December 20th, 2011

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON, M4P 1E4

via RESS and email

Dear Ms. Walli:

RE: **Phase 2 – Initiative to Develop Electricity Distribution System Reliability Standards**
Board File No.: EB-2010-0249

On November 23rd, 2011 the Ontario Energy Board (the "Board" or the "OEB") issued a letter (the "Letter") to electricity distributors inviting responses to a series of questions regarding electricity distribution system reliability standards.

This is the submission of the Coalition of Large Distributors (the "CLD") and Hydro One Networks Inc. The CLD consists of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited, and Veridian Connections Inc. The CLD and Hydro One appreciate this opportunity to provide input on how reliability measures should be monitored and reported in the province. The CLD and Hydro One's responses to the Board's questions on service reliability follow as Appendix 1 to this letter.

As noted in the Letter, the goal of Phase 2 of this consultation is "*to facilitate the consistency of the reliability data used by distributors across the province*". The CLD and Hydro One see merit in taking steps to ensure that reliability data, common to all distributors, is consistently reported. Further, the CLD and Hydro One support the need for metrics on system reliability to be reported to the OEB. However, it is worth noting that some distributors may utilize or forego further measures, depending on their operational and customer needs. Therefore, there must be a balance in the amount of information reported versus the cost to obtain that information.

To ensure the greatest value for the least costs, the CLD members and Hydro One believe that metrics reported to the OEB should be the same metrics that the individual CLD member companies and Hydro One use from an operational perspective to manage system reliability in their networks. This would ensure there is a clear line-of-sight between the information used by management to meet customer service standards on system reliability and the information provided to the OEB. This would be the most cost effective solution for providing data.

As a guiding principle, any consideration of additional reliability measures should be weighed against the associated costs relative to the customer and the operational benefit.

Furthermore, the CLD and Hydro One submit that while it believes that benchmarking reliability is important and useful, it would caution the Board against comparing distributors against one another for the purposes of performance-based regulation. Each distributor operates within a unique service territory, both in terms of geography and customer expectations, and therefore benchmarking distributors reliability against one another would not provide for a meaningful comparison. In fact, such comparisons may be detrimental. The CLD and Hydro One recommend that any exercise in benchmarking reliability be limited to measuring each distributor against its own past performance. Doing so will allow each distributor to improve its reliability to a point of economic efficiency and optimal customer satisfaction.

The CLD and Hydro One appreciate the opportunity to provide further insight and comment on the collection and reporting of reliability data though this consultation phase, as well as, through the future Reliability Data Working Group. The CLD and Hydro One expect that the Working Group of industry experts will be able to help the Board, and the industry, achieve industry standards for reporting.

Please contact the undersigned if you have any further questions on this submission.

Yours truly,

(Original signed on behalf of the CLD and Hydro One by)

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Appendix 1 – Responses to the Questions of the Board on Service Reliability

Questions on Improving Current Definitions

1. **Are the reliability definitions currently set out in the RRR's sufficient?**

   The CLD and Hydro One believe that the current definitions are sufficient indicators of overall system performance; however they could be improved upon in order to provide a greater amount of transparency and granularity.

   In general, the CLD and Hydro One recommend that the Board adopt the Canadian Electricity Association ("CEA") definitions where possible.

2. **If not, what revisions would be recommended?**

   The CLD and Hydro One would support tracking MAIFI, but only if the distributor can readily report on such data on all automatic devices on all feeders.

   Definitions for cause codes should be elaborated on, with examples and a possible hierarchy. For example, there are scenarios where several cause codes may apply, which are important to capture for operational purposes. How such cases would be weighted for benchmarking purposes is not clear. For example, a tree falling onto an overhead line, as a result of a storm – Is this considered adverse weather (Code 6) or tree contacts (Code 3)? The CLD and Hydro One recommend that the task of developing better and consistent definitions for cause codes be assigned to the working group.

3. **What is the most effective way to define an interruption?**

   The CLD and Hydro One recommend that the definition of outage and interruption be aligned with those definitions provided by the CEA. While the OEB tends to use the two terms interchangeably, the CEA distinguishes between the two by stating that an outage is an interruption that last longer than 1 minute.

4. **What is the most effective way to define the start time of an interruption?**

   The CLD and Hydro One believe that the definition provided in section 2.1.4.2 (1) of the RRR is adequate.

enersource horizon HydroOttawa PowerStream TORONTO HYDRO VERIDIAN hydro one

5. What is the most effective way to define the end time of an interruption?

The end time of an interruption should be defined as the time when power/service/supply is restored at the customer point of common coupling. If the restoration is completed in phases, then each restored portion of customers should be calculated individually to acknowledge staged restoration times. The end time of the interruption should be reported by the field crew that has restored service and/or by the control room if service is restored remotely.

6. What is the most effective way to define a "customer"?

"Customer" should be defined as a metered electrical service point for which an active bill account is established at a specific location (IEEE 1366).

7. What is the most effective way to define the "total number of customers served"?

The CLD and Hydro One believe that the definition provided in section 2.1.4.2 (2) of the RRR is adequate, but the use of the word 'customer' should be aligned with the definition provided above.

8. Are there any other factors of an outage that should be defined?

Loss of supply should be defined; the current Board definition is adequate.

Major Event Days ("MEDs") should be clearly defined if the Board intends to involve them in normalizing reliability data.

9. It has been suggested that the Board provide example calculations for various situations. Which types of situations would benefit from having examples provided?

Example calculations should be provided in the following areas:

- Definitions for cause codes should be elaborated on, with examples and a possible hierarchy. Clarification would be appreciated in scenarios where more than one cause code applies; for example, a significant wind storm causes tree branches to be blown into overhead distribution lines causing an outage. According to all analysis, the clearance of the tree branches to the overhead line meets all accepted requirements. Should this outage be classified as Adverse Weather (Code 6) or Tree Contacts (Code 3)?

- Whether distributors should be tracking restoration of service to individual customers, or tracking the restoration of a feeder, and then extrapolating data based on the records of the number of customer on the feeder. To ensure consistency in reporting methods, the CLD and Hydro One recommend that outage data be tracked at the most granular level possible by the distributor. It would be appreciated if a few examples were provided, taking into account different possible scenarios, such as when previously restored customers are once again interrupted during the stepped restoration process; and
- Any other areas where inconsistency in distributor practices is revealed.

Questions on Normalizing Reported Data

1. **Besides the two common normalization approaches mentioned (the % of customers or the IEEE standard), are there other methodologies that should be considered?**

   Another approach may be for distributors to report outages based on cause codes. Segregating the outage data would allow for events that are outside of the distributors control to be omitted from the results, when appropriate.

   Major Events Days ("MED") could also be based on special events. The definition of such events should be established by the Board and may include conditions such as a minimum threshold for wind speed or precipitation.

2. **Which normalization methodology would be the most efficient and effective?**

   The CLD and Hydro One would like to take this opportunity to mention that while some mechanisms need to be developed for normalizing data, they are not certain if either of the two options being presented are ideal. It is recommended that this topic be addressed within the working group that is currently being developed, and that the scope of this discussion go beyond the percentage of customer method and the IEEE standard. Following such consideration, the CLD and Hydro One would be better positioned to comment on the proposed models and provide a recommendation at such time.

3. **What are the perceived drawbacks and/or benefits of implementing the IEEE standard 1366 as a normalization approach?**

   Potential drawbacks of implementing the IEEE 1366 standard:
   - Each new Major Event Day will raise the threshold value and will cause similar MEDs in subsequent years to no longer qualify for exemption. As a result a distributor may have Major Events that, because they are less than the threshold, are not officially recognized as Major Event Days.
   - There may be an abnormal weather condition through which the IEEE 1366 calculation will not be captured, or pass the threshold.
   - Each distributor will have its own threshold, thus making comparisons inconsistent across the province.
   - The calculation is not consistent throughout the years, since it is based on the past five years of input. The problem with this is that normalized data today will not be comparable to normalized data 5 years from now since the threshold will be different every year.

4. **What are the perceived drawbacks and/or benefits of implementing a normalizing approach using the percentage of customer's affected as the trigger?**

   The CLD and Hydro One do not recommend using this approach, as it may cause a disproportionate amount of major events in smaller distributors. For example, under "the percentage of customers" method, a distributor with 10 or fewer feeders could have a Major Event Day whenever it loses a feeder (assuming an equal distribution of customers between the 10 feeders).

   The CLD and Hydro One believe that this method could be improved upon by requiring the affected distributor to file supporting documentation showing that the cause of the outage was outside their control, and recommends that this approach be investigated further in the working group.

5. **If the "customer's affected" approach is adopted, what percentage of total customers should be used as the trigger?**

   The CLD and Hydro One do not recommend using this approach and therefore, cannot provide a recommendation on what should be used as the trigger.

6. **How great of an administrative burden, or increased costs, would distributors face if required to normalize reliability data to account for major events and then report that data to the Board? What would those burdens or costs be?**

   Although some administrative burden can be expected in implementing either of these measures, the CLD and Hydro One find it difficult to comment at this time, as the response will likely depend on the final definitions adopted by the Board.

7. **What, if any, other barriers exist to implementing either the IEEE approach or the customer's affected approach? How could those barriers be addressed?**

   The CLD and Hydro One are of the view that the barriers to implementing either of these approaches will vary between distributors based on the amount of resources available and the capability of the distributor's current systems and procedures.

Questions on Cause of Outages Reporting

1. **Which Cause Codes should be selected as those which are within the control of the distributor?**

   With the exception of Loss of Supply (Code 2) all other cause codes are, to a certain degree, within the control of the distributor.

   Cause codes where the distributor has a somewhat limited amount of control include:
   - Adverse Weather (Code 6)
   - Foreign Interference (Code 9)
   - Adverse Environment (Code 7)
   - Lightning (Code 4)

   Distributors may undertake certain preventative measures, such as tree trimming and insulator washing (to remove reduce salt contamination); however, the majority of events are not within the control of the distributor.

2. **Which would be the best reporting approach to use:**
   - **Reporting total SAIDI, SAIFI and CAIDI results based solely on all the relevant Cause Codes?**
   - **Reporting SAIDI, SAIFI and CAIDI results based on each separate relevant Cause Code?**
   - **Reporting the number of outages (normalized to X number of customers) by each relevant Cause Code?**
   - **Another option that could be considered?**

   The CLD and Hydro One agree that reporting total SAIDI, SAIFI and CAIDI results based solely on all the relevant Cause Codes is the best approach.

3. **What improvements to distributor practices or procedures, could be implemented to ensure the cause is being categorized accurately?**

   With the assistance of the working group clearly defined guidelines should be established by the OEB in regards to what type of activities fall within each of the cause codes. This is especially the case where more than one cause code may apply to a situation.

   It may also be of benefit to distributors if they classified events internally by sub-class code. For example there are several types of Code 3 tree contacts possible (i.e., tree growth, tree failure, lightning strike, etc.),

   Each distributor should also ensure that staff is properly trained in classifying outages by cause code and all data should be subject to an internal audit and sign off procedure.

4. Are the current definitions of the Cause Codes sufficient or are there any suggestions on how to update the definitions so as to improve understanding?

With the assistance of the working group, clearly defined guidelines should be established by the OEB in regards to what type of activities fall within each of the cause codes. This is especially the case where more than one cause code may apply to a situation.

The working group should also focus on differentiating between causes and conditions. For example, if a branch from a tree falls on a line during a storm; Adverse Weather (code 6) is just a condition in this case, but Tree Contacts (code 3) is the cause. In such situations, there seems to be inconsistency between distributors as to what cause code to report.

Code 7, Adverse Environments, should reference "flooding" not "flowing".

5. How great of an administrative burden, or increased costs, would distributors face if required to report data on the causes of outages to the Board? What would those burdens or costs be?

The burden would be minimal if distributors were required to report on the cause of outages by using the relevant cause codes; however, it would be quite burdensome if distributors were expected to report on the details of the cause of each outage.

If the Board is requesting the latter, the CLD and Hydro One recommend that the OEB not require distributors to file specific details about all outages, but rather, the OEB make an inquiry to a distributor if additional information on a particular outage is required.

6. What, if any, other barriers exist to requiring distributors report data on outages caused by factors within the control of the distributor? How could these barriers be addressed?

No barriers aside from those mentioned above.

<u>**Questions on Customer Specific Reliability Measures**</u>

1. **Which, if any, customer specific reliability measures are distributor's currently using?**

   Although some members of the CLD and Hydro One have experimented with various customer specific reliability measures, such as Feeders Experiencing Sustained Interruptions ("FESI"), the experience has not always been satisfactory and, as a result, some distributors have begun to move away from such measures.

2. **Please provide the complete definitions of any customer specific reliability measure currently being used.**

   FESI-7 refers to feeders experiencing 7 or more sustained interruptions. This method is based on a one year rolling period and ranks the feeders based on the number of outages. Similarly, a feeder which has experienced, for example, 10 interruptions in the past 12 months, is referred to as FESI-10 feeder.

   As stated above, FESI has its limitations. The true impact of an outage is not captured by FESI as it fails to take into account the magnitude of each outage. For example, a distributor may have a FESI 12 (12 minor outages) and FESI 5 (with 5 major outages); however, according to current FESI definitions, FESI 12 will get a higher priority than FESI 5, despite the fact that its' outages have been less severe.

3. **Of the 4 customer specific measures mentioned (Customers Experiencing Multiple Interruptions, Customers Experiencing Long Duration Interruptions, Customer Interruptions per KM, and "Customer Hours of Interruptions per KM.) which one (or combination of more than one) would be the most efficient and effective for all distributors to monitor?**

   Customers Experiencing Multiple Interruptions and/or Customers Experiencing Long Duration Interruptions would be the most efficient and effective for distributors to monitor.

   These measures are better as they point us to the areas of the line segment that require improvement, and not just the entire feeder.

4. **How great of an administrative burden, or increased costs, would distributors face if required to monitor measures which are directed at tracking the reliability experience of individual customers? What would those burdens or costs be?**

At this time, it is expected that reporting at this level of detail would be quite costly and burdensome to implement.

Although some smart meters do have the ability to collect this data, trying to retrieve that data and report on it would require integration between various systems within the distributor, such as the AMI and Outage Management System ("OMS"). Some of the CLD members and Hydro One are in the very early stages of investigating how such a system might be implemented within their organization, but it is currently expected to be quite costly and therefore not economical to the majority of distributors within the province.

It should also be noted that not all smart meters are equipped with last gasp outage alarms. This would be an additional expense and potential barrier to such deployment.

5. What, if any, other barriers exist to requiring distributors to monitor measures which are directed at tracking the reliability experience of individual customers? How could these barriers be addressed?

In order to accurately answer this question, more detail on the level of capability being requested is required; however, some of the possible barriers include:

- Cost
- Time
- Labour Resources

The CLD and Hydro One would like to reiterate the fact that the cost to implement this sort of tracking will likely be very high. Before proceeding further on this the matter, the CLD and Hydro One recommend the Board weigh the benefits versus the costs of imposing such measures, and clearly communicate to stakeholders what those benefits may be.

Questions on Worst Performing Circuit Measure

1. **Which would be the most effective way to define or designate a "worst" performing circuit:**
    - **Worst SAIDI?**
    - **Worst SAIFI?**
    - **A combination of both the worst SAIDI & SAIFI?**
    - **Feeders Experiencing Multiple (ex: 5 or more) Interruptions in a year?**
    - **Feeders Experiencing the Longest Interruptions?**
    - **Another option to consider?**

    It is important to note that the worst performing circuits ("WPC") measure is one operational tool, amongst many, used by each distributor when assessing its reliability issues. How each distributor chooses to use this tool, and how effective it is, will vary between distributors. The CLD and Hydro One recommend that the Board not define how such a measure should be used, but rather leave it up to each distributor to assess whether or not this tool suits their needs and how best to measure it.

    Tracking the worst circuit by outage duration or outage frequency often leads to a similar list of WPC. One approach that has been used with some success is tracking WPC in terms of both Customers Interrupted ("CI") and Customer Minutes Out ("CMO").

    Another approach used by some distributors has been to define WPC by CI/km and CMO/km, so that the rating is independent of the length of the feeder.

    As a system planning tool, the definition of Worst Performing Circuit(s) is, and should be, driven by the needs of the distributor. For example, if the distributor wishes to address overall system reliability, a feeder CI and CMO approach would be appropriate. Whereas, if the distributor needs/wishes to address more localized reliability, a circuit level SAIDI or SAIFI WPC definition would be more appropriate.

2. **Should the number of customers who are being provided service by a feeder have an impact on the designation of "worst" performing? (For example, using customer-minutes of outage as a performance measure would result in feeders with the most customers naturally being highlighted more frequently then feeders with fewer customers, even though such a feeder may have poorer reliability.)**

    Yes. Another option would be to monitor load minutes of outage time in order to better account for those feeders with large load customers or bulk-metered residential customers.

The CLD and Hydro One's response to this question is based on best-practices used from an operational standpoint, and recommends that each LDC be free to use the WPC measure how they like, if at all.

3. Should there be expected distributor response to the identification of a worst performing feeder?

Not necessarily. There should be an overall asset management approach to control WPC rather than simply targeting an individual feeder.

4. If so, what type of expected response should be considered? (E.g. No feeder should be designated the "worst feeder" more than 2 years in a row.)

The CLD and Hydro One do not recommend having a response and would like to reinforce the fact that the WPC measure is only effective as an internal tool and should be considered amongst a variety of other factors when developing an overall asset management plan. Although problem feeders should be identified and corrected, a variety of other methods aside from WPC must be considered, and most importantly, done is a way that is economically efficient for the rate payers. The balance of cost versus reliability differs greatly between distributors, and as such, each distributor is in the best position to determine the appropriate balance for its customers.

5. How great of an administrative burden, or increased costs, would distributors face if required to monitor their worst performing circuits? What would those burdens or costs be?

Administrative costs may vary depending on the information being requested. However, given the response to the above questions, the CLD and Hydro One do not recommend that the Board implement a WPC measure.

6. What, if any, other barriers exist to requiring distributors to monitor a Worst Performing Circuit measure? How could these barriers be addressed?

Given the response to the above questions, the CLD and Hydro One do not recommend that the Board implement a WPC measure.