ONTARIO ENERGY BOARD

Ontario

Staff Discussion Paper

Review of the Board’s Polices and Processes to Facilitate Electricity Distributor Efficiency: Service Area Amendments and Rate-Making Associated with Distributor Consolidation

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The Ontario Energy Board ("the Board") issued its Report on a Renewed Regulatory Framework for Electricity Distributors in October 2012. In furtherance of the objectives of the renewed regulatory framework ("RRFE") and the Board's objective of ensuring that regulation is delivering value to consumers and encouraging improved performance in the distribution sector, the Board issued a letter on February 11, 2013 announcing an initiative to assess how the Board's regulatory requirements for electricity distributors may affect the ability of distributors to realize operational or organizational efficiencies (EB-2012-0397).

Consultations with stakeholders took place in February to identify Board policies and processes that may affect the ability of distributors to realize such efficiencies and to elicit stakeholder comment on potential changes to the Board's regulatory requirements that may facilitate efficiency improvements. Having considered the input received from stakeholders during that consultation, the Board determined that it was appropriate to focus its efforts on two Board policies in particular. To that end, the Board issued a letter on November 4, 2013 announcing that it would proceed with a further review of its policies related to service area amendments ("SAA") and rate-making associated with merger, amalgamation, acquisition and divestiture ("MAADs") transactions. The Board also indicated that it would announce additional initiatives at a future date in response to stakeholder suggestions for changes to other Board policies.

This Board staff Discussion Paper provides background on and related to the Board's current SAA and MAADs rate-making policies, summarizes stakeholder input received in relation to those policies and sets out questions for stakeholder comment with respect to potential changes to those policies.

A. BACKGROUND

The RRFE is a comprehensive performance-based approach to regulation that promotes the achievement of four performance outcomes to the benefit of existing and future customers: customer focus, operational effectiveness, public policy responsiveness, and financial performance. The framework aims to align customer and distributor interests, continues to support the achievement of important public policy objectives, and places a greater focus on delivering long term value for money. A key element of the framework is the focus on continuous improvement and increased efficiency in the distribution sector.

The report of the Ontario Distribution Sector Review Panel, issued in December 2012, set out a vision for consolidation resulting in the less costly and more efficient delivery of electricity, with a predicted cost savings of $1.2 billion over the next ten years. When the Minister of Energy responded to the Panel's report, he indicated that he expected that the sector would find ways to achieve those savings through more efficient service delivery, including negotiated consolidations. This was carried forward in the government's December 2013 Long Term Energy Plan ("LTEP"), where it is stated that the government expects electricity distributors to pursue innovative partnerships and transformative initiatives that will result in savings for electricity ratepayers.

The Board's decision to initiate a review and evaluation of its policies reflects its own expectations, as well as those of the government, that the distribution sector should continue to seek out efficiencies. This initiative is intended to assess whether and how the Board's policies may affect the ability of distributors to realize operational or organizational efficiencies, and whether and how changes to those policies might better support efficiency gains by distributors through economies of scope, economies of scale or consolidation.

For the purposes of the consultation that took place in February 2013 (the "February Consultation"), Board staff engaged Navigant Consulting Inc. ("Navigant") to survey stakeholders regarding their views on potential changes to the Board's regulatory requirements that may facilitate efficiency improvements. Navigant's findings were included in a report released on February 25, 2013. Board staff also held a meeting with stakeholders on February 27, 2013 to discuss the Navigant report and to hear stakeholder views on related issues. Stakeholders offered a number of comments and suggestions for changes to the Board's policies which, in their view, would allow distributors greater opportunities to achieve efficiency gains through consolidation or economies of scope and/or scale from their operations. These comments included suggestions relating to the Board's policies regarding SAAs as well as the Board's rate-setting policies associated with MAADs transactions. Each of these two areas is discussed in turn below. Although stakeholders also commented on other Board policies, in light of the Board's November 4, 2013 letter those comments are not addressed further in this Discussion Paper.

B. SERVICE AREA AMENDMENTS

Each licensed distributor is authorized to distribute electricity within, and only within, the geographic area described in its licence.[1] This is the distributor's licensed service area, and is the area for which the distributor is referred to as the "Incumbent Distributor" in this Discussion Paper (a distributor seeking to serve a customer located outside of its licensed service area is referred to in this Discussion Paper as the "Applicant Distributor"). The licences issued to distributors cover the entirety of the Province of Ontario save for areas that are served by distributors that are exempt by regulation from the requirement to be licensed.[2]

Under section 28 of the *Electricity Act, 1998*, a distributor is required to connect a building to its distribution system if the building lies along any of the lines of the distributor's distribution system. This obligation is repeated in the licences issued to distributors, as is a related obligation to make an offer to connect a building upon being requested to do so if the building is within the distributor's service area. To the same end, the licences also prohibit distributors from refusing to connect or to make an offer to connect unless they are permitted to do so by the *Ontario Energy Board Act, 1998*, a regulation made under that *Act* or a Board code.

B1. Overview of Current Board Policy

The Combined Proceeding

The principles and policy applied by the Board in considering SAAs are set out in a February 2004 Decision with Reasons issued following a combined proceeding held in relation to nine separate SAA amendment applications (the "Combined Proceeding") (RP-2003-0044). By way of summary:

- Economic efficiency is a primary consideration in assessing an SAA application, and failure on the part of an Applicant Distributor to adequately demonstrate the economic efficiency of the proposed SAA would generally constitute sufficient grounds for the Board to turn down the application. Similarly, it is expected that an Applicant Distributor will demonstrate that the proposed SAA does not reduce

[1] *Ontario Energy Board Act,* section 70(11).
[2] Ontario Regulation 161/99 (Definitions and Exemptions).

economies of contiguity, density and scale, and preferably that it enhances these economies. Moreover, inefficient historical connections should not serve as support for new proposals that would fail but for their proximity to old, inefficient connections (the example used here is where a proposed connection lies adjacent to an isolated pocket of distribution customers served by the Incumbent Distributor but is contiguous to a dense, highly developed distribution system operated by another distributor).

- Customer preference is an important, but not overriding, consideration when assessing the merits of a proposed SAA, and would only become a determining factor where: (i) competing offers to the customer(s) are comparable in terms of economic efficiency, system planning, safety and reliability and are demonstrably neutral in terms of price impacts on customers of the Incumbent Distributor and the Applicant Distributor; and (ii) where stranding issues are addressed.

- Existing customers of the Applicant Distributor should not be subsidizing the proposed new connection that is the subject of the SAA application, nor should their interests be prejudiced in any other manner. Any connection transaction must reflect the true cost of connection and the provision of ongoing service to the prospective customer.

- SAAs at the borders between contiguous distributors should be encouraged where there is agreement between the distributors and any affected customers that a realignment of the boundary would be economically efficient, consistent with system planning needs and in the public interest. Applications of this nature should be processed expeditiously by the Board.

- An SAA that involves contiguous distributors but that is opposed by the Incumbent Distributor may nonetheless be in the public interest where the SAA results in the most effective use of existing distribution infrastructure and a lower incremental cost of connection for the customer or group of customers.

- The onus of demonstrating that a contested SAA is in the public interest lies with the Applicant Distributor. At the same time, Incumbent Distributors should give proper consideration to rational and efficient service area realignment, even where it results in the loss of some territory. SAAs should not be resisted where the Applicant Distributor is clearly the most efficient service provider for the prospective customer.

- Overlapping and new embedded service areas will not generally be found to be in the public interest.

- SAA proposals to align service areas with municipal boundaries are ill-considered unless the Applicant Distributor can provide concrete evidence that the extended area is needed to provide service to actual customers in the area using assets and capacity in a manner that optimizes existing distribution assets and does not prejudice existing customers of the Applicant Distributor.

<u>SAA Applications since the Combined Proceeding</u>

Since 2004, SAA applications have been determined by the Board in accordance with the principles and policy set out in the Decision with Reasons issued following the Combined Proceeding.

The majority of the SAA applications that have come before the Board have been uncontested, and have generally involved new subdivisions that need immediate connection in circumstances where the Applicant Distributor has the capacity to provide service whereas the Incumbent Distributor does not. In addition, uncontested SAA applications have resulted from the resolution of many long-term load transfer arrangements.[3]

Contested SAA applications have tended to arise in circumstances where the prospective customer is located in a portion of the Incumbent Distributor's service area where service is not currently provided by that Distributor (referred to in this Discussion Paper as an "un-serviced area"). These cases have all involved new service to new customers, with emphasis being placed on an evaluation of the costs of connection. In each of these cases, the Board agreed with the Applicant Distributor that an extension to its service area to serve the new customers was appropriate.

<u>The Renewed Regulatory Framework</u>

Through the RRFE, the Board has established distribution planning as a key element in the achievement of the outcomes expected of the distribution sector, and has established regional planning as a means of ensuring that regional issues and requirements are effectively integrated into a distributor's planning process.

[3] See, for example, EB-2007-0917 (involving Hydro One Networks Inc. and Whitby Hydro Electric Corporation) and EB-2007-0947 (involving Hydro One Networks Inc. and Peterborough Distribution Inc.).

In undertaking regional planning, distributors are expected to take municipal planning into account and to use municipal planning information in support of the development of their infrastructure development plans. The LTEP highlighted the connection between municipal planning and regional planning as well as speaking toto the important role community energy planning should have in the development of the sector[4]. Municipal plans can be used to inform SAA proposals in the same way as they are instructive for other system expansions for purposes such as the establishment of future utility corridors.

B2. Stakeholder Comments during the February Consultation

A number of distributors expressed the view that the Board’s current SAA policy gives preference to the Incumbent Distributor, and questioned why this should be the case particularly in relation to un-serviced areas.

Some distributors suggested that the Board’s SAA policy limited the Applicant Distributor’s likelihood of success by placing the onus on the Applicant Distributor to “make the case” as to why the SAA should be allowed to proceed. These same distributors questioned why a distributor should be assigned to an un-serviced area based on geography rather than on the basis of the distributor’s ability to provide service in the area. However, there was some acceptance of the principle that an Applicant Distributor should be expected to demonstrate that the proposed SAA is cost efficient and in the public interest.

It was suggested by some distributors that a more efficient approach to un-serviced areas would be for the Board to treat these as essentially “open for competition”, and that there be no “default” distributor for such areas.

Some distributors suggested that, where an SAA application involves an un-serviced area, the Board should also consider the appropriateness of extending the SAA to include existing customers where they are near a boundary that is being amended for the purpose of serving new customers. Several distributors and others suggested that an approach that would allow for rationalization at or near boundaries, either municipal borders or service areas, could improve the efficient use of distribution assets since distribution costs, including capital costs, operating and maintenance costs, and

[4] LTEP, p. 6

settlement costs with the IESO, would decrease as a result of fewer wholesale metering points, fewer substations and the reduction of non-distribution assets.

Distributors generally agreed that a policy aimed at aligning service areas with municipal boundaries should nonetheless require the proponent to provide evidence that the amended service area is to provide service to actual customers using assets and capacity in a manner that optimizes existing distribution assets.

Certain stakeholders representing distributors and consumer groups expressed the view that the focus of any analysis of competing offers as between the Incumbent Distributor and the Applicant Distributor should go beyond connection costs. It was pointed out by these stakeholders that other benefits can arise from an expansion into an un-serviced area, including efficiencies in regards to supply and cost related to transmission and the IESO. Some stakeholders also stated that there is currently not sufficient emphasis placed on the impact of a proposed SAA on existing customers of the Incumbent Distributor, and that a more holistic approach would ensure the best outcome from an economic efficiency perspective.

B3. Board Staff Observations and Questions for Stakeholders

Board staff observes that the Board’s current SAA policy emphasizes economic efficiency and embodies an expectation that SAA applications will consider contiguity and system capacity. To the extent that there is a concern regarding the scope of the costs considered in an SAA application proceeding, Board staff notes that the current SAA policy contemplates that all costs will be considered as part of the assessment of SAA applications.

Board staff believes it is important to keep the current legislative and licensing framework in mind when considering potential changes to the Board’s SAA policy. As noted above, a distributor is required by law and by its licence to connect a building that lies along its distribution system and to make an offer to connect such building on request, provided of course that the building is located within the distributor’s licensed service area.

Board staff also observes that this policy review provides an opportunity to consider whether there can be further alignment between regional planning and the Board’s SAA policy, particularly in relation to the use of municipal planning information.

Based on the February Consultation, staff has identified the following areas as being of particular interest to stakeholders: (i) the treatment of un-serviced areas as "open for competition", it being noted that these situations are unlikely to involve the stranding of assets; (ii) facilitation of SAAs that result in alignment with municipal boundaries; and (iii) adequately consideration being given to the interests of Incumbent distributors and their current and future customers.

The following questions are intended to elicit stakeholder comment on these issues.

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?

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?

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?

C. RATE-SETTING ASSOCIATED WITH MAADS

C1. Overview of Current Policy

The Board's policy with regards to rate issues associated with MAADs transactions was developed in 2007, and is found in its *Report of the Board regarding Rate-making Policies Associated with Distributor Consolidation* (the "2007 Policy"). In establishing the 2007 Policy, the Board recognized that MAADs transactions can increase efficiency in the distribution sector and noted that the 2007 Policy was intended to create a more predictable regulatory environment for distributors that are considering consolidation, thereby facilitating planning and decision-making and assisting distributors to determine the value of consolidation transactions.

The Board recognized that providing a reasonable opportunity to at least offset the costs of a MAADs transaction will be an important factor in a utility's consideration of the merits of a given consolidation initiative. The types of consolidation costs included out of pocket/transaction costs, acquisition premiums and restructuring costs.

Under the 2007 Policy, when a distributor applies for approval of a MAADs transaction it may propose to defer rebasing of the rates of the consolidated entity for up to five years from the date of the closing of the transaction. The purpose of this policy is to allow the net savings of a consolidation to accrue to a distributor's shareholder(s) for an extended period. The five-year period was selected based on a review of practice in other jurisdictions, and taking into consideration the fact that the maximum duration of any rate plan for distributors at the time was three years. The Board considered that setting a longer term would be premature until experience was gained under the 2007 Policy.

The Board was satisfied that the deferral period would not place financial viability or consumer interests at risk given the licensing regime and the incentive rate mechanism that would control rate increases during the deferral period.

In order to provide greater predictability to the sector, the Board indicated that in the normal course the expectation would be that a rebasing deferral proposal made as part of the application for approval of a MAADs transaction would only be rejected if there was compelling evidence that the proposal would not result in just and reasonable rates.

In the five distributor consolidation proceedings that have occurred since the 2007 Policy was established, four rebasing deferrals were granted.[5] However, of those, in only one case did the merged entity opt to defer rebasing for the full five years allowed under the Policy.

C2. Stakeholder Comments during the February Consultation

The principal focus of comments on the Board's rate-making policy associated with MAADs transactions was on the length of the period over which rebasing of a consolidated entity's rates can be deferred.

Distributors noted that the ability to recover the costs of a MAADs transaction is directly tied to the rate-setting process and the period during which rebasing of the consolidated entity's rates may be deferred. Distributors expressed the view that the risk for shareholders of not recovering transaction costs is a significant impediment to consolidation.

In the view of these distributors, five years from the date of the closing of the MAADs transaction may not provide sufficient time to achieve the savings and efficiency gains necessary to enable the recovery of transaction costs. Distributors explained that the transition and integration costs of a MAADs transaction, although largely upfront costs, can continue for two to four years following the completion of the transaction, whereas efficiency gains and savings resulting from the transaction will not start to be realized until the transaction is completed and the new entity has begun to operate. Distributors indicated that given the nature and timing of these costs and savings, annual net benefits (operational costs less transition and integration costs) are in many cases negative during the first two to four years. Therefore, it may take anywhere from six to ten years to reach a break-even point at which the cumulative savings exceed the cumulative transition and integration costs.

Distributors therefore suggested that greater flexibility in terms of the rebasing time frame would allow a shareholder to assess the benefits and costs of a consolidation

[5] Niagara Falls Hydro Inc. and Peninsula West Utilities Limited (EB-2007-0749), 3 year deferral; Middlesex Power Distribution Corporation, Dutton Hydro Limited and Newbury Power Inc. (EB-2008-0332), 5 year deferral; Middlesex Power and Chatham-Kent Hydro Inc. (EB-2011-0328), 2 year deferral; Erie Thames Powerlines Corporation, West Perth Power Inc. and Clinton Power Corporation (EB-2010-0386), no deferral; and PowerStream Inc. and Barrie Hydro Distribution Inc. (EB-2008-0335), 4 year deferral.

without necessarily having to also consider the impact of rebasing. Distributors argued that allowing them to retain any achieved savings for a longer deferral period will provide encouragement to those that may be interested in pursuing consolidation opportunities, and that increased consolidation activity will provide greater opportunity for efficiency savings to be passed on to ratepayers.

Representatives of consumers expressed the view that the economies of scale and other savings that result from a MAADs transaction should be shared equitably between the ratepayers of the distributors involved and the distributors' shareholders. Given that the rate-setting formula is intended to provide consumers with rates that reflect the efficiencies that distributors achieve, allowing long delays erodes the benefit of the rate model for consumers. Ratepayer representatives suggested that for the rebasing to be put off, other benefits for consumers would need to be provided, either in the form of new services or of a certainty of savings that would continue after the rebasing. Consumer representatives noted in this regard that the Board takes a “no harm” approach in assessing MAADs transactions.

Consumer representatives also suggested that allowing a distributor to choose its own time for rebasing may not benefit consumers. A distributor able to cut costs could delay rebasing to keep its savings, but a distributor who experiences higher costs could rebase immediately in order to pass those incremental costs on to ratepayers. Consumer groups were concerned that allowing the distributor to choose the timing of rebasing would not lead to equitable outcomes.

Distributors also indicated that while an extended rebasing period may allow for the recovery of costs, the treatment of capital investments during an extended incentive rate-making period may reduce the benefits of the extension. Some of the distributors suggested that few, if any, distributors would be able to operate over an extended rebasing period without incorporating normal capital expenditures into rate base. Their concern was that, if capital additions cannot be incorporated into rate base, the shareholder's rate of return would diminish and there would be impacts on financing for capital investments.

Distributors also expressed concern that they will be forced to choose between early rate rebasing to address capital spending, or delayed rebasing in order to enhance the viability of a MAADs transaction. In their view, this may have a dampening effect on consolidation because the recovery of transaction costs will come at the expense of foregoing the recovery of capital expenditures. By contrast, if distributors who are considering a MAADs transaction know that they have the ability to apply to the Board for the inclusion of on-going capital investments into rate base during the extended rebasing period that is necessary to earn savings, they may be more willing to consider consolidation.

C.3 Board Staff Observations & Questions for Stakeholders

The findings of the Distribution Sector Review Panel referred to earlier in this Discussion Paper support the view that consolidation among distributors can be a significant opportunity for achieving efficiency improvements and cost savings in the sector. These improvements can be brought about through both reductions in operating costs and the reduced cost of borrowing for the larger consolidated entity.

Based on the February Consultation, staff has identified the following areas as being of particular interest to stakeholders: (i) the duration of the deferral period for rebasing following the closing of a MAADs transaction; and (ii) a mechanism for adjusting rates to reflect capital investments during the rebasing deferral period.

As part of the RRFE, the Board has established a new rate-setting approach for distributors. A distributor may now choose amongst three rate-setting options: the Price Cap option, the Custom IR option and the Annual Index option. The incentive period between rate rebasings under the Price Cap option has been extended to four years from three.

Under the RRFE rate-setting options, there will now be potential for distributors that are party to a MAADs transaction to be on different rate options at the time of consolidation, which Board staff believes warrants consideration as part of this review of the 2007 Policy. It would be consistent with the 2007 Policy for distributors that are on the Price Cap option at the time of consolidation to continue to have their rates adjusted under the same mechanism until rebasing. In the case of distributors on the Annual Index option, there is no set rebasing timeframe and therefore no need for a deferral period. The consolidated distributor would continue to operate under the Annual Index option unless and until it selects a different option. The situation for a distributor on Custom IR is somewhat different as there is no annual adjustment mechanism; rates are set at the outset for a five year period, which leaves open the question of how rates would be adjusted during a rebasing deferral.

With respect to the issue of the treatment of capital investments during an extended period following a MAADs transaction, Board staff observes that the Board considered this issue in developing the 2007 Policy. At the time, stakeholders representing consumers suggested that the existing incentive rate-setting mechanisms already provided for the funding of capital, and that any additional mechanisms may result in an over-recovery from the consumer and could possibly reward underperforming distributors. The Board determined that it would not establish a mechanism to adjust for capital investment during the rebasing deferral period, and suggested that the matter should be considered as part of the next incentive regulation review.

Subsequently, in its September 17, 2008 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, the Board established the Incremental Capital Module ("ICM") as the mechanism by which distributors could seek funding for significant and extraordinary capital investments during the incentive regulation term. Of the three RRFE rate-setting options, an ICM application is available only to distributors that have chosen the Price Cap option. One approach that Board staff believes warrants consideration would be to allow merged distributors who are under any of the three rate setting methodologies to use the same ICM model during a deferral period, and to expand the eligibility criteria to include normal capital investments.

Board staff also observes that the financing of distributor investments was an issue that the Distribution Sector Review Panel addressed in its report. The Panel suggested that a significant benefit from consolidation would be reduced financing costs and increased financial resources to support capital investments in the renewal of assets and in new technology that the Panel believed was necessary to increase sector efficiency.

The following questions are intended to elicit stakeholder comment on the issues raised in relation to the Board's rate-setting policy regarding MAADs transactions.

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?

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?*

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?

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?

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?

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?