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August 24, 2007

**SENT VIA EMAIL AND COURIER**

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

Dear Ms. Walli:

**Re: Distributed Generation: Rates and Connection**
**Ontario Energy Board File No. EB-2007-0630**

## Introduction

The following comments are those of Soave Hydroponics Company ("SHC"). SHC welcomes the opportunity to make comments to the Ontario Energy Board about such an important issue in the evolution of Ontario's electricity industry.

SHC is currently in the process of developing a 12 megawatt (12 MW) combined heat and power (CHP) facility near Kingsville, Ontario. SHC entered into a CHP Contract with the Ontario Power Authority in 2006 as part of the CHP request for proposals ("RFP"). SHC anticipates having generating operational in the first quarter of 2008 approximately 18 months after the submission of its proposal to the OPA.

We have reviewed the paper by EES Consulting – Discussion Paper on Distributed Generation (DG) and Rate Treatment of DG (the "EES Paper") and the Ontario Energy Board Staff Discussion Paper on Distributed Generation: Rates and Connection ("Staff Paper") and respond to issues raised in those papers. The comments have been organized to respond to the issues as raised in the Staff Paper.

## Preliminary Comments

Fundamentally, much of the difficulty in the discussion of the issues must evolve from the breadth of the definition of distributed generation ("DG") and the way in which DG is implemented. DG consists of renewable (wind, hydro, solar, landfill, biomass) and clean (combined heat and power) generating facilities and facilities that perform different roles with respect to the local distribution company and the generator/load customer. Some of these generators are baseload (landfill gas), intermittent (wind) and some could effectively self-schedule (CHP).

Furthermore, the economic models, to the extent the project is completed for primarily economic reasons, for each of these technologies vary. Renewable projects under the Renewable Energy Standard Offer Program ("RESOP") are based upon a fixed price with a potential adder for peak times whereas the combined heat and power model is based upon a spark spread calculation and a deemed operating timeframe.[1] These factors will result in differing signals and abilities to respond to such signals. Therefore, the operational pattern of these projects may vary significantly from month to month and year to year.

Also, as the electricity grid transforms from a central generating model to a more diverse, distributed generating form the need for a safe and reliable power supply remains paramount. The management of an integrated electricity grid is necessarily complicated. Therefore, any regulatory scheme must ensure that safety and reliability are not compromised for the sake of simplicity.

From a commercial perspective, there are two variables that can have an impact on the successful development of a project: time and cost. Estimates of capital cost per MW of installed capacity range from $1.75 million to in excess of $3 million. Probably the greatest uncertainty in estimating the cost of a project is the connection to the grid and the potential exposure to the upstream costs arising from the queuing procedure.

A developer of any generating facility wants and needs to understand what costs must be incurred and the timing of such costs. In this way the developer can develop the financial models to determine the feasibility of the project and cash flow requirements. Therefore, care should be taken to change rules and codes that could have an adverse impact on existing generators.

**Definition of DG**

The EES Paper defines DG as "*electric power generation equipment located near the customer that will use it and generally ranges from a few kW to 25MW in generation capacity*". The definition is problematic which is not to say it is a bad definition, but rather that any definition of DG attempting to capture the wide variety of applications, fuel sources and physical configurations will have a number of problems.

For the purposes of these comments, it is assumed that where the DG is not behind the meter of the load customer (i.e. not truly load displacement) much of the discussion becomes moot as there is no lost revenue for the distributor, no stranded assets and no real change for billing determinants.

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[1] See the Ontario Power Authority – Combined Heat and Power Request for Proposals, Appendix J. for the economic model for certain CHP facilities.

## Response to Issues Raised

**Standby Rates for Customers with Load Displacement Generation and Rate Classification**

- *What might be a reasonable billing determinant for recovering demand-related costs?*

No comment.

- *Should standby charges be further differentiated between backup, maintenance and supplemental services?*

The EES Report that proposes a rate classification for customers with DG for load displacement is appropriate. DG that fails to meet the criteria, greater than 500kW or 10% of its total load, should remain in the current rate classification.

If the capacity of the electricity generating facility is significantly larger than the requirements of the electricity load, as for some combined heat and power facilities, then the load displacement generator is effectively a central generating facility and is currently paying for the costs of connections and should be treated as a generator. As the load may require distribution service but this is relatively small in comparison to the generation, the load should continue to be treated as it is currently treated by the distributor. Therefore, in the present situation there should be no new standby charges.

- *Are there other issues that should be considered by the Board?*

The Board should consider the OPA's contract methodology as it is the primary source of contracts for new generation. Many of the contracts are based upon a spark spread calculation and so the amount of hours that the generation will operate is not predictable and there may be significant changes in the amount of time supplemental service required. Depending upon the complexity of dealing with rate issues there may be ways, through the OPA contracting process, to recognize the benefits of generation and create a more administratively streamlined process.

- *How should any distribution and transmission benefits provided by load displacement generation be identified and quantified?*

SHC agrees with the fundamental principle that costs and benefits should be allocated to the party responsible. However, given the nature of DG (various fuels and operation) this will be very difficult to quantify with any degree of certainty. Furthermore there are locational benefits and administrative burden issues to consider.

For small projects, less than 5MW, the administrative burden would be significant and therefore either should not be tracked or assigned a fixed value based upon a review that would provide an estimate of the average benefit. Large projects could be analysed individually to consider the benefits of the specific project.

The benefits could either be quantified through rates or the price of the commodity. SHC recognizes that commodity pricing is not within the OEB's purview. British Columbia is proposing to quantify some of the benefits in its Draft Standard Offer Program by attributing premiums/discounts for the commodity based upon location and operation of the generation. This is effectively a formula to assign benefits. For instance, new hydro generation that peaks during the spring freshet when there is an already an abundance of generation is treated differently than high-efficiency gas fired generation. In addition, the Draft Program proposes to socialize a portion of cost of the network upgrades.

- *Should a different approach be adopted depending on the size of the customer?*

Yes. At a certain level, very small generators provide negligible benefits to the transmission and distribution system. Further these generators are less likely to provide significant other benefits such as increasing security of supply or reducing line losses. In addition, there will be an additional administrative burden associated with these facilities at a time when LDCs are coping with the demands of smart meters, conservation and demand management and incentive regulation.

- *Should any benefit provided to customers with load displacement generation be recovered from all customers? If so, on what basis should this be done?*

If there is a decision to socialize some or all of the network upgrade costs then the amount of the benefit to the DG that has been socialized will need to be recovered from the remaining customers. It should be allocated across customer classes in the same manner as similar expenditures.

- *Are there other operational or implementation issues that should be considered by the Board?*

The OEB should keep the system as straightforward as possible to minimize the administrative burden on entities and to reduce the potential confusion.

- *Is a separate classification warranted and, if so, should it apply to all customers with load displacement generation, or to a subset of these customers as suggested in the EESC Report?*

DG that is not behind the meter should continue to be treated as it currently is treated.

- *Are there other criteria that should be used to justify a separate rate classification for a subset of these customers?*

Where DG is sized primarily for thermal load requirements and significantly exceeds the electrical load then the DG should be treated as a generator.

- *What would be an appropriate threshold for a generator rate class?*

No comment.

**Revenue Losses to Due to Load Displacement Generation**

- *Has net revenue loss due to customers with load displacement generation been material?*

It is unknown the magnitude of revenue losses resulting from load displacement generation. This is an issue that may benefit from further review.

However, distributors are at risk for load reductions resulting from investments in increased efficiency by load customers, investment in conservation and demand management and as noted, economic downturns. The losses from load displacement may be very small in proportion to the overall throughput of the distributor. Second, it may be that installing DG provides benefits to the load customer that keeps the load customer at the same or greater level of production thereby limiting the load reduction. In addition, reductions in load may be offset with load growth from new customers.

Also, if there are significant amounts of DG a distributor may reduce line losses and reduce the supply from the IESO which would reduce the level of prudentials required and provide further benefit to the distributor.

The Staff Paper notes that the distributor is often aware 6 to 12 months in advance of a load displacement project. It is submitted that given the connection process and the development time for DG projects, the distributor often has well over 12 months notice of DG projects. Many project are subjected to an environmental assessment process and other permits which can take several months to obtain.

Distributors should be aware of potential large DG projects and should be forecasting the expansion of this industry.

- *How might net revenue loss be quantified?*

For load displacement facilities the LDC could:

a) Make no attempt to quantify;

b) Quantify the losses based upon a year over year comparison on a typical normalized basis for each specific DG;

c) Quantify on the basis of installed DG capacity; or

d) Quantify based upon overall throughput of the utility on a normalized basis and accounting for load growth.

Given that it is not known if there is a significant revenue loss it would be premature to advocate for a particular solution. Further there are a number of factors that would factor into the analysis such as the administrative burden to determine the net revenue losses.

- *How might the Board determine an appropriate method to compensate electricity distributors for such revenue loss? Consideration should be given to a consistent approach between revenue loss caused by customers with load displacement generation and revenue loss caused by other load customers due to factors such as economic conditions. In evaluating each of the options presented above, consideration should also be given to the incentive regulation framework under which electricity distributors are currently operating.*

The Board could have distributors attempt to track the revenue loss to determine its significance prior to establishing a process for recovery.

- *What alternatives to the status quo should be considered and what is the rationale for each of these options?*

No comments.

- *If connection costs are socialized, is there a risk of uneconomic DG projects going forward? If so, how can that risk be mitigated or avoided? Would this approach affect the incentive for distributors to design economic connections?*

Connection costs should be considered on the basis of direct costs for the connection of the facility and upstream costs to accommodate the additional generation. To the extent that a project that is not economic under the current regime but becomes economic under a socialized regime there is a potential for additional projects to proceed. The risk is obviously greater with socialization of larger amounts of the connection costs.

The connection costs at the generator should be paid by the DG as those costs are attributable to those facilities and this is in keeping with the causation principle. The connection costs related to upstream or network upgrades is less clear as such upgrades may provide additional benefits to parties other than the DG.

<u>Example</u>

Assumes there is 25MW of generation capacity that could be installed without the need for upstream network upgrades. The area has 5 potential 10MW DG projects. For capacity beyond 25MW significant capital investments for network upgrades are required. As the process currently stands, the DG that tips the balance funds the network upgrades. Therefore, the first two 10MW projects that enter the queue, not necessarily those projects being the most advanced, can be completed without contributing to the network upgrade.

At that point, the next 10MW project would tip the scale and require the distributor to complete the network upgrades. The DG is, at least, initially responsible for the cost of the network upgrades. Therefore, the DG has to have an economic project incorporating all of the upgrade costs prior to completing the project. These costs are factored into the price of electricity. If the project is uneconomic the DG project will fall to the sideline and the same dilemma is present to the next DG.

However, if the project is economic and continues, the DG may get a rebate when the remaining two DGs develop their projects. These last DGs know that they will contribute to the first DGs cost and factor that into the economics of their project. This creates an unnecessary pressure to increase prices and provides a discriminatory effect as between the generators based upon entering the queue.

In British Columbia the proposed standard offer program provides a cap on the socialized upstream costs, Network Upgrade Threshold, of $200/kW.[2] In this way, some of the costs are socialized but there is a limit on the amount that socialized. A system such this would serve to reduce the potential for discrimination between DG.

- *Are there other rate-related issues associated with DG that should be addressed, or that should be addressed more fully? Is the experience in other jurisdictions on those issues relevant to the Ontario situation?*

Where DG provide load displacement the DG entity becomes a collector of the Debt Retirement Charge for the self generated electricity. SHC understands this is a requirement of the regulations, O. Reg. 493/01, and beyond OEB authority but a broader exemption for exempt self-generated electricity could encourage additional DG and not burden the distributor or the generator.

British Columbia is developing a standard offer program which provides a price structure dependent upon the time of year and the location. In this way, the program is intended to encourage small generating projects through pricing that reflects the locational benefits of the DG as well as the operation of the generation. As the program is limited to projects of less than 10MWs any socialized costs are effectively capped.

- *Are there unidentified barriers or is separate treatment required for embedded generation projects or for projects falling below the threshold of a new rate class?*

No comment.

- *What are the institutional or regulatory barriers to implementation of DG? How might such barriers best be addressed?*

One of the major barriers is having distributors that are organized and staffed to accommodate the needs of DG. As the electricity system transforms itself, the distributors have been working with a number of changing priorities. A possible method to resolve the

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[2] See the publication BC Hydro for Generations – Draft Standing Offer Program Rules, Revised July 5, 2007.

issue is to give priority of service to more developed projects so that queue management becomes more effective and the potential for queue squatting is avoided.

- *Are there DG-related issues, other than those relating to the rate or connection cost treatment of DG facilities that need to be addressed? Is the experience in other jurisdictions on those issues relevant to the Ontario situation?*

The issue of stranded costs has potential rate implications. Given that Ontario has a need for generation, and the age of the existing generating facilities, it should not be expected that significant stranded costs would be caused by the DG causing early retirement of existing generating facilities. It may be that this issue warrants further review in a few years to determine if there is a potential for a significant amount of stranded costs.

**Net metering**

O. Reg. 541/05 Net Metering mandates distributors bill on a net metering basis to only a select number of DG.[3] Reg. 541 is permissive in that other situations may be billed on a net metering basis but that is voluntary. This potentially creates an uneven playing field depending upon which LDC service territory the DG facility is located.

For load displacement generation, a mandatory net metering treatment would help industrial clients and an exemption from having to pay the Debt Retirement Charge on self-generated electricity would provide DG with a substantial benefit.

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[3] Eligible generator is defined in s.7(1) of the Reg. 541. as:

7. (1) A generator of electricity is an eligible generator if,

(a) the generator generates the electricity primarily for the generator's own use;

(b) the generator generates the electricity solely from a renewable energy source;

(c) the maximum cumulative output capacity of the equipment used to generate the electricity that the generator intends to return to the distributor for net metering purposes is no greater than 500 kilowatts based on the rated maximum output capacity of the equipment; and

(d) the generator conveys the electricity that is generated directly from the point of generation to another point for the generator's own consumption without reliance on the distributor's distribution system before conveying any electricity that is in excess of the generator's own needs at the time of generation into the distributor's distribution system.

(2) In this Regulation, electricity is generated from a renewable energy source if the electricity is generated from the wind, a drop in water elevation, solar radiation or an agricultural bio-mass resource or from any combination of them.

**Conclusions**

The treatment of load customers that install generating facilities that service a large thermal load and displace only a small electrical load should not have the treatment of the load customer changed. In such situations, it is more akin to a generator. Therefore, no standby charges should be developed in such a scenario as the potential revenue loss is unlikely to be significant. The current demand and usage charges should be sufficient.

The administrative burden of any system should be minimized.

If there are any comments please contact the undersigned at your earliest convenience.

Yours very truly,

**AIRD & BERLIS LLP**

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