deemed to be the potential for several connection requests in the same region. Each connection request would have the same queue position and the requests would be studied as a cluster.

9.2 Participant Comments

Feedback suggested that there is no one perfect solution and that flexibility based on specific circumstances, number of requests in the queue, number of requests in a specific geographic area, and customer commitment level should also be considered. APMC noted that all the options may have pros and cons and require significant further discussion as to how they would operate in practice and what all of the implications would be.

CEC noted Option 1 seemed preferable. Clustering when queue congestion is an issue becomes a reasonable response to the queuing as opposed to determining who benefits and who loses. Tariffs should include this caveat. CEC also felt

Option 4 is a useful approach in concept and is complementary to Option 1 with clustering formalization. BC Hydro may find it useful to have both Options 1 and 4.

CAPP noted there are merits in the Fast Track Process where a project that is 'shovel-ready' may connect prior to earlier queue customer(s) as long as there is no harm to the earlier queue customer(s) and their loads. CAPP also felt that where customers have provided monetary guarantees they should not be able to be bumped out of their position in the queue.

Aside from the mechanics of the queue management process several stakeholders took the opportunity to express frustration with the current connection timelines. The key issue for AMPC remains the lack of internal resources dedicated by BC Hydro to providing transmission extensions and the length of the queues and long lead and response times that result. AMPC suggested that reallocation and reorganization of resources within BC Hydro (under the existing rate-caps) should be the first priority to reduce lead times at all stages of study and interconnection. Approaches to managing the queue would be more appropriately considered after the queue has been diminished to a more manageable size.

CEC felt the queue issue is primarily a function of the scarceness of unutilized capacities in the current system. Allocating these benefits based on first come, first served can be problematic. This problem can be diminished significantly with postage stamp concepts and future capacity increment assessments to smooth out cost and benefits for all customers. In earlier engagement sessions the Commission has questioned if fixed fee for studies would help in part elevate the customers' frustration.

BCOAPO is less concerned with who gets connected (and when they are connected), and more concerned with how costs are allocated for connections

9.3 BC Hydro Consideration

Although queue management practices have been discussed many times with stakeholders over the years and BC Hydro recognizes the need to provide more transparency into the practices most stakeholders believe there needs to be flexibility in the practice so that there is fair and consistent treatment of requests that is more responsive to customers' project timeframes. BC Hydro will publish its current business practice and will continue to review it to develop more transparent rules for when BC Hydro may deviate from a first-come first-served principle in cases.

The feedback demonstrates that customer frustration with the interconnection process is not so much the queue management business practice but the overall time required to complete studies and construction facilities as can be seen in AMPC comments. BC Hydro will continue to review its interconnection processes for efficiencies and will be conducting additional jurisdictional reviews of comparable utilities to determine best practices. We will also continue to discuss the interconnection process with customers and industry associations to ensure there is a common understanding of the processes and challenges BC Hydro faces in when determining the impacts of a new load request.

2015 Rate Design Application
Module 2

Transmission Extension Policy

BC Hydro Summary and
Consideration of Participant Feedback to Date

Attachment 1

2015 RDA Module 1
Workshop No. 1 – November 18, 2014
Presentation

2015 RATE DESIGN APPLICATION (RDA)

TRANSMISSION EXTENSION POLICY – WORKSHOP #1

18 November, 2014

BC hydro
FOR GENERATIONS

Agenda

Approximate Time	Item	Presenter(s)
9 :00 – 10:15	Welcome Background & Legal context Bonbright Criteria Overview of Tariff Supplement No.6 (TS 6)	Anne Wilson Gord Doyle Sam Jones/Frank Lin
10:15-10:30	Break	
10:30 – 12:00	Sources Informing TS 6 Review Contribution Options Security Options	Justin Miedema Sam Jones / Frank Lin
12:00 – 1:00 PM	Break for lunch	
1:00 pm – 2:45	150 MVA Threshold Options Transition Rule Options Other Issues	Frank Lin Sam Jones
2:45 – 3:00	Closing and Next Steps	Anne Wilson

Background and Legal Context

Presenter

Gordon Doyle

Background and Legal Context

- TS 6 governs new customer payment towards new transmission required to serve them
- TS 6 became effective 21 January 1991 pursuant to British Columbia Utilities Commission (BCUC) Order G-4-91
- As discussed at the 8 May 2014 Introductory Workshop, BC Hydro’s view is that TS 6 is in scope for the 2015 RDA

Background and Legal Context

- However, section 3 of Direction No. 7 raises jurisdictional issues regarding TS 6
  - Subsection 3(2): BCUC “must ensure the rates for [BC Hydro] transmission service customers are subject to … the terms and conditions found in Supplements 5 and 6 of [BC Hydro’s] tariff”
  - The BCUC cannot unilaterally change TS 6
  - This jurisdictional issue was recognized in the BCUC’s 2009 report concerning BC Hydro’s Transmission service rate program

Background and Legal Context

- BC Hydro proposes that the BCUC's review of TS 6 take place under section 5 of the *Utilities Commission Act*
- The BCUC would make recommendations to the B.C. Government concerning TS 6, with the B.C. Government as the decision-maker
- BC Hydro is seeking further feedback on whether TS 6 can be part of a later 2015 RDA 'module' (not part of the anticipated late June 2015 RDA filing)

Bonbright Criteria

Presenter

Gordon Doyle

Application of Bonbright Criteria to Extension Policy

Used to assess TS 6 and options

Fairness

- Fair apportionment of costs among customers
- Avoidance of undue discrimination

Efficiency

- Price signals that encourage efficient use and discourage inefficient use

Practical

- Practical & cost effective to implement

Customer acceptance

- Customer understanding and acceptance
- Freedom from controversies as to proper interpretation

Revenue / rate impacts

- Recovery of the revenue requirement
- Revenue stability
- Rate & bill stability

Application of Bonbright Criteria to Extension Policy

BC hydro FOR GENERATIONS

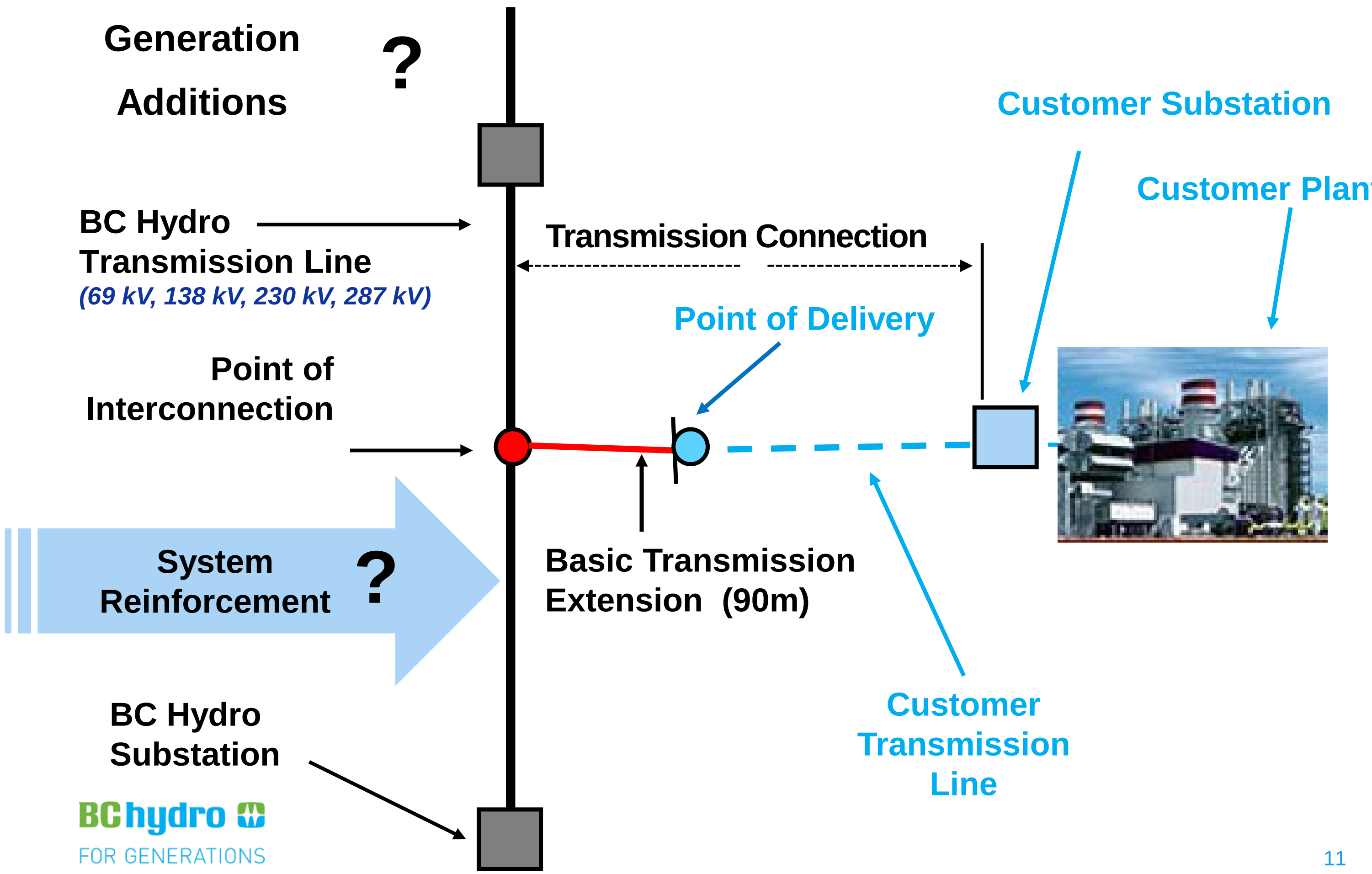
- Regulators in other jurisdictions have focused on fairness and efficiency Bonbright criteria
- Fairness – balance interests of existing customers in maintaining postage stamp rate levels with interests of new customers in receiving system access at a predictable and reasonable cost
- Efficiency - BCUC in 2012 Dawson Creek/Chetwynd Area Transmission Project (DCAT) Certificate of Public Convenience and Necessity (CPCN) decision: “new customers should be provided with price signals that encourage efficient economic decisions”
  - E.g., new customers request the most economical connection facilities and/or take into account the existing or planned transmission system when considering alternate locations for service
- Also important is Rate & Bill Stability – if there is a future change to TS 6, should consider grandfathering new customers in the interconnection queue

Overview of TS 6

Presenter

- Sam Jones
- Frank Lin

Contribution Policy
Illustrative Transmission Connection



11

TS 6 – Overview

Under TS 6, the connection between customer's facility and the BC Hydro grid has three parts:

- Customer undertakes the design, securing of government agency approval, land acquisition and construction of **transmission line connecting customer facility to BC Hydro's system (Customer Transmission Line)** where "reasonable, practical and economic"; if it is not "reasonable, practical and economic" for the customer, BC Hydro undertakes these activities – new customer is responsible for 100% of costs

- BC Hydro makes a **Basic Transmission Extension (BTE), in which it modifies its existing facilities to allow the customer transmission line to connect to the grid** – customer is responsible for 100% of costs

TS 6 – Overview

BC hydro
FOR GENERATIONS

BC Hydro identifies upgrades to its existing transmission system (known as System Reinforcement (SR)) required to supply electricity to point of BTE – SR costs are shared according to terms and conditions set out in TS 6

- BC Hydro share of incremental costs arising from new customer is referred to as **contribution** in this presentation
- BC Hydro contribution is the lower of either: (a) actual SR costs; or (b) first year of anticipated electricity sales revenue x 7.4
- New customer typically provides letter of credit (LoC) (or equivalent form of security) in regard to BCH contribution, which is drawn down annually as revenues are realized. Although contribution calculation is based on about 7.4 years, customer is given 12 years for revenues to be realized before any outstanding security would be called on
- SR costs do not include incremental generation costs or 500 kV transmission lines unless the load exceeds 150 megavolt amperes (MV.A)

TS 6 – BC Hydro's Contribution

- BC Hydro's contribution towards SR is based on total revenue (demand and energy) expected over about a 7.4 year period

- Detailed formula is:

$$I = \frac{(R-E)}{0.135} + B + D$$

I = BC Hydro maximum contribution towards cost of SR

R = incremental revenue in first year of normal operation

E = incremental Operating & Maintenance (O&M) expenses during first year of normal operation

B = other benefits to BC Hydro

D = ½ of annual depreciation associated with total cost of SR

System Reinforcements

BC hydro FOR GENERATIONS

- TS 6 defines SR as additions and alterations to existing BC Hydro facilities, required to supply the electricity to a "Transmission Connection" (Customer's Transmission Line and BTE)

- SR includes the following types of upgrades:
  - Thermal upgrades of transmission lines to increase operating temperature and clearances (includes raising poles, re-contouring terrain and re-tensioning of conductor)
  - Re-conductoring of transmission lines
  - Addition of voltage support equipment
  - Replacement of transformers and associated facilities at a source substation
  - Addition of protection and control and communication facilities at BC Hydro facilities
  - **Addition of a new transmission line between two points on existing BC Hydro transmission system and any associated substation equipment to terminate the new line**

System Reinforcements

- For most interconnections, SRs are planned and designed to meet the new load requirements e.g., voltage support equipment is specified for size of the new load
- In cases where new lines or transformer replacements/additions are required, the reinforcements can add more capacity than needed to supply the new load due to the fact these upgrades add capacity in larger blocks

Extensions

BC hydro FOR GENERATIONS

- Extensions are not a defined term in TS 6
- TS 6 refers to **"Transmission Connection"** which includes BTE and the Customer's Transmission Line
- The issue has been raised as to whether there are circumstances when a Customer's Transmission Line should/could be considered a SR and a utility contribution applied to the costs

System Reinforcement vs Extension

Extensions to single customer

- If an extension supplies a single customer then this should be treated as a customer connection
- If the line is transferred to BC Hydro and additional customers connect then pioneer rights would apply where new customers would contribute to the cost (depreciated) to the pioneer customer

System Reinforcement vs Extension

BC hydro FOR GENERATIONS

Extensions to clustered loads (more than one load)

When there is a reasonable expectation (based on customer enquiries/request, load forecasts and/or other industry indicators) that there would be additional customers that would connect to an extension within “X” year period, then:

1. BC Hydro would build the common transmission line and would treat this common line extension as an extension to the BC Hydro system, and using the pioneer principle, split the costs amongst the loads on a pro-rated basis upfront (load/total loads or load/line capacity). This would be a direct customer capital payment; or

2. BC Hydro would build the common transmission line and would treat this common line extension as a SR, and would apply the utility contribution to these costs and seek security from each customer on a pro-rated basis (load/total loads or load/line capacity)

System Reinforcement vs Extension

BC hydro FOR GENERATIONS

Extensions to clustered loads (continued)

Where BC Hydro would like to have the common line extension built to a higher capacity than required for the initial load(s), BC Hydro could prorate the costs based on:

1. The initial customer(s) contributing based on the avoided cost of the line required to serve its load. The incremental cost would be allocated to future customers based on their load over the incremental capacity from the large capacity line; or

2. All customers would be allocated costs based on their load over the total capacity of the line built

Sources Informing Review of TS 6

Presenter

Justin Miedema

21

Sources Informing Review of TS 6

BC hydro FOR GENERATIONS

- BCUC in the DCAT CPCN proceeding stated there are a number of issues concerning TS 6 that should be reviewed
- The Industrial Electricity Policy Review (IEPR) Task Force October 2013 Final Report notes that TS 6 is over 20 years old and recommended that TS 6 be reviewed in a BCUC public process
- Other BC Hydro tariffs - Northwest Transmission Line (NTL) tariff; Distribution extension policy
- Jurisdictional review
  - Each utility faces a unique set of circumstances including geography, industry structure, supply costs and economic growth
  - Different utilities use different terminology

NTL Tariff

- The NTL Tariff (TS 37) was approved in 2013 pursuant to BCUC Order G-52-13
- This tariff is supplemental to TS 6, with customer's incremental payment towards NTL costs based on a pro-rated share of the line from industrial customers and generators that connect to the line:

NTL Supplemental Charge = (Demand/NTL Capacity) x Actual Utility Cost

Contribution Policy – Distribution

BC hydro FOR GENERATIONS

- Distribution General Service contribution amount is a calculation based on Net Present Value (NPV) of a Distribution capital-related revenue stream

- The General Service contribution amount is:

  $200 per KW of estimated billing demand

- When calculating what a customer must pay for an extension, BC Hydro multiplies customer's estimated demand by the maximum contribution amount and then makes adjustments for:

  - Asset renewal credits ("depreciation allowance")
  - Shared or dedicated salvage credits
  - Telus contributions credits

Jurisdictional Review

BC hydro FOR GENERATIONS

- BC Hydro surveyed other utilities to determine how they treat their large transmission service customers

- Starting point was Energy + Environmental Economics, Inc.'s (E3) 2013 survey[1] of 12 jurisdictions submitted as part of the IEPR Task Force process

  - E3 reviewed the large load interconnections policies of Alberta Electric System Operator (AESO); Bonneville Power Administration (BPA); California; ERCOT (Texas); Hydro One (Ontario); Hydro Quebec; Manitoba Hydro; New Brunswick Power; Nova Scotia Power; PJM (a regional transmission organization (RTO) in the eastern U.S.); SaskPower; U.S. Midwest ISO (a regional RTO in the U.S. Midwest)

- BC Hydro updated E3's jurisdictional assessment and focused on: AESO, BPA, Hydro One, Hydro Quebec, Manitoba Hydro and SaskPower

[1] See Appendix A, http://www.empr.gov.bc.ca/EPD/Documents/IEPR%20Submission-BC%20Hydro%202.pdf

Jurisdictional Review

- BC Hydro chose to focus on jurisdictions with: similar industries served by the utility (e.g., gas and/or mining); hydroelectric system-based; long transmission system distances; and/or to cover differing approaches

    - BC Hydro does not favour the extremes of assessing costs solely to the new customers or not imposing any direct costs on the new customer

- The jurisdictional survey work focused on determining underlying policy drivers, and cost recovery mechanisms for connection facilities, extensions and system or network upgrades

- 'Extensions/Connections' are analogous to 'Customer Transmission Line' and 'Basic Transmission Extension' described in slide 12
- 'Network Upgrade' is analogous to 'System Reinforcement' described in slide 13

Extensions/Connections

- Customer pay extension and connection costs net of an investment by AESO:
  - Investment levels based on a formula that relates past connection costs and loads
  - Dataset includes 215 past connections including greenfield and upgrade projects from the late 1990s to present
  - 60% of total extension/connection costs are covered by contributions from AESO

Tier	Tier (a)	Tier (b)	Tier (c)	Tier (d)	Tier (e)
Investment	$52,000	$35,350	$13,050	$7,900	$4,250
Unit	/year	/MW/year	/MW/year	/MW/year	/MW/year

Current Investment function: First 7.5 MW | Next 9.5 MW | Next 23 MW | All add't MW

Network Upgrades

- System related costs are borne by all ratepayers and there is no cost to the connecting customer. AESO makes a case by case determination on which costs are system vs. participant related

- Generally, upgrades that are in AESO's long term planning are considered system related; however, customers may be charged for advancement costs

- AESO's tariff lists a number of criteria for the types of costs that can be deemed system or participant related

SaskPower

BC hydro FOR GENERATIONS

Extensions/Connections

- Customers pay extension and connection costs associated with connecting to the nearest transmission line based on fixed $/km construction costs
- If actual construction costs exceed the fixed $/km construction costs, SaskPower pays for the additional costs. SaskPower estimated its $/km charges at $1 million per km
- Utility builds and owns all line extensions and connections

Network Upgrades

- Customers are not charged for network upgrades

Extensions/Connections

- Customers pay extension and connection costs because since 23 June 2005, no utility contribution has been made in relation to facilities required to serve new loads exceeding 30 kilovolts (kV) or loads in excess of 5 MW
  - This action was taken to mitigate rate impacts on existing customers.
- Utility builds and owns all line extensions and connections

Network Upgrades

- Customers are not charged for network upgrades

Extensions/Connections

- Customer payment for extensions governed by a revenue test and Ontario Energy Board's (OEB) Transmission System Code
- Test examines NPV of customer revenue against extension expenses
- Length of evaluation period varies according to proponent risk:
  - 5 years for high-risk connections
  - 10 years for medium-high-risk connections
  - 15 years for medium-low-risk connections
  - 25 years for low-risk connections

Only customers with high credit ratings are classified as low or medium-low risk

Network Upgrades

- Historically, customers have not been charged for network upgrades, but utility can request approval to charge for these from OEB

Extensions/Connections

- Hydro Quebec applies a revenue test and contributes $378 per kilowatt (kW) to determine customer's payment for extension and connection-related costs
- New loads greater than 50 MW must receive Quebec Government approval before connecting to the Hydro Quebec system
  - Prior to 2008, threshold was 175 MW but this was reduced to 50 MW as a result of the 2006 Energy Strategy to minimize rate impacts associated with "granting large blocks of electricity" to specific customers

Network Upgrades

- Hydro Quebec does not charge customers for Network Upgrades

BONNEVILLE POWER

BC hydro FOR GENERATIONS

- BPA has a number of direct load customers including data centers, lumber mills, mines and aluminum smelters
- Any costs directly attributable to a customer's connection are born 100% by the connecting customer. This can include Network Upgrades that have no benefits to other customers on the BPA system
- If there are mutual benefits from Network Upgrades, connecting customer will pay full cost upfront and then be given "transmission service credits" in the form of reduced transmission use charges that they can use to offset transmission costs
- If new line will serve two or more large loads, line will be considered Network Upgrades and will be charged to the rate base

Summary	BC Hydro	AESO	SaskPower
Who pays for Extension/ Connection?	Customer	Customer net of utility contribution	Customer, but capped at $/km construction cost
Who pays for Network Upgrade?	In practice the utility, but customers could potentially be required to contribute	Connection costs deemed "system related" are paid for by utility	Utility
Methodology to determine utility contribution	Revenue test, including G, T and D revenue	Formula approach relating costs with customer capacity	N/A
Security	Posted prior to construction; Capped at maximum contribution as defined in TS 6; Refunded as revenues materialize (up to 12 years)	Security requirements increase as projects advance through proposal, application, and construction phases; Capped at AESO's maximum investment level and refunded when customer reaches Commercial Operation Date (COD)	Security of 25%, 50%, or 100% for the extension/connection can be collected depending on project risk

Summary	Manitoba Hydro	Hydro One	Hydro Quebec
Who pays for Extension/ Connection?	Customer	Customer net of utility contribution	Customer net of utility contribution
Who pays for Network Upgrade?	Utility	Utility, but an application can be made to OEB to charge the customer	Utility
Methodology to determine utility contribution	N/A	NPV formula using different time periods depending on project risk	Currently $378/kW
Security	Security can be held for up to 5 years at discretion of the utility	Amount of the deposit is proportional to credit worthiness; Refunded once customer connects to Hydro One	Both the utility contribution and network upgrade costs are secured; Refunded once customer has been connected for 12 months

Summary

BC hydro FOR GENERATIONS

- Utilities surveyed use different approaches - there is no industry standard method
- Extensions/Connections (i.e. Transmission Connection, i.e. Customer Transmission Line plus BTE) - Most utilities provide a contribution to customer extensions/connections (e.g., AESO, SaskPower, Hydro One, Hydro Quebec) while BC Hydro requires customers to pay 100% of these costs
- Network Upgrades (SR) - Most utilities do not charge for network upgrades as there is recognition that such upgrades often benefit both new and existing customers
    - Where there is a charge for network upgrades, revenue tests are often applied to determine proportion of the cost borne by connecting customer and by the utility (e.g., Hydro One, BC Hydro)
- Security is commonly collected to mitigate against stranded investment risk; typically held by utility until customer reaches COD or shortly thereafter

BC hydro
FOR GENERATIONS

Utility Contribution Options

Presenter

Sam Jones

Utility Contribution Option #1 Generation and Transmission Demand Revenue Model

BC hydro FOR GENERATIONS

Demand Revenue model - based on NPV of forecasted Rate Schedule (RS) 1823 demand revenue stream (which includes generations and transmission demand costs), adjusted for life expectancy of customer's facility

RS 1823 Demand Revenue Model
BC Hydro Maximum Contribution ($/kVA)

	Using the F16 - F20 rates announced in the 10 year plan
Estimated life of customer's facility	RS 1823 demand revenue
5 Year	$371
10 Year	$656
15 Year	$860
20 Year	$1,005
25 Year	$1,108
30 Year	$1,194

Issues
- No cost of service basis

BC Hydro view
- BC Hydro proposes no further analysis required

Utility Contribution Option #2
Transmission Cost of Service Model (capital, O&M, taxes)

Transmission Cost of Service model – based on NPV of forecasted transmission costs (capital, O&M & taxes), adjusted for life expectancy of customer's facility

Transmission Cost of Service Model (capital, O&M, taxes)
BC Hydro Maximum Contribution ($ / kVA)

	Using the F16 - F20 rates announced in the 10 year plan
Estimated life of customer's facility	Based on Transmission-related (capital, O&M, taxes) costs as identified in F13 cost of service study (COSS)
5 Year	$275
10 Year	$486
15 Year	$626
20 Year	$744
25 Year	$820
30 Year	$883

BC Hydro view

- BC Hydro proposes to carry forward for further analysis

Utility Contribution Option #3
Transmission Cost of Service Model (capital) - closest to BC Hydro Distribution extension policy

Transmission Cost of Service model – based on NPV of forecasted Transmission capital-related costs (excludes O&M, taxes), adjusted for life expectancy of customer's facility

Transmission Cost of Service Model (capital)
BC Hydro Maximum Contribution ($ / kVA)

	Using the F16 - F20 rates announced in the 10 year plan
Estimated life of customer's facility	Based on Transmission-related capital costs for as identified in F13 COSS
5 Year	$157
10 Year	$277
15 Year	$363
20 Year	$424
25 Year	$467
30 Year	$504

BC Hydro view

- BC Hydro proposes to carry forward for further analysis

Contribution Policy Offset Options #1, #2 and #3 – Application on historical and inflight projects

Using historical project cost data, BC Hydro compared Option #1, Option #2 and Option #3 to determine impact on customer projects

	Rates as of 1 April 2014	Using the F16 - F20 rates announced in the 10 year plan		
	TS 6	Option #1 Demand revenue	Option #2 Transmission revenue - (capital, O&M, taxes)	Option #3 Transmission revenue - (capital only)
Number of customers where utility contribution covers 100% of SR costs	49	45	42	36
Number of customers where utility contribution does not cover 100% of SR costs	0	4	7	13
% of customers where utility contribution does not cover 100% of SR costs	0%	8%	14%	27%

Notes:

- Does not include any consideration of BC Hydro benefit
- BC Hydro contribution based on life of projects

Utility Contribution Options #1, #2 and #3 – Application on historical and inflight projects

BC hydro FOR GENERATIONS

Using historical project cost data, BC Hydro compared Option #1, Option #2 and Option #3 to determine aggregated impact of contribution options

		Total Contribution - Rates as of 1 April 2014	Total Contribution - Using the F16 - F20 rates announced in the 10 year plan		
	SR Costs	TS 6	Option #1 Demand revenue model	Option #2 Transmission revenue (capital, O&M, taxes)	Option #3 Transmission revenue model (capital only)
Totals ($ millions)	$727	$4,814	$1,852	$1,370	$781
Amount of Unused contribution ($ millions)		$4,087	$1,125	$643	$54

* Does not include any consideration of BC Hydro benefit

Notes:

- BC Hydro contribution based on life of projects
- Total new load 1,785 MW

Utility Contribution Option #4
Fixed duration

BC hydro FOR GENERATIONS

Modification of Options #1, #2 and #3 by setting NPV revenue stream timeframe to 25 years, which is ½ the life of a transmission asset

Transmission Cost of Service Model
BC Hydro Maximum Contribution ($ / kVA)

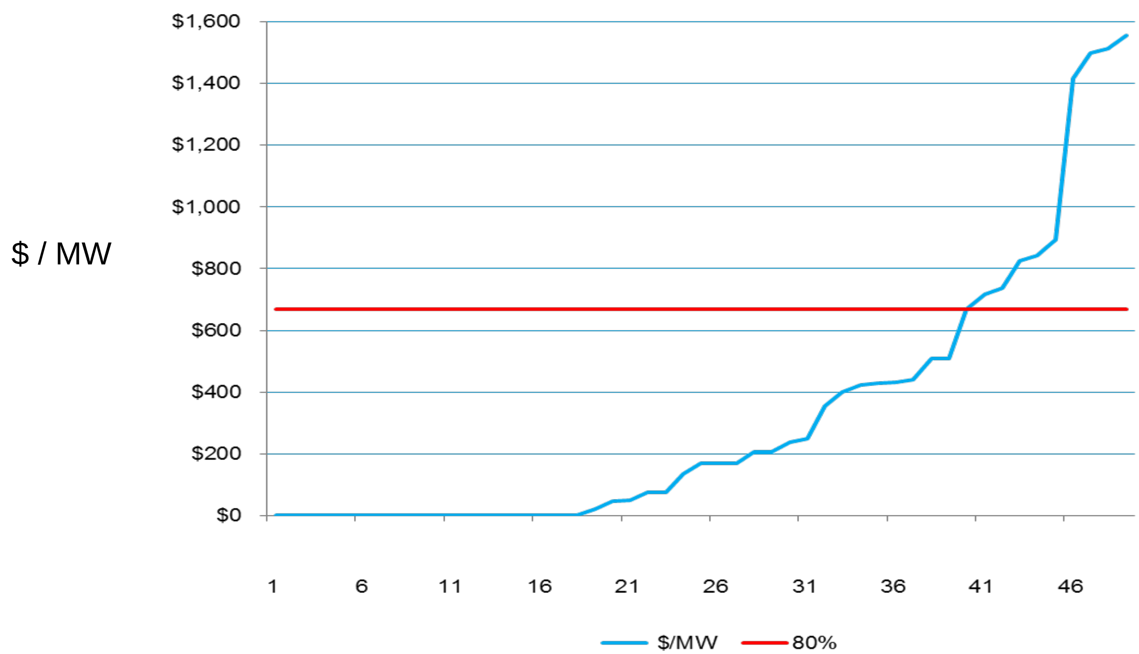
	Using the F16 - F20 rates announced in the 10 year plan		
Revenue Stream Timeframe	Option #1 - 1823 Demand revenue model	Option #2 - Transmission revenue model (capital, O&M, taxes)	Option #3 - Transmission revenue model (capital only)
25 year	1,108	820	467
50 year	1,318	975	557

Issues
- Timeframe does not impact Options #2 and #3; simplifies these options by not having to estimate expected life of customer facility

BC Hydro view
- BC Hydro proposes to carry forward for further analysis

Utility Contribution Option #5
Cost Multiplier (AESO consideration)

Utility contribution should be set so that amount will cover SR costs for most customers - 80/20 rule (20% of new customers make a payment)



BC Hydro view:

- This is more of check on results than a stand-alone option
- Carry forward as check on other option results?

Utility Contribution option #6
Forecast New Loads/Multiplier (AESO consideration)

Develop contribution based on forecast of new loads and reinforcements, and apply a cost multiplier

Issues

- Difficult to determine with any accuracy future loads that have not made enquiries, and even more difficult to predict reinforcement costs as these are site specific and dependent on who else connects or are in the queue
- Hard to balance risk between customer and BC Hydro
- Possible cross-subsidization

BC Hydro view

- Given the issues, BC Hydro proposes that no further analysis is required

Utility Contribution Option #7
Hydro One

BC hydro FOR GENERATIONS

Apply offset to BTE and extension (SR covered by utility)

Issues

- Does not fairly apportion costs of sole use facilities
- Possible cross-subsidization
- Upward rate impact

BC Hydro view

- Given the issues, BC Hydro proposes that no further analysis is required

Utility Contribution Option #8
SaskPower

Apply a fixed fee towards BTE and extension

Issues

- Difficult to establish costs as regional constraints and geography greatly affect interconnection costs
- Existing ratepayers bear risk of any cost incurred above the fixed fee and customer over contributes if costs are less than fixed fee
- Possible cross subsidization

BC Hydro view

- Given the issues, BC Hydro proposes that no further analysis is required

Utility Contribution Option #9
Hydro Quebec

Fixed offset ($/MW) for sole use and network upgrades

Issues

- Does not fairly apportion costs of sole use facilities
- Possible cross-subsidization
- Upward rate impact

BC Hydro view

- Given the issues, BC Hydro proposes that no further analysis is required

Utility Contribution Option #10
Manitoba Hydro

Apply 100% of BTE and extension to customer and utility covers SR

- Utility may require security during construction period to ensure customer connects; Security is released once customer project reaches COD

Issues:

  - Higher risk to existing ratepayer as no direct link between SR investment and revenue
  - Possible cross subsidization and rate impact

BC Hydro view

- Carry forward for further analysis

BC hydro
FOR GENERATIONS

Security Options

Presenter
Frank Lin

Existing Requirement

BC hydro FOR GENERATIONS

- Customer must provide security for full amount of BC Hydro contribution, in a form which has prior approval of BC Hydro which may include:
  - Irrevocable LoC;
  - Contract bond;
  - Guarantee by a corporation other than the customer;
  - Bank term deposit, to be deposited in trust for BC Hydro;
  - Negotiable bearer bond, that is government guaranteed at face value; or
  - Prepayment on account
- Over past decade, 18 customers have provided security. In that time, BC Hydro has never had to draw on the security
- Issues
  - Should security be required? For what amount?
  - When should security be released?

Amount of Security Options

BC hydro FOR GENERATIONS

Options	Pros	Cons
Existing approach: Security for full amount of contribution	Minimizes risk to existing ratepayers	Costs to industry. Possible barrier to customer project development
No security	Reduced administration and costs for industry	Risk of stranded assets
Security for construction period only	Addresses highest risk period	Risk of stranded assets after construction period
Security tied to proponent risk	Requires security only from riskiest counterparties	Possible barrier to customer project development

Release of Security Options

- Options under consideration for release of security:
  - After construction is complete?
  - After a fixed period, e.g., 5 years?
  - Based on an assessment of revenue recovered (similar to Distribution extension security)?

150 MVA Threshold Options

Presenter

Frank Lin

150 MVA Threshold - Background

- Under TS 6, SR to be funded by customer does not include additions or alterations to generation plant and associated transmission, or transmission lines at 500 kV and over, unless the new or incremental loads exceed 150 MV.A
- The threshold was established to mitigate against large rate impacts
  - Bulk generation costs are the most significant costs (versus bulk transmission)
- IEPR Task Force found that the 150 MV.A threshold was set based on the size cost of adding a new gas-fired generating facility to BC Hydro's resource stack

150 MVA Threshold - Background

- Application of the 150 MV.A threshold only considered by the BCUC in one instance with the Port Alberni Aluminum complaint in 2002
- IEPR Task Force recommended a review of the 150 MV.A threshold and questioned the need for a threshold if the contribution policy was updated
- Only one other jurisdiction has a threshold – Hydro Quebec (50 MW)
- Ontario has provision whereby utility can go to regulator to request transmission costs be assigned to new customer

150 MVA Threshold Considerations

- How to deal with staged projects and/or multiple sites that might trigger the 150 MV.A threshold
- How to deal with a mismatch in the life of customer plant and the life of a new generation built or purchase
- Timing of assessment of generation requirements (e.g., in surplus when originally assessed-project delayed 2 years and now in deficit)
- Potential inconsistency with the Heritage Contract – new customers should be able to benefit from low cost Heritage resources

150 MVA Threshold Options

BC hydro FOR GENERATIONS

1. Status Quo
   - Pros:
     - In case of very large load, protects existing ratepayers
     - Single threshold number is simpler to administer
   - Cons:
     - Limits customer project development?
     - Arbitrary - Difficult to justify why a hypothetical load of 149 MV.A would receive access to Heritage resources while a 150 MV.A load would pay full costs

- Variation on Option 1 is to revise application of existing threshold:
  - Bulk generation and bulk transmission costs?
  - Bulk transmission costs only?
  - Bulk generation costs only?
  - Only incremental amount above threshold?

150 MVA Threshold Options

BC hydro FOR GENERATIONS

2. Develop new threshold
   - Establishing a threshold
     - If load has a >XX% impact on rates
     - If load has is >XX% of installed generation capacity
     - Only incremental amount above XX threshold

3. No Threshold with Safety Valve (Ontario)
   - For exceptional cases where a new load would cause a significant rate impact, BC Hydro to have option to go to the BCUC for determination if and how generation and/or bulk system costs should be assigned to the new customer

4. No threshold

Transition Rule Options

Presenter

Frank Lin

Transition Rules

BC hydro FOR GENERATIONS

- If TS 6 is changed, there is a need to consider transition rules – this is consistent with application of Bonbright rate & bill stability criterion
- Customers are making final investment decisions (FID) based on existing TS 6 several years in advance of proceeding with their projects
- To the extent that there are TS 6 changes, this may impact overall economics of customer project, and in some cases whether they take electric service for load

Transition rules options

At what point should a customer be grandfathered under existing TS 6?

- System Impact Study (SIS) initiated - scope and costs are not identified until study is competed; customer commitment is minimal
- Facilities Study initiated - scope and first cut estimate identified; customer commitment is a deposit with customer starting to make decisions based on SIS
- Facilities Agreement executed – project plan completed; customer committed to implementation

- Other considerations:
- Should in-service date be considered?
- Should customer FID date be considered as FID may not align with Facilities Agreement execution?
- Should permit approvals (environmental, etc.) dates be considered?
- Other?

Transition rules options

BC Hydro's strawman transition rule for grandfathering, for stakeholder comment:

- Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro's satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6

Rationale:

- A timeframe for the transition is required to limit the time in which two tariffs are maintained and managed
- The Facilities Study Agreement is the appropriate position for apply grandfathering as this is the first point in the connection process after which the customer has been provided scope, cost, and schedule information (SIS report) which they can use in their business cases

Other Issues

Presenter
Sam Jones

Line Transfer

- Under TS 6, customer has option to transfer customer's transmission line to BC Hydro:
  - Line must be built to BC Hydro standards (engineering, First Nations consultation, Right-of-Way, environmental requirements, etc.)
  - Customer must declare intent to transfer prior to designing the line
  - In practice, line must be operated for minimum 12 months prior to transfer to ensure all transfer issues can be identified and resolved
  - The line is transferred to BC Hydro for $10

Line Transfer

- Issue
  - BC Hydro cannot require or decline a line transfer under TS 6
    - BC Hydro concerns are:
      - There are instances where due to geography constraints that only one line can be accommodated which could limit ability to serve future customers
      - Desire to limit the environmental impact of providing multiple lines into an area
      - Removes the requirement for third party connections and request for exemptions to ensure the customer is not regulated as a public utility
      - Cannot decline a line that has no ability to serve other customers or will put unreasonable costs on BC Hydro
- Options
  - Option #1 - Leave the line transfer as customer’s option only
  - Option #2 - Make the line transfer at either BC Hydro’s or customer’s option

Queue Management

- BC Hydro circulated a draft Queue Management Business Practice document, and is seeking comments as part of 45 day written comment period following posting of summary notes for this workshop

- BC Hydro manages a load interconnection queue for the following purposes:
  - Provide a non-discriminatory and transparent process
  - To determine order for initiating load interconnection studies
  - To set the base case for load interconnection studies and determine alternative scenarios to study
  - To determine subsequent cost allocation for facilities that are necessary to accommodate customer requests

Queue Management

BC hydro FOR GENERATIONS

- Current queue management practice follows these principles:
  - First-come first-served
  - Staged approach with deadlines
  - Flexibility to make efforts to meet each customer's requested ISD while being fair to all the customers

- Queue does not guarantee capacity or energy
  - Customer must meet all obligations to remain in the queue and proceeds through all stages of interconnection process

Queue Management Issues

- How to minimize the impacts to other customers when customer request changes
- How to help more likely & earlier customer ISD projects to proceed while being fair to earlier queue customers
- How to facilitate cluster studies in a capacity constrained area

Queue Management Options

- Tightening of existing process (staged approach with “soft” milestones)
- Staged approach with “hard” milestones
- Fast-track process
- Open call process

Next steps

BC hydro FOR GENERATIONS

TASKS	Date
45 day written comment period starting with posting of workshop notes to RDA website	December 2014 – January 2015
BC Hydro consideration memo, together with BC Hydro's position regarding filing Transmission Extension Policy as later RDA module II	March 2015
Continue to seek feed back from industry groups over the next several months as options are developed	December 2014 – Spring 2015
Update analysis of options based on feedback	December 2014 – Spring 2015
Develop interconnection scenarios to test leading options to be presented at Transmission Extension Policy Workshop #2	March 2015
Transmission Extension Policy Workshop #2	Spring 2015 – to be confirmed

THANK YOU

SEND COMMENTS TO:

bchydroregulatorygroup@bchydro.com

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333 Dunsmuir St., Vancouver, B.C. V6B-5R3

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2015 Rate Design Application

Module 2

Transmission Extension Policy

BC Hydro Summary and Consideration of Participant Feedback to Date

Attachment 2

2015 RDA Module 1

Workshop No. 1 – November 18, 2014

Notes

BC Hydro Rate Design Workshop

SUMMARY 18 NOVEMBER 2014 9:00 A.M. TO 3:00 P.M. BCUC Hearing Room Vancouver

TYPE OF MEETING	RDA Workshop No. 6 – Transmission Extension Policy
FACILITATOR	Anne Wilson, BCH
PARTICIPANTS	ARC Resources Ltd., Association of Major Power Consumers of British Columbia (AMPC), , B.C. Ministry of Energy and Mines (MEM), British Columbia Old Age Pensioners Organization (BCOAPO), British Columbia Sustainable Energy Association and Sierra Club B.C. Chapter (BCSEA), BCUC staff, Canadian Association of Petroleum Producers, Canadian Office & Professional Employees Union Local 378 (COPE 378), City of New Westminster (New Westminster), Clean Energy Association of British Columbia, Commercial Energy Consumers Association of British Columbia (CEC), Encana Corporation, First Nations Energy & Mining Council, FortisBC Inc. (FortisBC), KGHM International, Linda Dong Associates, Manitoba Hydro, Marayne Consulting Inc., Midgard Consulting, Mining Association of British Columbia (MABC), Municipality of Whistler, Seabridge Gold Inc. (Seabridge), Sinclar Group Forest Products Ltd., Teck Resources Limited, TransLink, University of British Columbia, Valard, Vancouver Airport Authority
BC HYDRO ATTENDEES	Gordon Doyle, Sam Jones, Frank Lin, Justin Miedema, Craig Godsoe, Bryan Hobkirk, Anne Wilson, Jeff Christian (Lawson Lundell)
AGENDA	1. Introduction including review of draft agenda 2. Background, Legal Context and Bonbright Criteria 3. Overview of TS 6 4. Sources Informing Review of TS 6 5. Utility Contribution Options 6. Security Options 7. 150 MV.A Threshold Options 8. Transition Rule Options 9. Other Issues – Line Transfers and Queue Management 10. Next Steps

MEETING MINUTES

ABBREVIATIONS		
	AESO.......Alberta Electric System Operator AUC.........Alberta Utilities Commission BCH ....BC Hydro BCUC......BC Utilities Commission BTE..........Basic Transmission Extension CFO.........Chief Financial Officer COS..........Cost of Service CP............Coincident Peak CPCN...... Certificate of Public Convenience and ....Necessity DCAT......Dawson Creek/Chetwynd Area Transmission ....Project ESA.........Electricity Supply Agreement IEPR.......Industrial Electricity Policy Review	IPP.........Independent Power Producer IRP.........BC Hydro's 2013 Integrated Resource Plan kV......... Kilovolt kW.........Kilowatt MV.A ....Megavolt Amperes MW.........Megawatt NTL........Northwest Transmission Line OEB........Ontario Energy Board RDA........Rate Design Application TS 6 ....Tariff Supplement No. 6 UCA.........Utilities Commission Act

1. *Introduction*

Anne Wilson opened the meeting by reviewing the agenda set out at slide 2 of the Workshop No. 6 slide deck.

2. Presentation: Background, Legal Context and Bonbright Criteria

Gordon Doyle highlighted the jurisdictional issue posed by section 3 of Direction No. 7, which is that the BCUC cannot unilaterally change TS 6 under its UCA rate setting powers. BCH proposes that TS 6 be reviewed through a section 5 UCA inquiry process whereby the BCUC would review TS 6 as part of the 2015 RDA, make recommendations in a report to the B.C. Government, and the B.C. Government would be the decision-maker. As part of this discussion, Gord raised the phasing of the 2015 RDA, first discussed at Workshop No. 1, with BCH proposing that TS 6 be part of a later module or phase consistent with some participant statements at Workshop No. 1 in May 2014.
Gord also reviewed the Bonbright criteria used to assess TS 6 and options, and indicated that in BC Hydro's opinion

fairness (allocation between existing customers and new customers), efficiency (incenting customers to request the most economical connection facilities), and rate and bill stability are the most important criteria in the context of TS 6 and Transmission extension policy.

	FEEDBACK	RESPONSE
1.	**COPE 378** Another way to deal with the BCUC jurisdictional issue is to request that the B.C. Government amend section 3 of Direction No. 7.	COPE 378's suggested approach was raised in 2009 in respect of Direction No. 7's predecessor, Special Heritage Direction No. HC2, as part of the BCUC's review of Transmission service rates and was not acted on. BCH has been in discussions with MEM. Use of the section 5 UCA process accords with the recent task force's draft report concerning its review of the BCUC, and permits the B.C. Government to be the final decision maker as TS 6 has economic development implications.
2.	**COPE 378** COPE 378 encourages BCH to file Transmission extension/TS 6 proposals as part of the main 2015 RDA as there is a relationship between the pricing of electricity for industrial users and Transmission extension policy.	
3.	**AMPC** There is a relationship between Transmission extension policy and rates, but having Transmission extension/TS 6 proposals be part of a later 2015 RDA module does not necessarily sever this link. AMPC is not against having Transmission extension/TS 6 proposals as a later RDA module.	
4.	**BCUC staff** BCH should consider providing a broader rationale for whatever Transmission extension policy it proposes. Transmission extension policy is typically driven by government policies which may be in addition to the Bonbright criteria. It would be helpful if BCH asked the B.C. Government to be clear on its policies. A good example is the 150 MV.A threshold – its removal may encourage larger customers to proceed but this may also have ratepayer impacts particularly if the larger customers are 'energy hogs'. BCH should also consider what has changed since 1991 when TS 6 was adopted.	
5.	**COPE 378** COPE 378 agrees with the BCUC staff comment. One perspective put forward in the IEPR review process was that the B.C. Government should bear the costs of its electricity policies in certain contexts as opposed to imposing such costs on ratepayers. In COPE 378's view, what has changed since 1991 is the large difference in energy costs between embedded Heritage hydro costs and new energy sources. The addition of new customers is not a net benefit to BCH or its existing customers.	

6.	**AMPC** AMPC agrees with the BCUC staff comment, but TS 6 and options should be assessed using the Bonbright criteria – the Bonbright criteria are as relevant to Transmission extension policy as to other rate design issues.	
7.	**New Westminster** Has BCH reviewed IPP interconnection agreements to inform its review of TS 6?	BCH will review IPP interconnection agreements as part of the overall review of TS 6. For purposes of this workshop, BCH used jurisdictional assessment, other BCH tariffs such as the NTL tariff and Distribution extension, the BCUC's DCAT CPCN proceeding submissions and decision, and the IEPR review as the basis for its proposed options.

3. Presentation: Overview of TS 6

Sam Jones and Frank Lin gave an overview of TS 6, emphasizing the three parts of a connection between a customer's facility and the BCH grid: (1) customer transmission line; (2) BTE; and (3) System Reinforcement. Slide 11 shows the customer transmission line to the right and System Reinforcement to the left. Differentiating System Reinforcements from extensions was the focus of the presentation.

Also discussed were how BCH's contribution to System Reinforcement costs is determined; security requirements; and the 150 MV.A threshold.

	FEEDBACK	RESPONSE
1.	**AMPC** When it comes time to examine possible TS 6 amendments, it would be helpful if BCH clarified the language around: BCH offset, BCH contribution, customer contribution, radial vs. non-radial, extension, customer extension, etc.	Agreed. For purposes of this workshop, BCH uses the terms 'utility contribution' (this is consistent with its Distribution extension terms found in sections 1 and 8 of the *Electric Tariff*) and 'customer payment', referring in each case to what the applicable party contributes to the incremental costs of connecting and serving the new customer.
2.	**AMPC** It would be helpful for the utility contribution discussion purposes if on slide 11 we clearly differentiate between the right side – customer transmission line and BTE; left side – System Reinforcement, and then discuss as between utility and new customer who is responsible.	
3.	**AMPC** Regarding the last item on slide 15 (bolded), if a gas-fired generation solution was proposed at the end of a radial line as an alternative to System Reinforcement transmission, would the new customer be required to make a payment that included the gas-fired generator?	TS 6 as currently worded contemplates transmission solutions as reflected in the definitions of "Facilities", "System Reinforcement", "Basic Transmission Extension", etc.[1] Regardless, BCH recognized the possibility of gas-fired generation alternatives to System Reinforcements in the DCAT CPCN proceeding. Any gas-fired generation alternative would be subject to the *Clean Energy Act*'s 93% clean or renewable energy objective.

[1] Note to readers: a copy of TS 6 is posted to BC Hydro's 2015 RDA website (http://www.bchydro.com/about/planning_regulatory/2015-rate-design/resources.html) under 'Resources'.

4.	**BCSEA** When BCH talks about new customer responsibility re: customer transmission line, does BCH mean responsible for costs or for constructing the line? Re: slide 19 and more broadly, are we talking about actual examples or theoretical?	Costs – under TS 6, the customer is responsible for all costs associated with the customer transmission line in all cases. As set out on slide 13, the customer is also responsible for constructing the customer transmission line where "reasonable, practical and economic". Both. One option going forward is to treat extensions to clusters (multiple customers are forecasted to connect) differently – in BCH's view, it is more clear cut that the new customer should pay for the customer transmission line/BTE where it is a single new customer. This cluster option requires forecasting.
5.	**AMPC** While forecasting is difficult and the results are almost always wrong, it is imperative for Transmission extension policy that BCH forecast new customer load and rate impacts.	Agreed.
6.	**COPE 378** The business practices queue management document BCH circulated references First Nation consultation. One of the costs of transmission interconnections is First Nation consultation and accommodation, correct?	Yes.
7.	**COPE 378** The impact of costs of incremental energy needs must be taken into account. Is this still an issue that is open for comment and debate as part of the RDA stakeholder engagement process?	Yes; however, as we will see with the jurisdictional assessment, no other jurisdiction BC Hydro is aware of takes into account generation costs when deciding on the utility contribution/new customer payment allocation in the transmission extension policy context.
8.	**AMPC** Please confirm that the TS 6 utility contribution formula has never resulted in a customer payment for System Reinforcements.	Confirmed.
9.	**BCOAPO** What is the rationale for the 7.4 years revenue and the one-half annual depreciation in the TS 6 utility contribution formula?	Both result from 1991 and BCH's records from that time do not indicate the rationale. Both aspects are being reviewed and may change.
10.	**AMPC** The reference to 13.5% discount rate/rate of return in the TS 6 utility contribution formula is strange; it may be that there was an unusual definition of shareholder's equity at the time TS 6 was developed in 1991.	BCH will review the 13.5% discount rate, which is materially different from the Distribution extension current 8% nominal discount rate which was based on BCH's Weighted Average Cost of Capital in 2007.
11.	**BCUC staff** We do not recall return on equity being material in the development of TS 6 in 1990 through the negotiated process.	
12.	**BCOAPO** Why would BCH build transmission facilities with a higher capacity than required at the time of the build?	BCH does this as a result of its load forecasts which show future growth in areas such as South Peace. In addition, as noted by AMPC, it is difficult to expand transmission in small increments, and there are economies of scale.

13.	**COPE 378** The problem is that there is no overarching analysis of how BCH builds transmission for the future; there appears to be a 'build it, and they will come' mentality as exemplified by NTL.	BCH does not agree with the statement. The 2013 IRP[2] contains clustering and transmission analysis in Chapters 3, 4 and 6.
14.	**BCUC staff** When BCH uses the term 'peak load' in this context, does that refer to CP?	Yes, in the context of transmission.
15.	**New Westminster** Peak may not meet contract demand as set out in customer ESAs.	While typically ESA contract demand is set somewhat above peak demand, for purposes of Transmission extension-related studies BCH assumes peak and contract demand are the same.
16.	**BCUC staff** Is there a provision in ESAs to increase demand?	Yes, a customer can increase demand within contract confines, e.g., contacted demand is 10 MV.A, actual demand is 8 MV.A, customer can increase demand up to 10 MV.A.

4. *Presentation: Sources Informing Review of TS 6*

Justin Miedema referenced the four sources that to date have informed BCH's review of TS 6: (1) other BCH tariffs such as the NTL tariff and Distribution extension; (2) the DCAT CPCN proceeding submissions and decision; (3) the IEPR review; and (4) BCH's jurisdictional assessment.

	FEEDBACK	RESPONSE
1.	**MABC** Is TS 6 broken? For example, have there been any real examples of stranded asset risk? A refinement of TS 6 should be an option, e.g., reviewing the security provisions, which in the mining industry's view are onerous.	Both the BCUC in the DCAT CPCN proceeding and the IEPR called for a public review of TS 6. To date, BCH has not had to use security; the forecasted revenues have shown up. Agreed that this is one option (variation on status quo).
2.	**BCUC staff** Is the NTL tariff cost sharing the same as TS 6?	No. NTL is an extension and under TS 6, NTL cost would be 100% customer, with the first customer paying the entire cost and recourse being the 5 year pioneer period in consideration of subsequent customers that connect. It was decided that for NTL tariff purposes, each new customer cost would be allocated based on load/total capacity of NTL/NTL capital cost, and not revenue.
3.	**BCOAPO** What % of NTL capacity is now subscribed?	***Revised Response*** Of NTL's 375 MW of capacity, the load subscription is about 15% and the IPP subscription is about 75%.
4.	**BCSEA** Are existing ratepayers at risk to the extent NTL is not fully subscribed? Have recent announcements of NTL capital cost increases impacted mine industry interest in subscribing?	Yes. However, a number of mine customers have expressed interest and are in the interconnection study process. NTL capital cost increases could impact mine project economics but BCH understands that these increases have not in and of themselves caused mine project proponents to not want to request service.

[2] A copy of the 2013 IRP can be accessed at https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html.

5.	**COPE 378** Regarding first customer paying problem, has BCH investigated an option of the first new customer having the nominal right to collect revenue from subsequent customers through a wheeling charge?	Not to date; however, BCH is reviewing its current 5 year pioneer period as part of the TS 6 review. If the first mine customer owns the transmission line and charges a wheeling fee as suggested by the COPE 378 option, it is a "public utility" as defined by section 1 of the UCA. This would result in complications as mine customer would be regulated (e.g., the rate charged, etc.) or a section 22 UCA Ministerial exemption would be required for each new mine customer.
6.	**CEC** Is there a problem with the 5 year pioneer period?	The 5 year period applies to BTE and System Reinforcement components. Customer transmission lines transferred to BCH are eligible for refunds as long as there is a Net Book Value of the original asset. BCH has limited experience with the pioneer aspect of TS 6 as BCH has not actually had to apply it.
7.	**BCOAPO** On slide 24, where does the $200 per kW figure come from regarding BCH's maximum contribution in General Service Distribution context?	The figure originates from BCH's COS – what portion is Distribution-relate, what portion of Distribution is demand, what portion is capital, and out of that BCH present values over a 20 year period to arrive at the $200 per kW figure. BCH's maximum contribution is set out in section 8.3 of the *Electric Tariff* and will be considered at the Distribution extension workshop scheduled for 16 December 2014.
8.	**AMPC** Regarding the AESO model, please confirm that System Reinforcements (referred to as Network Upgrades) are rolled into rates and the utility contribution is with respect to the customer extension side of things.	Confirmed.
9.	**AMPC** AMPC understands AESO's 60% of extension/connection costs being covered by utility results from forecasts. It should be noted that for AESO, the corresponding utility coverage figure for System Reinforcements is 100%.	Slide 27 of the presentation slide deck confirms AESO looked at 215 historical projects for determining the 60% figure. If System Reinforcement or a component of System Reinforcement is only for the benefit of one customer those costs could be classified as customer-related. In general most System Reinforcement costs are non-customer and the utility pays.
10.	**BCUC staff** It is important to understand why utilities are doing what they are doing in these jurisdictional references.	***Revised Response*** Agreed, but it is difficult and time consuming to glean a clear expression of policy rationales for extension policies. One method is to review regulatory decisions. For example, BCH understands from a 2012 AUC decision that AESO put forward three primary policy extension objectives (provide effective price signals; maintain intergenerational equity; be based on cost causation) and five secondary objectives which seem to have originated from the Bonbright criteria. The AUC found that AESO emphasized inter-generational equity as a transmission extension policy objective.[3] However, regulatory decisions are not generally available for some utilities such as SaskPower, and may not capture government policy underpinnings.

3 AUC, Decision 2012-362, *Alberta System Operator: 2012 Construction Contribution Policy*, 28 December 2012, pages 4-5 and 7-8 (http://www.aeso.ca/downloads/Decision_2012-362_AESO_2012_Construction_Contribution_Policy_(2012-12-28).pdf).

11.	**BCSEA** Is there a criterion for measuring the success of other jurisdictional models?	BCH chose jurisdictions based on the criteria set out in slide 26, including to provide a range of options for discussion. BCH uses the Bonbright criteria to assess each option. BCH is not aware of any other published metrics to evaluate 'success'.
12.	**BCUC staff** There may be important differences between AESO' transmission system configuration and BCH's, like BCH's need for regional forecasts vs. AESO's industrial make-up (oil and gas), which may make the AESO system more interconnected.	Agreed that geographic and industrial customer make up differences need to be considered. AESO does have a different industrial customer make-up and a very different market structure.
13.	**MABC/AMPC** MABC stated that AESO is an 'energy only' market[4] and so generation is not an issue. AMPC noted that prior to the Alberta 'energy-only' market, generation costs were not considered part of utility contribution/customer payment allocation for extensions except where generation was an alternative to transmission.	
14.	**BCSEA** Does BCH know what % of customer extension costs SaskPower picks up?	SaskPower's contribution to customer extensions occurs when actual construction costs exceed the fixed $/km, with customer paying up to the fixed $/km. Note that SaskPower builds the customer extension. BCH understands from SaskPower that the fixed $/km is dated and that actual construction costs have been greater than forecast, so likely SaskPower is picking up a large portion of customer extension costs.
15.	**BCUC staff** BCUC staff understand that BCH is examining the SaskPower model for its simplicity. Is the fixed $/km charge a way of addressing comments that the BCH queue process takes too long?	The SaskPower model is simpler than TS 6/BCH queue process, but would entail more risk to BCH and its existing ratepayers. Geographic differences are important. Saskatchewan is flat; transferring one overall fixed $/km as the basis for utility contribution toward customer extensions to BCH would be difficult given the terrain of BCH's service area. In addition, under the SaskPower model the utility builds the customer extension – adopting this model would be a significant departure from TS 6, where the customer builds its extension.
16.	**KGHM International** The SaskPower model is attractive from a new mine customer perspective. It looks like the utility covers all System Reinforcement costs, and there is no need to get into a queue to know how much a new customer must pay.	Confirmed that under the SaskPower model, System Reinforcements (referred to as Network Upgrades) get rolled into rates. There is no customer payment toward System Reinforcements.

[4] Alberta currently operates a wholesale power market that sets a price for electricity in each and every hour of the year, and this market is commonly referred to as a 'power pool'. This market is operated by AESO, which was established by the Alberta *Electric Utilities Act*. The large majority of power produced and consumed within Alberta notionally (financially) flows through this pool, and the hourly price determines the revenue for generators, as well as the cost for consumers.

17.	**Midgard Consulting** Does the SaskPower contribution toward customer extensions include modifications to substations or is it purely transmission lines?	***Revised Response*** BCH committed to following up on this question. SaskPower advises that the SaskPower contribution toward customer extensions does not include modifications to transmission customer-owned substations.
18.	**COPE 378** Do either the Hydro Quebec or Hydro One revenue tests include energy?	No. No generation costs are included in either the Hydro Quebec or the Hydro One revenue tests.
19.	**BCUC staff** The Hydro One model where System Reinforcement costs are covered by the utility but there is a safety valve for the utility to apply to the regulator is something for BCH to consider.	Agreed, as will be discussed in respect of the 150 MV.A threshold options later in the presentation.
20.	**BCOAPO** Is the Hydro One safety valve applicable to generation costs?	No. Hydro One can only apply to its regulator (OEB) to have the new customer pay toward transmission costs.[5] BCH understands that Hydro One has not to date used the safety valve and applied to its regulator.
21.	**BCUC staff** One aspect of the Hydro One model – judging how risky a customer is – could be problematic as it may slow things down due to debate.	Appendix 4 of the OEB Transmission System Code sets out how customer financial risk is to be classified.
22.	**AMPC** In regard to Hydro Quebec's 50 MW threshold, if service to the new customer is approved by the Quebec government is the utility contribution to the customer extension based only on $378/kW? What happens with respect to System Reinforcements (referred to as Network Upgrades)?	***Revised Response*** Yes. BCH confirmed with Hydro Quebec that no generation costs are charged to Hydro Quebec customers greater than 50 MW. BCH understands that Hydro Quebec collects security for Network Upgrades/System Reinforcement but does not require a customer payment toward the Network Upgrades/System Reinforcement. Hydro Quebec told BCH that it cannot recall any defaults re: security, and security is released as soon as the customer project enters service.

[5] The wording from OEB's Transmission System Code (http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Transmission_System_Code.pdf) pertaining to this matter is as follows:

"6.3.5 A transmitter (Utility) shall not require any customer to make a capital contribution for the construction of or modifications to the transmitter's *network facilities* that may be required to accommodate a new or modified connection. If exceptional circumstances exist so as to reasonably require a customer to make a capital contribution for network construction or modifications, the transmitter or any other interested person may apply to the Board for direction. A transmitter:

(a) shall notify the customer as soon as possible of the transmitter's intention to apply to the Board for direction under this section 6.3.5; and

(b) shall not, without the prior written consent of the customer, refuse to commence or diligently pursue construction of or modifications to its network facilities pending direction from the Board under this section 6.3.5 provided that the customer has provided a security deposit to the transmitter in accordance with section 6.3.10. Where the customer requests that the transmitter not commence with construction pending direction from the Board, the transmitter shall promptly return to the customer any outstanding security deposit related to the construction". [Emphasis added].

The term "network facilities" is defined in section 2 of the OEB Transmission System Code to mean "those facilities, other than connection facilities, *that form part of a transmission system that are shared by all users, comprised of network stations and the transmission lines connecting them* [emphasis added].

23.	**BCSEA** None of the jurisdictions reviewed seem to require a new customer payment toward System Reinforcements. Did BCH look further afield?	BCH used E3's jurisdictional survey submitted in the IEPR process, which looked at a number of U.S, and Canadian utilities – refer to slide 25.
24.	**AMPC** Based on prior work which looked further afield, it is correct that most utilities do not require a new customer payment toward System Reinforcements; System Reinforcement costs are usually rolled into rate base.	

5. *Presentation: Utility Contribution Options*

Sam Jones described 10 utility contribution options BCH has developed.

Note to readers – in light of stakeholder feedback at Workshop No. 6 and for purposes of assisting with written feedback, BCH groups the utility contribution options into four general categories as follows. In each case, a Hydro One safety valve approach could be considered:

Category 1 – Status quo, with cluster extension option variation set out on slide 19 as a subset of Category 1.

Category 2 – Customer pays for System Reinforcement with utility contribution; customer pays for customer transmission line/BTE. Category 2 includes options 1-4 and is based on DCAT CPCN proceeding comments. BCH believes one of these options should be brought forward for further analysis and favours option 3 for this purpose as it is closest to BCH's Distribution extension policy.

Category 3 – Utility pays for System Reinforcements; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (option 10). BCH believes option 10 should be brought forward for further analysis because: it is simple; it is similar to the outcome of applying TS 6 (rate and bill stability) but more transparent; and is fair, at least in the context of a single customer extension. A cluster extension variation could be included as a subset.

Category 4 – Utility pays for System Reinforcement; Customer pays for customer transmission line/BTE with a utility contribution. Category 4 includes options 5, 6, 7, 8 and 9. One issue to consider with Category 3 is that in most cases (SaskPower – option 8; Hydro Quebec – option 9) the utility builds and owns the customer transmission line/BTE. BCH believes option 9 (Hydro Quebec) should be brought forward for further analysis due to simplicity, similar market structure/utility transmission system; however, Hydro Quebec build and owns the customer transmission line. BCH also believes that the Hydro One model (option 7) should be brought forward as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a true up of costs.

	FEEDBACK	RESPONSE
1.	**COPE 378** With regard to option #1, why did BCH look at a 5-10 year estimated life of the customer facility?	Some brownfield mines have a 7 year life or so.
2.	**Midgard Consulting** With regard to the "using the F16-F20 rates announced in the 10 year plan" column of the options #1-#4 slides, what did BCH assume for the last 5 years of the 10 year plan?	BCH used the rates caps set out in section 9 of Direction No. 7 for F2017, F2018 and F2019; assumptions for F2020 and F2021; and flat rates for the remainder of the period for purposes of these slides. BCH will include inflation or placeholder assumptions next time it analyzes these options.

3.	**AMPC/MABC** Please confirm that options #1-#4, which have no utility contribution to customer transmission line/BTE and which require customer payment for System Reinforcements, do not have jurisdictional support.	Confirmed. BCH developed options 1-#4 in response to arguments put forward in the DCAT CPCN proceeding. Note that given utility contribution formula, currently TS 6 has had the same effect as the Manitoba Hydro model (option 10), which is that utility pays for System Reinforcements and customer pays for customer transmission line/BTE.
4.	**BCSEA** Regarding slides 41/42, what is the project cost data? Is there an issue of the accuracy of customer project-related revenue projections?	It is a back-casting mix of actual customer project costs and customer projects not yet in service. Yes. This was discussed at the 15 October 2014 information session concerning transmission load interconnection process/timelines/requirements. Option #6 was suggested by a participant at this information session.
5.	**BCUC staff** Why is BCH not proposing to bring forward option #8 (SaskPower model)? Its main positive value is its simplicity.	BCH believes the Manitoba Hydro model (option #10) also has simplicity as a virtue, and better balances existing customer/new customer interests. As discussed, option #8 would be difficult to transfer to BCH's service area and has more risk to BCH than the current TS 6. Nevertheless, BCH is open to input, and in particular whether option #8 has a high value to BCH's industrial customers.
6.	**AMPC** It is premature to reject any options. We are discussing tariff mechanics and formulae when we should be looking at over-arching policy objectives (e.g., how to balance rate impacts with intergenerational equity). We need to discuss transmission extension policy objectives. There may be a need to amend the 'next steps' to include a time to debate objectives. AMPC agrees that transmission extension policy should form a later RDA module on the basis that there needs be an objectives discussion.	
7.	**BCUC staff** We agree with AMPC's comment. We do not know the basis for preferring one option over another, because we do not know BCH's objectives.	BCH does not agree that some options cannot be rejected now based on the information provided, e.g., option #8. Nevertheless, BCH hears that stakeholders desire an opportunity to have input into transmission extension objectives. For feedback purposes it would be useful if stakeholders could indicate if by objectives they mean objectives beyond the eight Bonbright criteria, or if what is meant is how BCH weighs the Bonbright criteria in the context of transmission extension policy. BCH will consider amending the 'next steps' to include a time to debate objectives after reviewing feedback.
8.	**BCUC staff** If industrials are going to be charged for System Reinforcements, should a similar policy be in place for residential and commercial customers where they are driving costs – an example being Interior to Lower Mainland Transmission reinforcement project.	

BC Hydro Rate Design Workshop

SUMMARY 18 NOVEMBER 2014 9:00 A.M. TO 3:00 P.M. BCUC Hearing Room Vancouver

6. *Presentation: Security Options*

Frank Lin reviewed the existing TS 6-related security requirements, and outlined four options. Key issues are: should security be required and if so, for what amount and when should security be released?

	FEEDBACK	RESPONSE
1.	**AMPC** Stranded asset risk appears to be low for System Reinforcements. In contrast, there may be a rationale for requiring security if the utility contributes to customer radial extensions.	Agreed that stranded asset risk is low on System Reinforcements; over the last decade, BCH has not had to draw on posted security. Timing is really the issue; the customer may not be ready.
2.	**BCUC staff** Is paying back out of the revenue really a problem?	Most customers get security back within a 5 year period. BCH is exploring an option of releasing security more quickly; however, BCH understands the customer issue to be not so much how long the security is kept but rather the posting of a Letter of Credit up front.

7. *Presentation: 150 MV.A Threshold Options*

Frank Lin provided background on the 150 MV.A threshold – customers with new or incremental load exceeding 150 MV.A must pay for bulk transmission (500 kV and over) and generation costs. Frank outlined four options, and stated that BCH favours a Hydro One safety valve approach (no numeric threshold).

	FEEDBACK	RESPONSE
1.	**AMPC** It is AMPC's understanding that the Hydro Quebec 50 MW threshold is not comparable to the 150 MV.A threshold as in the case of Hydro Quebec, if new customer load is over 50 MW and approved for service, new customer is not charged bulk transmission and/or generation costs.	AMPC is correct in its understanding of the Hydro Quebec 50 MW threshold.
2.	**BCUC staff** Is there a risk with the current threshold that a new customer will argue that given they have made payment toward bulk transmission/generation, they should not be subject to future rate increases? This may also apply to options where new customers pay for System Reinforcements.	Given the hypothetical nature of the question and the lack of a factual context, BCH prefers not to speculate on whether the BCUC would accept such an argument.
3.	**MABC** In the case of Hydro One, is the safety valve application to the regulator or to government? Is BCH looking at a safety valve option where the application is to the government?	To the regulator. Yes, BCH is open to this. The safety valve option BCH has considered so far is the Hydro One model of making application to the regulator.
4.	**COPE 378** Applying to the regulator is more transparent.	

5.	**AMPC** Option 3 – the safety valve approach – should be advanced. The details of whether the application is made to government or the regulator can be worked out later. The point is that there should not be an arbitrary size threshold.	BCH agrees that if BCH proposes a utility contribution model where the utility pays for System Reinforcement, it is prudent for BCH to have a safety valve. BCH favours the Hydro One safety valve approach over option #1 (status quo), option #2 (size threshold, but with customer only responsible for incremental amount) and Option #4 (no safety valve).
6.	**BCUC staff** Option #2 looks like it could be complicated.	Agreed.
7.	**BCUC staff** Forecasts of future load and System Reinforcement costs should factor into the use of any safety valve. Would the cost be the full cost or the cost of advancing transmission infrastructure?	Note that BCH's industrial load forecast is different than the residential load forecast in that it is partly a bottom's up forecast informed by specific customer connection requests. In BCH's view we are mainly talking about the advancement of transmission infrastructure costs. There seems to be no jurisdictional support for the inclusion of generation costs.
8.	**FortisBC** The adoption of an economic test to evaluate whether a proposed customer project provides a net benefit to BCH ratepayers could obviate the need for a threshold.	***Revised Response*** BCH assumes FortisBC is referencing the economic test it advanced in the IEPR process. FortisBC's economic test would compare transmission-related revenues from a proposed industrial customer project against a threshold target regardless of customer project size. The threshold target would be based on a predefined level over the 'current average cost of transmission'. If the proposed transmission-related revenues exceed this threshold then the project would be rolled into rates. If the proposed revenues fall below the threshold then a customer payment would be required to address the shortfall.[6] It is not clear to BCH how this economic test protects existing ratepayers against a major load. In any event, BCH assumes that the FortisBC economic test would apply to customer extensions and not System Reinforcements as there is no 'average transmission cost' for System Reinforcements. If so, FortisBC's economic test seems similar to AESO's contribution to customer extension approach.
9.	**Seabridge** BCH needs to liaise with the B.C. Government regarding what the Province is trying to do with transmission extension policy – is it trying to attract industry? If so, the current threshold is a cost barrier that does not appear to be found in other jurisdictions and sends a signal that new loads are not supported in B.C.	

6 http://www.empr.gov.bc.ca/EPD/Documents/IEPR%20Submission-Fortis%20BC.pdf.

Page 12 of 14

BC Hydro Rate Design Workshop

SUMMARY 18 NOVEMBER 2014 9:00 A.M. TO 3:00 P.M. BCUC Hearing Room Vancouver

8. *Presentation: Transition Rule Options*

Frank Lin stated that this is a priority area for the reasons set out in slide 61 and set out BCH's strawman proposal for grandfathering new customers in the queue.

	FEEDBACK	RESPONSE
1.	**AMPC** Many transitions give the customer the option of choosing between the new arrangement and the old arrangement. AMPC agrees with that aspect of the BCH strawman that signals there has to be some skin in the game to take advantage of grandfathering.	
2.	**MABC** BCH should look at a menu-type approach where a new customer can choose which aspects of the old tariff and which aspects of the new tariff should apply to it. It should not be an 'all or nothing approach'.	***Revised Response*** BCH does not agree that there should be a menu-type approach for a new customer to choose between aspects of the new and old tariffs. Particular terms are not developed in isolation and need to be considered in the context of other terms of the contract. By allowing customers to cherry-pick individual aspects of each contract there may be unintended consequences to BCH and other rate payers. In addition, a menu-type approach effectively means individual tariffs for individual customers.
3.	**BCOAPO** Did BCH look at the posting of security as the trigger for grandfathering?	Yes, but this seemed to BCH to be too late in the process for grandfathering as customers have already made business decision.
4.	**COPE 378** In terms of equity, there should be a notice of change; e.g., effective date for new tariff, notice of scope of change.	Agreed.
5.	**BCUC staff** During the transition period, would BCH have two tariffs?	Yes.

9. *Other Issues: Line Transfers and Queue Management*

Sam Jones canvassed the main issue with the current line transfer provisions, which is that only the new customer has the option to transfer the customer transmission line to BCH; BCH cannot require or decline a line transfer. Sam outlined two high-level options to address this.

Sam also stepped through the draft Queue Management Business Practice document.

	FEEDBACK	RESPONSE
1.	**BCSEA** Option 2 is ambiguous as currently worded. Under Option 2, would BCH have the option to acquire the customer transmission line even if the customer does not want to transfer it? Does Option 2 also include BCH having the option of taking or rejecting the customer transmission line if the customer wants to transfer it?	Yes. Yes.

2.	**BCOAPO** So as part of Option 2 BCH could decline a transfer?	Yes.
3.	**BCUC staff** This issue is tied to other options for TS 6, particularly utility contribution options.	Yes.
4.	**COPE 378** On slide 65, what is meant by First Nation consultation?	BCH is an agent of the Crown. BCH would assess the adequacy of the customer's consultation with First Nations and what other government agency permitting is required.
5.	**CEC** What obligations does BCH assume if there is a customer transmission line transfer?	BCH must operate and maintain the transferred line. BCH assumes all the same obligations it has with regard to the lines that it builds, owns and operates from inception.
6.	**MABC** MABC is of the view that there are existing BCH capacity issues when it comes to queue management. Will BCH be looking at its own resources to tackle this?	Yes.
7.	**CEC** Is there a particular part of the Queue Management Business Practice document/existing queue process that BCH would like comments on? CEC thinks BCH should look at an option that does not require a queue system. CEC is prepared to discuss this option.	Queue management is not working that well when there are a number of customers requesting in the same area. A Manitoba Hydro contribution model would not require a queue. A queue is required if the new customer is paying for and BCH is making an offsetting contribution toward System Reinforcements. BCH asks that CEC submit details on its option as part of the written comment process following this workshop.
8.	**Midgard Consulting** An overview of the particular area to determine if it is transmission constrained or not could assist with the queue process.	BCH reviews system constraints as part of each Transmission extension-related study. The load size will determine if there is a constraint and how to resolve it.
10. ***Closing Comments: Next Steps***		
Anne Wilson thanked everyone for making the time to participate in the workshop and reviewed the ways that feedback can be submitted to BCH and the proposed timelines set out in the 'next steps' slide 71. Meeting adjourned at 3:00 p.m.		

2015 Rate Design Application
Module 2

Transmission Extension Policy

BC Hydro Summary and
Consideration of Participant Feedback to Date

Attachment 3

2015 RDA Module 1
Workshop No. 1 – November 18, 2014
Feedback Forms

2015 Rate Design Application (RDA) – November 18th, 2014

Transmission Extension Policy

Workshop # 1 - Feedback Form

Name/Organization:
Richard Stout for AMPC

Presentation Topics	
A. Transmission Extension Policy Objectives	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) **Bonbright Criteria:** In the context of transmission extension policy, BC Hydro noted on slide 9 of the presentation slide deck that regulators have traditionally emphasized three Bonbright criteria: (1) fairness; (2) efficiency; and (3) rate and bill stability. Which of the eight Bonbright criteria do you consider most important in the transmission extension policy context, and why?	All Bonbright criteria are important and need to be considered in each design. The weighting or relative importance of each criterion is specific to the application and hard to evaluate, especially before it is clear what the over-arching objectives of the proposed transmission extension policy are. The ideal transmission extension policy will attract new customers without placing an undue burden on existing ratepayers. Transmission extension policy concerns revolve around fairness between new and existing customers (both across and within rate classes) and interpretations of postage stamp rates. Fairness is thefore the most important criteria. As transmission extensions are not made in small increments analogous to distribution additions, efficiency is a less important consideration. Predictability, clarity, stability and customer acceptance are often considered more important than dynamic efficiency considerations. This is especially the case when economic development is an overall policy goal.The Bonbright principal of efficiency may therefore be given little weight in this instance, and may not even appear in the top three list. AMPC will address the principles of transmission extension policy and hopes to provide advice in a separate document

2) **Bonbright Criteria:** Do you have any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers will receive fair contribution from the utility and that contribution will not place undue upward pressure on rates' is an element of fairness, what does 'undue upward pressure on rates' mean in quantitative terms?	This is a complex issue that deserves deeper consideration than a questionnaire, and more discussion than was possible during the recent workshop. AMPC hopes to provide a more comprehensive consideration of these issues in a later document. An acceptability threshold for "undue upward pressure on rates" cannot be usefully considered as a single number. It depends on many considerations including other coincident expenditures of the utility, forecast load growth, competition, rates of other utilities, and overall economic goals. The idea of an acceptable threshold is also premised on the regulator being able to determine or adjust all utility expenditures and load forecasts that will determine future rate levels.
3) **Other Objectives:** In addition to the eight Bonbright criteria, are there are any other objectives which should inform BC Hydro's transmission extension policy?	The are many objectives that will inform BC Hydro's transmission extension policy.These includes the goals of the shareholder to support economic growth in resource industries, and to maintain competitive rate levels for existing customers. They also include acceptable interpretations of "postage stamp" rates for new areas and industries, the presence or absence of tariff preferences for specific industries, the significance or desirability of preferred end-uses, and the willingness to consider least-cost developments where local generation might substitute for transmission reinforcements. All of these factors must be considered and balanced where conflicts arise. A transparent discussion of these overarching goals, potential conflicts and balances is necessary to inform the context in which the Bonbright criteria will be applied to transmission extensions. Although it is not an explicit Bonbright criterion, comparisons to the detailed extension policies of other jurisdictions must also be included as this informs measures of fairness, customer acceptance, and stability.

B. Extensions	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Clustered Loads When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with: 1) First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect. 2) BC Hydro builds the common transmission extension and charges each customer an upfront payment based on a prorated basis. 3) BC Hydro builds the common transmission extension and treats this as System Reinforcements (SR) which it would apply the utility contribution towards and seek security /payment based on a prorated basis. *Please provide in the "Comments" column the rationale for your preference and provide commentary on what you think the guidelines would be for determining a reasonable expectation.*	The responses to this specific issue and questions posed will depend on the resolution of unresolved objectives listed above, and other policy considerations that will determine the extent of "system reinforcement" and "customer related" additions that may be "rolled-in" to the tariff, or alternatively recovered as a customer contribution. Transmission extension policy development tends to be an iterative process where the broader policy issues are resolved first and overall contribution and rate impacts assessed before more detailed timing, cluster and financial security issues can be constructively discussed.

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2) Transmission Extensions in Constrained Areas

There may be instances where, due to geographical constraints, environmental impacts, etc., only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In this situation do you prefer:

1) The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity).

2) Allocating the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line.

Please provide in the "Comments" column of this form your preference, or combination thereof, including the rationale for your preference.

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As explained above, this issue cannot be usefully addressed before the broader electric service and tariff policy issues outlined above are better articulated, and at least partially resolved.

Due to the the economies of scale, transmission lines are frequently built with capacity in excess of the forecast load being served. "Systemic" growth not explicitly forecast then frequently absorbs some or all of the excess capacity over time. Important questions that must first be addressed are the circumstances and extent that any such "excess" capacity is allocated as a "system" versus a "local" or "customer" cost.

A further prerequisite is to determine under what circumstances a portion of a customer-related extension might be considered a "system" cost to be borne by all customers.

Under the fairness criterion it is hard to see why the initial customer should pay a contribution based on any more than the theoretical cost of extenson (or local generation) required to serve the contracted load (after a reduction has been made to reflect the appropriate system investment in any radial line extenson).

AMPC will provide further elaboration in a subsequent document.

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C. Utility Contribution Models	**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 described in the November18, 2014 Transmission Extension Policy Workshop notes, BC Hydro grouped the utility contribution options into four general categories as noted below. *Please provide the rationale for your comments in the “Comments” column of this form.*	

Category 1 – Status quo Tariff Supplement No. 6 (TS 6), with cluster extension option variation set out on slide 19 as a subset of Category 1. BC Hydro proposes to advance Status Quo TS 6 with an extension option variation for further analysis. Do you agree, and if not, why not?	Disagree. AMPC cannot accept a transmission extension policy based on the status quo, or modifications to TS#6 that retain this core structure and definitions. Many of the flaws of TS#6 were described in the evidence filed by AMPC in the previous DCAT proceedings. In particular, the unfairness of the vastly different contributions assessed by TS#6 for two different groups of customers who presented comparable incremental costs and revenues to the system. TS#6 is based on unrecorded shareholder goals and circumstances of more than 20 years ago that remain obscure and cannot be articulated or explained by BC Hydro today. TS#6 utilizes unique procedures that are inconsistent with the practices of all other utilities surveyed. A comprehensive RDA is the ideal opportunity to redesign the transmission extension policy from first principles (discussed above) that are consistent with current tariffs, economic circumstances and goals and the practices of other utilities.

Category 2 – Customer pays for SR with utility contribution; customer pays for customer transmission line/Basic Transmission Extension (BTE). Category 2 includes Options 1-4 and is based on Dawson Creek/Chetwynd Area Transmission Project Certificate of Public Convenience and Necessity proceeding comments. BC Hydro proposes to advance Option 3 for further analysis as it is closest to BC Hydro's Distribution extension policy. Do you agree, and if not, why not?	Disagree. As discussed above, AMPC cannot support any transmission extension policy that retains the core structure of TS#6, even if some changes or options are included. The basic issue of who pays for system reinforcements, who pays for customer related extensions, and the acceptable level of rate impacts must first be clearly addressed in principle, and not get lost in the details, definitions and mechanics of an existing flawed policy that cannot be satisfactorily explained. Concepts and terminology imported from the distribution system such as the single span "BTE" are not relevant or useful to a transmission extension policy and should be abandoned in favour of a review from first principles, economic objectives, and long term cost-causation. More suitable terminology can then be developed.
Category 3 – Utility pays for SR; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (Option 10). A cluster extension variation could be included as a subset. BC Hydro proposes to advance Option 10 (Manitoba Hydro model) for further analysis because of its simplicity and because it is closest to the actual outcome of the Status Quo TS 6. Do you agree, and if not, why not?	Agree. While this approach does not define which portions of customer related extensions could be considered System Reinforcements, elements of this approach could be built into a new tariff that includes an off-ramp for government or the BCUC in extraordinary circumstances. However, we must restate that simply rearranging the existing components of TS#6 to resemble the results of another utility's policy does not deal with the principles, objectives and balances that need to be considered before the more detailed mechanics of application are developed. A more fundemental re-examination of government and BC Hydro's extenson policy objectives is required. It may be that the agreed result resembles Manitoba – but to be supportable it must be developed from the principles and goals discussed and agreed upon in BC

Category 4 – Utility pays for SR; Customer pays for customer transmission line/BTE with a utility contribution. BC Hydro proposes to advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity, and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the customer transmission line which is different than the Status Quo TS 6. As a result, BC Hydro believes that Option 7 (Hydro One model) should also be brought forward for further analysis as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a 'true up' of costs. Do you agree, and if not why not?	Agree, with the aforementioned caveats.

D. Security	**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's current security policy requires customers to provide security for the amount of the BC Hydro contribution. Issues under consideration include:	
1. Should security be required, if so for what amount? ☐ Actual cost of SR. ☐ Based on a $/kW. ☐ Based on a historical average. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	This question cannot yet be answered. Much depends on how "System reinforcement" is to be defined and allocated. System reinforcements are rarely made solely for a single new customer or even a group of new customers. The definitions and allocations between system and local or customer related are not trivial or capable of precise determination. Much depends on the resolution of these issues and related load forecasts that have not so far been explored or discussed. The amount of transmission system reinforcements provided to accommodate IPPs is also a significant issue (suggesting a rate for IPP transmission system access) that has so far not been addressed by BC Hydro.
2. When should security be released? ☐ After construction is complete. ☐ After a fixed time period. ☐ Based on an assessment of revenue recovered. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	See answer above.
3. What forms of security should be allowed? *Please provide your comments in the "Comments" column of this form.*	See answer above.

4. Other comments with respect to security? *Please provide your comments in the "Comments" column of this form.*	See answer above.

<table>
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<th>E. 150 MVA threshold</th>
<th>Comments

(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).</th>
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<td>The 150 MVA threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and new generation in the definition of SR was questioned in the 2013 Industrial Electricity Policy Review task force process and in subsequent 2015 RDA engagement to date. Four options for dealing with this threshold were discussed:

• Status Quo
• Develop New Threshold
- Should the cost of generation be included or should cost be confined to transmission as with the jurisdiction that has a safety valve (Ontario), and if generation cost is included, should it be applied to the total load or to the just the incremental load above the threshold?
• No Threshold with Safety valve
- For the exceptional case where a new load would cause a significant rate impact BC Hydro would have the option to seek BCUC (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer.
- If this option is pursued, should the safety valve include generation costs or as with Ontario should it be confined to transmission costs?
• No Threshold

Please state in the “Comments” column of this form your preference of the options and the rationale for your preference.</td>
<td>The status quo is unacceptable.There should be no specific MVA threshold. A simple MVA threshold at any level violates Bonbright principles (fairness and predictability in particular), is challenging to apply, and easy to defeat in practice by a determined proponent.

Every utility requires a transmission investment “safety valve” of some sort, and BC Hydro is no exception. Tariff wording is necessary to avoid the roll-in of extraordinary costs of local extension or system reinforcements necessary to serve a new customer under unusually expensive circumstances. How those circumstances might be identified without impeding desirable economic development requires significant further discussion and development.

Whatever the circumstances finally determined,it is doubtful if a significant generation advancement cost could be attributed to any likely new load, given the aggregate uncertainty of forecast demand and timing of new generation developments. This relates to the as-yet undetermined definition of “system costs”.</td>
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F. Transition Rules	**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 recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under: 1) **System Impact Study (SIS)** – customer has initiated a SIS 2) **Facilities Study (FS)** - customer has initiated a FS 3) **Facilities Agreement (FA)** – customer has an executed FA. BC Hydro also questioned if other factors should be considered such as: • In-service date • Customers Final Investment Decision date • Permitting approvals. BC Hydro proposed the following strawman transition rule: ▪ Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro's satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6. *Please comment if you agree or not with the proposed strawman transition rule and the reasons for your comments in the "Comments" column of this form.*	Clear transition rules to move away from TS#6 and implement a new and fair extension policy are necessary. We need to understand what the new policy will be, before appropriate transition rules can be developed. System impact and facilities studies are expensive and represent considerable investments for customers who reasonably expect that adverse changes will not be made afterwards that would add significant costs to the customer's project. Considering the large amounts charged for conducting these studies it would be fair and reasonable to provide the models and data that would allow the customer's own engineering staff or independet consultants to confirm the conclusions reached and to provide assistance in meeting MRS requirements.
G. Line transfer	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**

The current line transfer provisions in the TS 6 are at the sole discretion of the customer. Should the line transfer provisions be modified to allow BC Hydro to require a line be transferred when there is a system benefit or decline a line transfer when there is no benefit and/or a significant risk/burden to rate payers. *Please indicate your preference with respect to the Line Transfer provisions to be included in the TS 6 and the rationale for your preference in the "Comments" column of this form.*	This depends greatly on the form of the extension and contribution policy developed and a useful response cannot be provided at this stage. Utility investment in customer lines or consideration of "customer" relatd lines as being at least in part a "system" development suggests that automatic line transfers may be desirable in these circumstances.

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

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BC Hydro circulated a draft of the current queue management business practise with the workshop preparation materials and is seeking comments on the current business practice and comments on the following proposed changes for consideration:

Staged Approach with Soft Milestone. BC Hydro has discretion on timeframes if others later in the queue are not harmed by extensions to deadlines. Modify existing language to include additional milestones (permitting, financing, etc.) to stay in the queue. Formalize cluster study and allocation of study costs.
Staged Approach with Hard Milestones. Strict adherence to timeframes and add language regarding what constitutes a material changes (changes in load size, point of interconnection, deferral of in-service date by X years, etc.) that will require a customer to lose its current queue position and be moved to the bottom of the queue
Fast Track Process. Should later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) be allowed to connect prior to earlier queue customers. If so what rules should be in place:

No harm to earlier queue customer – no increased costs or timing of connection
Earlier queue customer must advance their project
Risk and cost of any re-studies borne by customer requesting to be fast tracked

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These measures may all have pros and cons and require significant further discussion as to how they would operate in practice and what all of the implications would be.
The key issue for AMPC remains the lack of internal resources dedicated by BC Hydro to providing transmission extensions and the length of the queues and long lead and response times that result.
AMPC suggests that reallocation and reorganization of resources within BC Hydro (under the existing rate-caps) should be the first priority to reduce lead times at all stages of study and interconnection. Approaches to managing the queue would be more appropriately considered after the queue has been diminished to a more manageable size.
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4. **Open Call**. When there is deemed to be the potential for several connection requests in the same region, BCH would initiates a Call for projects that want to connect to the BC Hydro transmission system. Each connection request would have the same queue position and the requests would be studied as a cluster. This would result in the best use of BC Hydro planning resources and the most optimum SR. Rules for allocation of study costs and system reinforcement costs would also be required. *Please state in the "Comments" column of this form your preference of the option(s) and the rationale for your preference.*	

Additional Comments, Items you think should be in-scope, not currently identified:

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

Signature:___Richard Stout_______________________ Date: __2015-02-12____________

Thank you for your comments.

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

You can return completed feedback forms by:

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

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

Email: bchydroregulatorygroup@bchydro.com

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

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

2015 Rate Design Application (RDA) – November 18th, 2014

Transmission Extension Policy

Workshop # 1 - Feedback Form

Name/Organization: **Sarah Khan and Erin Pritchard, BC Old Age Pensioners' Organization *et al.***

Presentation Topics	
A. Transmission Extension Policy Objectives	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Bonbright Criteria: In the context of transmission extension policy, BC Hydro noted on slide 9 of the presentation slide deck that regulators have traditionally emphasized three Bonbright criteria: (1) fairness; (2) efficiency; and (3) rate and bill stability. Which of the eight Bonbright criteria do you consider most important in the transmission extension policy context, and why?	• Fairness and rate and bill stability
2) Bonbright Criteria: Do you have any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers will receive fair contribution from the utility and that contribution will not place undue upward pressure on rates' is an element of fairness, what does 'undue upward pressure on rates' mean in quantitative terms?	• The most practical approach to ensuring fairness and rate stability is to base the utility contributon on the costs that are reflected in the (current) rates that the new customer will pay.
3) Other Objectives: In addition to the eight Bonbright criteria, are there are any other objectives which should inform BC Hydro's transmission extension policy?	• Minimizing rate impacts on existing customers – cost to existing customers now when new load comes online (as compared to when there was a surplus of heritage power, and there was a benefit to all custmers when new load came online)

B. Extensions	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Clustered Loads When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with: 1) First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect. 2) BC Hydro builds the common transmission extension and charges each customer an upfront payment based on a prorated basis. 3) BC Hydro builds the common transmission extension and treats this as System Reinforcements (SR) which it would apply the utility contribution towards and seek security /payment based on a prorated basis. *Please provide in the "Comments" column the rationale for your preference and provide commentary on what you think the guidelines would be for determining a reasonable expectation.*	• BCOAPO prefers the first approach • It is assumed that the second approach will require upfront payments at the time of construction and that the "additional customers" would have to commit dollars now. This would only likely occur if there was a high or virtually certain expectation (as opposed to just a reasonable expectation) that they will connect to the extension. As a result, the second approach may not provide the degree of flexibility desired by BC Hydro. • It is unclear what the rationale for the third option would be, unless the extension somehow reinforces the existing system and also benefits existing customers. Note: It is assumed that the facility to be contstructed would be designed to accommodate the first customer and that the ability to service additional loads arises from the fact transmission facility capacity comes in "lumpy" increments. Presumably the following item #2 addresses the circumstance where the capcity to be constructed is being designed to meet more than just the first cusomer's load.

<table>
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<td>
2) Transmission Extensions in Constrained Areas

There may be instances where, due to geographical constraints, environmental impacts, etc., only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In this situation do you prefer:

1) The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity).

2) Allocating the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line.

Please provide in the “Comments” column of this form your preference, or combination thereof, including the rationale for your preference.
</td>
<td>
• BCOAPO prefers the first approach.

• Construction in such instances should be subject to BCUC review/approval before proceeding in order to test the prudence of proceeding with the project that involves constructing capacity over and above what customers are currently willing to commit to.
</td>
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C. Utility Contribution Models	**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 described in the November 18, 2014 Transmission Extension Policy Workshop notes, BC Hydro grouped the utility contribution options into four general categories as noted below. *Please provide the rationale for your comments in the "Comments" column of this form.*	
Category 1 – Status quo Tariff Supplement No. 6 (TS 6), with cluster extension option variation set out on slide 19 as a subset of Category 1. BC Hydro proposes to advance Status Quo TS 6 with an extension option variation for further analysis. Do you agree, and if not, why not?	• BCOAPO is unable to agree with the continuation of the Status Quo TS6 without further justification of the current contribution formula (e.g. the 7.4 times x annual revenue and the ½ annual depreciation).
Category 2 – Customer pays for SR with utility contribution; customer pays for customer transmission line/Basic Transmission Extension (BTE). Category 2 includes Options 1-4 and is based on Dawson Creek/Chetwynd Area Transmission Project Certificate of Public Convenience and Necessity proceeding comments. BC Hydro proposes to advance Option 3 for further analysis as it is closest to BC Hydro's Distribution extension policy. Do you agree, and if not, why not?	

Category 3 – Utility pays for SR; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (Option 10). A cluster extension variation could be included as a subset. BC Hydro proposes to advance Option 10 (Manitoba Hydro model) for further analysis because of its simplicity and because it is closest to the actual outcome of the Status Quo TS 6. Do you agree, and if not, why not?	• Given there is no cap on the SR for which the utility could be responsible, BCOPAO is concerned about the implications with respect to both fairness and rate stability for existing customers. • We would note that MH's extension policy has never been subjected to regulatory review by the Public Utilities Board
Category 4 – Utility pays for SR; Customer pays for customer transmission line/BTE with a utility contribution. BC Hydro proposes to advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity, and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the customer transmission line which is different than the Status Quo TS 6. As a result, BC Hydro believes that Option 7 (Hydro One model) should also be brought forward for further analysis as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a 'true up' of costs. Do you agree, and if not why not?	• This approach gives rise to even more concerns regarding fairness and rate stability as there is no cap on BC Hydro's potential SR cost responsibility but it will also be required to make a contribution towards the customer transmission line/BTE. • BCOAPO also has concerns with potential for upward rate impact with the Hydro One model

D. Security	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's current security policy requires customers to provide security for the amount of the BC Hydro contribution. Issues under consideration include:	
1. Should security be required, if so for what amount? ☐ Actual cost of SR. ☐ Based on a $/kW. ☐ Based on a historical average. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	• Security should be required. The jurisdictional review indicates virtually all utilities require security. • We would note that it is not only risky companies that could be a problem. For example, a credit-worthy company could ask for an extension and then decide not to go ahead with the new facility. • BCOAPO prefers the status quo option; that is, requiring security for the full amount of BC Hydro contribution; this minimizes risk to ratepayers
2. When should security be released? ☐ After construction is complete. ☐ After a fixed time period. ☐ Based on an assessment of revenue recovered. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	• BCOPAO prefers the option in which security is released based on an assessment of revenue recovered • This option provides the most protection for ratepayers
3. What forms of security should be allowed? *Please provide your comments in the "Comments" column of this form.*	• The forms of security currently approved by BC Hydro (per p. 51 in slide deck) are reasonable. • We agree with the current requirement that the form of security must have BC Hydro's prior approval

4. Other comments with respect to security? *Please provide your comments in the “Comments” column of this form.*	

E. 150 MVA threshold	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
The 150 MVA threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and new generation in the definition of SR was questioned in the 2013 Industrial Electricity Policy Review task force process and in subsequent 2015 RDA engagement to date. Four options for dealing with this threshold were discussed: • **Status Quo** • **Develop New Threshold** ☐ Should the cost of generation be included or should cost be confined to transmission as with the jurisdiction that has a safety valve (Ontario), and if generation cost is included, should it be applied to the total load or to the just the incremental load above the threshold? • **No Threshold with Safety valve** ☐ For the exceptional case where a new load would cause a significant rate impact BC Hydro would have the option to seek BCUC (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer. ☐ If this option is pursued, should the safety valve include generation costs or as with Ontario should it be confined to transmission costs? • **No Threshold** *Please state in the "Comments" column of this form your preference of the options and the rationale for your preference.*	• It should be noted that Ontario's approach whereby the costs included are limited to transmission is a function of the market structure and the fact that Generation is not part of the regulated utility. Also Ontario's introduction of a "safety valve" is directly related to the fact that its Transmission System Code requires utilities to otherwise pay for all incremental network cost triggered by a new connection. • Some form of threshold is required and BCOAPO is strongly opposed to the "no threshold option"; further, it is unlikely that BC Hydro can afford to completely elimate the threshold. • Once put into practice there may not be that much distinction between a "safety valve" and a "threshold" approach since the triggering of the safety valve will likely occur at some threshold value. • The principle as to what the threshold is meant to accomplish/protect is what should be considered at this point

<table>
<tr>
<th>F. Transition Rules</th>
<th>Comments

(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).</th>
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<td>BC Hydro recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under:

1) System Impact Study (SIS) – customer has initiated a SIS
2) Facilities Study (FS) - customer has initiated a FS
3) Facilities Agreement (FA) – customer has an executed FA.

BC Hydro also questioned if other factors should be considered such as:
• In-service date
• Customers Final Investment Decision date
• Permitting approvals.

BC Hydro proposed the following strawman transition rule:
▪ Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro's satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6.

Please comment if you agree or not with the proposed strawman transition rule and the reasons for your comments in the "Comments" column of this form.</td>
<td>• Agree in principle, given that we understand that the customer is committed to implementation by the time the Facilities Agreement is entered into, but we would like further information about what evidence will be considered to "demonstrate to BC Hydro's satisfaction that [a project is] likely to come into service within 24 months of the effective date."</td>
</tr>
</table>

G. Line transfer	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
The current line transfer provisions in the TS 6 are at the sole discretion of the customer. Should the line transfer provisions be modified to allow BC Hydro to require a line be transferred when there is a system benefit or decline a line transfer when there is no benefit and/or a significant risk/burden to rate payers. *Please indicate your preference with respect to the Line Transfer provisions to be included in the TS 6 and the rationale for your preference in the "Comments" column of this form.*	• BC Hydro should be allowed to decline a line transfer when there is no benefit and/or a significant risk/burden to ratepayers. • BC Hydro should also be permitted to require a line transfer subject to BCUC review and approval in circumstanes were the customer disagrees.

H. Queue Management	**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 circulated a draft of the current queue management business practise with the workshop preparation materials and is seeking comments on the current business practice and comments on the following proposed changes for consideration: 1. **Staged Approach with Soft Milestone**. BC Hydro has discretion on timeframes if others later in the queue are not harmed by extensions to deadlines. Modify existing language to include additional milestones (permitting, financing, etc.) to stay in the queue. Formalize cluster study and allocation of study costs. 2. **Staged Approach with Hard Milestones.** Strict adherence to timeframes and add language regarding what constitutes a material changes (changes in load size, point of interconnection, deferral of in-service date by X years, etc.) that will require a customer to lose its current queue position and be moved to the bottom of the queue 3. **Fast Track Process.** Should later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) be allowed to connect prior to earlier queue customers. If so what rules should be in place: ☐ No harm to earlier queue customer – no increased costs or timing of connection ☐ Earlier queue customer must advance their project ☐ Risk and cost of any re-studies borne by customer requesting to be fast tracked	• BCOAPO is less concerned with who gets connected (and when they are connected), and more concerned with how costs are allocated for connections • Our main concern here is that BC Hydro clearly define when a customer has been deemed to have joined the queue – must be some formal commitment by the customer and not just an indication that it could potentially be seeking service.

4. **Open Call**. When there is deemed to be the potential for several connection requests in the same region, BCH would initiates a Call for projects that want to connect to the BC Hydro transmission system. Each connection request would have the same queue position and the requests would be studied as a cluster. This would result in the best use of BC Hydro planning resources and the most optimum SR. Rules for allocation of study costs and system reinforcement costs would also be required. *Please state in the “Comments” column of this form your preference of the option(s) and the rationale for your preference.*	

Additional Comments, Items you think should be in-scope, not currently identified:

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:________”Erin Pritchard”______________________________________Date: _____”Feburary 11, 2015”______________

Thank you for your comments.

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

You can return completed feedback forms by:

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

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

Email: bchydroregulatorygroup@bchydro.com

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

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

2015 Rate Design Application (RDA) – November 18th, 2014

Transmission Extension Policy

Workshop # 1 - Feedback Form

Name/Organization: **BC Sustainable Energy Association and Sierra Club BC**

Presentation Topics	
A. Transmission Extension Policy Objectives	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) **Bonbright Criteria:** In the context of transmission extension policy, BC Hydro noted on slide 9 of the presentation slide deck that regulators have traditionally emphasized three Bonbright criteria: (1) fairness; (2) efficiency; and (3) rate and bill stability. Which of the eight Bonbright criteria do you consider most important in the transmission extension policy context, and why?	These three Bonbright criteria, interpreted broadly, adequately express the potentially competing interests from a utility regulation perspective. In addition, there may be government policy objectives that come into play.
2) **Bonbright Criteria:** Do you have any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers will receive fair contribution from the utility and that contribution will not place undue upward pressure on rates' is an element of fairness, what does 'undue upward pressure on rates' mean in quantitative terms?	BCSEA-SCBC don't have a fixed view on how to define "undue upward pressure on rates" in quantitative terms.
3) **Other Objectives:** In addition to the eight Bonbright criteria, are there are any other objectives which should inform BC Hydro's transmission extension policy?	Government policy objectives should inform the transmission extension policy, including particularly the Energy Objectives listed in the *Clean Energy Act*.

B. Extensions	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Clustered Loads When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with: 1) First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect. 2) BC Hydro builds the common transmission extension and charges each customer an upfront payment based on a prorated basis. 3) BC Hydro builds the common transmission extension and treats this as System Reinforcements (SR) which it would apply the utility contribution towards and seek security /payment based on a prorated basis. *Please provide in the "Comments" column the rationale for your preference and provide commentary on what you think the guidelines would be for determining a reasonable expectation.*	BCSEA-SCBC don't have a fixed view on this topic at this time.

2) Transmission Extensions in Constrained Areas There may be instances where, due to geographical constraints, environmental impacts, etc., only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In this situation do you prefer: 1) The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity). 2) Allocating the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line. *Please provide in the "Comments" column of this form your preference, or combination thereof, including the rationale for your preference.*	BCSEA-SCBC do not have a fixed position on this topic at this time. This issue and issue #1, above (Clustered Loads) raise the possibility of BC Hydro, rather than a particular prospective customer, initiating an application for an extension, and doing so in circumstances where the prospective loads and recoveries of costs could be considerably less certain than in the case of the application of a particular prospective customer for service. This raises numerous issues, including the public interest in grid extensions and risk allocation to existing ratepayers, which would likey require careful consideration, and which may require significantly different rules and policies than BC Hydro's existing transmission extension policies.

C. Utility Contribution Models	**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 described in the November18, 2014 Transmission Extension Policy Workshop notes, BC Hydro grouped the utility contribution options into four general categories as noted below. *Please provide the rationale for your comments in the "Comments" column of this form.*	
Category 1 – Status quo Tariff Supplement No. 6 (TS 6), with cluster extension option variation set out on slide 19 as a subset of Category 1. BC Hydro proposes to advance Status Quo TS 6 with an extension option variation for further analysis. Do you agree, and if not, why not?	Yes, BCSEA-SCBC agree with further examination of the Status Quo TS 6 with an extension option. Allowing for a different treatment of potential clusters makes sense in principle; however, it would be useful at the same time to define in more detail where geographically such potential is thought to be.
Category 2 – Customer pays for SR with utility contribution; customer pays for customer transmission line/Basic Transmission Extension (BTE). Category 2 includes Options 1-4 and is based on Dawson Creek/Chetwynd Area Transmission Project Certificate of Public Convenience and Necessity proceeding comments. BC Hydro proposes to advance Option 3 for further analysis as it is closest to BC Hydro's Distribution extension policy. Do you agree, and if not, why not?	Yes, BCSEA-SCBC agree with further examination of Option 3. We note that Option 3 results in the highest percentage of new customers where the utility does not cover 100% of the SR costs. (slide 41)

Category 3 – Utility pays for SR; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (Option 10). A cluster extension variation could be included as a subset. BC Hydro proposes to advance Option 10 (Manitoba Hydro model) for further analysis because of its simplicity and because it is closest to the actual outcome of the Status Quo TS 6. Do you agree, and if not, why not?	We agree with further examination of Option 10, with a cluster extension subset.
Category 4 – Utility pays for SR; Customer pays for customer transmission line/BTE with a utility contribution. BC Hydro proposes to advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity, and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the customer transmission line which is different than the Status Quo TS 6. As a result, BC Hydro believes that Option 7 (Hydro One model) should also be brought forward for further analysis as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a 'true up' of costs. Do you agree, and if not why not?	We understand that BCH is proposing to advance both Option 9 (Hydro Quebec model) and Option 7 (Hydro One model). We agree with further consideration of both of these models.

D. Security	**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's current security policy requires customers to provide security for the amount of the BC Hydro contribution. Issues under consideration include:	
1. Should security be required, if so for what amount? ☐ Actual cost of SR. ☐ Based on a $/kW. ☐ Based on a historical average. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	BCSEA-SCBC's view is that security should be required. We don't have a fixed view at this time regarding how the amount of security should be defined, and when it should be released.
2. When should security be released? ☐ After construction is complete. ☐ After a fixed time period. ☐ Based on an assessment of revenue recovered. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	
3. What forms of security should be allowed? *Please provide your comments in the "Comments" column of this form.*	In BCSEA-SCBC's view, the allowable forms of security must first and foremost provide real security. Beyond that, we see no reason not to allow a variety of forms of security to meet the convenience of the new customers.
4. Other comments with respect to security? *Please provide your comments in the "Comments" column of this form.*	

November 18th, 2014 Transmission Extension Policy Workshop # 1 - Feedback Form

<table>
<tr><th>E. 150 MVA threshold</th><th>Comments
(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).</th></tr>
<tr><td>The 150 MVA threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and new generation in the definition of SR was questioned in the 2013 Industrial Electricity Policy Review task force process and in subsequent 2015 RDA engagement to date. Four options for dealing with this threshold were discussed:

• Status Quo
• Develop New Threshold
▯ Should the cost of generation be included or should cost be confined to transmission as with the jurisdiction that has a safety valve (Ontario), and if generation cost is included, should it be applied to the total load or to the just the incremental load above the threshold?
• No Threshold with Safety valve
▯ For the exceptional case where a new load would cause a significant rate impact BC Hydro would have the option to seek BCUC (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer.
▯ If this option is pursued, should the safety valve include generation costs or as with Ontario should it be confined to transmission costs?
• No Threshold

Please state in the “Comments” column of this form your preference of the options and the rationale for your preference.</td><td>BCSEA-SCBC agree that the status quo 150 MVA threshold is problematic due to the all-or-nothing aspect; however, it is not obvious what a preferable alternative might be to balance costs and benefits to existing and potential new customers.

BCSEA-SCBC think further consideration should be given to inclusion of generation costs in the formula for transmission extension customer contributions.

Whatever the rest of the formula consists of, BCSEA-SCBC think there should be a safety valve component. The safety valve component should include generation costs.

BCSEA-SCBC oppose the option of ‘no threshold, and no safety valve.’</td></tr>
</table>

F. Transition Rules	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 recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under: 1) **System Impact Study (SIS)** – customer has initiated a SIS 2) **Facilities Study (FS)** - customer has initiated a FS 3) **Facilities Agreement (FA)** – customer has an executed FA. BC Hydro also questioned if other factors should be considered such as: • In-service date • Customers Final Investment Decision date • Permitting approvals. BC Hydro proposed the following strawman transition rule: ▪ Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro's satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6. *Please comment if you agree or not with the proposed strawman transition rule and the reasons for your comments in the "Comments" column of this form.*	BCSEA-SCBC agree with having a transition provision. BCH's proposed transition rule seems reasonable, but we would like to hear the comments of other stakeholders.

G. Line transfer	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
The current line transfer provisions in the TS 6 are at the sole discretion of the customer. Should the line transfer provisions be modified to allow BC Hydro to require a line be transferred when there is a system benefit or decline a line transfer when there is no benefit and/or a significant risk/burden to rate payers. *Please indicate your preference with respect to the Line Transfer provisions to be included in the TS 6 and the rationale for your preference in the "Comments" column of this form.*	BCSEA-SCBC tend to think that BCH should have sole discretion to take or reject ownership of transmission extensions. Presumably this would create a transfer of risk to the new customer and away from BCH. If so, this should be taken into account in the transmission extension rules.

H. Queue Management	**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 circulated a draft of the current queue management business practise with the workshop preparation materials and is seeking comments on the current business practice and comments on the following proposed changes for consideration: 1. **Staged Approach with Soft Milestone**. BC Hydro has discretion on timeframes if others later in the queue are not harmed by extensions to deadlines. Modify existing language to include additional milestones (permitting, financing, etc.) to stay in the queue. Formalize cluster study and allocation of study costs. 2. **Staged Approach with Hard Milestones.** Strict adherence to timeframes and add language regarding what constitutes a material changes (changes in load size, point of interconnection, deferral of in-service date by X years, etc.) that will require a customer to lose its current queue position and be moved to the bottom of the queue 3. **Fast Track Process.** Should later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) be allowed to connect prior to earlier queue customers. If so what rules should be in place: - No harm to earlier queue customer – no increased costs or timing of connection - Earlier queue customer must advance their project - Risk and cost of any re-studies borne by customer requesting to be fast tracked	BCSEA-SCBC don't have any comments on the queue management process at the present time.

4. **Open Call**. When there is deemed to be the potential for several connection requests in the same region, BCH would initiates a Call for projects that want to connect to the BC Hydro transmission system. Each connection request would have the same queue position and the requests would be studied as a cluster. This would result in the best use of BC Hydro planning resources and the most optimum SR. Rules for allocation of study costs and system reinforcement costs would also be required. *Please state in the "Comments" column of this form your preference of the option(s) and the rationale for your preference.*	

Additional Comments, Items you think should be in-scope, not currently identified:

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: ___29 January 2015____________

Thank you for your comments.

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

You can return completed feedback forms by:

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2015 Rate Design Application (RDA) – November 18th, 2014
Transmission Extension Policy
Workshop # 1 - Feedback Form

Name/Organization:

British Columbia Utilities Commission

Presentation Topics	
A. Transmission Extension Policy Objectives	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Bonbright Criteria: In the context of transmission extension policy, BC Hydro noted on slide 9 of the presentation slide deck that regulators have traditionally emphasized three Bonbright criteria: (1) fairness; (2) efficiency; and (3) rate and bill stability. Which of the eight Bonbright criteria do you consider most important in the transmission extension policy context, and why?	Without diminishing the importance of the three criteria mentioned, how important are criteria such as practicality or customer acceptance when considering the robustness of the TX Policy against ‘gaming’ – for example by overstating expected usage or by ‘outwaiting’ a contribution period for lines built in anticpation of ‘clustered’ loads?

2) **Bonbright Criteria:** Do you have any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers will receive fair contribution from the utility and that contribution will not place undue upward pressure on rates' is an element of fairness, what does 'undue upward pressure on rates' mean in quantitative terms?	Before addressing how to measure the Bonbright criteria, it may be useful to refine what each criterion means. For example, when describing fairness as: 'fair apportionment of costs among customers' and 'avoidance of undue discrimination' (slide 8), are all customers equally affected, or is it necessary to differentiate when we are discussing apportionment of costs among customers within the class versus all customers? For example if there is a revenue deficiency as a result of TS6, which class or classes of ratepayers pick(s) up the revenue deficiency, and if more than one class, how it is allocated? Similarly, defining 'undue upward pressure on rates' in precise quantitative terms may be difficult since the TX policy may be dependent on customer revenue forecasts that are subject to some uncertainty. If so, then does the definition of undue upward pressure on rates have to be a range assuming best and worst case scenarios, or should it be a limit on the maximum upward pressure on rates? Also, without indulging into how much emphasis 'Efficiency' should receive among the Bonbright criteria, a point for discussion may be the extent to which the formula for contributions may provide a disincentive for efficient electricity use by a new customer because inefficient use could potentially increase the revenue contribution to BC Hydro.
3) **Other Objectives:** In addition to the eight Bonbright criteria, are there are any other objectives which should inform BC Hydro's transmission extension policy?	Are there specific BC Government policy initiatives that need to be considered in addition to the Bonbright Criteria? For example, are there policies that encourage economic development or regional development in specific areas?

B. Extensions	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
1) Clustered Loads When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with: 1) First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect. 2) BC Hydro builds the common transmission extension and charges each customer an upfront payment based on a prorated basis. 3) BC Hydro builds the common transmission extension and treats this as System Reinforcements (SR) which it would apply the utility contribution towards and seek security /payment based on a prorated basis. *Please provide in the “Comments” column the rationale for your preference and provide commentary on what you think the guidelines would be for determining a reasonable expectation.*	Are there cases that meet one or more of the 3 approaches? For example, one might envisage a case where the transmission extension might attract anciliary development due to the first primary user but the first primary user could not afford the full initial investment. Could the 3 approaches be blended or might one presume the current policy to prevail (#1) unless there are good reasons to allow some BCH contributions?

2) Transmission Extensions in Constrained Areas There may be instances where, due to geographical constraints, environmental impacts, etc., only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In this situation do you prefer: 1) The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity). 2) Allocating the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line. *Please provide in the “Comments” column of this form your preference, or combination thereof, including the rationale for your preference.*	A point for discussion of these proposals is the extent they take into account the time value of money and/or the depreciated nature of the line to which customers other than the initial customer will be attaching. It would also be helpful to have a discussion on the risks posed to BCH under each of the 2 preference options. i.e Would there be a stranded asset risk for BCH if option 1 was preferred? The third bullet of Slide 28 states that AESO’s tariff lists a number of criteria for the types of costs that can be deemed system or participant related? Acknowledging the differences between the AESO system and the BC Hydro system, would it help to inform the BC Hydro TS 6 review to discuss what those AESO criteria are, and how relevant they are to the BC Hydro application?

C. Utility Contribution Models	**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 described in the November18, 2014 Transmission Extension Policy Workshop notes, BC Hydro grouped the utility contribution options into four general categories as noted below. *Please provide the rationale for your comments in the "Comments" column of this form.*	
Category 1 – Status quo Tariff Supplement No. 6 (TS 6), with cluster extension option variation set out on slide 19 as a subset of Category 1. BC Hydro proposes to advance Status Quo TS 6 with an extension option variation for further analysis. Do you agree, and if not, why not?	In the discussion of slide 24, BC Hydro stated that the General Service contribution amount of $200/KW of estimated demand was based on a COS study. A question asked during the workshop was: Will that COS study be updated for the TS 6 review? A follow-up question is whether the $/KW contribution amount will be updated to reflect the new COS results.
Category 2 – Customer pays for SR with utility contribution; customer pays for customer transmission line/Basic Transmission Extension (BTE). Category 2 includes Options 1-4 and is based on Dawson Creek/Chetwynd Area Transmission Project Certificate of Public Convenience and Necessity proceeding comments. BC Hydro proposes to advance Option 3 for further analysis as it is closest to BC Hydro's Distribution extension policy. Do you agree, and if not, why not?	

Category 3 – Utility pays for SR; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (Option 10). A cluster extension variation could be included as a subset. BC Hydro proposes to advance Option 10 (Manitoba Hydro model) for further analysis because of its simplicity and because it is closest to the actual outcome of the Status Quo TS 6. Do you agree, and if not, why not?	Slide 49 (Option #10) discusses the Manitoba Hydro utility investment policy. A question for discussion may be how important time in the queue is to prospective customers, and whether time in the queue would be reduced by the time required for a System Impact Study if BC Hydro covered System Reinforcements. If the utility covers the SR, then a related question is whether there should be an exception option whereby for very large and/or remote loads, BC Hydro could apply to the Commission to charge the customer for a part of the SR costs.

Category 4 – Utility pays for SR; Customer pays for customer transmission line/BTE with a utility contribution. BC Hydro proposes to advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity, and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the customer transmission line which is different than the Status Quo TS 6. As a result, BC Hydro believes that Option 7 (Hydro One model) should also be brought forward for further analysis as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a 'true up' of costs. Do you agree, and if not why not?	Slides 48 (Hydro Quėbec-Option 9) and 46 (Hydro One – Option 7) conclude that no further analyses are required for these options. If BC Hydro considers that they should be brought forward, further discussions related to how their issues concerning unfair apportionment of costs, cross-subsidization and upward rate impact would be important. Furthermore, there may be an advantage in separating out – in all options – the issues surrounding the Customer Transmission Line and the BTE, from those surrounding SR, because the magnitude and frequency of SR may be quite different than Customer Transmission Lines and BTE which one would expect to be required in all cases. Another issue is, if the Utility pays for the SR (as in Option 7 – Hydro One), whether new loads over a certain size would require commission or government approval before connecting to the utility system. For example, would Hydro Quėbec's extension/connection policy that new loads greater than 50 MW must receive the provincial government approval before connecting to the utility's system be an important feature in minimizing rate impacts associated with granting large blocks of electricity to specific customers?

D. Security	**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's current security policy requires customers to provide security for the amount of the BC Hydro contribution. Issues under consideration include:	

1. Should security be required, if so for what amount? ☐ Actual cost of SR. ☐ Based on a $/kW. ☐ Based on a historical average. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	
2. When should security be released? ☐ After construction is complete. ☐ After a fixed time period. ☐ Based on an assessment of revenue recovered. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	
3. What forms of security should be allowed? *Please provide your comments in the "Comments" column of this form.*	BC Hydro indicated that security is generally returned (based on revenue) in less than 5 years under the current system. But the feedback from customers as noted in the workshop summary indicated an issue was not how soon the Letter of Credit/security was returned but their ability to get the security in the first place. To what extent to different forms of security provide a potential solution to this problem, while still offering a reasonable degree of risk mitigation for other customers?
4. Other comments with respect to security? *Please provide your comments in the "Comments" column of this form.*	

E. 150 MVA threshold	**Comments** (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).

The 150 MVA threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and new generation in the definition of SR was questioned in the 2013 Industrial Electricity Policy Review task force process and in subsequent 2015 RDA engagement to date. Four options for dealing with this threshold were discussed: • **Status Quo** • **Develop New Threshold** □ Should the cost of generation be included or should cost be confined to transmission as with the jurisdiction that has a safety valve (Ontario), and if generation cost is included, should it be applied to the total load or to the just the incremental load above the threshold? • **No Threshold with Safety valve** □ For the exceptional case where a new load would cause a significant rate impact BC Hydro would have the option to seek BCUC (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer. □ If this option is pursued, should the safety valve include generation costs or as with Ontario should it be confined to transmission costs? • **No Threshold** *Please state in the "Comments" column of this form your preference of the options and the rationale for your preference.*	One issue seems to be the discrete nature of 150 MVA triggering a potentially very large cost to new customers over 150 MVA and no bulk transmission or generation reinforcement costs to new customers of 149 MVA. The current policy promotes most new industrial developments on the one hand but discourages very large new customers that could be a burden to existing customers on the other hand. Have the economic policy drivers changed over time and would option 3 solve the 'all or nothing nature' of the 150 MVA threshold? If a large new customer were charged for bulk system reinforcement, would they then be exempt from future revenue requirement costs for bulk transmission or generation additions? Could this vintaging create a problem of potential cost allocation difficulty for all other customers? If new industrial customers were to be charged the potential cost of future bulk transmission or generation additions to serve them, should BCH also consider streaming future bulk tramsmission or generation costs to Residential or General Service customers if their growth in a region were the direct cause of a bulk transmission or generation addition? If BCH is not aware of any utility charging for generation reinforcement, what is the special circumstance in BC for its inclusion? Can the potential for LNG development be such a special circumstance? If most utilities do not charge for bulk transmission system reinforcements, it would be helpful if BCH articulate the need for such policies in BC. If no customers have ever been charged for a bulk transmission reinforcement in BC, should the requirement be discarded?

<table>
<tr><th>F. Transition Rules</th><th>Comments
(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).</th></tr>
<tr><td>BC Hydro recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under:
1) System Impact Study (SIS) – customer has initiated a SIS
2) Facilities Study (FS) - customer has initiated a FS
3) Facilities Agreement (FA) – customer has an executed FA.
BC Hydro also questioned if other factors should be considered such as:
• In-service date
• Customers Final Investment Decision date
• Permitting approvals.
BC Hydro proposed the following strawman transition rule:
▪ Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro’s satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6.
Please comment if you agree or not with the proposed strawman transition rule and the reasons for your comments in the “Comments” column of this form.</td><td></td></tr>
</table>

G. Line transfer	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
The current line transfer provisions in the TS 6 are at the sole discretion of the customer. Should the line transfer provisions be modified to allow BC Hydro to require a line be transferred when there is a system benefit or decline a line transfer when there is no benefit and/or a significant risk/burden to rate payers. *Please indicate your preference with respect to the Line Transfer provisions to be included in the TS 6 and the rationale for your preference in the "Comments" column of this form.*	This provision seems to be entirely to BC Hydro's benefit. The fairness to the transmission customer having built and owned the line should be further investigated. Is there an issue related to allegations that BCH construction costs seem to be much higher than transmission customers' costs? If there are benefits to BCH in excess of the depreciated cost of the transmission line, should the customers be compensated?

H. Queue Management	**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 circulated a draft of the current queue management business practise with the workshop preparation materials and is seeking comments on the current business practice and comments on the following proposed changes for consideration: 1. **Staged Approach with Soft Milestone**. BC Hydro has discretion on timeframes if others later in the queue are not harmed by extensions to deadlines. Modify existing language to include additional milestones (permitting, financing, etc.) to stay in the queue. Formalize cluster study and allocation of study costs. 2. **Staged Approach with Hard Milestones.** Strict adherence to timeframes and add language regarding what constitutes a material changes (changes in load size, point of interconnection, deferral of in-service date by X years, etc.) that will require a customer to lose its current queue position and be moved to the bottom of the queue 3. **Fast Track Process.** Should later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) be allowed to connect prior to earlier queue customers. If so what rules should be in place: ☐ No harm to earlier queue customer – no increased costs or timing of connection ☐ Earlier queue customer must advance their project ☐ Risk and cost of any re-studies borne by customer requesting to be fast tracked	Regarding Transition rules and queue management options, BC Hydro stated that 24 months is adequate to process applications in most situations, but if a new transmission line was required, it could take much longer than that to get a new project in service. Including some data on numbers of applications and processing times, with and without a new transmission line requirement, would help to inform the review.

4. **Open Call**. When there is deemed to be the potential for several connection requests in the same region, BCH would initiates a Call for projects that want to connect to the BC Hydro transmission system. Each connection request would have the same queue position and the requests would be studied as a cluster. This would result in the best use of BC Hydro planning resources and the most optimum SR. Rules for allocation of study costs and system reinforcement costs would also be required. *Please state in the "Comments" column of this form your preference of the option(s) and the rationale for your preference.*	

Additional Comments, Items you think should be in-scope, not currently identified:

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 (RDA) – November 18th, 2014

Transmission Extension Policy

Workshop # 1 - Feedback Form

Name/Organization: **Canadian Association of Petroleum Producers**

Presentation Topics	
A. Transmission Extension Policy Objectives	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Bonbright Criteria: In the context of transmission extension policy, BC Hydro noted on slide 9 of the presentation slide deck that regulators have traditionally emphasized three Bonbright criteria: (1) fairness; (2) efficiency; and (3) rate and bill stability. Which of the eight Bonbright criteria do you consider most important in the transmission extension policy context, and why?	Rates that are derived in a fair and equitable manner will consequently possess other cost and revenue related attributes identified by the Bonbright criteria. If costs are fairly apportioned among customers then usage levels among customer groups will respond accordingly and inefficient levels of consumption will be discouraged. Arbitrarily discriminating between customers by vintage or industry type, for example, will be unlikely to result in appropriate price signals that achieve efficient patterns of consumption. Accordingly, CAPP would advocate that above all, rates and tariffs must be established in a fair and non-discriminatory manner, especially with respect to vintage (i.e. new versus old customers) and industry type.
2) Bonbright Criteria: Do you have any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers will receive fair contribution from the utility and that contribution will not place undue upward pressure on rates' is an element of fairness, what does 'undue upward pressure on rates' mean in quantitative terms?	Trying to quantify specific thresholds is probably not useful from a broad policy perspective. A project with demonstrated customer need may have different rate impacts depending on the timing of the application (e.g. is the system in a state of generation surplus or deficit). The policy needs to be more enduring than this. Accordingly, CAPP believes that a particular quantitative threshold/measure of rate impact cannot be universally implemented across all projects, and rather, project and site-specific circumstances must be evaluated on a case-by-case basis. CAPP remains of the view that customers must receive fair contribution from the utility for transmission extensions, and in particular (and supported by BCH's jurisdictional evaluation) that system reinforcement costs should be borne by the utility, while costs for the BTE may continue to be borne (in all or in part) by the customer.

3) **Other Objectives:** In addition to the eight Bonbright criteria, are there are any other objectives which should inform BC Hydro's transmission extension policy?	As BC is seeking to develop a world class environmentally friendly LNG industry, an opportunity exists to minimize upstream-related GHG emissions to the extent natural gas producers are provided with a fair and equitable rate/tariff framework to electrify upstream operations. It is important that this opportunity is not lost by denying access for new customers (namely oil and gas producers looking to electrify facilities) to the benefits of low cost existing generation by making the rates and/or tariff unduly burdensome and uncompetitive. There is a further risk that if negative competitiveness due to rate or tariff changes result from the RDA, that upstream support for future transmission reinforcement project (such as the Peace River Electricity Supply project, PRES) may be at risk, as operators may elect to use self-generated electricity or gas drive facilities, particularly in periods of low natural gas prices.

B. Extensions	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Clustered Loads When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with: 1) First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect. 2) BC Hydro builds the common transmission extension and charges each customer an upfront payment based on a prorated basis. 3) BC Hydro builds the common transmission extension and treats this as System Reinforcements (SR) which it would apply the utility contribution towards and seek security /payment based on a prorated basis. *Please provide in the "Comments" column the rationale for your preference and provide commentary on what you think the guidelines would be for determining a reasonable expectation.*	CAPP believes that in the case of a transmission extension (versus system reinforcement, like DCAT/PRES) that there is potentially a greater risk of stranded capital for the utility as new transmission is being built to an area that was previously not served by BCH (and especially if the extension only serves a limited number of new customers). Accordingly, treating an extension as a system reinforcement alone and applying the existing utility contribution could potentially put other ratepayers at risk if loads fail to materialize. CAPP agrees that in these circumstances the customer builds and pays for the extension and receives pioneer right to recoup costs if other customers connect. In the case of reinforcements of an existing transmission system (like DCAT and PRES) the risk of stranded capital due to underutilization of the reinforcement is much lower (as the capacity will be used as load growth in the region continues). Accordingly, these system reinforcements should be treated as a utility cost (and borne by all ratepayers).

2) Transmission Extensions in Constrained Areas There may be instances where, due to geographical constraints, environmental impacts, etc., only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In this situation do you prefer: 1) The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity). 2) Allocating the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line. *Please provide in the "Comments" column of this form your preference, or combination thereof, including the rationale for your preference.*	

C. Utility Contribution Models	**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 described in the November18, 2014 Transmission Extension Policy Workshop notes, BC Hydro grouped the utility contribution options into four general categories as noted below. *Please provide the rationale for your comments in the "Comments" column of this form.*	
Category 1 – Status quo Tariff Supplement No. 6 (TS 6), with cluster extension option variation set out on slide 19 as a subset of Category 1. BC Hydro proposes to advance Status Quo TS 6 with an extension option variation for further analysis. Do you agree, and if not, why not?	As an initial matter CAPP believes that in any options being reviewed, the arbitrary 150 MVA threshold in TS 6 should be removed. CAPP observes that the jurisdictional review by BCH revealed that some utilities are responsible for costs of system reinforcements in addition to basic transmission extensions/customer transmission lines. To the extent that the current TS 6 provides a significant offset which results in system reinforcements being paid for by the utility, CAPP supports this option. CAPP believes that system reinforcement costs should not be borne by customers, and rather should be the responsibility of the utility (and all rate payers). There is jurisdictional support for this approach as AESO, Sask Power, MB Hydro, Hydro One and Hydro Quebec DO NOT charge customers for system reinforcements. Furthermore, system reinforcements benefit not only the customer who triggers them, but all other ratepayers in the area, and thus should not be considered a customer-specific cost. For example, some system reinforcements (such as DCAT) result in the creation of more capacity than is needed by a customer, and therefore the SR accrues benefits to other ratepayers as well. With BCH considering CAPP's position on system reinforcement costs, CAPP would support further analysis of this option.

Category 2 – Customer pays for SR with utility contribution; customer pays for customer transmission line/Basic Transmission Extension (BTE). Category 2 includes Options 1-4 and is based on Dawson Creek/Chetwynd Area Transmission Project Certificate of Public Convenience and Necessity proceeding comments. BC Hydro proposes to advance Option 3 for further analysis as it is closest to BC Hydro's Distribution extension policy. Do you agree, and if not, why not?	CAPP is concerned that BC Hydro proposes to advance Option 3 for further analysis simply because it is closest to BC Hydro's Distribution extension policy when this is the least competitive option from a transmission customer perspective (in options 1 to 4). This concern is amplified by the fact that the jurisdiction review revealed that network upgrades/system reinforcements are often borne by the utility with no need for a customer contribution. Thus, CAPP does not support this option, nor any other option where a less competitive utility contribution formula (compared to the existing TS 6) is employed (options 1-4). As per its prior comment, CAPP believes that SR costs should not be borne by customers but rather should be the responsibility of the utility CAPP could support the continuation of a utility contribution where an appropriate formula (such as the existing TS 6 formula) to derive the contribution is utilized. Alternatively, CAPP understands that to date the 'benefits' portion of the existing contribution formula has never been employed – CAPP believes that if BCH is to begin quantifying 'benefits' (to the BCH system resulting from a system reinforcement) as part of an offset calculation, that it should be done in a transparent manner that is fully communicated and well understood by customers. CAPP also believes that further consideration/analysis should be given to having customer transmission line costs and BTE costs being borne the utility and included in the rate base.

Category 3 – Utility pays for SR; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (Option 10). A cluster extension variation could be included as a subset. BC Hydro proposes to advance Option 10 (Manitoba Hydro model) for further analysis because of its simplicity and because it is closest to the actual outcome of the Status Quo TS 6. Do you agree, and if not, why not?	CAPP strongly supports the further analysis of this option. As stated in BCH's comments, the Manitoba Hydro model is the closest to the actual outcome of the existing TS 6. Furthermore, as outlined above, system reinforcement costs should not be borne by customers on a project-specific basis as the benefits of these reinforcements are realized by other ratepayers as well. CAPP also believes that there is strong jurisdictional support for this approach (given that most utilities in the jurisdictional review do not require system reinforcement costs to be borne by the customer), and that this model will help to support future transmission reinforcement projects such as PRES and the electrification of upstream facilities. As stated previous, CAPP also believes that further consideration/analysis should also be given to having customer transmission line costs and BTE costs being borne the utility and included in the rate base.

Category 4 – Utility pays for SR; Customer pays for customer transmission line/BTE with a utility contribution. BC Hydro proposes to advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity, and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the customer transmission line which is different than the Status Quo TS 6. As a result, BC Hydro believes that Option 7 (Hydro One model) should also be brought forward for further analysis as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a 'true up' of costs. Do you agree, and if not why not?	CAPP is supportive of this option being included for further analysis. CAPP strongly supports the view that system reinforcements should be the responsibility of the utility and not the customer. Furthermore, CAPP welcomes analysis around an option whereby a utility contribution is given to customers when building a transmission line/basic transmission extension.

D. Security	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's current security policy requires customers to provide security for the amount of the BC Hydro contribution. Issues under consideration include:	
1. Should security be required, if so for what amount? ☐ Actual cost of SR. ☐ Based on a $/kW. ☐ Based on a historical average. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	Any security provided to BCH should be a function of the actual SR costs to be incurred. Using a $/kW value is arbitrary or a historical average may be arbitrary and may not be reflective of the actual costs of a new SR.
2. When should security be released? ☐ After construction is complete. ☐ After a fixed time period. ☐ Based on an assessment of revenue recovered. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	CAPP supports the release of security after the highest risk period, i.e. customer construction period only, or short (6 to12 months) fixed term after construction to ensure that revenues from customers are being realized. As in the distribution model, security should be released after the risk of stranded resources has been decreased (though not necessarily until the whole amount of the security is recovered through a customer's revenues as under the current TS6). This approach is jurisdictionally supported as well with most other jurisdictions only requiring security to mitigate stranded investment risk, and security is typically only held until the customer reaches its commercial operation date (COD). Once a customer has built its facilities and has commenced service from BC Hydro, there is very little risk that the utility facilities will be stranded given the substantial investments made and costs incurred.

3. What forms of security should be allowed? *Please provide your comments in the "Comments" column of this form.*	BCH currently accepts a broad range of security. CAPP supports the need to have a sufficiently large number of alternatives so that customers can choose the option that best accommodates their financial circumstances while providing adequate security to BCH. However, CAPP encourages BCH to maximize the use of Parental Guarantee (PG) to the greatest extent possible for customers who may be considered financially 'low risk'. This approach of 'risking' customers is jurisdictionally supported by Hydro One. CAPP notes that BCH's maximum thresholds for PG coverage are relatively low and results in competitiveness challenges when Letters of Credit are consequently required - other stakeholders/industry associations have voiced this concern as well. This effect is further amplified by the need for BCH to hold this security until revenues have been recovered from the customer to fully pay off the amount (potentially up to 12 years under the current TS6). Decreasing security burdens and/or the duration of time over which security is required would provide significant benefits to customers while still protecting ratepayers (because security is still required for higher risk customers and/or project periods)
4. Other comments with respect to security? *Please provide your comments in the "Comments" column of this form.*	CAPP believes that there may be an opportunity to use security as a mechanism for transitioning between the old and new tariffs. Without investment certainty around PRES in the context of the tariff, the project will very likely be at risk, especially if the new version of TS6 is less competitive for customers (and O&G customers elect to self-supply). CAPP proposes a framework whereby a customer that wishes to secure load under the terms and conditions of the old tariff, that security be provided up-front and be grandfathered under the old tariff until the load comes online.

E. 150 MVA threshold	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
The 150 MVA threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and new generation in the definition of SR was questioned in the 2013 Industrial Electricity Policy Review task force process and in subsequent 2015 RDA engagement to date. Four options for dealing with this threshold were discussed: • **Status Quo** • **Develop New Threshold** □ Should the cost of generation be included or should cost be confined to transmission as with the jurisdiction that has a safety valve (Ontario), and if generation cost is included, should it be applied to the total load or to the just the incremental load above the threshold? • **No Threshold with Safety valve** □ For the exceptional case where a new load would cause a significant rate impact BC Hydro would have the option to seek BCUC (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer. □ If this option is pursued, should the safety valve include generation costs or as with Ontario should it be confined to transmission costs? • **No Threshold** *Please state in the "Comments" column of this form your preference of the options and the rationale for your preference.*	CAPP strongly supports the removal of any threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and associated new generation. CAPP believes that any threshold would be arbitrary, and that an important point to observe is that it is not correct that only "new" customers cause the incurrence of any higher marginal cost for new supply. "Old" customers who continue to take service are just as responsible for new supply requirements as "new" customers. With respect to the issue of a 'safety valve' CAPP is concerned that such an approach might effectively create a new "threshold" while not being explicitly identified as being one. Having said that, CAPP is supportive of further analysis being conducted to see what rate impacts might be associated with new transmission projects of various size.

F. Transition Rules	**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 recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under: 1) **System Impact Study (SIS)** – customer has initiated a SIS 2) **Facilities Study (FS)** - customer has initiated a FS 3) **Facilities Agreement (FA)** – customer has an executed FA. BC Hydro also questioned if other factors should be considered such as: • In-service date • Customers Final Investment Decision date • Permitting approvals. BC Hydro proposed the following strawman transition rule: ▪ Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro's satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6. *Please comment if you agree or not with the proposed strawman transition rule and the reasons for your comments in the "Comments" column of this form.*	CAPP supports grandfathering existing rules for Customers that have entered into a Facilities Study Agreement; however, it has some concerns with also having to demonstrate that projects are likely to come into service within 24 months of the effective date of a new TS6. Some projects involve much longer timelines from facility studies to in service date than others due to complexity, size, need for any extensive environmental approvals etc. A 24 month period might be adequate for routine projects but will likely be wholly inadequate for others e.g. PRES. It would not be fair to expect customers underpinning larger and more complex projects to proceed without knowing what tariff rules might apply to them and such uncertainty may impair system development. A potential solution to this approach may be to use the provision of security as a mechanism to enable grandfathering under the old tariff. For loads that a customer wishes to secure under the current TS6 provisions, security may be provided up-front based on the magnitude of anticipated load and an estimate of the anticipated SRs. This provision of security would allow customers to be grandfathered under the old tariff until the load comes online or the security is relinquished. While CAPP understands that BCH desires a sunset clause for grandfathering purposes, CAPP believes that given the uncertainty regarding the timing for PRES (due to project complexity and scope) that requiring a 2 year sunset clause will put the broader PRES project at risk.

G. Line transfer	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
The current line transfer provisions in the TS 6 are at the sole discretion of the customer. Should the line transfer provisions be modified to allow BC Hydro to require a line be transferred when there is a system benefit or decline a line transfer when there is no benefit and/or a significant risk/burden to rate payers. *Please indicate your preference with respect to the Line Transfer provisions to be included in the TS 6 and the rationale for your preference in the "Comments" column of this form.*	The current line transfer provisions should be modified to allow BCH to request a line to be transferred when there is a system benefit but in such cases BCH should pay customers a fair share of the costs incurred to build the line. If BCH is given the right to refuse to take over line ownership then a similar right should be granted to customers if they do not wish to transfer a line to BCH.

<table>
<tr><th>H. Queue Management</th><th>Comments

(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).</th></tr>
<tr><td>BC Hydro circulated a draft of the current queue management business practise with the workshop preparation materials and is seeking comments on the current business practice and comments on the following proposed changes for consideration:

1. Staged Approach with Soft Milestone. BC Hydro has discretion on timeframes if others later in the queue are not harmed by extensions to deadlines. Modify existing language to include additional milestones (permitting, financing, etc.) to stay in the queue. Formalize cluster study and allocation of study costs.

2. Staged Approach with Hard Milestones. Strict adherence to timeframes and add language regarding what constitutes a material changes (changes in load size, point of interconnection, deferral of in-service date by X years, etc.) that will require a customer to lose its current queue position and be moved to the bottom of the queue

3. Fast Track Process. Should later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) be allowed to connect prior to earlier queue customers. If so what rules should be in place:

□ No harm to earlier queue customer – no increased costs or timing of connection

□ Earlier queue customer must advance their project

□ Risk and cost of any re-studies borne by customer requesting to be fast tracked</td><td>CAPP is supportive of greater customer flexibility to the extent other prospective customers are not negatively affected. As such, CAPP is supportive of a staged approach with soft milestones so that a customer can retain their place in the queue as long as other customers later in the queue are not harmed by extensions to deadlines. By the same token CAPP also sees the merits of a Fast Track Process where a project that is ‘shovel-ready’ may connect prior to earlier queue customer(s) as long as there is no harm to the earlier queue customer(s) and their loads.

Where customers have provided monetary guarantees they should not be able to be bumped out of their position in the queue.

CAPP also considers that BCH should make its queue management practices as transparent and publicly accessible as possible</td></tr>
</table>

4. **Open Call**. When there is deemed to be the potential for several connection requests in the same region, BCH would initiates a Call for projects that want to connect to the BC Hydro transmission system. Each connection request would have the same queue position and the requests would be studied as a cluster. This would result in the best use of BC Hydro planning resources and the most optimum SR. Rules for allocation of study costs and system reinforcement costs would also be required. *Please state in the "Comments" column of this form your preference of the option(s) and the rationale for your preference.*	CAPP has a number of concerns with the open call process and in particular the fact that timelines may become protracted due to the need to study all loads together. A soft milestone queue process would be more suitable to ensure that individual projects may be approved on a case by case basis and not unduly hinder development.

Additional Comments, Items you think should be in-scope, not currently identified:

CAPP understands that there has been discussion with respect to bifurcating TS6 related issues into a separate proceeding from the rest of the RDA. While CAPP recognizes that there may be some natural breaks in the hearing process given the multiplicity and complexity of issues, CAPP believes that BCH and the BCUC should target a single decision/report coming out of the RDA process. CAPP's position on this matter arises due to potential uncertainty that could result until all rules are finalized from a phased approach. CAPP believes that although rates themselves are important, they are only part of the RDA, and customers will also need to know the terms and conditions (i.e. tariff) as well before they can proceed with projects.

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:

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

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2015 Rate Design Application (RDA) – November 18th, 2014

Transmission Extension Policy

Workshop # 1 - Feedback Form

Name/Organization: **Commercial Energy Consumers Associaton of BC (CEC)**

Presentation Topics	
A. Transmission Extension Policy Objectives	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Bonbright Criteria: In the context of transmission extension policy, BC Hydro noted on slide 9 of the presentation slide deck that regulators have traditionally emphasized three Bonbright criteria: (1) fairness; (2) efficiency; and (3) rate and bill stability. Which of the eight Bonbright criteria do you consider most important in the transmission extension policy context, and why?	Revenue and Rate Impacts, because this is the essential condition for the regulatory impact. This priority does not lessen the value of the other criteria.
2) Bonbright Criteria: Do you have any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers will receive fair contribution from the utility and that contribution will not place undue upward pressure on rates' is an element of fairness, what does 'undue upward pressure on rates' mean in quantitative terms?	'Undue upward pressure on rates' should be evaluated in the context of other rate pressure in aggregate. As well the transmission extension rate pressure for the year in aggregate should be assessed. Project specific rate pressure should be assessed also. Measurement is best evaluated in terms of % rate increase impact. This leads to condition dependent policy. Evaluation should also consider uncertainty and/or probability assessment.
3) Other Objectives: In addition to the eight Bonbright criteria, are there are any other objectives which should inform BC Hydro's transmission extension policy?	In addition to Bonbright, the Commission must consider Government objectives which may include economic development plans.

B. Extensions	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Clustered Loads When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with: 1) First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect. 2) BC Hydro builds the common transmission extension and charges each customer an upfront payment based on a prorated basis. 3) BC Hydro builds the common transmission extension and treats this as System Reinforcements (SR) which it would apply the utility contribution towards and seek security /payment based on a prorated basis. *Please provide in the "Comments" column the rationale for your preference and provide commentary on what you think the guidelines would be for determining a reasonable expectation.*	Determining the preferred method of establishing customer obligation should be condition-dependent, and consider the number, likelihood, and timing of additional customer participation. This will achieve a fairer distribution of the associated costs and result in cost-effective decision-making for customers and the utility while also serving the public interest. Where individual customers are initiating an extension with limited potential for additional customer participation it is reasonable to assign a greater burden to that customer by requiring high upfront charges, accompanied by lower ongoing charges. Where a group of customers are coordinated and demonstrating commitment to the project, mid-range upfront charges are reasonable with mid-range ongoing charges. Where the project may be seen as contributing to economic development in the region with high likelihood of extensive customer use and value, it is reasonable to provide for a lower upfront charge and higher ongoing charges. Analysis should consider: 1. Total Customer potential a) individual plus other that may arise b) pre-established group of coordinated customers c) project contribution to economic development of area 2. Timing based on a) specific individual customer preference, b) commitment from a defined group c) planning horizon for economic development 3. Certainty of Customer Potential a) high b) medium c) low

2) Transmission Extensions in Constrained Areas There may be instances where, due to geographical constraints, environmental impacts, etc., only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In this situation do you prefer: 1) The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity). 2) Allocating the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line. *Please provide in the "Comments" column of this form your preference, or combination thereof, including the rationale for your preference.*	Situation 1 seems more appropriate in terms of fairness to customers and in terms of responsibility for incremental capacity justification. Incremental capacity can be allowed for in different ways with significantly different costs. BCH should justify what is required beyond a customer's basic requirement and plan accordingly. This would then result in the attendant impacts on all customer rates. This should be done subject to BCH justification being reviewed by the Commission at the time.

C. Utility Contribution Models	**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 described in the November18, 2014 Transmission Extension Policy Workshop notes, BC Hydro grouped the utility contribution options into four general categories as noted below. *Please provide the rationale for your comments in the “Comments” column of this form.*	
Category 1 – Status quo Tariff Supplement No. 6 (TS 6), with cluster extension option variation set out on slide 19 as a subset of Category 1. BC Hydro proposes to advance Status Quo TS 6 with an extension option variation for further analysis. Do you agree, and if not, why not?	Agree with advancing this option. BC Hydro will need this at a minimum to compare other options against.
Category 2 – Customer pays for SR with utility contribution; customer pays for customer transmission line/Basic Transmission Extension (BTE). Category 2 includes Options 1-4 and is based on Dawson Creek/Chetwynd Area Transmission Project Certificate of Public Convenience and Necessity proceeding comments. BC Hydro proposes to advance Option 3 for further analysis as it is closest to BC Hydro’s Distribution extension policy. Do you agree, and if not, why not?	Option 3 includes only capital and excludes O&M and taxes. As O&M and taxes are a real part of costs impacting rates it would be more suitable to consider incorporating all costs or at least demonstrate immateriality. Options 1,2 and 3 use F16 to F20 rate and Option 4 uses 10 year rate plan rates. It would be better to use a long term rate forecast for revenue assessment.

Category 3 – Utility pays for SR; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (Option 10). A cluster extension variation could be included as a subset. BC Hydro proposes to advance Option 10 (Manitoba Hydro model) for further analysis because of its simplicity and because it is closest to the actual outcome of the Status Quo TS 6. Do you agree, and if not, why not?	The Option 10 method appears to be a reasonable base approach and so should be carried forward. The rationale is based on a logic of Customer Contribution (CC) = Project Cost less the following: • Customer Revenue Projection • BC Hydro Future Customer Revenue Projection • BC Hydro System Reinforcement Cost • Basic Transmission Extension Allowance Plus the following: • Basic Transmission Extension Revenue Allocation
Category 4 – Utility pays for SR; Customer pays for customer transmission line/BTE with a utility contribution. BC Hydro proposes to advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity, and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the customer transmission line which is different than the Status Quo TS 6. As a result, BC Hydro believes that Option 7 (Hydro One model) should also be brought forward for further analysis as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a 'true up' of costs. Do you agree, and if not why not?	Option 9 is worth examining because it is one of the other major Hydroelectric utilities in Canada. Option 7 is worth examining as Hydro One is a major utility in Canada and is a useful comparison. Overall the logic of Customer Contribution = Project Cost less: • Customer Revenue Projection • BC Hydro Future Customer Revenue Projection • BC Hydro System Reinforcement Cost • Basic Transmission Extension Allowance Plus: • Basic Transmission Extension Revenue Allocation (adjusted for customer ownership of Transmission option) would seem to capture the relevant concept. Parameters for calculation and determination of values then becomes significant.

D. Security	**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's current security policy requires customers to provide security for the amount of the BC Hydro contribution. Issues under consideration include:	Basic security should be in place to ensure connection.
1. Should security be required, if so for what amount? ☐ Actual cost of SR. ☐ Based on a $/kW. ☐ Based on a historical average. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	Security should be for the Basic plus Actual SR cost minus an historic average cost less any SR cost being included for future customer potential, which BCH should justify. This provides for a postage stamp approach with suitable allocation of responsibility for variance.
2. When should security be released? ☐ After construction is complete. ☐ After a fixed time period. ☐ Based on an assessment of revenue recovered. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	Basic security can be released after construction and connection. Remaining security can be released as customer contribution requirements are paid. Security release shoud be based on credit risk for both.
3. What forms of security should be allowed? *Please provide your comments in the "Comments" column of this form.*	Security should vary based on credit risk assessment from Letter of Credit to take or pay contract.

4. Other comments with respect to security? *Please provide your comments in the "Comments" column of this form.*	Basic security can be an amount $/kW plus contract over time sufficient to ensure connection.

E. 150 MVA threshold	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
The 150 MVA threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and new generation in the definition of SR was questioned in the 2013 Industrial Electricity Policy Review task force process and in subsequent 2015 RDA engagement to date. Four options for dealing with this threshold were discussed: • **Status Quo** • **Develop New Threshold** □ Should the cost of generation be included or should cost be confined to transmission as with the jurisdiction that has a safety valve (Ontario), and if generation cost is included, should it be applied to the total load or to the just the incremental load above the threshold? • **No Threshold with Safety valve** □ For the exceptional case where a new load would cause a significant rate impact BC Hydro would have the option to seek BCUC (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer. □ If this option is pursued, should the safety valve include generation costs or as with Ontario should it be confined to transmission costs? • **No Threshold** *Please state in the "Comments" column of this form your preference of the options and the rationale for your preference.*	• Status Quo is not particularly helpful in dealing with primary issues. • A new threshold is not required if a safety valve is provided in terms of unacceptable levels of rate impact which are projected as possible. Without a safety valve there should not be a bright line threshold but a cumulative aggregate progression of responsibility to the customers relative to transmission and generation where incremental costs vary widely from embedded cost. This responsibility would likely be minimal in most cases but could provide rate impact protection. • A safey valve is likely the better approach where specific case examples can be examined and suitable rate impact protection can be provided. Transmission Generation should be considered. • No threshold or safety valve would be a poor solution going backward even from status quo.

<table>
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<tr><td>BC Hydro recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under:
1) System Impact Study (SIS) – customer has initiated a SIS
2) Facilities Study (FS) - customer has initiated a FS
3) Facilities Agreement (FA) – customer has an executed FA.
BC Hydro also questioned if other factors should be considered such as:
• In-service date
• Customers Final Investment Decision date
• Permitting approvals.
BC Hydro proposed the following strawman transition rule:
▪ Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro’s satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6.
Please comment if you agree or not with the proposed strawman transition rule and the reasons for your comments in the “Comments” column of this form.</td><td>• Assuming that a customer can have significant investment of time & money to evoke any of these studies ti would seem fair to include transition for any of the studies, and a notice period to all, which the RDA proceeding can be part of.
• For specific customers, where their prior investments to anticipate business have been made assuming current practice, it would be fair to make exceptions for other factors.
• The 24 month in-service date can be a problem is arbitrarily destroying a customer investment to date. It may be better to let this issue attenuate more naturally than to force it with a bright line.</td></tr>
</table>

G. Line transfer	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
The current line transfer provisions in the TS 6 are at the sole discretion of the customer. Should the line transfer provisions be modified to allow BC Hydro to require a line be transferred when there is a system benefit or decline a line transfer when there is no benefit and/or a significant risk/burden to rate payers. *Please indicate your preference with respect to the Line Transfer provisions to be included in the TS 6 and the rationale for your preference in the "Comments" column of this form.*	Line transfers should be negotiated whether the customer intitiates the transfer or BCH. Both can initiate transfer proposals. Compensation should be fair and the potential for BCUC arbitrated fair compensation could be part of the tariff understanding for customer-built transmission lines. It would be useful to establish Commission guidelines for fair compensation.

H. Queue Management	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 circulated a draft of the current queue management business practise with the workshop preparation materials and is seeking comments on the current business practice and comments on the following proposed changes for consideration: 1. **Staged Approach with Soft Milestone**. BC Hydro has discretion on timeframes if others later in the queue are not harmed by extensions to deadlines. Modify existing language to include additional milestones (permitting, financing, etc.) to stay in the queue. Formalize cluster study and allocation of study costs. 2. **Staged Approach with Hard Milestones.** Strict adherence to timeframes and add language regarding what constitutes a material changes (changes in load size, point of interconnection, deferral of in-service date by X years, etc.) that will require a customer to lose its current queue position and be moved to the bottom of the queue 3. **Fast Track Process.** Should later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) be allowed to connect prior to earlier queue customers. If so what rules should be in place: ☐ No harm to earlier queue customer – no increased costs or timing of connection ☐ Earlier queue customer must advance their project ☐ Risk and cost of any re-studies borne by customer requesting to be fast tracked	The queue issue is primarily a function of the scarceness of unutilized capacities in the current system. Allocating these benefits based on first come, first served can be problematic. This problem can be diminished significantly with postage stamp concepts and future capacity increment assessments to smooth out cost and benefits for all customers. Options of this nature should be examined. Among the options BC Hydro is requesting comments on, the first Option, 1, sounds closer to the better solution. Clustering when queue congestion is an issue becomes a reasonable response to the queuing as opposed to determining who benefits and who loses. Tariffs should include this caveat.

4. **Open Call**. When there is deemed to be the potential for several connection requests in the same region, BCH would initiates a Call for projects that want to connect to the BC Hydro transmission system. Each connection request would have the same queue position and the requests would be studied as a cluster. This would result in the best use of BC Hydro planning resources and the most optimum SR. Rules for allocation of study costs and system reinforcement costs would also be required. *Please state in the "Comments" column of this form your preference of the option(s) and the rationale for your preference.*	Option 4 is also a useful approach in concept and is complementary to Option 1 with clustering formalization. BC Hydro may find it useful to have both options. a) To cluster itself b) To make a call for customer potential. Eventually the clustering of congested queues will lead t better system design, better planning and ultimately fairer approaches to customers. Timeframes for assessment will be a challenging parameter to manage but should remain circumstance dependent.

Additional Comments, Items you think should be in-scope, not currently identified:

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2015 Rate Design Application (RDA) – November 18th, 2014

Transmission Extension Policy

Workshop # 1 - Feedback Form

Name/Organization:
COPE 378

Presentation Topics	
A. Transmission Extension Policy Objectives	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Bonbright Criteria: In the context of transmission extension policy, BC Hydro noted on slide 9 of the presentation slide deck that regulators have traditionally emphasized three Bonbright criteria: (1) fairness; (2) efficiency; and (3) rate and bill stability. Which of the eight Bonbright criteria do you consider most important in the transmission extension policy context, and why?	*Fairness and efficiency are the most important, where fairness refers to equity both within and between customer classes, and efficiency refers to both whether and the manner in which extensions of service are made.*
2) Bonbright Criteria: Do you have any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers will receive fair contribution from the utility and that contribution will not place undue upward pressure on rates' is an element of fairness, what does 'undue upward pressure on rates' mean in quantitative terms?	*The main concern we would raise is the consistency of the application of Bonbright criteria. Consistent principles should be applied in this context as are used for the recovery of distribution extension costs and also in the recovery of generation and other system annual revenue requirements.*
3) Other Objectives: In addition to the eight Bonbright criteria, are there are any other objectives which should inform BC Hydro's transmission extension policy?	

B. Extensions	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Clustered Loads When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with: 1) First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect. 2) BC Hydro builds the common transmission extension and charges each customer an upfront payment based on a prorated basis. 3) BC Hydro builds the common transmission extension and treats this as System Reinforcements (SR) which it would apply the utility contribution towards and seek security /payment based on a prorated basis. *Please provide in the "Comments" column the rationale for your preference and provide commentary on what you think the guidelines would be for determining a reasonable expectation.*	*The issue here is twofold – which approach will ensure the extension for the ultimate set of needs is undertaken in the most efficienct way, and who should bear the risks of anticipated loads not appearing. There likely is no single answer for all circumstances, but rather the default should be the customer assumes responsibility unless an explicit case can be made by BC Hydro to the BCUC that it should build the extension – that that will result in the most efficient extension and that the risks are rrelatively low. If BC Hydro is requested to make the extension by government as part of an economic development or other public policy initiative, BC Hydro should recommend that government assume the risks.*

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2) Transmission Extensions in Constrained Areas

There may be instances where, due to geographical constraints, environmental impacts, etc., only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In this situation do you prefer:

1) The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity).

2) Allocating the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line.

Please provide in the "Comments" column of this form your preference, or combination thereof, including the rationale for your preference.

</td>
<td>

The system of allocating extension costs between pioneer and subsequent customers does not appear to be fair or consistent with the postage stamp principles used in the establishment of rates. An alternative would be for the first customer to pay a full cost recovery wheeeling charge for the extension until such time as there were subsequent customers, at which point all of the customers would share on a prorata basis a full cost recovery wheeling charge for the connection (net of the depreciation to that point in time).

With this principle in place for standard extensions, then in a case where BC Hydro built a bigger line in anticipation of future loads, the new customers would pay their prorata share of the hypothtical extension that would have been needed to serve their loads, and BC Hydro would assume the costs of any incremental costs until the larger extension was justified.

With reference to the discussion at the workshop, this approach would not be structured such that the pioneer customer assumes the status of a "utility" in any sense.

</td>
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</table>

C. Utility Contribution Models	**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 described in the November18, 2014 Transmission Extension Policy Workshop notes, BC Hydro grouped the utility contribution options into four general categories as noted below. *Please provide the rationale for your comments in the "Comments" column of this form.*	
Category 1 – Status quo Tariff Supplement No. 6 (TS 6), with cluster extension option variation set out on slide 19 as a subset of Category 1. BC Hydro proposes to advance Status Quo TS 6 with an extension option variation for further analysis. Do you agree, and if not, why not?	*The staus quo is not an acceptable option as the SR contribution formula does not accurately reflect the impact of the new customer on BC Hydro revenue requirements (existing customers), nor is it consistent with with what is done for distribution extensions*
Category 2 – Customer pays for SR with utility contribution; customer pays for customer transmission line/Basic Transmission Extension (BTE). Category 2 includes Options 1-4 and is based on Dawson Creek/Chetwynd Area Transmission Project Certificate of Public Convenience and Necessity proceeding comments. BC Hydro proposes to advance Option 3 for further analysis as it is closest to BC Hydro's Distribution extension policy. Do you agree, and if not, why not?	*This warrants further analysis with a utlity contribution formula designed to reflect the net benefits, if any, of the customer's electricity purchases, taking all factors into account.*

Category 3 – Utility pays for SR; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (Option 10). A cluster extension variation could be included as a subset. BC Hydro proposes to advance Option 10 (Manitoba Hydro model) for further analysis because of its simplicity and because it is closest to the actual outcome of the Status Quo TS 6. Do you agree, and if not, why not?	*This warrants futher consideration with an explicit threshold on any negative impact of the new load on BC Hydro revenue requirements taking all factors into account*
Category 4 – Utility pays for SR; Customer pays for customer transmission line/BTE with a utility contribution. BC Hydro proposes to advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity, and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the customer transmission line which is different than the Status Quo TS 6. As a result, BC Hydro believes that Option 7 (Hydro One model) should also be brought forward for further analysis as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a 'true up' of costs. Do you agree, and if not why not?	*We are not supportive of options that would see BC Hydro contribute to the basic customer transmission extension, but would rather see options that provide more fairness between pioneer and subsequent customers as suggested in point B 2 above*

D. Security	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's current security policy requires customers to provide security for the amount of the BC Hydro contribution. Issues under consideration include:	
1. Should security be required, if so for what amount? ☐ Actual cost of SR. ☐ Based on a $/kW. ☐ Based on a historical average. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	
2. When should security be released? ☐ After construction is complete. ☐ After a fixed time period. ☐ Based on an assessment of revenue recovered. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	
3. What forms of security should be allowed? *Please provide your comments in the "Comments" column of this form.*	
4. Other comments with respect to security? *Please provide your comments in the "Comments" column of this form.*	

<table>
<tr><th>E. 150 MVA threshold</th><th>Comments

(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).</th></tr>
<tr><td>The 150 MVA threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and new generation in the definition of SR was questioned in the 2013 Industrial Electricity Policy Review task force process and in subsequent 2015 RDA engagement to date. Four options for dealing with this threshold were discussed:

• Status Quo
• Develop New Threshold
  □ Should the cost of generation be included or should cost be confined to transmission as with the jurisdiction that has a safety valve (Ontario), and if generation cost is included, should it be applied to the total load or to the just the incremental load above the threshold?
• No Threshold with Safety valve
  □ For the exceptional case where a new load would cause a significant rate impact BC Hydro would have the option to seek BCUC (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer.
  □ If this option is pursued, should the safety valve include generation costs or as with Ontario should it be confined to transmission costs?
• No Threshold

Please state in the “Comments” column of this form your preference of the options and the rationale for your preference.</td><td>There should be a threshold based on total impact on revenue requirements (existing customers) taking all transmission and generation cosequences into account. The current threshold is not appropriate, but should be replaced not simply eliminated.

To avoid inequities for customers just below or above the threshold, whatever value is established it should act to ensure customers are responsible for <u>costs in excess of</u> the threshold, as opposed to all costs.</td></tr>
</table>

F. Transition Rules	**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 recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under: 1) **System Impact Study (SIS)** – customer has initiated a SIS 2) **Facilities Study (FS)** - customer has initiated a FS 3) **Facilities Agreement (FA)** – customer has an executed FA. BC Hydro also questioned if other factors should be considered such as: • In-service date • Customers Final Investment Decision date • Permitting approvals. BC Hydro proposed the following strawman transition rule: ▪ Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro's satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6. *Please comment if you agree or not with the proposed strawman transition rule and the reasons for your comments in the "Comments" column of this form.*	

G. Line transfer	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
The current line transfer provisions in the TS 6 are at the sole discretion of the customer. Should the line transfer provisions be modified to allow BC Hydro to require a line be transferred when there is a system benefit or decline a line transfer when there is no benefit and/or a significant risk/burden to rate payers. *Please indicate your preference with respect to the Line Transfer provisions to be included in the TS 6 and the rationale for your preference in the "Comments" column of this form.*	*Yes*

H. Queue Management	**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 circulated a draft of the current queue management business practise with the workshop preparation materials and is seeking comments on the current business practice and comments on the following proposed changes for consideration: 1. **Staged Approach with Soft Milestone**. BC Hydro has discretion on timeframes if others later in the queue are not harmed by extensions to deadlines. Modify existing language to include additional milestones (permitting, financing, etc.) to stay in the queue. Formalize cluster study and allocation of study costs. 2. **Staged Approach with Hard Milestones.** Strict adherence to timeframes and add language regarding what constitutes a material changes (changes in load size, point of interconnection, deferral of in-service date by X years, etc.) that will require a customer to lose its current queue position and be moved to the bottom of the queue 3. **Fast Track Process.** Should later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) be allowed to connect prior to earlier queue customers. If so what rules should be in place: ☐ No harm to earlier queue customer – no increased costs or timing of connection ☐ Earlier queue customer must advance their project ☐ Risk and cost of any re-studies borne by customer requesting to be fast tracked	

4. **Open Call**. When there is deemed to be the potential for several connection requests in the same region, BCH would initiates a Call for projects that want to connect to the BC Hydro transmission system. Each connection request would have the same queue position and the requests would be studied as a cluster. This would result in the best use of BC Hydro planning resources and the most optimum SR. Rules for allocation of study costs and system reinforcement costs would also be required. *Please state in the "Comments" column of this form your preference of the option(s) and the rationale for your preference.*	

Additional Comments, Items you think should be in-scope, not currently identified:

With reference to the discussion surrounding slide 10, under heading 1. Fairness, we take issue with the comment that Special Direction 7 section 5 precludes marginal-cost based pricing or that applying marginal cost to Treansmission Extensions would deprive new customers of access to heritage energy. We understand BC Hydro's position on this issue, however.

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:

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2015 Rate Design Application (RDA) – November 18th, 2014

Transmission Extension Policy

Workshop # 1 - Feedback Form

Name/Organization: **BC First Nations Energy and Mining Council (FNEMC)**

Presentation Topics	
A. Transmission Extension Policy Objectives	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Bonbright Criteria: In the context of transmission extension policy, BC Hydro noted on slide 9 of the presentation slide deck that regulators have traditionally emphasized three Bonbright criteria: (1) fairness; (2) efficiency; and (3) rate and bill stability. Which of the eight Bonbright criteria do you consider most important in the transmission extension policy context, and why?	*In the context of transmission extension policy, FNEMC views* ***fairness*** *as most important in terms of balancing the interests of existing customers in maintaining postage stamp rate levels with the interests of new customers in receiving system access at a predictable and reasonable cost.*
2) Bonbright Criteria: Do you have any suggestions for how BC Hydro should measure the Bonbright criteria in the context of transmission extensions? For example, if 'new customers will receive fair contribution from the utility and that contribution will not place undue upward pressure on rates' is an element of fairness, what does 'undue upward pressure on rates' mean in quantitative terms?	
3) Other Objectives: In addition to the eight Bonbright criteria, are there are any other objectives which should inform BC Hydro's transmission extension policy?	*Regional economic development initiatives.* *Transmission extension policy that recognizes First Nations' Rights and Title and takes into account the circumstances of:* - *Rural and off-grid First Nations communities to connect to the BC Hydro grid in order to access clean, low-cost electricity.* - *Need for business and economic development on First Nations lands*

B. Extensions	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
1) Clustered Loads When there is a reasonable expectation that there would be additional customers that would connect to an extension within a defined time period, which approach for dealing with transmission extension costs do you agree with: 1) First customer builds and pays for extension then gets pioneer rights to recoup costs when other customers connect. 2) BC Hydro builds the common transmission extension and charges each customer an upfront payment based on a prorated basis. 3) BC Hydro builds the common transmission extension and treats this as System Reinforcements (SR) which it would apply the utility contribution towards and seek security /payment based on a prorated basis. *Please provide in the "Comments" column the rationale for your preference and provide commentary on what you think the guidelines would be for determining a reasonable expectation.*	*FNEMC prefers **option 1** whereby the customer builds and pays for the extension and then gets pioneer rights to recoup costs when other customers connect. This option seems to have the least risk to BC Hydro without any adverse rate payer impacts.*

2) Transmission Extensions in Constrained Areas There may be instances where, due to geographical constraints, environmental impacts, etc., only one transmission line can be built in an area, and BC Hydro may want a transmission line built with higher capacity to accommodate future growth than would be required for the initial customer. In this situation do you prefer: 1) The initial customer contributes based on their avoided cost of the line required to service its load. The incremental cost would be allocated to future customers on a prorated basis (new load/incremental capacity). 2) Allocating the total cost of the transmission line built to each customer connecting based on their load over the total capacity of the line. *Please provide in the "Comments" column of this form your preference, or combination thereof, including the rationale for your preference.*	*FNEMC prefers **option 1** whereby the initial customer contributes based on their avoided cost of the line required to service its load. This option seems to have the least risk to BC Hydro and minimizes rate payer impacts.*

C. Utility Contribution Models	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 described in the November18, 2014 Transmission Extension Policy Workshop notes, BC Hydro grouped the utility contribution options into four general categories as noted below. *Please provide the rationale for your comments in the "Comments" column of this form.*	
Category 1 – Status quo Tariff Supplement No. 6 (TS 6), with cluster extension option variation set out on slide 19 as a subset of Category 1. BC Hydro proposes to advance Status Quo TS 6 with an extension option variation for further analysis. Do you agree, and if not, why not?	*In the previous section (B1) FNEMC's preference was for **option 1** whereby the customer builds and pays for the extension and then gets pioneer rights to recoup costs when other customers connect as compared to option 3 which includes this extension option variation that is being applied to Status Quo TS 6. Option 1, as compared to option 3, seems to have the least risk to BC Hydro without any adverse rate payer impacts.* *However, FNEMC supports a balanced approach between minimizing upward rate impacts and increasing economic development opportunities for BC First Nations.* *Therefore FNEMC supports BC Hydro conducting further analysis and determining associated rate impacts with Status Quo TS 6 with the extension option variation.*

Category 2 – Customer pays for SR with utility contribution; customer pays for customer transmission line/Basic Transmission Extension (BTE). Category 2 includes Options 1-4 and is based on Dawson Creek/Chetwynd Area Transmission Project Certificate of Public Convenience and Necessity proceeding comments. BC Hydro proposes to advance Option 3 for further analysis as it is closest to BC Hydro's Distribution extension policy. Do you agree, and if not, why not?	*FNEMC supports BC Hydro conducting further analysis and determining associated rate impacts with the potential of making changes to the utility contribution model in TS 6 particularly in terms of customer contribution to SR costs.* *FNEMC supports having customers make some contribution to SR costs as the data BC Hydro presented on slide 41 indicated that over the 7 year term none of the 49 customers contributed to SR costs and the utility contribution covered 100% of SR costs under TS 6.* *However, FNEMC supports a balanced approach between minimizing upward rate impacts and increasing economic development opportunities for BC First Nations.*
Category 3 – Utility pays for SR; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (Option 10). A cluster extension variation could be included as a subset. BC Hydro proposes to advance Option 10 (Manitoba Hydro model) for further analysis because of its simplicity and because it is closest to the actual outcome of the Status Quo TS 6. Do you agree, and if not, why not?	*FNEMC is concerned about the issues BC Hydro presented on slide 49 pertaining to this option; higher risk to existing ratepayers and possible cross subsidization and rate impacts.* *However, FNEMC supports BC Hydro conducting further analysis and in particular determining associated rate impacts with this option due to the reasons that BC Hydro states:* - *Simplicity* - *Closest to the actual outcome of Status Quo TS 6* *FNEMC supports having customers make increased contribution to SR costs as the data BC Hydro presented on slide 41 indicated that over the 7 year term none of the 49 customers contributed to SR costs and the utility contribution covered 100% of SR costs under TS 6.* *However, FNEMC supports a balanced approach between minimizing upward rate impacts and increasing economic development opportunities for BC First Nations.*

Category 4 – Utility pays for SR; Customer pays for customer transmission line/BTE with a utility contribution. BC Hydro proposes to advance Option 9 (Hydro Quebec model) for further analysis due to its relative simplicity, and Hydro Quebec's similar market structure/utility transmission system; however, Hydro Quebec builds and owns the customer transmission line which is different than the Status Quo TS 6. As a result, BC Hydro believes that Option 7 (Hydro One model) should also be brought forward for further analysis as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a 'true up' of costs. Do you agree, and if not why not?	*In the workshop material BC Hydro presented on slides 46 and 48, BC Hydro's view was that no further analysis was required due to the issues associated with options 7 and 9 and in particular possible cross-subsidization and upward rate impacts and therefore these options were eliminated.* *However, FNEMC supports BC Hydro conducting further analysis and in particular determining associated rate impacts with these options due to the reasons BC Hydro states:* *OPTION 9* - *Relative simplicity* - *Hydro Quebec's similar market structures/utility transmission system* - *Hydro Quebec building/owning transmission line which differs from Status Quo TS 6.* *OPTION 7* - *Gives customer/utility options around transmission line building and ownership* *FNEMC supports having customers make some contribution to SR costs as the data BC Hydro presented on slide 41 indicated that over the 7 year term none of the 49 customers contributed to SR costs and the utility contribution covered 100% of SR costs under TS 6.* *However, FNEMC supports a balanced approach between minimizing upward rate impacts and increasing economic development opportunities for BC First Nations.*

D. Security	**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's current security policy requires customers to provide security for the amount of the BC Hydro contribution. Issues under consideration include:	
1. Should security be required, if so for what amount? X Actual cost of SR. ☐ Based on a $/kW. ☐ Based on a historical average. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	*FNEMC prefers the **status quo** since this minimizes BC Hydro risk and impact to rate payers.*
2. When should security be released? ☐ After construction is complete. ☐ After a fixed time period. X Based on an assessment of revenue recovered. *Please select your preference and provide your rationale for selection in the "Comments" column of this form.*	*FNEMC prefers the **status quo** since this minimizes BC Hydro risk and impact to rate payers.*
3. What forms of security should be allowed? *Please provide your comments in the "Comments" column of this form.*	
4. Other comments with respect to security? *Please provide your comments in the "Comments" column of this form.*	

E. F. G. 150 MVA threshold	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**

The 150 MVA threshold for triggering the inclusion of costs for additions and alterations to the bulk system (500 kV) and new generation in the definition of SR was questioned in the 2013 Industrial Electricity Policy Review task force process and in subsequent 2015 RDA engagement to date. Four options for dealing with this threshold were discussed:
• **Status Quo**
• **Develop New Threshold**
  ▫ Should the cost of generation be included or should cost be confined to transmission as with the jurisdiction that has a safety valve (Ontario), and if generation cost is included, should it be applied to the total load or to the just the incremental load above the threshold?
• **No Threshold with Safety valve**
  ▫ For the exceptional case where a new load would cause a significant rate impact BC Hydro would have the option to seek BCUC (or B.C. Government) direction on whether some or all of the bulk transmission costs should be borne by the new customer.
  ▫ If this option is pursued, should the safety valve include generation costs or as with Ontario should it be confined to transmission costs?
• **No Threshold**
Please state in the "Comments" column of this form your preference of the options and the rationale for your preference.
	*FNEMC prefers the **status quo** or developing a new threshold so that large consumers pay for any incremental generation costs and 500 kV (and over) transmission upgrades in order to mitigate against any large rate impacts*
	However, FNEMC supports a balanced approach between minimizing upward rate impacts and increasing economic development opportunities for BC First Nations.

H. Transition Rules	**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 recognizes that any changes to TS 6 may impact the economics of a customer's proposed project and as such transition rules are required to determine when the old tariff applies and the new one takes over. BC Hydro presented three options of when in the interconnection process a customer can decide which tariff to be treated under: 1) **System Impact Study (SIS)** – customer has initiated a SIS 2) **Facilities Study (FS)** - customer has initiated a FS 3) **Facilities Agreement (FA)** – customer has an executed FA. BC Hydro also questioned if other factors should be considered such as: • In-service date • Customers Final Investment Decision date • Permitting approvals. BC Hydro proposed the following strawman transition rule: ▪ Prior to the effective date of new TS 6, customers who have entered into a Facilities Study Agreement and can demonstrate to BC Hydro's satisfaction that their projects are likely to come into service within 24 months of the effective date have the option to continue under old TS 6. Customers who have not met both conditions on the effective date must proceed under new TS 6. *Please comment if you agree or not with the proposed strawman transition rule and the reasons for your comments in the "Comments" column of this form.*	*FNEMC, <u>in principle</u>, supports the strawman transition rule in grandfathering new customers in the interconnection queue should there be any changes to TS 6 therefore aligning with Bonbright's criteria of rate and bill stability.* *However, FNEMC is not sure that it agrees with the specifics of BC Hydro's rule conditions in terms of the particular stage of study agreements entered into by the customer and the 24 month project in-service date as well as the impact of other contributing factors such as in-service date, customer FID date, permitting approvals, construction schedule, etc. More information would be helpful in making this assessment as well as understanding the changes to TS 6.*

I. Line transfer	**Comments** **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
The current line transfer provisions in the TS 6 are at the sole discretion of the customer. Should the line transfer provisions be modified to allow BC Hydro to require a line be transferred when there is a system benefit or decline a line transfer when there is no benefit and/or a significant risk/burden to rate payers. *Please indicate your preference with respect to the Line Transfer provisions to be included in the TS 6 and the rationale for your preference in the "Comments" column of this form.*	*Yes. BC Hydro should also have the same option as the customer especially where there might be significant risk/burden to rate payers.*

J. Queue Management	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 circulated a draft of the current queue management business practise with the workshop preparation materials and is seeking comments on the current business practice and comments on the following proposed changes for consideration: 1. **Staged Approach with Soft Milestone**. BC Hydro has discretion on timeframes if others later in the queue are not harmed by extensions to deadlines. Modify existing language to include additional milestones (permitting, financing, etc.) to stay in the queue. Formalize cluster study and allocation of study costs. 2. **Staged Approach with Hard Milestones.** Strict adherence to timeframes and add language regarding what constitutes a material changes (changes in load size, point of interconnection, deferral of in-service date by X years, etc.) that will require a customer to lose its current queue position and be moved to the bottom of the queue 3. **Fast Track Process.** Should later queue projects that are ready to proceed to implementation (acquired all needed permits, financing, etc.) be allowed to connect prior to earlier queue customers. If so what rules should be in place: □ No harm to earlier queue customer – no increased costs or timing of connection □ Earlier queue customer must advance their project □ Risk and cost of any re-studies borne by customer requesting to be fast tracked	

4. **Open Call**. When there is deemed to be the potential for several connection requests in the same region, BCH would initiates a Call for projects that want to connect to the BC Hydro transmission system. Each connection request would have the same queue position and the requests would be studied as a cluster. This would result in the best use of BC Hydro planning resources and the most optimum SR. Rules for allocation of study costs and system reinforcement costs would also be required. *Please state in the "Comments" column of this form your preference of the option(s) and the rationale for your preference.*	

Additional Comments, Items you think should be in-scope, not currently identified:

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

CONSENT TO USE PERSONAL INFORMATION

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

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MABC
MINING ASSOCIATION OF BRITISH COLUMBIA

March 27, 2015

Mr. Gordon Doyle
Manager, Tariffs, Regulatory and Rates Group
BC Hydro, Regulatory Compliance & Filings
16th Floor - 333 Dunsmuir Street
Vancouver, BC V6B 5R3
By Email: bchydroregulatorygroup@bchydro.com

Re: MABC Comments on BC Hydro 2015 RDA Review of Load Interconnection Business Practices

Dear Mr. Doyle:

I am writing to provide additional feedback on questions raised by BC Hydro (BCH) following its November 2014 workshop on transmission extension policy and load interconnection business practices.[1] In February 2015, the Association of Major Power Customers (AMPC) submitted its meeting feedback form. As a member of AMPC, MABC supports recommendations for additional consultations on a narrowed set of extension policy options that encourage growth in all regions of the Province without placing an undue burden on existing ratepayers. However, MABC would like to raise several different areas for business practice improvements of importance to the mining industry that should be considered by BCH in advance of the next round of consultations.

Flexibility in Queue Management

At the November 18, 2014 Transmission Extension Policy Workshop, BCH circulated a draft document outlining its current queue management practices and sought comments on potential changes from stakeholders. AMPC's workshop feedback submission found that while changes could be made to the queue management process, the most pressing issue was a lack of internal BCH resources dedicated to providing timely interconnection services. In addition, MABC has concerns that certain changes to queue management practices under the consideration of BCH, such as "hard milestones," could actually hinder economic development.

In our submission to the 2013 Industrial Electricity Policy Review (IEPR), MABC outlined the unique economic challenges associated with developing a mine (including the mine, processing facilities and related infrastructure). We highlighted the long development lead times and explained how proponents, who are dependent on markets and lending institutions for the increasingly scarce capital needed to build mines, require certainty on access to electricity infrastructure well in advance of in-service dates as this access is often a prerequisite for financing.

[1] Load Interconnection is defined as the initial contact with the customer through energization, inclusive of all commercial arrangements from the System Impact Study, through the execution of the Electricity Supply Agreement ("ESA").

In addition to electrical load interconnection certainty, mining proponents also need BCH's load interconnection business practices to be responsive to the dynamic, market-driven characteristics of mine development. Changes to design and development timelines may be necessitated at multiple points due to a variety of factors, including fluctuations in commodity prices, learnings from First Nations and community consultations, or changing regulatory requirements. For these reasons, flexibility should be an inherent characteristic of any mining-friendly BCH queue management or interconnection business practice.

System Reinforcement Offsets/Revenue Guarantees

As AMPC explained in its feedback to date, the more detailed mechanisms of extension policies should be based on clarified extension policy principles and objectives. However, we support the BCH review of different contribution models because the current load interconnection process is very costly for MABC members and others seeking system change.

Although refundable over a seven year period of operations, Tariff Supplement #6 requires a front-end cash contribution or letter of credit, both of which divert scarce capital away from mine development costs. As BCH noted at the November meeting, BC is one of the few jurisdictions that requires such an up-front offset from new customers. This affects our competitiveness as a mining jurisdiction. BCH should review whether proponents paying to move projects through the interconnection queue should also be required to provide refundable offsets given the long-term benefits that mines provide to BCH and the BC economy in the forms of electricity rates, taxes, royalties, employment, and related economic development.

Interconnection Cost Certainty

MABC members have noted that more certainty and clarity could be brought to BCH load interconnection cost projections. While it is reasonable to expect that cost estimates will cover a range of unknown variables, MABC members have asked whether the +100/-50% cost estimate range for System Impact Studies is consistent with estimates prepared by utilities in other jurisdictions. Concerns have also been raised over a lack of transparency on the high cost of completed studies. MABC understands that each project will present its own unique complexities for the BCH system which in turn will affect study costs. However, by bringing greater transparency to cost estimates and justifications there may well be an opportunity for proponents to assist with identifying cost and time efficiencies.

More clarity could also be brought to the BCH load interconnection procurement process. BCH should investigate whether there are ways it can improve collaboration with proponents on load interconnection procurement to identify and take advantage of cost reduction opportunities for all parties.

Economic Development- Focused Load Interconnection Business Practices

The interconnections branch of BCH is also an economic development branch, yet current and future BCH mining customers have expressed concern over a perceived lack of resources for assisting the proponent to meet development milestones within often limited windows of opportunity. Study timelines for upgrades or expansions could be reduced if the interconnections and economic development branch of BCH was better resourced (increased staff and related support infrastructure). The interconnections branch should also have the resources and organizational structure it needs to provide timely service to existing customers while also helping future customers succeed in connecting to the system in a timely fashion. To attract new industrial customers, economic development objectives should drive BCH's load interconnection process, from the initial contact with a prospective customer through all commercial agreements on the path to energization.

First Nations Consultations

The BC mining industry is a leader in industry-First Nations relations and has a proven track record of collaboration with First Nations on the development of mining projects. Nevertheless, BCH consults with First Nations on new project connections separately from the consultations organized by the project proponent. The proponent is then charged for that separate consultation process. MABC understands the unique consultation expectations placed on BCH as a Crown corporation. However, BCH should investigate whether or not efficiencies could be found, for BCH, First Nations representatives and proponents, through closer collaboration on interconnection consultations, particularly if the interconnection takes place on the proponent's land or leases.

A Model for Closer Collaboration with Industry

As extension policy principles and objectives are clarified through the 2015 RDA consultation process, BCH should consider forming a working group with industry to identify opportunities for improvement of the load interconnection and economic development process. In November 2013, the Alberta Electric System Operator (AESO) formed a Connections Process Working Group as a tool for positive industry collaboration to improve the connections process. Over the long term, this may be a model to follow in creating a forum for greater collaboration between BCH and industry to explore opportunities to improve BCH load interconnection and economic development business practices. MABC would be pleased to participate in such a connections process working group.

Sincerely,

Karina Briño
President & CEO