Meeting Notes

Regional Planning and Cost Allocation (EB-2016-0003) Working Group Meeting #1

Meeting Date: Tuesday, July 12, 2016 **Time:** 9:30 am – 12:30 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)
Nancy Marconi Bob Chow Joe Toneguzzo Phillip Chisulo	Independent Electricity System Operator (IESO)
Henry Andre Carolyn Russel Michael Sullivan Natalia Gaydukevych Wade Frost*	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)
Martin Benum*	London Hydro

Mathew McGrath*	Hydro Ottawa
Patrick Brown	
David Ferguson*	E3 (Entegrus)
Mark Danelon*	E3 (ELK Energy Inc.)
Kris Taylor*	E3 (Essex Power)
Randy Aiken*	London Property Management Association (LPMA)
Vince DeRose*	Canadian Manufacturers & Exporters (CME)
Absent	
Indy Butany*	Coalition of Large Distributors (CLD / Horizon Utilities)

* Participated via Tele-Conference call/WebEx.

Meeting Purpose

These meeting notes are intended to provide a summary of key issues discussed during the 1st Working Group (WG) meeting.

This consultation is aimed at ensuring the cost responsibility provisions for load customers in the OEB's Transmission System Code (TSC) and Distribution System Code (DSC) are aligned and facilitate regional planning and the implementation of regional infrastructure plans.

Background Discussion:

- ✓ Introduction and welcome

- ✓ WG meeting #1 agenda:
  - o OEB's Introduction
  - o IESO's Presentation – Background
  - o HONI's Presentation – Background
  - o Q&A followed by Group Discussion identifying other issues that exist
  - o WG meeting #2 Objectives, date

- ✓ OEB staff noted that WG meeting #1 is intended to focus primarily on identifying the gaps and inconsistencies that currently exist in the codes before moving to the proposed solution phase in WG meeting #2.

- ✓ OEB staff clarified the scope. The OEB kick-off letter noted the focus of this consultation is load customers. Some letters of participation identified that cost responsibility rules related to generation needed to be included as well. OEB staff noted that the code provisions that focus solely on generators (e.g., enabler lines) continue to remain out-of-scope for this consultation as identified in the kick-off letter, however, OEB staff clarified that code provisions involving a mix of load and generator customers are in scope for this consultation since it impacts load.

- ✓ VECC requested that references be made to the relevant code provisions when discussing the gaps/issues; OEB staff noted they would strive to do so during the discussion.

IESO's presentation:

- ✓ IESO staff noted that their goal is to promote the lowest overall cost integrated solution (i.e. wires and non-wires) that meets the needs of an area.

- ✓ IESO staff identified a number of cost allocation issues make it challenging to implement the ‘optimal’ planning solution. Five issues were highlighted in their presentation:

- o **Issue 1: Broadening the “Beneficiary Pays” Principle**
    - ▪ IESO is supportive of the principle, however, the IESO’s view is that a broader application of the beneficiary pays principle should be pursued; i.e. when system reinforcement is required, a broad analysis of potential benefits should be undertaken.

    - ▪ A question was raised regarding what end-of-life (EOL) considerations were referring to within this context. IESO staff discussed replacing an old transformer that was at its EOL with a larger transformer to solve the capacity problem as well as the EOL issue, instead of replacing like-for-like (OEB staff clarified that like-for-like replacement at no cost to the customer was addressed in the s.6.7.2 of the TSC).

    - ▪ <u>Example 1</u> – Supply to Essex County Transmission Reinforcement (SECTR) Project was briefly explained.

        - VECC noted that there are a number of ways of doing the actual cost allocation, when it comes to determining the value of alternative solutions (within context of SECTR project).
        - IESO staff responded in noting that the issue is not about the value the project is bringing to the table. Rather, it’s about “who pays” for it and their relative contributions, i.e. cost allocation.

    - ▪ <u>Example 2</u> – It involved a “Feeder Transfer” between two LDCs, from LDC #2 to LDC #1, which was presented as a distribution solution that would avoid the need for a more costly transmission solution.
        - LDC #2 transferring load from Station A to B requires agreement between LDC 1 and LDC 2 in this example.
        - AMPCO expressed the view that this may not be a desirable approach for one of the LDCs, as there is no incentive for them to allow the other LDC to transfer load to its station.
        - IESO staff identified this is a fairly simple example; there are more complex scenarios, where IESO has not found a solution yet (from the system planning perspective).

- **Issue 2: Recognition of Lumpy Investments**
  - LDCs often experience *slow, incremental* load growth, but investments are *lumpy* and cannot be sized to perfectly match the load customer's incremental requirements. In some cases, this can result in investments not being made because parties cannot afford them. The LDC may therefore choose to have a higher level of unreliability, invest in a sub-optimal solution that meets their immediate needs or may be forced to pay for the lumpy solution. It was noted this issue is relevant to *lines* (as *stations* can be sized to meet the customer's needs)
    - No mechanism is currently in place to assist with paying for lumpy investments that exceed the needs of such customers.

  - VECC noted we need to know what the value is to the customer (i.e., monetizing the values/benefits).

  - IESO noted they focus on the optimal technical solution from a system planning perspective. When an LDC cannot pay for the proposed solution, due to financial limitations, in reality that puts an end to the proposed optimal solution.

- **Issue 3: Non-wires options to alleviate transmission investments**
  - In some circumstances, non-wires investments (generation, demand response, conservation, storage, etc.) can alleviate transmission and distribution constraints, or defer transmission / distribution investments.
    - There is currently no mechanism in place to recover the costs associated with non-wire investments through rates

  - OEB staff noted that approving cost recovery associated with non-wires options in rates is beyond the OEB's current legislative authority

  - VECC clarified that LDCs can apply to the OEB for approval of LDC-specific Conservation and Demand Management (CDM) solutions that are recovered through distribution rates. These would be incremental to IESO CDM programs recovered through the global adjustment.

- **Issue 4: Payment for Local Choices**
  - A community may desire a solution that will address local needs by going beyond the 'base' solution or 'minimum' standards at higher cost (e.g. *underground* transmission wires rather than the base solution – *overhead* lines).

- Currently there is no mechanism in place to allow local communities to fund these local choices.

- **Issue 5: Lack of Cost Sharing between Generation and Load**
  - Generation and load use the same transmission connection assets. In some cases, both may benefit from an upgrade, but the current provision in the TSC that addresses a load/generation mix results in only one paying (i.e., initial trigger of upgrade).

  - SECTR is a good example in this case: Combined heat and power (CHP) facilities in the Kingsville-Leamington area will benefit from additional capacity provided by the SECTR project and could not connect or get a contract without it; however, as this investment is primarily driven by load customers, any CHP facilities that connect will get a “free ride”. If generation was the primary driver, the load customer would get a “free ride”.
    - OEB staff noted that it is relatively straightforward to allocate the cost where the customers are the same type (e.g. based on relative peak demand for two loads), but raised the question what basis would be used for a load/generator mix on a line connection since they are not the same (i.e., demand vs. output).
    - IESO staff noted peak capacity from generation perspective and peak demand from the load might be a possible way; however, IESO has not looked into this very closely.

HONI’s presentation:

- ✓ Beneficiary Pays and Proportional Benefit approaches were discussed

- ✓ Beneficiary Pays - If an investment benefits an LDC’s system that LDC’s ratepayers should pay. If an investment benefits a large distribution-connected end use customer, they must pay under both codes.
  - Proportional Benefit - Beneficiaries pay according to the proportion of the overall benefit received.
    - “Benefit” -- incremental capacity created by the investment; therefore, costs are assigned according to each beneficiary’s proportional use of the total incremental capacity.

- ✓ HONI Distribution indicated that it was not appropriate for them to pay 100% of the cost (capital contribution to a transmitter and any distribution-related costs) where they are not the sole beneficiary because this results in HONI Distribution ratepayers subsidizing those of other utilities.

- ✓ OEB staff noted that issue reflects one inconsistency between DSC and TSC: – LDCs are treated as a customer in the TSC and must provide a capital contribution to the transmitter, where necessary. However, the DSC is different as an LDC is not treated as a customer of another LDC. As a result, the *host* LDC cannot, in turn, require a capital contribution from the *embedded* LDC(s). Staff clarified the relevant provision in the DSC is s.3.2.4.

- ✓ A consumer group representative noted that one key element is the incremental capacity required by each LDC and how HONI allocates the cost should be based on the allocated incremental capacity if the DSC is revised to permit it.

- ✓ OEB staff requested clarification as to whether the reference to “TX process” refers to the TSC rules in HONI’s presentation on slide # 6 (last bullet point). HONI staff confirmed it referred to the TSC rules.[1]
- ✓ Balancing Fairness and Feasibility
  - o Clear Identification of Benefits and Beneficiaries
    - ▪ where *embedded* LDCs benefit from new/upgraded transmission investment and/or an investment in *host* LDC facilities, they should pay their fair share

    - ▪ the most feasible approach to assigning cost responsibility for transmission investments, is to treat embedded LDCs as though they are transmission-connected, and

    - ▪ large distribution-connected end-use customers also should pay their share if they benefit from large investments that otherwise would not be needed.

  - o The need to balance fairness with feasibility raised the question as to whether consistent treatment of beneficiaries (i.e., alignment of approach) is required.

[1] OEB staff followed up with HONI staff and they identified it was section 6.3.15 (b), which states: *“Where more than one load customer triggers the need for a new or modified transmitter-owned connection facility, a transmitter shall attribute the cost to those load customers: ….(b… in proportion to their respective non-coincident incremental peak load requirements, as reasonably projected by the load forecasts provided by each such load customer or by such modified load forecast as may be agreed by such load customer and the transmitter and, in the case of line connection facilities, taking into account the relative length of line used by each load customer.”*

    - between transmission (TX) and distribution (DX); and
    - within DX, between LDC ratepayers (pooled) and benefiting customers

- OEB staff asked if this was the rationale for proposing to apply the TSC rules at the distribution level in the SECTR case. HONI staff noted that was correct, but stressed that it was re-thinking the application of some of these rules below the level of the LDCs (as noted in the fourth question in the point below).
    - HONI staff highlighted the following questions for consideration by the WG with respect to addressing the issue of cost allocation:
        - Should one process be established for all situations?
        - Does it depend on the:
            - size of the investments?
            - number of beneficiaries?
        - What are the appropriate decision rules for deciding the approach?
        - Must the cost responsibility treatment in the TSC and DSC be aligned, in terms of defining beneficiaries, processes used and time horizon?

- The value of precision
    - Precision in capacity and cost assignment, load and revenue true-ups, followed by refunds and/or payments helps ensure greater fairness in the eventual cost allocation between:
        - host and embedded LDCs,
        - All of the LDC's customers (pooled) and benefiting end-use customers, and
        - today's and tomorrow's beneficiaries.

    - HONI DX continues to believe that the precision of the SECTR approach is appropriate for the assignment of TX and DX costs between itself and embedded LDCs.

- Planning certainty
    - HONI DX believes the SECTR approach would result in more disciplined forecasting and planning from all parties, leading to more prudent investments.

   - Everyone will benefit from clear rules.

   - The rules and related administrative effort should be reasonable.

   - HONI staff raised further questions for consideration.
     - Should the cost (TX capital contribution and related DX investments) be allocated to LDCs only, large sub-transmission (ST) customers, all ST customers, large general service (GS) customers, etc.?
     - Is there value in a 'blended approach' which uses the SECTR method for assigning TX and related DX costs between the host LDC and embedded LDCs, and splits the remaining TX and DX costs between all of the LDC's ratepayers and large DX-connected end-use customers, utilizing routine rate recovery methods for the former and a form of capacity charge for the latter?
     - Is there value in treating such investments at the DX system level as system "enhancements" as defined in the DSC, i.e., cost socialization?

- ✓ HONI staff added cost allocation should be fair, clear, predictable and reasonable in terms of implementation.

- ✓ VECC raised the following question: *Should the end-use consumer pay if they are not benefiting or getting any incremental capacity?* Maybe not.
  - o HONI noted that costs are pooled under current rules, but their position is that if a party (LDC or end-use customer) does not benefit from incremental capacity, it should not pay (i.e., a change is needed).

- ✓ HONI staff described its suggested process, according to the original SECTR proposal, for allocation of transmission costs between individual LDCs and then between LDCs and their customers. The initial allocation of project costs would be based on each LDC's share of the incremental capacity. A discounted cash flow (DCF) calculation for each LDC then would determine the capital contribution required from each. Each LDC could then determine how best to recover their capital contribution. HONI's proposal for its service area, was to split its contribution between its ratepayers (pooled) and large end-use customers. A DCF calculation would be run for the pool and each large customer. Contracts and Connection & Cost Recovery Agreements

(CCRAs) with the end-use customers would then be executed and the remaining amount would be recovered via HONI's distribution rates.

- ✓ In the intervening year since the SECTR Technical Conference, HONI believes that the originally suggested process for allocating the transmission costs and determining the capital contributions from individual end use customers is still appropriate, *but that cost recovery from those customers through a CCRA is likely not feasible and other options such as a capacity charge, should be explored.*

- ✓ VECC asked, if ST customers are paying a certain portion, how does that contribution come into play with the rates that are being paid by the ST customers?
  - o HONI responded that would need to addressed to avoid double charging the ST customers.
- ✓ OEB staff asked about the size of their ST customers.
  - o HONI clarified that they are over 500 kW.

- ✓ It was noted that the accuracy of LDC load forecasts is an issue and LDCs are accountable for their forecasts since investments are made based on them

- ✓ CCC noted beneficiaries should be defined clearly.
  - o HONI agreed. "Benefit" was defined as the incremental capacity created by the investment and a beneficiary as the party which received a portion of that incremental capacity.
    - ▪ Incremental capacity is the capacity added beyond the *total normal supply capacity (TNSC)* of the existing facility. If a facility is overloaded (i.e., loaded beyond the TNSC) for a few years before it is upgraded or a new facility built, the parties which contributed to the overload in the interim, would be responsible for their portion of the cost associated with that overload, even if their forecasts from then on, remain flat.

      (Upon transfer to the new or modified connection facility, after that facility comes into service, that overload would then start to count as a load credit for economic evaluation purposes, thus lowering the capital contribution required.)

    - ▪ If capacity from an overloaded facility is freed up by the transfer of connected parties to a new facility, a party which remains connected to the first (i.e., overloaded) facility and benefits from increased use of the freed-up capacity is also a beneficiary of the investment which enabled the freed-up capacity. That beneficiary, accordingly, should contribute their portion of the cost.

- ✓ VECC added that, in terms of the beneficiaries, it's important to identify the actual benefits. In the absence of this information, VECC raised a concern that certain beneficiaries may be allocated costs that are more than the actual benefits they receive.
  - HONI staff responded that cost allocation has been done based on capacity; the cost of capacity may vary between different projects depending on the capital cost and the amount of load involved.

  - IESO staff suggested that capacity essentially costs nothing ($0) in Toronto, but the exact same capacity costs a lot in the Kingsville area; currently, the capacity is portfolio-based (depending on the overall cost of the project). Is it right to pay for assets or for the value (capacity received)? One way would be to pay for the capacity that has a fixed value/cost assigned to it.[2]

Other issues for considerations:

- ✓ HONI staff noted that large customers of LDCs triggering TX costs are encountered occasionally and that in some cases the number of large customers expected to connect to an upgraded facility can be significant. HONI suggested that portions of the TSC methodology (specifically, contract management, with true-up and related credit/payment processes) become very complex and therefore, burdensome, both:
  - for LDCs to maintain, given the number of end use customers which may connect to these facilities over time, and

  - for customers, which may not have the level of expertise to perform 25-year forecasts or deal with true-ups.

[2] OEB staff followed up with IESO staff to better understand what was being conveyed. IESO staff noted it was in response to an AMPCO observation that, under today's cost responsibility rules, the cost of additional capacity differs from case to case. IESO noted the reason for that is the beneficiary is charged the cost of the facilities required (*"facility" based*) rather than a fixed cost for service (*"value" based*). This contributes to the "lumpy" investment issue; e.g., Leamington requires 13 km of 230 kV line to connect a new station, however, a similar new station in Toronto would likely require no new line (or shorter line) due to numerous existing lines. Capacity therefore costs much more in Leamington than Toronto. An alternative approach could be to treat investments in a portfolio manner with the cost evenly shared by beneficiaries based on an *average fixed charge per unit* of service to levelize "winners" and "losers" via cost averaging.

- ✓ IESO staff commented that regional planning stops at the “who pays” stage due to the lumpy costs

- ✓ VECC asked what the “system benefit” definition is. Is the benefit an *immediate* benefit or a *future* benefit?
  - o If the benefit is not immediate, how should the uncertainties related to future benefits be addressed?

- ✓ CCC added that a comparison between the “Cost of the project” vs. “customer/system benefit” should be done.

- ✓ HONI raised the following question: Are we going to apply “Proportional Benefit” approach to TX system investment and some DX system investment related to that or alternatively treat the DX system portion of the total investment as an “Enhancement”, which simply means socialization of the cost (under the DSC)? Further, which DX system investments associated with TX system investment would be subject to the “Proportional Benefit” cost allocation?

OEB staff noted that, under the DSC, “enhancements” are intended to be limited to investments needed to address “general” load growth across all of the LDC’s customers and/or reliability issues – not an investment triggered by one customer or a small group of customers due to their need for additional capacity.

Summary of Gaps/ Inconsistencies Identified:

1. TSC is “prescriptive” (e.g., “shall” require Capital Contribution), while DSC is “permissive” (e.g. “may” require Capital Contribution or recover via revenue requirement).

2. Inconsistent treatment of LDCs in DSC and TSC
   - o TSC – LDCs are treated as a customer and must provide a Capital Contribution to the transmitter if they are a beneficiary.
   - o DSC – Embedded LDCs not treated as a customer and Capital Contribution cannot be required by *host* LDC where *embedded* LDC is a beneficiary

3. Approach to “apportion” costs, where both “local” and “system” needs are involved
   - o HONI/IESO SECTR approach vs. OEB Supplementary Proposed Amendment approach

4. “Beneficiary Pays” principle should be “broadened” to go beyond transmission “system vs. local benefits” and include other considerations:
   - End-of-Life cost considerations
   - Impacts on neighboring LDCs – Issue #1, Example 2 in IESO’s presentation (Feeder Transfer)
   - Sustainment Impacts i.e., reduced Sustainment Operating, Maintenance and Administration (OM&A)

5. LDCs often experience slow “incremental” load growth, but investments are “lumpy”. They cannot always afford the “optimal” regional solution; thus, sub-optimal investment may be made and/or less reliable service may be provided

6. Non-Wires options (e.g. generation, Conservation & Demand Management (CDM), etc.) can alleviate/defer need for wires investment, but currently there is no mechanism in place to recover non-wire investments through rates.
   - This seems to be outside of the scope of OEB’s legislative authority.

7. Cost allocation / Payments for Local Choices
   - An LDC (or community) may propose a system solution that will address local needs by going beyond the ‘base’ solution or ‘minimum’ standards (e.g. underground wires rather than the base solution - above ground lines); currently there is no mechanism in place to allow local communities to fund the incremental costs associated with these local choices

8. Bypass Compensation
   - Addressed in TSC, while DSC is silent on the issue.

9. Asset Replacement
   - Addressed in TSC (only like-for-like), while DSC is silent on the issue.

10. Mix of load and generation customers connecting to asset(s)
    - TSC is still based on “trigger” (not “beneficiary”) pays, while DSC addresses the issue based on “beneficiary pays” principle.

11. Capital Contribution “refund” (from subsequent customer(s) to the first customer)
    - Increased to 15 years (from 5 years) in TSC, while it remains at 5 years in DSC.

12. Need to determine if and where DSC and TSC should differ (e.g. based on different customers, large industrial vs. residential).

13. Capacity Assignment
    - Addressed in TSC, while DSC is silent on the issue.

The WG members asked if OEB staff could prepare a table that sets out the gaps and inconsistencies identified during WG meeting #1 and reference the relevant sections in the codes. OEB staff agreed to prepare such a table.

Action Items:

- ✓ OEB staff to prepare a table summarizing the gaps and inconsistencies and related code sections, where applicable, which will be shared with WG members.

- ✓ 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.

Next WG Meeting:

1. Next WG meeting (#2) will be held on **August 5th** and the WG concluded it should be an all-day meeting.

2. The purpose of WG meeting #2 will be to focus on solutions to address gaps and inconsistencies identified in WG meeting #1.