Meeting Notes

Regional Planning and Cost Allocation (EB-2016-0003) Working Group Meeting #2

Meeting Date: Friday, August 5, 2016 **Time:** 9:00 am – 4:00 pm

Location: Ontario Energy Board Offices
2300 Yonge St., ADR room, 25th Floor

Attendees

Andres Mand Barbara Robertson Chris Cincar Jason Craig Saleh Lavaee	Ontario Energy Board (OEB)
Bob Chow Joe Toneguzzo Phillip Chisulo	Independent Electricity System Operator (IESO)
Carolyn Russell Natalia Gaydukevych Paul Brown Bing Young	Hydro One Networks Inc. (HONI)
Ruth Greey	Consumers Council of Canada (CCC)
Bill Harper	Vulnerable Energy Consumers Coalition (VECC)
Mark Rubenstein	School Energy Coalition (SEC)
Wayne Clark	Association of Major Power Consumers in Ontario (AMPCO)
Mathew McGrath	Hydro Ottawa
Kris Taylor	E3 (Essex Power)
Randy Aiken*	London Property Management Association (LPMA)

Absent	
Indy Butany	Coalition of Large Distributors (CLD / Horizon Utilities)
Nancy Marconi	Independent Electricity System Operator (IESO)
Henry Andre	Hydro One Networks Inc. (HONI)
Patrick Brown	Hydro Ottawa
Martin Benum	London Hydro
David Ferguson	E3 (Entegrus)
Mark Danelon	E3 (Essex Power)
Vince DeRose	Canadian Manufacturers & Exporters (CME)

* Participated via Tele-Conference call

Meeting Purpose

These meeting notes are intended to provide a summary of key issues discussed during the 2nd Working Group (WG) meeting.

The intent of the meeting was to provide stakeholders with the opportunity to provide input to the OEB on issues and potential solutions related to cost responsibility provisions for load customers in the OEB's Transmission System Code (TSC) and Distribution System Code (DSC) to ensure they are better aligned and facilitate regional planning and the implementation of regional infrastructure plans.

Background Discussion:

- ✓ WG meeting #2 agenda:
    - OEB's Welcome and Introduction
    - Outstanding clarification of items on WG meeting #1 – Meeting Notes
    - Other issues that have not already been identified in the Cost Allocation – WG Issues Table
        - IESO's Presentation – Sustainment Impacts
    - Discussion of proposed solutions Part 1 – simpler issues
    - Discussion of proposed solutions part 2 – more complex issues

- ✓ The following documents were provided to WG members before WG meeting #2 by OEB staff:
    - Issues Table
    - Compendium of Documents (applicable sections from DSC, TSC, and RRFE Board Report, IESO SECTR proposal summary, etc.)
    - Flowcharts visually presenting existing cost responsibility rules in TSC and DSC

- ✓ OEB staff noted that WG meeting #2 is intended to focus primarily on the proposed solutions to address the issues identified in WG meeting #1 (as set out in the Issues Table).

- ✓ OEB staff advised that SECTR is a great example when it comes down to Cost Responsibility, but this WG was created to look at a broader scope of issues; not focus on SECTR issues.

IESO's presentation:

- ✓ IESO provided their presentation on "sustainment impacts". The issue was identified in their presentation in the first WG meeting as one of three sub-issues under "Broadening the Beneficiary Pays" but was not discussed. OEB staff therefore asked the IESO to explain it to the WG. Below is a brief summary. The full IESO presentation is posted on the OEB website along with these meeting notes.

- The example used by IESO was related to the new line to Pickle Lake -- 230 kV line connection required to supply Remotes Communities and future mining development (as part of North of Dryden IRRP)
- Currently, a 115 kV line is in place and is pretty old (built in 1939). As a result, there are numerous forced outages (about 10 per year) and planned outages due to age related replacements.
- As a consequence, sustainment OM&A costs are high (including work on holidays / weekends) to mitigate impacts on the large mining customer, which currently only has one source of supply.
- The new 230 kV line would become the normal supply for the large mining customer and Pickle Lake community. It's expected forced outages would decline from about 10 to about 2 per year. The line also reinforces the local system such that additional electrical demand can be accommodated including the ability to connect Remote Communities.
- Benefits include: the majority of Remote Communities would no longer operate on diesel, improved reliability for the mining company and customers at Pickle Lake, significantly reduced flow on the existing 115 kV line would substantially reduce line losses.
- All ratepayers would benefit from the reduced line losses, the reduction in sustainment OM&A costs and lower costs for serving the Remote Communities over the long-term which receive RRRP.

✓ WG member's comments are as follows:

- Timing and implementation of changes related to cost allocation and responsibility done in this proceeding are very important. WG members suggested that the first case involving this issue will be important, as it will be a reference for other following cases involving applications that are similar in nature.

- Hydro One clarified their current approach in treating upstream costs under the existing rules which involves pooling the upstream costs and goes into rate base.

- In response to a question about the IESO's presentation, IESO advised that there are currently some placeholders in the matrix on one slide that set out the benefits. There are some “zeros” and this matrix will be updated.

- ✓ *The WG discussion then turned to matters that were not specific to the IESO presentation:*

  - Hydro One discussed a fixed Capacity Charge concept: Hydro One makes the investment and triggering customers pay $/MW and then future customers pay the same fixed Capacity Charge ($/MW). Hydro One noted this approach may work, especially when there are a lot of beneficiaries and that the $/MW Capacity Charge could be established on a provincial or local / regional basis. IESO agreed a fixed price for capacity (regardless of the location of the investment) might be a solution. *[NOTE: OEB staff followed up with HONI to better understand how a Capacity Charge (CC) may work in practice. HONI provided an example – a new 230 kV line generally provides about 400 MW of capacity. If the customer that triggered the need for the new line required 25% of that capacity (100 MW), they would pay 25% of the cost based on the $/MW charge. The line connection pool would cover the remaining 75% of the cost at the outset for the remaining capacity (300 MW). As additional customers connect over time, they would pay the same $/MW CC and the cost to the pool would decline; e.g., if second customer requires 200 MW, the pool would then be responsible for the remaining 100 MW of capacity and related cost (25%). HONI also noted that, after further thought, developing the CC on a provincial basis may not be the best approach given the cost of building the line could vary materially across Ontario (e.g., acquiring land in the GTA would cost significantly more than it would in northern Ontario, etc.). A local / regional CC may therefore be more appropriate. The above example is based on <u>transmission</u> and reflects one possible approach. HONI noted the same concept could also be applied at the <u>distribution</u> level. There may be other approaches].*

  - Solution may provide more capacity than originally needed due to the lumpy nature of line connection investments – IESO advised that most of the time the party triggering the investment does not need a 400 MW upgrade to 230 kV, but that is the minimum standard in the industry. It is not possible to size a line connection investment to meet the customer’s need (e.g., 100 MW).
    - VECC advised that someone ends up paying for the portion (i.e., excess capacity) that nobody is using.

  - AMPCO representative noted that lumpy investment is a topic that links to other issues as well. For example, mining companies need a limited amount of capacity, but they end up paying a lot more for what they do not really use.

- IESO's prediction is that, going forward, leave to construct (LTC) applications will become more complicated because of multiple benefit streams and impacted parties.

- SEC representative noted that calculating costs and benefits over time for the life of an asset (20, 30, 40 years) can be a challenging issue. Benefits and costs are calculated now, but the aim here is to predict all these costs/benefits over time as well.

Issues Table

WG members started with the "Less Complex issues" first:

- ✓ **Issue 1 – High level - Utility discretion in cost responsibility sections of the codes:**
  - The DSC provides LDCs with much more discretion, in this area, than the TSC provides to the Transmitter.

  - SEC raised a question for LDCs. Is cost responsibility done on a consistent basis or treated on a case by case basis?

    - Hydro One's response was case by case basis in a manner that is as consistent as possible.
    - Some members of the WG (VECC and E3) advised that a having room for flexibility might help and requested a rationale as to why the OEB staff would like to eliminate this flexibility.
    - OEB staff responded that this is inconsistent with TSC. TSC changed "may" to "shall" and OEB staff noted the goal is to achieve consistency between the codes to ensure all customers are treated consistently. OEB staff added that the flexibility in the DSC results in each LDC, not the OEB, determining whether the beneficiary pays or not in some cases.

  - SEC noted that changing "may" to "shall" may not work all the time, but in some cases, it should be "shall" and referred to DSC section 3.1.5 which states *"… either as part of its revenue requirement or through a basic connection charge".* SEC noted, while there are currently only two ways, it's important to advise LDCs which one to go with.

  - Hydro Ottawa mentioned that it has similar practices to Hydro One when recovering connection costs from the customer. It was noted that customer connection and system expansion costs are two different issues and should be treated as such when looking to make changes to the DSC as there may be a requirement for more flexibility on one vs. the other. In addition, if the OEB intends to make the DSC more prescriptive on this issue, a review should be undertaken to ascertain how much flexibility should be maintained to make sure various scenarios can be addressed.

- ✓ **Issue 4– Definition of "Customer":**
  - The table provided by OEB staff identified that the definition of "customer" is quite specific and clear in the TSC in identifying each type, while the definition in the DSC was open to interpretation in referring to "persons".

  - VECC noted that the end use customer is not always directly involved; for example, sometimes there is a developer or a representative of the customer involved.

  - Hydro One advised that rather than changing the definition of "Customer", the wording of section 3.2.4 in the DSC should change.

  - SEC advised that changing the definition of "Customer" in the DSC to be consistent with the more specific definition in the TSC might affect other provisions in the DSC.

- ✓ **Issue 7 – Capital Contribution refund/rebate to initial customer(s) (15 years vs. 5 years):**
  - Hydro One noted that issuing refunds for 5 years is administratively complex at the distribution level due to the higher number of customers relative to the transmission level. Hydro One therefore feels it would be very burdensome for Hydro One Distribution to manage refunds/rebates beyond 5 years.

  - Hydro One added that the current 15 years in the TSC makes a lot of sense, from the transmission perspective.

  - Hydro One Distribution posed a question regarding the value of accuracy. "It's great to be very accurate, but what's the price for that and what value does that bring?"

  - AMPCO representative suggested that, at the distribution level, a materiality threshold (i.e. magnitude of refund) could be used to determine the time period for the refund. For example, if the refund is small (e.g., $5,000), the timeline can remain at 5 years; however, if it is large (e.g., $500,000), the timeline could be increased to 15 years. This would make it more consistent with the TSC and also address the administrative burden concerns raised by Hydro One.

- E3 commented that extending the timeline to 15 years might be burdensome for E3, but if the investment is large enough, there might be a value in extending that timeline.

✓ **Issue 8 – Bypass Compensation (addressed in TSC, but not DSC):**

- Hydro One Transmission expressed the view that Bypass Compensation is a significant issue and suggested that this issue should be out of scope for this consultation process because of the scale of it. Hydro One suggested that it should be addressed in the DSC, as part of a *separate* consultation, once the OEB has decided on all the cost responsibility rule changes as part of the *current* consultation.

✓ **Issue 9 – Replacement issue:**

- OEB staff identified that relocation of connection assets has been addressed in the TSC, while the DSC is silent on it.

- VECC requested clarification on what “silent” means. OEB staff responded that “silent” means it is not currently addressed in the code and LDCs, for example, can do anything which can lead to inconsistent treatment of customers since no OEB direction has been provided.

✓ **Issue 10 – Relocation**

- OEB staff identified that relocation of connection assets was similar in that it has been addressed in the TSC, while the DSC is silent on it.

✓ **Issue 11 – Non-Wire Options (e.g. Gx, CDM, etc.) can alleviate/defer wires investments, but no mechanism is currently in place to recover non-wire investments via rates (bias towards choosing wires investment):**

- OEB staff advised that this issue is “Out of Scope”, as the OEB does not currently have legislative authority to include non-wire solutions, such as generation, in distribution / transmission rates.

- IESO noted that non-wires could be treated as a wires “cost avoidance” issue.

- SEC agreed that, while this issue may be out of scope for this WG, it would be great to recommend that this to be looked at, in some other forum, and highlighted in the outcome of this WG.

✓ **Issue 12 – Community may desire more than “base” solution, but no mechanism in place to fund local choices that cost more than “base” solution (e.g. bury TX lines underground, higher standards for urban centers, etc.):**

- Hydro Ottawa mentioned that a community in the City of Ottawa wanted to bury wires. The City of Ottawa charged the citizens residing in that area some sort of levy to recover the extra cost (above the base solution) through property tax.

- Hydro One Transmission noted that, as long as the benefitting customers pay for it, there is no problem and above-base-solution can be implemented where wires are involved.

✓ **Issue 13 – Mix of load and generation customers on connection assets:**

- OEB staff advised that the TSC is based on ‘trigger’ pays (s.6.3.16), but the DSC is based on ‘beneficiary’ pays (s.3.2.27). OEB staff suggested it may be appropriate to amend the TSC to be consistent with the DSC, since the OEB identified a shift in emphasis from ‘trigger’ to ‘beneficiary’ pays as part of the RRFE consultation.

- Hydro One Transmission advised that it would be helpful to consider this subsection (6.3.16) and to make the language clearer.

- Hydro One Distribution identified that the issue related to15 years comes into play here again (Issue #7).

- OEB and IESO staff identified that, if the TSC is not changed, ‘free ridership’ will continue.

- CCC asked whether there is a time horizon for a mix of load and generators.

- OEB staff were asked if this is an area where the DSC is more progressive than the TSC. OEB staff noted it was, as the applicable provision was added in a relatively recent policy consultation process which was referred to as Distribution Connection Cost Responsibility (DCCR), where changes were made to address renewable generation.

- ✓ **Issue 14 - Need to determine, if and where, DSC and TSC should differ (Different customer bases – large industrials vs. residential subdivisions):**
    - OEB staff explained that this was a placeholder to capture scenarios in which DSC and TSC should be different.

    - The WG did not identify any specific areas.

WG members then focused on "More Challenging/Complex Issues":

- ✓ **Issue 5 – "Broaden" beneficiary pays principle beyond TX "system vs. local benefits" to include other considerations:**
    - VECC raised the question on what to include and how to value the associated benefits; i.e., how to quantify them.

    - SEC asked whether there was agreement that reliability should be valued and, if so, how would that value be quantified. In SEC's view, different customers value reliability differently (e.g. industrial customers vs. residential customers).

    - IESO explained the "Capacity" and "Performance Reliability" terminologies. Capacity refers to the capacity of a station for instance and performance reliability refers to the reliability of the station to deliver that (name plate) capacity.

    - IESO suggested that instead of dealing with a standard on a case by case basis for each application, one approach would be to define the standard and apply it consistently to each case.
        - OEB staff requested clarification on what standards IESO was referring to and/or what document.
        - IESO responded it was ORTAC (Ontario Resource and Transmission Assessment Criteria) which is used for planning purposes (e.g., restoration requirements). OEB staff advised that the OEB does not have oversight on ORTAC, but IESO does.

- Hydro One added that the SECTR application is a relevant example here, as the proposed investment would solve both the ORTAC reliability restoration standard and the capacity issues.

- SEC representative asked what happens if the reliability improves beyond the standard.

- AMPCO explained an example relevant to this issue: In Barrie, customers have poor reliability (i.e., many outages). As a result, some customers installed backup generation and tried other means to solve the problem themselves. AMPCO therefore questioned, if the LDC now makes an investment to improve the reliability, should those customers pay again to receive the level of reliability from their LDC that they were entitled to in the first place?
    - IESO noted that maybe those customers that took action on their own should not pay for the reliability fix, if they had a lower level of reliability and that gets improved to a reasonable level.
    - CCC representative highlighted that some customers do not want to pay more for improved reliability. They expect LDCs to provide the standard reliability with what they already pay to LDCs.
    - Hydro One noted that LDCs should consult their customers regarding how much they value increased reliability and their willingness to pay for it. All LDCs have stakeholder meetings with their customers and that's the opportunity to get such feedback.

- SEC noted that the issue is how to value "reliability benefits" (above the standard)
    - IESO identified it is possible to quantify some "Network/System benefits" but not others.

- SEC suggested that the WG create a list of benefits or categories of benefits and identify the way they should be calculated (quantified). Time horizon would be something the codes can reflect as well.
    - VECC suggested that it might be better to keep the benefits list open, as they might differ from case to case.

- AMPCO identified an example involving Hydro Ottawa where a 230 kV line (instead of 115 kV) was installed and it will avoid a system upgrade in the future. IESO suggested this should be part of the benefit list.

- IESO noted that they are a neutral party which can comment on system benefits at the transmission level, but cannot comment on distribution level benefits. Regional Planning is now involved when there is a need to be addressed; e.g. an LDC wants to upgrade a station and other LDCs benefit from that upgrade as well.

- VECC asked how the code(s) should be amended to ensure the optimum solution determined through the Regional Planning process is implemented (i.e., require the utility to propose it).

- Hydro One Transmission noted that, if an LDC does not want to implement the “optimum” solution determined through Regional Planning, they are on the hook to justify the “other” solution when they come before the OEB for approval to recover the cost, since the optimum solution will be identified in the Regional Infrastructure Plan (RIP) which LDCs must submit to the OEB as part of their rate application.

- OEB staff asked WG members if they have any proposed “solutions” to address the issue and, if yes, how that should be reflected in the code(s).

- VECC and CCC representatives noted that there are a lot of items included in a rate application and it is not easy for intervenors and also the OEB panel to address all those issues in detail (e.g., upgrade costs, etc.) when they are embedded in a rate application.
    - SEC noted that, for example, a rate application from Hydro One does not include all the other affected LDCs.
    - OEB staff suggested that one possible solution is to have a “combined” proceeding with all impacted LDCs in a regional plan, for that issue, when the first rate application is submitted that identifies the cost consequences resulting from the proposed solution. This approach would ensure they are all considered by the OEB Panel together, including the cost impact on each LDC.

- In Hydro One's staff view, the cost of electricity has become a major issue and customers are therefore more concerned with the cost rather than fairness.

- SEC suggested listing all the categories of benefits and beneficiaries.

- WG members listed the following benefits:
    - Improved Reliability
        - AMPCO – It is difficult to get two sides to agree on the value of reliability (especially for non-industrial customers); not practical.
    - Capacity
    - Reduced System Losses
    - Deferral of Cost/Investment
    - Improved System Efficiency (reductions in congestion, line losses, CMSC payments, etc.)
    - Restoration (i.e., ORTAC)

- VECC noted that the timing of these benefits should be considered as well. For example, long term for transmission (~40 years) vs. short term for distribution (~5 years).

- OEB staff asked WG members whether the code(s) should specify time horizons for cost allocation purposes

- AMPCO raised the question that, if a customer is considered to be around for 5 years, why should the benefits accrue over a time horizon that exceeds 5 years? AMPCO suggested this is more of an issue at the TX level where customers range from low risk LDCs to higher risk mining customers. The benefits should be accrued until the CCRA expires.
    - Hydro One Transmission expressed the view that it will be quite complicated if we mix *cost allocation* with *cost recovery* when considering time horizons. These two are separate items and should not be combined.

✓ **Issue 3 – Approach to "apportion connection investment costs where both "local" and "system" needs ("Proportional Benefit Approach" in SECTR and OEB letter):**

- VECC suggested that the party incurring the cost might be best to apportion the cost as well.

- Hydro One noted the Codes should clarify who the cost allocator is depending on the level of the issue (TX level vs. DX level).

- IESO clarified that Regional Planning at this point does not get into cost allocation.

- AMPCO suggested that checks and balances should be in place on the inputs and outputs when calculating the forecast growth, capital contribution, etc. Forecast accuracy might be an issue.

- Hydro One noted that it is difficult to collect money, once other connected customers receive ‘collateral’ benefits due to an upgrade or investment required by the customer (i.e., ‘direct’ beneficiary). The code(s) need to provide some clarity on collecting funds from ‘collateral’ beneficiaries.

✓ **Issue 2 – Inconsistent treatment of LDCs (“upstream Investment Issue” in SECTR case and OEB letter):**

- Hydro One noted that some thinking needs to be done around the treatment of embedded LDCs and large industrial customers. Hydro One would like to carry on with treating embedded distributors differently than large industrials. Embedded distributors are regulated entities. The issue eventually comes down to risk in recovering the cost. From a process perspective, there might be a need to treat these two set of customers differently.

✓ **Issue 6 – LDC slow, “incremental” load growth vs. “lumpy investments”:**

- Hydro One asked if financing is an option for LDCs.

- SEC noted, at the end of the day, it is a rate impact issue.

- OEB staff noted a possible option to mitigate the rate impact is to smooth the cost of the investment over time through a rate rider, instead of a lumpy upfront investment. The beneficiary would still pay under this approach.

- E3 noted that smaller LDCs are at disadvantage, as they do not have access to necessary funds.

- IESO added it’s a general problem. If we go outside of the GTA, lumpy investments are a common issue (except for Ottawa).

- IESO noted there are other non-wire solutions (e.g. CDM, DR, etc.) but LDCs cannot recover the cost of those investments through rates. If the lumpy investment is the only option, some level of socialization might be acceptable.

WG members requested the following two issues to be considered and discussed:

- ✓ **Issue Added 1 – Capacity Assignment**
  - Hydro One suggested that it would be wise to have a procedure for capacity assignment in the DSC that is similar to the one in the TSC.

- ✓ **Issue Added 2 – Load Forecasting**
  - CCC representative asked whether load forecasting process should be more structured / accurate.

  - VECC summarized 3 areas where load forecasting comes into play:
    1. at the time of needs identification,
    2. linkage to capacity assignment, and
    3. for Customer Connection and Cost Recovery Agreements (CCRAs).

  - AMPCO noted that the problem that arises is the load forecast for the CCRA is often materially different from the load forecast at the needs level, as things change over time.

  - Hydro One advised that the utilities may require changing the load forecast at various check points along the process; unlike the TSC, there is no provision to address changes in load forecasts in the DSC. [NOTE: OEB staff reviewed the codes following the meeting and the TSC has a number of sections under the title *“Economic evaluation true-up calculations for load customers”*. For example, s.6.5.6 states *“Where a true-up calculation shows that a load customer's actual load and updated load forecast is lower than the load in the initial load forecast … a transmitter shall require the load customer to make a payment to make up the shortfall….“.* The DSC has no similar true-up provisions. OEB staff believes this is what HONI was discussing as HONI staff did not identify any specific TSC provisions].

- ✓ Hydro Ottawa asked OEB staff whether any the outcome of this consultation can be retroactively applied on recent issues. OEB staff responded that it is unlikely this becomes retroactive but that would be a Board decision.

Action Items:

- ✓ OEB staff will prepare draft meeting notes for WG member review. Once finalized, they will be posted along with the presentations on the OEB website.

- ✓ OEB staff will communicate with the WG members as to whether or not a 3rd WG meeting is required. At this point, there is no plan to hold a 3rd WG meeting.