Cornerstone Hydro Electric Concepts Association Inc.

May 5, 2014

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario M4P 1E4

Re: Review of the Board's Policies and Processes to Facilitate Electricity Distributor Efficiency: Service Area Amendments and Rate-Making Associated with Distributor Consolidation – Board File No. EB-2014-0138

Dear Ms. Walli:

Attached please find Cornerstone Hydro Electric Concepts Association's (CHEC) comments with respect to the Board's review of the Policies and Processes to Facilitate Electricity Distributor Efficiency: Service Area Amendments and Rate-Making Associated with Distributor Consolidation

As you are aware, CHEC is an association of fourteen local distribution companies (LDC's) that have been working collaboratively since 2000. The comments over the following pages express the views of the CHEC members, with the exception of *Innisfil Hydro Distribution Systems Limited "IHDSL") for Service Area Amendments (SAA's)*. IHDSL is in agreement with the MAAD's portion of Attachment A, but due to their unique situation with respect to service territories will be submitting a response on SAAs under separate cover. This submission also addresses the several questions outlined in the letter dated March 31, 2014, and follows the same format (Attachment A).

We trust these comments and views are beneficial to the Board's review process. CHEC looks forward to continuing to work with the Board in this matter.

Yours truly,

Gord Eamer

Gordon A. Eamer, P.Eng.
Chief Operating Officer
43 King St. West, Suite 201
Brockville, ON K6V 3P7
geamer@checenergy.ca
613-342-3984

CHEC Members

Centre Wellington Hydro	COLLUS PowerStream
Innisfil Hydro Distribution Systems	Lakefront Utilities
Lakeland Power Distribution	Midland Power Utility
Orangeville Hydro	Orillia Power
Ottawa River Power	Parry Sound Power
Rideau St. Lawrence Distribution	Wasaga Distribution
Wellington North Power	West Coast Huron Energy

ATTACHMENT A

<u>SERVICE AREA AMENDMENTS:</u>

Question 1 – What are the benefits of an "open for competition" approach to un-serviced areas? How would the Board implement such an approach in light of section 28 of the Electricity Act, 1998 and existing licence conditions? Under an "open for competition" approach: (i) how will the Board ensure that all prospective new customers will receive an offer to connect on fair and reasonable terms; and (ii) how should the interests of Incumbent Distributors and their ratepayers be taken into consideration?

To assist with the understanding of changes to the current SAA process a number of terms need to be more fully defined. A consistent understanding of these terms will help to ensure the overall efficiency of the SAA process. The terms requiring further clarification as they apply to SAAs and suggested interpretation include:

"**Un-Serviced Area**": The areas which are subject to a SAA are typically referred to as un-serviced. In many cases there is service provided for current use however not for future proposed use, which is usually an increase in density. As such the un-serviced area definition should be expanded to include: "An area located on the outskirts of an existing distributor's boundary, which is not currently serviced by a distribution system or is underserviced for the proposed future use". In many instances these may be referred to as "undeveloped "or "green space" areas.

"**Open for Competition**": This term does not specify whether this is a general philosophy or applies to specific areas within distributors' service territories. It is proposed that the intent is not to make all "un-serviced areas" open for competition, regardless of the location of the service territory, but to specifically restrict competition to those un-serviced areas that are towards the boundaries of service territories. As such, it is suggested that those SAAs that are "open for competition" be limited to areas which are in proximity to Hydro One and an adjacent Distributor, which would result in contiguous distribution territories.

Suffice it to say, the current rules for Service Area Amendments (SAAs) are based on economic efficiency, and economies of contiguity, density and scale. However, this process can also be cumbersome, expensive, and lengthy. Any SAA process should be streamlined to be as efficient and cost effective as possible.

Based on the proposed clarification of definitions with respect to a SAA, only contiguous distributors with assets in reasonable proximity to an un-serviced area should be able to compete. This will ensure the best alternatives are considered from an economic and system planning perspective. The evaluation of the competing offers should be based on an economic evaluation model that provides an apples-to-apples comparison among competing entities.

Distributors are conscious of the timeliness of the overall SAA process and the need to provide an offer to connect in accordance with the current rules (60 days). Delay in providing the offer to connect extends the overall SAA process which can be detrimental to developers and may remove customer choice if delays occur over an extended period of time. Continued efficiencies within the SAA process are suggested to allow timely decisions as well as compliance to existing rules.

It is also important to ensure the SAA process is customer focused. Under the current rules, customer preference is an important, but not overriding consideration. Where appropriate, the customers' needs and preference for servicing should be given additional consideration. Furthermore the longer term costs, beyond the current development cost should be considered by including some consideration of the cost of service to the end use customer.

Question 2 – Should the Board's SAA policy facilitate SAAs that have the effect of aligning a distributor's service area with municipal planning boundaries and, if so, in what way? What are the benefits and risks of such an approach for Incumbent Distributors, Applicant Distributors and their respective ratepayers? What role should municipal planning, community energy plans and regional planning have in the SAA process?

Although alignment of the distributor and municipal boundaries can assist to reduce customer confusion, impacts on the incumbent distributor should be included in the evaluation. The need for distributors to plan delivery throughout their current service territory will have driven design and system planning decisions based on the access to un-serviced area. As such the expansion of one distributor into the other distributor's service area may significantly impact the incumbent distributor. Facilitation of supply to the area could be accomplished by proposing applicant distributors acquire distribution assets through a MAAD application with imminent customers used as part of the purchase calculation, providing the end result is improved efficiency and cost effectiveness.

With respect to planning, municipalities should become increasingly more important to the SAA process. A local distribution presence that is aligned with the municipality allows distributors and municipalities to collaborate and is conducive to planning between the two entities. In instances where an SAA involves a municipal/distributor and a rural (Hydro One) boundary, regional planning may become a more important factor to the SAA process.

A risk of a SAA is potential stranded assets for a distributor. There is a need for coordinated planning among an un-serviced area in close proximity to service area boundaries. Loss of revenue is a further risk associated with a SAA. This requires an evaluation of the impact on the distributor, as noted above, to be considered.

When evaluating the benefit to customers the current position on long-term load transfers and the need for an SAA should be reconsidered. There may be instances where installing a metering point to address the long term load transfer would allow an LDC to maintain a service territory as part of their long term plan while providing a medium to short term solution of the immediate supply issue. In instances where an LDC would incur significant cost to maintain supply in their service territory (and perhaps within their municipal boundaries) these costs can be avoided while ensuring the eventual contiguous and efficient supply to the area.

Question 3 – For either proposed change to the Board's current policy: (i) How should the Board approach its analysis? (ii) What criteria should be used by the Board and what type of evidence would be necessary? (iii) How can the Board ensure that the proposed change would not adversely affect overall economic efficiency in the sector? (iv) How should the Board assess the impact on existing and future customers in terms of cost and the reliability and quality of electricity service? (v) How can the Board be satisfied that the process will ensure that the connection of new customers proceeds in a timely manner?

The Board should approach its analysis by examining both costs and historical SAA outcomes. With respect to costs, the existing premise of economic efficiency should remain a top priority in the SAA process. In each SAA application the Board should consider costs to the developer, reliability costs, and costs to end customers, with emphasis on costs to the end consumer as the primary overlying factor. With respect to historical SAA outcomes, current and past SAA applications could be used to identify potential issues that may arise in the application of a new SAA policy. Continued input from the distributors would also aid to monitor implementation realities beyond the written policy objectives. By analyzing these factors, a more optimal and timely decision making SAA process could be achieved.

As indicated above, the existing SAA process should be streamlined to improve the efficiency of processing applications. Evidence presented through a single economic model as well as input from the end customer could be utilized to ensure economic efficiency and customer focus is adequately aligned. An effective timeframe for all SAA applications should be implemented and enforced to ensure applications are processed in a timely fashion. Under specific circumstances and where appropriate, SAAs should be expedited (i.e.: where an SAA is uncontested). Finally, wherever possible, the application should be supported through distributor, municipal, and regional plans.

RATE-SETTING ASSOCIATED WITH MADDS:

Question 1 –What are the merits and risks of allowing a consolidated entity to set its own rebasing deferral period? Should the Board establish a "default" minimum deferral period and, if so, what should the length of that deferral period be?

The merit to having an entity set its own rebasing deferral period is to allow the flexibility for planning and completing the consolidation of the entities. In turn, this could positively affect the ratepayer in terms of the cost, reliability, and quality of service provided. The risk in having an entity set its own rebasing deferral period is the distributor could take too long before rebasing. In turn, this could adversely affect the ratepayer in terms of the cost, reliability and quality of service provided.

With respect to a minimum "default" period, it is suggested that flexibility in rebasing is important, providing the entities involved can maintain regulatory compliance with respect to ROE. This flexibility is also in alignment with respect to the RRFE and the annual IR indexing rate option. A base 5 - 10 year timeframe is considered to be reasonable timeframe before a consolidated entity should be required to rebase.

Question 2 – Should the consolidated entity be required to elect its rebasing deferral period at the time of the MAADs application (as is the case under the 2007 Policy), or should the entity be allowed to address this at a later date and, if so, when? What information should a consolidated entity provide to support its proposed rebasing deferral period?

There are merits to both methodologies. Establishing a rebasing period at the time of application allows for distributor and consumer expectations to be clear from the onset. Alternatively, allowing a distributor to select its rebasing period at a later date allows the consolidating entities to gather additional information that may not be available at the time of application. A better methodology would be to set initial expectations at the time of application but allow the default period to be revised should future evidence warrant the amendment.

Evidence to support a rebasing deferral period should be in the form of a strategic plan that details how the consolidating entities will transition during the consolidation period. Included in the strategic plan should be plans for entity consolidation, timelines for conversion of key areas, and financial predictions with detailing benefits to the end customer. Where the distributor makes application for a change to the deferral period the strategic plan could be updated to provide the supporting evidence.

Question 3 – Once a consolidated entity has proposed a rebasing deferral period, should it be required to wait for the entire period before applying for a rebasing of its rates, or should it be allowed to apply for rebasing at any time within the proposed period? What are the merits and risks of each approach?

Under the new RRFE, existing rules provide for a rate application to be made at any time, therefore under a MAAD application, the consolidated entity should also be awarded the same opportunity. If a consolidated entity does decide to rebase, the distributor should be required to provide reason for the change and show evidence that the consumers are not adversely affected. In general the following is suggested for rebasing when a MAAD has occurred:

- The consolidated entity identifies a rebasing period between 5 to 10 years
- The consolidated entity can request a rebasing at any time, but is required to provide reasons for the change and evidence that the consumer is not adversely affected.

Question 4 – In the case of a distributor that is on Custom IR at the time of consolidation, how should its rates be set for the duration of the rebasing deferral period following completion of the Custom IR period?

This is a complex and difficult issue. However, in general, the MAAD application should include the Custom IR as the term of consolidation. Rates established under this methodology should continue as planned unless the consolidating entities can show evidence for a more optimal solution.

Question 5 – What are the merits and risks of the suggestion that a newly consolidated entity apply for new rates under the Custom IR option that recognize both costs and projected efficiency savings, (e.g. an efficiency carryover to allow the distributor to recoup transaction costs)? Is this complimentary to or a substitute for an approach that allows the deferral of rebasing?

A Custom IR is a complex, costly and time consuming process. As a result, there is a substantial risk that the cost of rebasing under the Custom IR option would offset any cost or efficiency savings achieved through consolidation. Therefore, each application should be taken on its own merits and should not change unless projected costs or efficiency gains necessitate a new rate application.

Question 6 – What are the merits and risks of using a modified ICM (which allows broader eligibility of expenditures) to address the recovery of capital investments during any rebasing deferral period? How should the Board evaluate an ICM request under this scenario to ensure that any financing is for investments that are incremental to the capital amount built into rates?

There are arguments both for and against using a modified ICM during a rebasing deferral period. Utilizing a modified ICM has the benefit of lower costs and improved efficiency. Since the ICM process is simpler and less costly than a full rate application it could be used as a quick and easy methodology for submitting changes with respect to managing the consolidated asset base. It allows the consolidating entity to deal with capital issues without having to incur the costs of rebasing.

However, this methodology can also increase the risk of asset inefficiency. A modified ICM being a simpler process may inadvertently exclude projects that warrant immediate attention. To mitigate this risk, an entity's Distribution System Plan (DSP) may also need to be reviewed in conjunction with a modified ICM to ensure asset inefficiency does not occur. Otherwise, a full rate application may be justified.