Ontario Energy Board

EB-2009-0349

Board Staff Discussion Paper

Proposed Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09

December 14, 2009

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1 INTRODUCTION

The *Green Energy and Green Economy Act, 2009* (the "Green Energy Act"), which received Royal Assent on May 14, 2009, made a number of amendments to the *Ontario Energy Board Act, 1998* (the "Act"). Among these amendments, the Board has, as a new objective, to *"promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities"* (paragraph 5 of subsection 1(1) of the Act).

Consistent with its new objective of promoting the use and generation of electricity from renewable energy sources, the Board has reviewed the cost responsibility policies with respect to the connection of renewable energy generation to distribution systems. As a consequence, in EB-2009-0077, the Board has issued final amendments (on October 21, 2009) to the Distribution System Code (DSC) in relation to *Distribution Connection Cost Responsibility* (the "DCCR Amendments") to revise its approach to assigning cost responsibility between a distributor and a generator. For the purposes of assigning cost responsibility, the Board decided that such investments be classified within three general categories:

1. Connection assets (*generator* responsibility);
2. Expansions (*shared* responsibility based on a cost cap or *distributor* responsibility if identified in a Board-approved investment plan); and
3. Renewable enabling improvements (*distributor* responsibility).

The consequences of these changes in cost responsibility will mean that some of the costs related to connecting renewable generators – previously the responsibility of the connecting generator – will shift to ratepayers.

Evidence from the Renewable Energy Standard Offer Program ("RESOP") suggests that distribution-connected renewable energy generation development will not be distributed evenly among the service territories of the electricity distributors. As a result, in the absence of a cost-sharing mechanism, the cost burden of distribution system investment to accommodate this renewable generation would not be shared equally amongst distributors (and their ratepayers).

The *Green Energy Act* recognizes that some portion of such investment costs incurred by individual distributors should be shared amongst the province's ratepayers. Specifically, the *Green Energy Act* amended the Act to introduce a mechanism under section 79.1 whereby some of the Board-approved costs incurred by a distributor to make an *'eligible investment*' for the purpose of connecting or enabling the connection of a renewable energy generation facility to its distribution system may be recovered from all provincial ratepayers rather than solely from the ratepayers of the distributor making the investment. (see Appendix 3 for full text of section 79.1). The structure of this rate protection provision closely resembles the provision in section 79 of the Act for Rural and Remote Rate Protection (RRRP).

To enable this rate protection provision, the Government filed Ontario Regulation 330/09 ("O. Reg. 330/09") on September 9, 2009 which sets out details related to the implementation of the cost recovery framework established in section 79.1. That cost recovery framework establishes a process for the collection – by the Independent Electricity System Operator (IESO) – of the amounts that qualify for rate protection and a process for the IESO to make compensation payments to distributors based on the rate protection amounts as determined by the Board to which each distributor is entitled. (see Appendix 4 for Regulation 330/09).

Regulation 330/09 sets out the following formula:

A = B - C, where:

A = the amount of *rate protection* to be provided to prescribed consumers in a distributor's service area,

B = eligible investment *costs* determined by the Board to be the responsibility of the distributor in accordance with the DSC, and

C = the amount the Board determines to represent the direct *benefits* that accrue to prescribed consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.

The Board's DCCR amendments process addressed the first part of the formula (see "**B**" above) by determining the "eligible investment costs" and those include *Expansion* and *Renewable Enabling Improvement* investments, as described above.

The focus of this new Board consultation process entails completing the framework for determining the amount of rate protection to be provided by specifying the "direct benefits" component of the regulation formula (see "**C**" above).

The purpose of this consultation process is therefore to establish a Board policy that identifies:

1. the direct benefits that must be taken into account; and
2. a standard methodology to be used in calculating or quantifying those direct benefits.

From a different perspective, the DCCR amendments set out the framework for establishing the 'gross' eligible investment costs and this consultation process will establish the framework for determining the 'net' costs (i.e., direct benefits) to be recovered from customers of the individual distributor making the eligible investment. The difference between those 'gross' and 'net' costs represents the amount to be recovered from all Ontario electricity consumers. As a consequence of the determination of the direct benefits, the cost allocation between provincial ratepayers and the ratepayers of the individual distributor will be determined.

2 SETTING THE CONTEXT

Prior to discussing the proposed types of direct benefits and the associated methodologies for quantification, Board staff feels it is important to provide some context as well as some clarifications in relation to O. Reg. 330/09.

The first observation is in relation to the relative magnitude of the eligible investment costs, particularly over the next couple of years. The Board has received Distribution System Plans from three distributors, including Hydro One Networks, Orangeville Hydro and Toronto Hydro Electric Services, outlining their anticipated expenditures related to connecting renewable energy generation (as well as investments related to the development of the smart grid and CDM). Although none of these Distribution System Plans have been approved by the Board, the information that can be extracted from these plans is helpful in setting the context.

- Of these, the "Green Energy Plan" filed by Hydro One, as part of its distribution rate application (EB-2009-0096), anticipates the largest expenditures. Hydro One's estimate of the gross eligible investment costs (i.e., before taking the benefits into account) rise from $155 million in 2010 to about $297 million in 2014, for a cumulative total of $1.315 billion over the five year period (or almost $265 million per year). Hydro One has also provided its estimate of the direct benefits (i.e., the allocation of those costs) to Hydro One ratepayers at $16 million (2010) and $40 million (2014).

- In contrast to Hydro One, Toronto Hydro focused solely on smart grid investments and the plan, therefore, makes no reference to the amount of renewable generation it plans to connect or the estimated gross eligible investment costs (and associated direct benefits).

- Orangeville Hydro also did not include estimated eligible investment costs associated with connecting renewable generation, as its plan notes *"Presently there are no large scale generation projects planned for our service territory"*, but does make reference to connecting *"800 premises with small scale renewable energy based generation capabilities with a total capacity of 2,400 kWs"*.[1]

To place these above figures in perspective, the total capital expenditures for all Ontario electricity distributors were about $1.4 billion in 2008. It is important to note, while the gross eligible investment costs are not the focus of this proceeding, the relative magnitude of those costs inform the Board of the potential magnitude of the direct benefits, since the benefits represent a portion of those gross eligible investment costs.

The degree of diversity in relation to the circumstances of the individual distributors also informs Board staff in regard to whether a single methodology for estimating the direct benefits is appropriate for all distributors. For example, under the Renewable Energy

[1] It is important to note that these dollar amounts and cost allocations in these three Distribution System Plans have not yet been decided upon by the Board and are only presented here for context purposes.

Standard Offer Program ("RESOP") which was launched in 2006, about 70% of the generation capacity that has been awarded a contract is located in the distribution territory of one distributor -- Hydro One Networks -- and the remaining 30% is spread across the territories of 47 other electricity distributors. It is also notable that 40 of those distributors each have less than 1% of the contracted capacity (including 26 distributors that each have less than 0.1%). The remaining distributors – about 30 – have no contracted RESOP generation at all. Given the diverse circumstances of distributors as illustrated by these figures and the three Distribution System Plans discussed above, a single methodology for estimating the direct benefits may not be appropriate for all distributors. For example, where the eligible investment costs are relatively large, a more rigorous and detailed assessment which allows for a more accurate estimate of the benefits can be justified. On the other hand, a less rigorous approach may be justified where the costs are relatively insignificant. In other words, Board staff believes it would be pragmatic to avoid an outcome whereby the costs incurred by a distributor to estimate the direct benefits exceed the direct benefits that the distributor is estimating. Otherwise, it would defeat the purpose of O. Reg. 330/09, which is to provide rate protection, as such implementation costs incurred by distributors will ultimately be recovered from their customers.

Regulation 330/09: Board Staff Observations

As discussed above, there is a relationship between the eligible investment costs and the associated direct benefits. As such, a clear understanding of what constitutes an eligible investment is necessary before discussing the related direct benefits. Board Staff therefore wishes to set out the following observations in relation to O. Reg. 330/09.

- "Eligible investment" costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the Act, are not limited to only the initial capital investment costs but also includes the *up-front* OM&A costs necessary for the purpose of "enabling the connection of a qualifying generation facility". However, given that section 79.1 focuses solely on the initial investment, *ongoing* OM&A costs that are incurred by the distributor after the investment has been made will not be eligible for provincial recovery.[2]

- The *Green Energy Act* focused on investments related to both the smart grid and the connection of renewable energy generation. However, O. Reg. 330/09 applies to only investments related to the connection of renewable energy generation in relation to being "eligible investments". As a result, unless a certain smart grid related investment has been identified in the DSC as a Renewable Enabling Improvement, such investments are not "eligible investments" for the purpose of the Act and the regulation.

[2] Board staff understands that there may be a misconception that the provincial recovery mechanism will be implemented through the Global Adjustment Mechanism (the "GAM"). That will not be the case. Under O. Reg. 330/09, the rate protection amounts approved by the Board will be recovered by distributors from consumers through the Wholesale Market Service Charge in a similar manner to RRRP. The IESO will establish a new charge-type for recovery from wholesale market participants.

- Not all investments made by a distributor to accommodate renewable generation will qualify as an "eligible investment". Investments to connect such generation that is contracted under the feed-in tariff ("FIT") program will be treated as an "eligible investment". However, similar investments to connect generation that was contracted under the RESOP program will not be treated as an "eligible investment". The important distinction is not between the two OPA programs. Instead, it is related to the Board's cost responsibility rules under the DSC and the timing of the recent DCCR amendments. RESOP generation was contracted before those DCCR amendments were made. As a consequence, investments to connect a RESOP generator remain the cost responsibility of the generator. In contrast, investments made by a distributor to connect FIT generators will occur after the Board issued its revised cost responsibility rules on October 21, 2009 and are therefore eligible for the provincial recovery mechanism. As such, the "direct benefits" which are the focus of this proceeding only take into consideration those related to investments to connect renewable generation under the FIT program.[3] Such generation is referred to as 'qualifying' renewable generation in this report.

- *Upstream* costs and benefits related to renewable generation connected in the distribution system will not be taken into account for the purpose of the Act and O. Reg. 330/09.

    - The Board's Notice (June 5, 2009) related to the DCCR Amendments (EB-2009-0077) states *"Some generation connections may trigger the need for upstream upgrades to the system of a host distributor or of a transmitter, in addition to triggering the need for the expansion of the distribution system to which the generation facility will be connected. Although the DSC is silent on the issue of cost responsibility for these upstream upgrades, the practice is for distributors to pass these costs on to the connecting generator. The Board does not propose to revise this approach at this time…".* Since such costs have been determined by the Board to be the responsibility of the generator, these investments would not be considered "eligible investments" under O. Reg. 330/09 and, as a consequence, would not be considered in determining the direct benefits.

    - Similarly, a potential *upstream* benefit often associated with distribution generation is related to the deferral or avoidance of certain transmission network investments. Such *upstream* benefits may be realized. However, these *upstream* benefits accrue to all provincial ratepayers – not only the customers of the distributor making the investment and, therefore, will not be considered in this particular proceeding.

[3] Any investment made by a distributor on or after October 21, 2009 to connect *merchant* renewable generation would also be considered an "eligible investment".

3 DIRECT BENEFITS

3.1 Rationale for taking Direct Benefits into Account

As noted above, the Government's intent is for the Board to provide rate protection. As a result, if the direct benefits that accrue to only the customers of the distributor making the investment are not taken into account, the Board would be going beyond providing rate 'protection' and approving a rate 'subsidy' to the customers of distributors with a material amount of investment to connect new renewable energy generation (while the remaining electricity consumers in Ontario would be required to pay that subsidy). As such, O. Reg. 330/09 enshrines the concept of Board-approved costs net of any Board-determined direct benefits in determining an appropriate amount of rate protection. It is also important to note the benefits do not appear to be limited to the investment as O. Reg. 330/09 specifically refers to the direct benefits that accrue to the prescribed consumers *"as a result of"* the eligible investment.

3.2 Identifying the Direct Benefits

As discussed above, O. Reg. 330/09 requires that the Board determine the *direct* benefits and O. Reg. 330/09 defines the prescribed consumers or classes of consumers to which these benefits accrue as those *"served by a licensed distributor that has incurred costs to make an eligible investment"*.

Board staff therefore proposes to limit the scope of the direct benefits to those that meet the following criteria:

1. the benefit is directly attributable to only the customers of the distributor making the investment; and
2. the benefit is readily quantified in monetary terms.

This approach would therefore exclude, for example, environmental benefits that may be attributed to additional renewable generation (i.e., potential displacement of coal generation). Such environmental benefits would accrue to the province as a whole – not be restricted within the territory of a specific distributor that made the investment – since these benefits would be associated with improvements in air quality. Similarly, local economic or fiscal impacts (e.g., additional local tax revenues) would also be excluded from the Board's determination of *direct* benefits, since such benefits would be *indirect* benefits.

Board staff has, on this basis, identified two benefits that meet the above criteria and are proposed to be used in determining the direct benefits that accrue to the prescribed customers of the distributor associated with connecting additional renewable energy generation. Those two direct benefits are as follows:

1. Reduced *network* transmission charges and reduced wholesale market service charges (WMSC) realized by the distributor as a consequence of electricity

production from new renewable generation connected by an eligible investment; and
2. Improved capabilities of the distribution system for load customers as a consequence of the eligible investments made by a distributor.

These direct benefits are explained further below.

3.2.1 Reduced Network Transmission and WMSC Charges

Distributors pay network transmission charges based on their electricity peak demand, while Wholesale Market Service Charges are based primarily on the distributor's allocated quantity of energy withdrawn (AQEW) from the transmission grid. As additional renewable generation is connected within a distribution system and begins to produce power, it will reduce both the peak demand and the total quantity of energy withdrawn by the distributor. This, in turn, reduces these charges that must be *paid* by the distributor to the IESO.[4] At the same time, there is no impact on the demand or quantity of energy consumed by that distributor's customers. This means that the charges *collected* by the distributor do not decline. As a result, surplus network transmission and WMSC charges will be collected by the distributor which will be recorded in the distributor's applicable variance account and that surplus will ultimately be paid (i.e., disbursed) to only its customers.

Customers of a particular distributor would realize a benefit (i.e., net reduction in such charges) if the quantity of energy produced by renewable generation connected to the eligible investments of that distributor exceeds the average across all distributors. The actual magnitude of the benefit to a particular distributor would depend on the total production by renewable generators connected to that distributor (relative to other distributors). The table below summarizes possible impacts on wholesale market service costs for distributors from this effect with different shares of renewable generation connected.

Share of energy supplied by distribution connected renewable generation	Reduction in average wholesale market service costs paid by distributor
0%	0.0%
10%	1.5 - 2.0%
20%	3.0 - 4.0%

Board staff's view is that such a reduction in these two charges constitutes a direct benefit to the customers of the distributor and should be reflected in the determination of the "direct benefits" for the purpose of O. Reg. 330/09. Another way to look at this is, since provincial ratepayers will be required to pay some or all of the costs of the eligible investment needed to connect the renewable energy generation (from which this benefit is directly derived), it is appropriate that those provincial ratepayers should also share in the benefit that was realized. In the absence of an eligible investment paid for by

[4] Other charges such as the Global Adjustment would not be taken into account because the Global Adjustment regulation already requires the IESO to take embedded generation into account as part of the forecast when it applies the Global Adjustment charge (i.e., AQEW + Embedded Generation).

provincial ratepayers, this benefit would not exist. The methodology to estimate this direct benefit is discussed in section 3.3.1 below.

3.2.2 Improved Capability of Distribution System for Load Customers

Certain investments in the distribution system to accommodate additional renewable generation will also result in benefits for load customers of the distributor making the investment. Many of the eligible investments will convey energy to load customers as well as from renewable energy generation. For example, an expansion investment, such as rebuilding or overbuilding an existing line to provide an additional circuit to a new generator location, may delay the need for an investment that would have been needed, in the absence of generation, to serve load growth. The investment may also replace an asset that would have required replacement, in the near future, solely for the purpose of serving load customers. Certain Renewable Enabling Improvement investments (e.g., distribution station monitoring) that are installed to connect generation may also enhance service quality for load customers.

The DCCR amendments defined two categories of investment which constitute the "eligible" investments. Since the benefits will differ and will need to be assessed in some cases based on whether the investment qualifies as an Expansion or Renewable Enabling Improvement, Board staff will take this opportunity to identify which types of specific investments are included in these two categories:

> *Expansion* investments include: rebuilding lines from single-phase to three-phase, rebuilding lines with a larger conductor size, rebuilding or overbuilding an existing line to provide an additional circuit, converting a voltage to operate at a higher voltage, replacing transformers to a larger MVA size, upgrading voltage regulating transformers or station controls to a larger MVA size; and adding or upgrading capacitor banks.
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> *Renewable Enabling Improvement (REI)* investments are limited to: modifications or additions to protect electrical equipment, modifications or additions of voltage regulating transformer controls or station controls, provisions to protect against islanding (e.g. transfer trip) bidirectional reclosers, tap-changer controls or relays, replacing breaker protection relays, SCADA system design, construction and connection, any modifications or additions to allow for 2-way power flows; and, communication systems to facilitate connection of renewable generation.

Issue for Comment:

1) In addition to the two types of direct benefits identified above (i.e., reduced transmission and WMSC charges, improved capability of the distribution system), should the Board take into account any other direct benefits that accrue to customers of the distributor making the investment?

3.3 Quantifying the Direct Benefits

3.3.1 Reduced Network Transmission and WMSC Charges

At the outset, Board staff considered two approaches – *ex-ante* and *ex-post* – for estimating the direct benefits associated with reduced network transmission and WMSC charges. Board staff preferred the *ex-post* approach for reasons that are set out below.

A determination of benefits in relation to reduced network transmission and WMSC charges will depend on the actual energy production from the renewable generation connected to eligible investments, its contribution to reduced peak demand and the estimated network transmission and WMSC charges. In practice, these charges will need to be forecast as the regulation requires that the amounts be set on an annual basis. All forecasts involve uncertainty, with a consequence that distributors may either recover less or more than the forecasted benefit estimated. To the extent that the benefits are over- or under-estimated, the Board approved forecast costs will be over- or under-recovered since those costs are a direct function of the forecast benefits.

Under an *ex-post* approach, quantifying the annual benefits in this category for a given year would be calculated by multiplying the actual rate (WMSC and transmission) by the actual renewable energy production from the *previous* year.

In the first year the Board determines the amount of rate protection (2010), Board staff is of the view that this benefit can be assumed to zero as 2009 would be used as the base year under an *ex-post* approach. The Ontario Power Authority's (OPA) feed-in tariff (FIT) program was just recently launched and, based on OPA experience to date, with the exception of some small rooftop solar, all other forms of renewable generation which are material in nature will require over one year to achieve commercial operation (i.e., permitting, construction, etc.). As such, Board staff expects there will still be relatively negligible amounts of generation producing power in 2010, but there will be some benefits to take into account. As a result, when the Board determines the amount of rate protection in 2011, an *ex-post* approach will be possible and it would be based on the actual amount of energy supplied by renewable energy generation connected to an eligible investment in a distributor's service territory over the most recent year (2010).

This *ex-post* approach would ensure 100% accuracy over the long term but with a one year lag. A potential drawback to this approach is, where renewable generation is added to a distributors system, it may understate the benefit in that year. This potential understatement will depend on the type and amount of renewable generation added in that year as well as the weather (i.e., wind conditions) relative to the previous year. Based on RESOP experience to date, over 90% will be intermittent in nature with most being wind and solar generation. Both types of generation have relatively low capacity factors. However, to the extent it understates the benefit in any one year, that understatement will automatically be taken into account the following year. As a result, this *ex-post* approach achieves the same outcome as using a variance account, however, it avoids the administrative burden and related costs associated with managing and clearing a variance account each year.

Board staff also considered an *ex-ante* approach that would require distributors to forecast the benefit in this category based on a forecast of energy produced by qualifying renewable generation in its territory.[5] Such a forecast would be completed each year by each distributor. This approach permits the renewable generation that is added within a year to be included in the calculation. However, it may or may not be more accurate than the *ex-post* approach within that year. One certainty about forecasts is they are never 100% accurate. For example, there is always a forecast error given the number of variables that need to be taken into account, particularly where the majority of the generation that is expected to be connected in the distribution system is either intermittent wind or solar generation as well as the complexities specifically associated with forecasting network transmission charges (see below). The distributor's forecast would also need to take into account the expected commercial operation date (COD) of each applicable renewable generation facility that will go into service during the forecast year. Generators often also announce COD changes due to unforeseen delays which would directly affect the accuracy of the distributor's forecast.

In addition, an *ex-ante* approach would entail two separate forecasts. For WMSC charges, it would be more straightforward as it is based on energy (i.e., kWh). However, in relation to network transmission charges, a forecast is relatively complicated because, in Ontario, this charge is based on the *higher of* the distributor's *coincident peak demand in the hour of monthly system peak and 85% of its non-coincident peak demand*. There is also the nature of generation that needs to be considered -- *wind* generation is expected to produce most during *off-peak* periods (i.e., during non-coincident peak) while *solar* generation is expected to produce most during *peak* periods (i.e., during coincident peak). For an accurate forecast to be possible, it therefore necessitates an hourly forecast for each weekday of the year by distributors.

An important trade-off that was weighed by Board staff in relation to the two approaches – *ex-ante* and *ex-post* – discussed above is the administrative burden imposed on distributors each year (and the consequential implementation costs) against the potential incremental precision.

The *ex-post* approach is proposed for a number of reasons.

1. The methodology will need to be implemented annually by all electricity distributors that make an eligible investment.
2. Striving for greater accuracy through the use of an annual forecast would require substantial resources and costs to be incurred by distributors on an annual basis, while the incremental precision may be relatively minor depending on the forecasting capabilities and expertise of the individual distributor, and whether factors such as the weather (e.g., wind conditions, amount of sun, etc.) deviate

[5] Qualifying renewable generation, for the purposes of this report, means a renewable generator in respect of which the new cost responsibility rules under the DSC apply as of October 21, 2009.

materially from normal.[6] Such implementation costs would ultimately be recovered from Ontario electricity consumers that are served by distributors.

3. As noted above, an *ex-post* approach guarantees a 100% accurate calculation of the direct benefits in this category. On the other hand, an *ex-ante* approach (i.e., use of an annual forecast) would guarantee the opposite – possibly close but never 100% accurate.

Issue for Comment:

2) Are there any circumstances under which a distributor should be permitted to deviate from the proposed *ex-post* approach and use an *ex-ante* (i.e., forwarding looking forecast) approach?

3.3.2 Improved Capability of Distribution System for Load Customers

3.3.2.1 Proposed Approach

The following is the proposed framework for the estimation of the direct benefits related to this category. Board staff has identified a number of proposed principles and criteria to be taken into account by the distributor in estimating the benefits that will accrue to the customers of the distributor as a consequence of making the eligible investment(s).

Proposed Guiding Principles

Board staff is proposing the following guiding principles as a basis for the more detailed discussion of the criteria that follow.

- The benefit is directly attributable to only the customers of the distributor making the investment (i.e., limited to distribution system investments) and the benefit is readily quantified in monetary terms.

- The level of detail and analysis provided by a distributor underlying the estimation of the direct benefits should be commensurate with the circumstances of the distributor.

- Portions of certain eligible investments may not ultimately be used by only qualifying renewable generation facilities to which the Board's new cost responsibility policies apply. Consistent with O. Reg. 330/09, to the extent the investment is used for other purposes (e.g., connect a load customer(s), that

[6] All forecasts in Ontario in relation to the electricity sector are based on a "normal" weather forecast and the weather is beyond the control of utility. This is the reason utilities often present and measure the accuracy of previous forecasts on a weather-corrected basis. However, for the purpose of estimating the benefits in relation to O. Reg. 330/09, an actual forecast would be used (i.e., not weather-corrected).

portion of the investment would not be recovered through the provincial recovery mechanism.

- Where any existing distribution asset is replaced to accommodate qualifying renewable generation, customers of the distributor making the investment will realize a direct benefit of some magnitude and therefore a certain portion of the costs should not be recovered through provincial recovery mechanism.

- To the extent certain eligible investments (e.g., Renewable Enabling Improvements) that accommodate qualifying renewable generation are expected to improve service quality for the load customers of the distributor making the investment, such service quality improvements will represent a direct benefit to only the customers of that distributor (i.e., not paid for under the provincial recovery mechanism).

- Distributors should not be required to estimate certain benefits (e.g., line losses) that may, in theory, sometimes be associated with distributed generation in a generic sense, but do not take into consideration the practical circumstances unique to Ontario under the *Green Energy Act*.

Issues for Comment:

3) Are there any potential refinements to the proposed Guiding Principles discussed above?
4) Should any additional Guiding Principles be considered by the Board?

Proposed Criteria

Given the extreme diversity of distributors (as discussed above in section 2), Board staff is of the view that such diversity should be recognized. As such, Board staff proposes that the *level of detail and analysis provided by a distributor should be commensurate with the circumstances of the distributor* in terms of the amount (MW) of renewable energy generation to be connected and the magnitude of the associated eligible investment in the Distribution System Plan of that distributor.

The specific proposed criteria are comprised of the following.

Portion of Eligible Investments not used by Qualifying Generators

The distributor should, in its Distribution System Plan, estimate to what degree (i.e., share) the investment will be used by *load customers* (as well as by qualifying renewable generators). Board staff expects that investments serving higher customer density areas will result in higher benefits in monetary terms to the distributor’s customers, since more load customers will be served by the assets that are upgraded or added to accommodate the generation. To the extent those new customers are served by a new, upgraded or replacement asset(s), the distributor will benefit from additional distribution revenues. In contrast, in circumstances where a generator is being connected in a remote area where few customers of the distributor are located, the benefits to the specific distributor's customers may be relatively low. In the absence of a detailed density study, distributors may use an alternative approach to estimate the extent that load customers will benefit.

The distributor should also estimate the portion of the investment that will be utilized by *non-qualifying generators*. This is not limited to non-renewable distributed generation that may be connected. It also includes renewable generation that has proceeded under a RESOP contract, as different cost responsibility rules apply under which the majority of the costs remain the responsibility of the connecting generator.

To the extent this criterion is not appropriately taken into account, the distributor would derive two revenue streams for the same asset via distribution revenues or a capital contribution (as well as 'compensation payments' for 'rate protection' purposes).

There may be instances where the Board has determined an investment to be an eligible investment but circumstances resulted in the distributor subsequently utilizing the asset for other purposes (e.g., to connect load customers and/or non-qualifying generators). In such cases, Board staff is of the view that any direct benefits, which were not previously taken into account in an appropriate manner, should be applied by the distributor as a direct benefit to reduce future eligible investment costs of that distributor. The amount of rate protection would accordingly be reduced by the Board going forward. Absent such a provision, Board staff is of the view that the intent of O. Reg. 330/09 (i.e., provincial recovery limited to eligible investments) cannot be met. Board staff notes, in cases where it is simply a matter that planned renewable generation has not been connected and the distributor has not used the asset for other purposes, there would be no direct benefits to take into account (i.e., no adjustments would be necessary).

Customer Load Growth

The distributor should also estimate the extent to which an eligible investment might replace an investment that would otherwise be required to accommodate load growth. For example, in relation to an Expansion-related eligible investment involving new assets (e.g., a new distribution line), where load growth is relatively high, an expansion would have been required in the future even if there was not a new generator to connect.

In applying this criterion, the load growth used should be as specific as possible to the area/region where the generation will connect. For example, the degree of load growth tends to vary across a distributor's system. As such, use of a distributor's system-wide load growth would not provide an accurate estimation of the direct benefits.

While an Expansion-related eligible investment has been used as an example above, this criterion will also be applicable to Renewable Enabling Improvement (REI) investments.

Asset Condition

Where an eligible investment is a replacement asset, the direct benefit to load customers of the distributor will depend on the condition and remaining useful life associated with the asset it replaces. The distributor should, in its Distribution System Plan, estimate the remaining useful life of the asset being replaced. For example, a 15 MVA transformer may need to be upgraded to a 25 MVA transformer. The benefits to the distributor will depend, in part, on the remaining useful life of the 15 MVA transformer that was replaced. If the transformer would have required replacement in the near future, regardless if a generator needed to be connected, the direct benefits to the distributor's customers would be relatively significant. On the other hand, if the existing transformer was in good operating condition and was expected to have many years of service remaining, the direct benefits, in most cases, would be expected to be relatively minor.

Given the above, where <u>any</u> asset is replaced, it is expected that a certain portion of the costs would be allocated to its own customers, as a replacement asset will always extend the timeframe over which the asset would have needed to be replaced anyway and therefore represent a direct benefit.

Size of Renewable Energy Generator(s)

The size of the generator(s) that are to be connected to a specific asset should also be taken into account by distributors in undertaking its assessment of the benefits. For example, where it involves the connection of generators that are relatively small, it should be easier to integrate such generators into the existing distribution system through upgrades. On the contrary, where it involves the connection of a relatively large generator, it may be more costly to integrate it into the existing system and, in certain cases, may even necessitate a dedicated new asset solely or primarily to serve the generator. In such cases, it is also expected that the benefits that are attributable to the customers of the distributor making the investment would be much more limited.

Service Quality Improvements

Renewable Enabling Improvement investments (e.g., two-way flow management, voltage regulation, new protection devices) can also improve service quality to a distributor's load customers. The degree of improvement depends on the customer density in that specific part of the distribution system. Board staff expects that higher customer density will tend to result in higher benefits in monetary terms to the distributor's customers, since more load customers will be served by the assets that are upgraded or added to accommodate the generation. In contrast, in circumstances where the generator is being connected in a remote area where few customers of the distributor are located, the benefits to the specific distributor's customers are expected to be lower.

Similar to the customer load growth criterion above, in applying this criterion, the customer density used should be as specific as possible to the area/region where the generation will connect (i.e., not system-wide customer density).

Information regarding customer density may not be readily available for many distributors. Board staff therefore requests feedback from distributors in regard to the availability of such information and, from all parties including distributors, whether there is a relatively accurate manner in which customer density can be reasonably estimated based on other information that is available.

Line Losses

Board staff is of the view that distributor's should *not* be required to take this criterion into account in estimating the direct benefits at this time.

There is a common understanding in a generic sense that adding distributed generation will likely reduce line losses in the distribution system as generation is added closer to the load customers. However, this expectation tends to be based on circumstances where the utility has a certain degree of control over *where* the new generation is connected as well as the *type* of distributed generation that is connected. This, in turn, permits the distributor to connect generation where it is most needed and determine an appropriate balance between intermittent and non-intermittent generation in its service territory.

Under other circumstances, it is possible for line losses to increase due to distributed generation. For example, in a recent study prepared in New Zealand, entitled *Costs and Benefits of Connecting Distributed Generation to Local Networks,* it notes:

> *"The analysis shows that NPV costs can be reduced significantly by connecting DG at appropriate locations based on the existing network characteristics… the impact of DG types on network losses is difficult to predict primarily due to the following difficulties*
>
> - *Estimation of effect of DG on minimising peak demand*
> - *Profile mismatch between DG dispatch and network load demand.*
>
> *For cost benefit analysis it is assumed that DG will increase the network losses as the probability of generation from intermittent DG that is able to meet peak network demands is very low. DG intermittency will also impact on the cost associated with network upgrades resulting from the connection of DG and to a lesser extent power quality. With increasing amounts of*

> *intermittent DG penetration the cost of energy loss increases as compared to the base case with no intermittent DG."*[7]

As generators – not distributors – in Ontario will be determining the point of connection, the distributor will have no control in relation to the impact of the generator on line losses. Given the uncertainty regarding the impact on line losses in terms of costs or benefits to the distributor's customers, Board staff is of the view that some experience should first be gained within this context. Once more information is available, Board staff believes the Board will be in a better position to determine if such a criterion can be incorporated into a benefits assessment framework with relative certainty and accuracy.

Alternative Criteria for Specific Investments

While Board staff expects applying the general criteria above in a similar manner to all eligible investments to be the most practical approach for distributors, certain selected asset investments may be more amenable to a benefit evaluation based on an alternative criterion (i.e., may not take any of the above criteria in account). Board staff proposes that, if a distributor feels that another criterion would result in a more accurate estimate of the benefits, the distributor may propose such a criterion. Board staff expects that this would be the exception rather than rule and that the distributor would make a case that the alternative criterion was more appropriate in that particular instance.

The following is a series of questions where Board staff is requesting input. It is not intended to be exhaustive. In providing such input, Board staff requests that parties take into consideration the relative magnitude of these costs at this time, the incremental precision it will provide and the administrative burden it will impose on distributors.

[7] *Costs and Benefits of Connecting Distributed Generation to Local Networks: Final Report*, Energy Efficiency and Conservation Authority, 24 September 2008, pages 46 - 47.

Issues for Comment:

5) Are there any potential refinements to the proposed criteria discussed above for the purpose of estimating the direct benefits?
6) Are there any other criteria that the Board should potentially take into consideration or should certain criterion listed above not be taken into account? In proposing the addition and/or elimination of certain criteria, a solid business case should be made for the Board to consider the merits.
7) Is a ranking or weighting of the criteria above necessary? If so, please propose an appropriate ranking or weighting, from most to least applicable, and provide a supporting justification.
8) Are there any information limitations that may prevent certain distributors from providing an assessment of any criteria above?
9) In the absence of having the best available information possible (e.g., recently completed study), are there any factors above for which a distributor would not be able to provide a reasonable estimate?
10) What information should all distributors already have on hand (e.g., for distribution planning) that would allow for a reasonable estimate that is specific to certain areas of a distributor's territory of: (1) load growth; and (2) customer density?
11) Where provincial ratepayers have provided rate protection and the asset is not ultimately used by the distributor as an eligible investment, Board staff proposed that the amount of rate protection should be reduced accordingly going forward to reflect the use of the investment for other purposes. In such cases, are there any circumstances under which the amount of rate protection provided by provincial ratepayers should not be reduced? If so, please explain.

3.3.2.2 <u>Potential Future Option</u>

Board staff recognizes that quantifying the direct benefits, associated with the improved capability of the distribution system for load customers as a result of making eligible investments to connect renewable generation, will involve estimating a number of variables.

Board staff also recognizes that it is important to take into account the circumstances of the distributor and that it may be desirable to consider two different approaches based on the circumstances of the distributor in the future. For example, in regard to distributors that are undertaking a large number of investments, the proposed methodology that is outlined above (in section 3.2.2.1) to assist distributors in estimating these benefits would continue to apply. On the other hand, if the future is consistent with the figures provided by the OPA in relation to the locations of RESOP contracts to date, Board staff also recognizes that the majority of distributors would have a much lower level of investment in monetary terms. For such distributors, undertaking a full analysis to estimate these benefits every year may result in administrative costs that represent a significant fraction of the benefit being estimated. For this reason, the Board may wish to consider a less resource-intensive standardized approach or methodology (i.e., rule of thumb) to be used to estimate these benefits, where appropriate. For example, such a rule of thumb could be based on historical distributor-specific Board-approved results associated with implementation of the principles and criteria discussed above in section 3.3.2.1.

The rationale for a two-pronged approach noted above is that in some, but not all cases, the cost of achieving precision could outweigh the value of the precision achieved. If there is relatively little distribution revenue at issue, a relatively simple approximation may be justified. Board staff notes that the Board currently takes a similar two-pronged approach to estimating distributor working capital allowances which amount to about $1.5 billion annually (and contributes to rate base). Within the context of establishing working capital allowances, where it has become justified over the years, a limited number of larger distributors were recently required to begin undertaking a relatively rigorous and detailed calculation involving a lead/lag study. On the other hand, for the remaining distributors, a standardized 15 percent guideline (i.e., 15% of the sum of the cost of power and controllable expenses) has been employed by the Board since 2000.[8] Similar to working capital allowances, the Board may wish to consider an evolutionary policy construct for the purpose of this policy, with a more rigorous and detailed analysis required (as described in section 3.3.2.1) as and when it is justified.

At the same time, Board staff is of the view that such a standardized approach is not possible at the outset for the purpose of determining these direct benefits. Given the diverse nature of the distributors in relation to certain of the proposed criteria outlined above (e.g., customer load growth, customer density, etc.) and that the Board does not yet have any historical information to draw upon, the Board will have no foundation to provide the basis for a standardized approach at this time. In contrast, in the case of working capital, the 15% guideline had previously been employed by Ontario Hydro. Board staff is therefore of the view that a necessary prerequisite for the Board to be able to consider a standardized approach is the need to first develop a ‘baseline’ for each distributor based on some historical results (for example, a certain percentage of Expansion investments and a certain percentage of REI investments with adjustments where appropriate).

As a result, since Board staff presently has no basis on which to propose a standardized approach that will result in a relatively accurate estimate of the direct benefits for each distributor, Board staff proposes that the framework described above in section 3.3.2.1 apply to all distributors at the outset.

[8] Prior to the OEB, Ontario Hydro employed the same 15% guideline. Two of about 80 distributors currently have rates in place that were based on a Board directed Lead/Lag study. For about five years, all electricity distributors employed the 15% guideline, and Hydro One then became the first distributor to submit such a study followed by Toronto Hydro. London Hydro was also recently directed by the Board to file such a study in its next Cost of Service application.

Issues for Comment:

12) Should the Board consider a certain standardized approach? If so, how should the approach be standardized?
13) Would a certain percentage of expansion investments and a certain percentage of REI investments (using a historical "baseline" specific to each distributor) provide a reasonable estimate on a go forward basis?
14) If the Board decided a standardized approach would be appropriate for certain distributors:
    (i) What *timeframe* would be suitable for implementation?
    (ii) What would an appropriate *threshold* be to determine which distributors could proceed under a standardized approach and which distributors should be required to continue under the more rigorous assessment discussed in section 3.3.2.1?

4. CONCLUSION

The Board's first phase of determining cost responsibility was completed in October 2009 and determined the allocation of costs between generators and distributors.

Building on phase one, this second phase is needed to allocate the non-generator costs between the ratepayers of the distributor making the investment and provincial ratepayers (load customers of the IESO and distributors). The direct benefits as determined by the Board will represent the allocation of costs to the ratepayers of the distributor making the investment.

Board staff has proposed two categories of direct benefits that accrue to the customer's of the distributor making the investment to form the basis from which this allocation will be determined. Those direct benefits are comprised of: (1) surplus Network transmission and wholesale market service charges; and (2) a portion of the Expansion and Renewable Enabling Improvement (REI) eligible investment costs.

For the first category of direct benefits, the same *ex-post* approach is proposed to apply to all distributors for quantifying these benefits. Based on the actual production from renewable generation the previous year, the surplus network transmission and WMSC charges collected by the distributor, as a consequence of new embedded renewable generation connected to eligible investments, would be determined to be a direct benefit that accrues to the customers of the distributor as a result of the eligible investments.

For the second category of direct benefits, Board staff is also proposing that a similar approach apply to all distributors, at least in the near term. The methodology to derive those benefits would be based on the proposed principles and criteria discussed above in section 3.3.2.1. As noted, Board staff proposes that the level of detail and analysis provided by a distributor should be commensurate with the circumstances of the distributor. Following the development of a 'baseline' for each distributor that takes into account the diverse circumstances of each distributor (e.g., rural vs. urban, high vs. low load growth, etc.), the Board may wish to consider transitioning to a standardized approach for certain distributors as discussed in section 3.3.2.2; e.g., in cases where there is relatively little incremental renewable generation connected, an approximation may be justified based on a standardized approach. As such, the Board may wish to consider an evolutionary policy construct for the purpose of this policy, with a more rigorous analysis required where and when it is justified (i.e., disproportionate share of incremental renewable generation connections).

Consequently, the formula to determine aggregate rate protection amounts would be as follows:

Aggregate Rate Protection
=
Eligible Investment Costs (100% of Expansions + 100% of REIs)
less
Direct Benefits (xx% of Expansions + yy% of REIs + reduced Network Tx & WMSC charges)

Once the Board establishes the Aggregate Rate Protection amount, the Board will establish a rate that would be applied to all Ontario electricity customers of distributors in a manner that is consistent with the cost recovery framework set out in O. Reg. 330/09.[9]

Board staff considers this proposed approach to be a transitional and evolutionary policy. A transitional policy that takes into account the following:

1. O. Reg. 330/09 which clarified the Board's responsibilities in this regard was issued only a couple of months ago;
2. the relative magnitude of the estimated costs and, therefore, the associated direct benefits at this time; and
3. estimating direct benefits in relation to such investments, for the purpose of establishing rates, is a new responsibility for the Board, particularly given the manner such generation will be connected which is unique to Ontario.[10] As a consequence, results from other jurisdictions cannot be directly applied to Ontario.

Over time, as material amounts of renewable energy generation is connected across Ontario, Board staff expects there will be an opportunity to gain experience, in relation to quantifying the direct benefits, based on actual results. In doing so, as the Board, distributors and other parties in this proceeding attain a better understanding of the direct benefits (and costs), under the circumstances unique to Ontario, it should allow the Board to refine its policy approach in this regard.

Board staff is of the view that the proposed approach discussed above strikes a reasonable balance between administrative burden and incremental precision.

Appendix 1: *Compilation of Issues for Comment*
Appendix 2: *Table - Proposed Rules for Determining Provincial vs Distributor Cost Recovery*
Appendix 3: *Section 79.1 - Ontario Energy Board Act, 1998*
Appendix 4: *Full Text of Ontario Regulation 330/09*

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[9] The rate set by the Board will be a function of the Aggregate Rate Protection Amount and an IESO forecast (AQEW + Embedded Generation). Under Regulation 330/09, the fixed annual rate set by the Board (included in the WMSC) will only be applied by distributors. The IESO will collect the actual amounts of 'rate protection' each month from Market Participants, including distributors, as determined by the Board (and pay out the exact same amount in Monthly Compensation Payments to distributors based on their share as set out by the Board). The IESO will therefore charge a different "notional" rate to Market Participants that varies each month (i.e., not fixed) with fluctuations in market consumption.

[10] In other jurisdictions (e.g., New Zealand), where benefits have been estimated, the local distribution companies were provided with more control over where distributed generation is connected and the type of generation (i.e., an appropriate balance between intermittent and non-intermittent generation) in a manner that allowed for the "optimization" of the network and the maximization of the benefits associated with distributed generation. In contrast, under the *Green Energy Act*, distributors will have an obligation to connect renewable generation facilities regardless of the location and type of generation.

Appendix 1:

Compilation of Issues for Comment

Section		Issues for Comment
3.2	**Identifying the Direct Benefits**	1) In addition to the two types of direct benefits identified above (i.e., reduced transmission and WMSC charges, improved capability of the distribution system), should the Board take into account any other direct benefits that accrue to customers of the distributor making the investment?
3.3	**Quantifying the Direct Benefits**	**Reduced Network Transmission and WMSC Charges** 2) Are there any circumstances under which a distributor should be permitted to deviate from the proposed *ex-post* approach and use an *ex-ante* (i.e., forwarding looking forecast) approach?
		Improved Capability of the Distribution System for Load Customers *Proposed Guiding Principles* 3) Are there any potential refinements to the proposed Guiding Principles discussed above? 4) Should any additional Guiding Principles be considered by the Board?
		Proposed Criteria 5) Are there any potential refinements to the proposed criteria discussed above for the purpose of estimating the direct benefits? 6) Are there any other criteria that the Board should potentially take into consideration or should certain criterion listed above not be taken into account? In proposing the addition and/or elimination of certain criteria, a solid business case should be made for the Board to consider the merits. 7) Is a ranking or weighting of the criteria above necessary? If so, please propose an appropriate ranking or weighting, from most to least applicable, and provide a supporting justification. 8) Are there any information limitations that may prevent certain distributors from providing an assessment of any criteria above?

<table>
<tr><th colspan="2">Section</th><th>Issues for Comment</th></tr>
<tr><td rowspan="2">3.3</td><td rowspan="2">Quantifying the Direct Benefits (cont'd)</td><td>Proposed Criteria (cont'd)

9) In the absence of having the best available information possible (e.g., recently completed study), are there any factors above for which a distributor would not be able to provide a reasonable estimate?
10) What information should all distributors already have on hand (e.g., for distribution planning) that would allow for a reasonable estimate that is specific to certain areas of a distributor's territory of: (1) load growth; and (2) customer density?
11) Where provincial ratepayers have provided rate protection and the asset is not ultimately used by the distributor as an eligible investment, Board staff proposed that the amount of rate protection should be reduced accordingly going forward to reflect the use of the investment for other purposes. In such cases, are there any circumstances under which the amount of rate protection provided by provincial ratepayers should not be reduced? If so, please explain.</td></tr>
<tr><td>Potential Future Option

12) Should the Board consider a certain standardized approach? If so, how should the approach be standardized?
13) Would a certain percentage of expansion investments and a certain percentage of REI investments (using a historical "baseline" specific to each distributor) provide a reasonable estimate on a go forward basis?
14) If the Board decided a standardized approach would be appropriate for certain distributors:
(i) What timeframe would be suitable for implementation?
(ii) What would an appropriate threshold be to determine which distributors could proceed under a standardized approach and which distributors should be required to continue under the more rigorous assessment discussed in section 3.3.2.1?</td></tr>
</table>

Appendix 2:

Proposed Rules for Determining Provincial vs Distributor Cost Allocation

<table>
<tr><th rowspan="2">Investment type</th><th rowspan="2">Cost Responsibility
(as per October 2009 DCCR DSC Amendments)</th><th colspan="2">Allocation of Non-Generator Cost Responsibility:
Provincial vs Distributor Recovery</th></tr>
<tr><th>Provincial</th><th>Distributor</th></tr>
<tr><td>Connection Assets:
Dedicated facilities to connect a customer to the existing main distribution system
Not intended to be shared with other users</td><td>Generator</td><td>N/A</td><td>N/A</td></tr>
<tr><td rowspan="3">Expansions:
rebuilding single-phase to three-phase to generator location
rebuilding existing line with larger size conductor to generator location
rebuilding or overbuilding existing line to provide additional circuit to generator location
converting lower voltage line to operate at higher voltage</td><td>When investment triggered by a specific generator connection:

Costs up to threshold:
Distributor</td><td>xx%
(of costs up to threshold)</td><td>xx%
(of costs up to threshold)</td></tr>
<tr><td>Costs above threshold:
Generator</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Investment in Board-approved Distribution System Plan:
Distributor</td><td>xx%
(of all costs)</td><td>xx%
(of all costs)</td></tr>
<tr><td>Renewable Enabling Improvements:
Accommodating 2-way (as opposed to radial) electrical flows
Upgrade electrical protection facilities
Enhance voltage regulating facilities
Provide for protection against islanding (transfer- trip)</td><td>Distributor</td><td>yy%
(of all costs)</td><td>yy%
(of all costs)</td></tr>
</table>

Appendix 3:

Section 79.1: Ontario Energy Board Act, 1998

Cost recovery, connecting generation facilities
79.1 (1) The Board, in approving just and reasonable rates for a distributor that incurs costs to make an eligible investment for the purpose of connecting or enabling the connection of a qualifying generation facility to its distribution system, shall provide rate protection for prescribed consumers or classes of consumers in the distributor's service area by reducing the rates that would otherwise apply in accordance with the prescribed rules.

Distributor entitled to compensation re lost revenue
(2) A distributor is entitled to be compensated for lost revenue resulting from the rate reduction provided under subsection (1) that is associated with costs that have been approved by the Board and incurred by the distributor to make an eligible investment referred to in subsection (1).

Consumers' contributions
(3) All consumers are required to contribute towards the amount of any compensation required under subsection (2) in accordance with the regulations.

Regulations
(4) The Lieutenant Governor in Council may make regulations,

(a) prescribing consumers or classes of consumers eligible for rate protection under this section;
(b) prescribing criteria to be met by a qualifying generation facility;
(c) prescribing the criteria to be satisfied for an in-vestment to be an eligible investment;
(d) prescribing rules for the calculation of the amount of the rate reduction;
(e) prescribing maximum amounts of the total annual value of rate protection that may be provided under this section;
(f) prescribing rules respecting the amounts that must be collected to compensate distributors, including rules,

(i) respecting the calculation of those amounts,
(ii) establishing the time and manner of collection,
(iii) requiring the amounts to be paid in instalments and requiring the payment of interest or penalties on late payments,
(iv) prescribing methods of ensuring that the amounts required cannot be bypassed, and
(v) respecting the distribution of the amounts collected;

(g) prescribing the powers and duties of the Board in relation to the calculation of amounts to be collected and the time and manner of collection and distribution;

Definitions
(5) In this section,

"eligible investment" means an investment in the construction, expansion or reinforcement of a distribution line, transformer, plant or equipment used for conveying electricity at voltages of 50 kilovolts or less that meets the criteria prescribed by regulation;
"qualifying generation facility" means a generation facility that meets the criteria prescribed by regulation.

Appendix 4:

Full Text of Ontario Regulation 330/09

Definitions and interpretation

1. (1) In this Regulation,

“consumer” has the same meaning as in the *Electricity Act, 1998*;

“embedded distributor” means a licensed distributor who is not a market participant and to whom a host distributor distributes electricity;

“embedded generator” means a generator who is not a market participant and whose generation facility is connected to a distribution system of a licensed distributor, but does not include a generator who consumes more electricity than it generates;

“host distributor” means a licensed distributor who is a market participant and who distributes electricity to another licensed distributor who is not a market participant;

“licensed distributor” means a distributor who is licensed under Part V of the Act;

“qualified distributor” means a distributor serving consumers or classes of consumers that are being provided rate protection pursuant to subsection 79.1 (1) of the Act in accordance with this Regulation;

“rate protection” means rate protection under section 79.1 of the Act.

(2) The prescribed criterion for falling within the definition of an “eligible investment” under subsection 79.1 (5) of the Act is that the costs associated with the investment are determined to be the responsibility of the distributor in accordance with the Board’s Distribution System Code.

(3) The prescribed criterion for falling within the definition of a “qualifying generation facility” under subsection 79.1 (5) of the Act is that the generation facility satisfies the criteria necessary to be a renewable energy generation facility under the *Electricity Act, 1998*.

Consumers eligible for rate protection

2. Consumers or classes of consumers are prescribed consumers or classes of consumers for the purposes of subsection 79.1 (4) of the Act if they are served by a licensed distributor that has incurred costs to make an eligible investment that has been approved by an order of the Board.

Calculation of rate protection

3. (1) The Board shall calculate the annual amount of rate protection to be provided to prescribed consumers or classes of consumers using the following formula:

$$A = B - C$$

where,

A is the amount of rate protection to be provided to prescribed consumers or classes of consumers in a distributor’s service area, B is the costs associated with the eligible investment described in subsection 1 (2), and

C is the amount that the Board determines to represent the direct benefits that accrue to prescribed consumers or classes of consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.

(2) The Board shall calculate a monthly amount of compensation, referred to as the distributor's monthly compensation amount, to which each qualifying distributor is entitled, which amount shall be based on the amount calculated under subsection (1).

(3) Where the Board provides rate protection for a qualified distributor's prescribed consumers or classes of consumers, the Board shall, as often as is necessary and no less frequently than annually, calculate an aggregate monthly compensation amount by aggregating the amounts calculated under subsection (2) for each qualified distributor for each month for which collection is required.

(4) The Board shall, as often as is necessary and no less frequently than annually, calculate the monthly amount to be collected by the IESO under subsection 4 (2), such that the total amount that is to be collected is equal to the total amount of rate protection that is to be provided.

(5) The Board shall, as often as is necessary and no less frequently than annually, calculate the amount of the charge to be collected by each distributor under subsection 4 (3) for each kilowatt hour of electricity that is distributed to a consumer or embedded distributor, such that the total forecasted amount that is to be collected is equal to the total amount of rate protection that is to be provided.

(6) In any year, if the amounts collected by distributors in accordance with subsection (5) are greater or less than the amounts calculated under subsection (3), the excess or shortfall shall be considered by the Board in calculating the amount of the charge that is to be collected by distributors under subsection (5) for the following year.

(7) Qualified distributors and persons to whom this Regulation applies shall provide the information relating to this Regulation that the Board requires, in a form and within the time specified by the Board.

IESO calculation of proportional share

4. (1) On a monthly basis, the IESO shall collect from market participants the amount calculated by the Board under subsection 3 (4) based on each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid, as determined in accordance with the Market Rules, where the electricity is for the use of consumers within Ontario.

(2) For the purposes of subsection (1), the IESO shall proportionately charge market participants based on the total of the net volume of electricity withdrawn by the market participants from the IESO-controlled grid during the month and, if the market participant is a licensed distributor, the sum of,

(a) the total volume of electricity supplied by embedded generators during the month to the market participant, adjusted for losses as required by the Retail Settlement Code; and

(b) the total volume of electricity supplied by embedded generators during the month to all embedded distributors for whom the market participant is the host distributor, adjusted for losses as required by the Retail Settlement Code.

(3) On a monthly basis, each distributor shall collect from each consumer in its service area and from each embedded distributor to which it distributes electricity an amount proportionate to the volume of electricity distributed to the consumer or to the embedded distributor, including the total volume of electricity supplied by embedded generators to embedded distributors in the host distributor's service areas in the manner described in clause (2) (b).

(4) A distributor who bills a consumer from whom the distributor must collect an amount in accordance with subsection (3) shall aggregate the amount that the consumer is required to contribute to the compensation required under subsection 79.1 (2) of the Act and this Regulation with the amount otherwise payable by the consumer in respect of the wholesale market service rate described in the Electricity Distribution Rate Handbook issued by the Board, as it read on May 11, 2005.

IESO, monthly payments

5. (1) The IESO shall make a monthly payment to each qualified distributor that is equal to the monthly compensation amount determined by the Board under subsection 3 (2), including any payments for an embedded distributor to which the distributor delivers electricity.

(2) On a monthly basis, a host distributor shall, for each embedded distributor to which the host distributor distributes electricity, adjust the accounts between the host distributor and the embedded distributor by crediting the amount calculated by the Board under subsection 3 (2) to the embedded distributor.

(3) Payments required by this Regulation between licensed distributors and the IESO may be made, at the option of the IESO, by way of set off in the accounts maintained by the IESO.

(4) Payments required by this Regulation between an embedded distributor and its host distributor may be made, at the option of the host distributor, by way of set off in the accounts maintained by the host distributor.

IESO to provide certain information

6. (1) For the purpose of calculating the amounts referred to in subsection 3 (5), at least 60 days before the end of each calendar year the IESO shall submit to the Board,

(a) a forecast of the number of net kilowatt hours of electricity that are expected to be withdrawn from the IESO-controlled grid, as determined in accordance with the market rules, for use by consumers within Ontario during the IESO's next fiscal year;

(b) a forecast of the total volume of electricity that is expected to be supplied to distributors and embedded distributors by embedded generators;

(c) documentation supporting the forecasts referred to in clauses (a) and (b);

(d) a calculation of the total amount of excess or shortfall held in variance accounts maintained by distributors resulting from the difference between the amounts charged to distributors by the IESO and the amounts collected from consumers by distributors;

(e) documentation supporting the calculation referred to in clause (d); and

(f) such other information as the Board may require for the purposes of this Regulation, in the form specified by the Board and before the expiry of the period specified by the Board.

(2) The forecast referred to in clause (1) (a) shall be derived from information submitted to the Board by the IESO pursuant to section 19 of the *Electricity Act, 1998* in respect of the IESO's next fiscal year.

(3) At the end of each calendar year, the IESO shall submit to the Board the figures for the total amount of the monthly compensation that was paid out to each qualified distributor for each month of the year.

(4) Each distributor who is a market participant shall give the IESO such information as the IESO may require from the distributor for the purposes of this Regulation and shall do so in the form specified by the IESO before the expiry of the period specified by the IESO. O. Reg. 330/09, s. 6 (4).

(5) Each embedded distributor shall give its host distributor such information as the IESO may require from the host distributor for the purposes of this Regulation and shall do so in a form specified by the host distributor before the expiry of the period specified by the host distributor.

Reliance on information

7. (1) For the purposes of this Regulation, the IESO shall rely on the information provided to it by each distributor who is a market participant.

(2) For the purposes of this Regulation, host distributors shall rely on the information provided to them by their embedded distributors.