Ontario

Ontario Energy Board

Standard Offer Program for Eligible Distributed Generation

Staff Discussion Paper

EB-2005-0463

Nov 17, 2005

1. Introduction

1.1 Background

On August 19, 2005, the Chair of the Ontario Energy Board (the OEB) received a letter from the Minister of Energy asking the OEB to work jointly with the Ontario Power Authority (the OPA) in developing the terms and conditions for a standard offer program for small generators using clean or renewable resources that are embedded in distribution systems.

Earlier, the Minister had commissioned the Ontario Sustainable Energy Association (OSEA) to report on how to overcome the barriers to participating in Ontario's electricity supply sector for small renewable generators. The Minister's letter to the OEB and the OPA asks the two agencies to consider the OSEA report in developing the program.

1.2 Project Approach

The OEB, in accordance with its authority over connection policies and delivery obligations of distributors, will focus on the necessary changes to codes and connection requirements, and on ensuring non-discriminatory access to the electricity system. More information about the Board's process can be found at: http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_standardofferprogram.htm

The Board will propose amendments to regulatory instruments as required, primarily the Distribution System Code (DSC). Code amendments will be subject to a notice and comment process before being adopted, and once adopted must be published in the Ontario Gazette.

The purpose of this Board staff discussion paper is to identify issues under the Board's jurisdiction and solicit stakeholder comment. Each section deals with a particular issue under the Board's jurisdiction dealing with distributed generation (DG) in general and generation eligible for the standard offer program (SOP) in particular. Board staff welcomes comments on these issues or other issues relating to perceived barriers to the development of DG.

The OPA, in accordance with its authority to procure electricity supply and capacity, will investigate the appropriate price and eligibility requirements for projects to qualify for the standard offer program. The OPA released a discussion paper on November 2, 2005 for comment and will be hosting a series of presentations by stakeholders from November 16 to 18 and receiving written comments until November 25, 2005.

The OEB the OPA are working together to develop the elements of the standard offer program. More information and a link to the OPA's processes can be found at: http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_standardofferprogram.htm.

2. Licensing Requirements

2.1 Distributors

Under the *Ontario Energy Board Act, 1998* (the OEB Act), a distributor is a person who owns or operates a system for conveying electricity at voltages of 50 kilovolts or less.

Local electricity distribution companies have a number of obligations under the OEB Act as well as the *Electricity Act, 1998* (the E Act). Subject to any applicable exemptions, they must have a Board-issued licence and a Board-approved rate order for distribution charges.

There are prohibitions on their activities other than distribution. Under the OEB Act (s. 71 (2)), distributors are allowed to provide service related to load management and the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. Section 29.1(2) of the E Act makes it clear that distributors can be involved in generation only through an affiliate.

By licence condition, distributors must comply with regulatory instruments developed by the Board including the Distribution System Code (DSC), the Retail Settlement Code, the Affiliate Relationships Code, Reporting and Record-keeping Requirements (RRR), and the Standard Supply Service Code[1].

Distributors must provide non-discriminatory access to their distribution system to generators, consumers and retailers according to the conditions of their licence. The requirement relating to the connection of generation facilities are contained primarily in the DSC.

2.2 Generators

Under the OEB Act, a generator is a person who generates electricity or provides ancillary services for sale through the markets administered by the Independent Electricity System Operator (IESO) or directly to another person, other than a consumer. Generators are licensed by the OEB and have to meet the relevant requirements of the Reporting and Record-keeping Requirements. Licenses for generators typically have a 20 year term.

The IESO does not require any generator to be a market participant. The IESO only requires market participants to be licensed by the OEB. Generators can choose to self-schedule and take the market clearing price for what they inject into the system without bidding into the market. Embedded generators greater than 20 MVA must abide by the monitoring requirements of Chapter 4 Section 7.3.1 of the Market Rules. In general,

[1] Applicable codes and RRR for distributors and generators can be found on the Board's website: http://www.oeb.gov.on.ca/html/en/industryrelations/rulesguidesandforms_regulatory.htm

these generators are to provide specific data to enable the IESO to maintain reliability of the IESO-controlled grid.

For the 2005-2006 fiscal year, the Board began to charge an $800 annual registration fee to each licensed generator of greater than 0.5 megawatts of capacity. The annual registration fee serves two purposes: generators make a contribution to the cost of funding the operations of the Board and generators with multi-year licences confirm that they are active and operating.

2.3 Distributed Generators

It is expected that SOP generators will be engaged in the generation of electricity or ancillary service for sale (other than to a consumer) since they will be contracted to produce more than they consume. Therefore they must be licensed by the Board.[2]

Are aspects of the licensing process or requirements onerous for distributed generators? What changes would clarify requirements and simplify the application process and thereby improve the timing and economics of projects?

Application information

It can also be expected that generators will need to supply substantially the same information for the Board's application for licence, the OPA's contract and the distributor's request for connection. It may be possible for the parties to coordinate the format and content of the forms so that common information need only be compiled once. The advisability and feasibility of having that applicants file once and have the entities share the information may also be considered. The Board requires financial information and information on individuals as part of its application process. This information is considered confidential.

Would coordinating the application process be helpful? Will the Board's treatment of certain information as confidential make sharing information difficult?

Licence fees

The Board's annual registration fee is currently set at $800 for all generators over 0.5 MW.

The Board is currently researching changes to the Cost Assessment Model for determining its fees, as it committed to do in the Model published in March 2005. The purpose of the Model is to fairly allocate the costs of regulation to licence holders. The Board's costs in dealing with SOP generators are not known at this time. The results of the current examination of the Cost Assessment model will be sent to all licence holders for their review and input. Comments on this issue will be shared with this process.

[2] Licence applications and sample licences can be found on the Board's website: http://www.oeb.gov.on.ca/html/en/licences/applyforalicence.htm

Generators will also have an opportunity to comment when the cost assessment changes are sent for review.

Are registration fees an economic barrier for generators larger than 0.5 MW but smaller than some other threshold? Could a tiered system of fees be tolerated? At what level(s)?

Record-keeping and Reporting Requirements

Generators that are less than 25 MW who are not market participants are exempt from regular RRR requirements. This exemption is likely to apply to SOP generators. Otherwise, generators are required to file certain information once and when there are changes to the information. There is significant overlap with the licence application information so coordination of the information requirements could reduce the entry burden on generators.

Are there any parts of the RRR code that are a barrier for DG?

3. Connection

3.1 Background

"While small renewable energy projects certainly help the government meet broad objective such as cleaner air and improved energy supply, they also offer a unique set of additional benefits to the province"[3]. Potential benefits of distributed generation to a distribution system include[4]:

- Reduction of transmission and distribution losses. By placing supply close to load, overall power flows are reduced and therefore line losses are reduced. These benefits flow to all consumers as reduced commodity consumption. Reduced losses mean that, overall, less power needs to be produced, easing capacity constraints.

- Relief of transmission congestion. DG in congested areas reduces out of merit generation dispatch and improves the economic efficiency of the market. It also results in fewer congestion management payments in the IESO-administered market and therefore a reduction in uplift charges.

- Deferment of transmission and distribution investment. Supply close to load can be an alternative to expanding or reinforcing the transmission grid to bring more power from larger, remote sources for new or increased needs. In distribution system instances of long feeders with multiple loads, DG can be an alternative to transformers for increasing voltage.

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[3] OSEA, "Powering Ontario Communities: Proposed Policy for Projects up to 10 MW", 2005, p. 10.

[4] "An Arthur D. Little White Paper - Distributed Generation: Policy Framework for Regulators", 1999.

- Provision of ancillary services. Depending on technology, DG can be a source of spinning reserves, reactive power, and/or black-start capability.

Distribution systems traditionally have been designed to take power from high voltage grids and distribute this power to end consumers. Most distribution systems in Ontario are radial systems. Power is taken from the grid and delivered to load along individual paths. Some urban distribution systems have networked areas where feeder lines are interconnected and electricity may take alternative paths to a final load.

In many cases in North America, distributed generation has been added to the system as load displacement and operated as an island, i.e. while the plant is generating, the site is electrically isolated from the larger system. In this mode, the introduction of generating capacity need not cause great changes to this system.

However, connection of generation in synchronous or parallel operation is neither simple nor trivial. Once power is sent into the system, the flows of electricity will be changed and even reversed from the design parameters and normal operation. This can lead to a number of technical problems that can affect the stability of the network and quality of electricity supplied[5].

- Voltage control. Distribution network operators are normally obliged to keep network voltages within a certain range. Voltages outside parameters can affect the life of equipment or the operation of sensitive devices. Electricity sent into the distribution network tends to cause an increase in voltage. Where this voltage increase is not needed on the system, it can be alleviated by upgrading transformers for improved voltage control. Rapid changes in voltage can occur e.g., at switchings in a wind farm. Harmonics at multiples of frequencies may require filtering in inverter-based applications e.g., photovoltaic (PV) systems and most wind turbines[6].

- Reactive power. Depending on the type of generation, DG can either supply reactive power or will be dependent on it.

- Protection. Protection systems are required to ensure that DG is not supplying the system during outage conditions and can be resynchronised to the grid when power is restored. This is both a system safety and personal safety issue. Fuse co-ordination studies are also required when introducing a new supply point that changes direction of flow.

Some generators feel that these technical issues have tended to make distributors reluctant to connect DG and alter the operations of their systems.

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[5] International Energy Agency, “Distributed Generation in Liberalised Electricity Markets”, 2002, p. 73.

[6] See Kauhaniemi, Kimmo et al., “Distributed Generation – New Technical Solutions Required in the Distribution System”, Nordic Distribution and Asset Management Conference, 2004, for a discussion of connection issues specific to different technologies. http://powersystems.tkk.fi/nordac2004/papers/nordac2004_kauhaniemi_et_al_paper.pdf

A European Union directive[7] requires that the EU countries should create connection rules that are equal to all the players in the electricity market. As of late 2004, work in Finland was still ongoing.[8]

3.2 Standardized Design

3.2.1 Technical Standards

A typical connection system includes three kinds of equipment:

- Control equipment for regulating the output of the DG;
- A switch and circuit breaker (including a "visible open") to isolate the DG unit; and
- Protective relaying mechanisms to monitor system conditions[9].

Appendix F.2 of the DSC contains standardized technical requirements including system operations, reliability, power quality, safety and measurement issues as well as introducing broader standardization of similar technical requirements involving Federal and other Ontario standards. Appendix 1 of this paper includes a summary of those specifications.

There is no single recognized standard for connection design. This leads to disputes between distributors and generators regarding the design and costing of the connection and related reinforcement.

The producers of the smallest generating plants (i.e. some PV systems) increasingly are incorporating the connection and protection equipment in the systems for a more plug-and-play installation and an extremely simple connection agreement and process. This remains unlikely for larger systems.

The development of connection standards and procedures to help distributors assess the effect of DG on a local system will reduce transaction costs for distributors and generators. The benefits of DG are driving the development of standards. The use of national standards is common in Europe; these are usually stricter than the European norm (EN50160)[10]. IEEE 1547: Standard for Interconnecting Distributed Resources with Electric Power Systems" has made significant progress as a consensus standard but still identifies areas for development particularly around connecting to networked systems. Most American states have unique standards set by the local public utilities commission or by individual utilities. The Federal Energy Regulatory Commission is also developing

[7] Directive 2001/77/EC of the European Parliament and of the Council – of 27 September 2001 – on the promotion of electricity produced from renewable energy sources in the internal electricity market.

[8] Kauhaniemi, Kimmo et al., "Distributed Generation – New Technical Solutions Required in the Distribution System", 2004.

[9] "An Arthur D. Little White Paper – Distributed Generation: System Interfaces", 1999.

[10] IEA, "Distributed Generation in Liberalized Electricity Markets", 2002, p. 74.

a standard for small generators to be finalized later in 2005.[11] The Notice of Proposed Rulemaking has been released.

Electro-Federation Canada and Natural Resources Canada are sponsoring a Decentralized Energy Management Advisory Council to develop and encourage standardized practices as explicit codes, standards and regulations evolve. They have compiled a comparison of DG connection standards attached as Appendix 2 to this paper.

What is the best way to set technical standards for DG connection in Ontario?

3.3 System Information

One of the barriers facing developers of distributed generation is a lack of information about the distribution systems to which they want to connect. Technical and administrative information is necessary to properly evaluate generation opportunities, but presently local distributors are not obligated to make system information publicly available.

Generators considering a particular distributor's system for a project must request information specific to their project and generally pay for the cost of preparing it. Lack of an overall system perspective prevents generators from easily comparing options within a utility and between utilities. Lack of information about system expansion plans prevents generators from coordinating their plans with those of the utility to maximize the benefits of embedded generation to the distributor and to minimize connection costs to the generator.

A potentially better system of making development decisions is to have distributors publish information about their systems that would be useful for siting small embedded generation. Two other jurisdictions have implemented such a system. In the United Kingdom (UK)[12], the regulator has made public disclosure of system information a licence condition for distribution network operators. In that case, the objective is specifically to facilitate and encourage distributed generation. In Australia, the regulator in New South Wales (NSW)[13] has mandated a similar disclosure program for distributors.

Both the UK and the Australian initiatives are comparatively recent but a recent evaluation by Ofgem of the UK initiative concluded that the program had already demonstrated its value in encouraging embedded generation.

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[11] Massachusetts Distributed Generation Collaborative, "2005 Annual Report", May 2005.

[12] For further information on the UK requirements see the Office of Gas and Electricity Marketing (Ofgem) site http://www.ofgem.gov.uk/ofgem/index.jsp and use "long term development statements" to search the site.

[13] For further information on the NSW requirements see the Department of Energy, Utilities and Sustainability website at http://www.deus.nsw.gov.au/ . Click on Publications and select *Demand Management for Electricity Distributors NSW Code of Practice.*

3.3.1 Potential for System Information Disclosure in Ontario

Generators need information.

Embedded generators need information on distribution system design and operations to properly evaluate opportunities to site a generating station. A proper assessment should also take into account future development of the distribution system such as expected load growth, major new connections, planned expansion of station and line capacity and anticipated changes to design and operating practices. Publication of system information will allow generators to overcome these barriers.

Lack of public information limits alternatives to system constraints.

Distributors currently respond to increases in demand and other constraints on their systems by expansion of the network transformation capacity and/or feeder capacity. Distributors have not normally considered alternatives that would postpone or eliminate the need for additional station or line capacity. Publication of system information including expected system constraints over a reasonable planning horizon might prompt DG approaches to resolving the constraint.

Quality and timeliness of information can be variable.

Information required to evaluate connection points (such as system line drawings, station capacities, line loads and normal operating parameters) is available from distributors on a request basis. The Distribution System Code requires that requests for system information must be addressed in "timely manner"[14] but does not otherwise define content or what constitutes timeliness. These issues are left to the requestor and the distributor to resolve. As a result considerable variability can exist in responding to individual generator requests both in terms of the quality of information provided and in the time it takes to get that information.

Distributor's connection costs are not sufficiently transparent.

Connection costs for generation are highly location specific. For instance, generation is better tolerated either on its own feeder or where the combined load is more than the proposed supply[15].

Currently, generators seeking connection to a distributor's system would have difficulty proposing alternative designs or connection points. Under the present regulatory regime, distributors have no incentive to minimize connection costs or to look for innovative solutions to connection barriers. Generators do have incentive to minimize connection costs and to create alternative solutions to connection barriers. However, without detailed knowledge of system configuration and the distributor's design and operating practices, they are unable to improve on a distributor's connection design and costs. Publication of relevant information will allow generators to better evaluate how cost

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[14] See Step 2, Provision of Information in the Distribution System Code - Appendix F.

[15] John Bowen and Carl Wall, "Do Your Homework When Interconnecting Generation", Transmission and Distribution World, September 2005, pp 116-120.

estimates have been arrived at and might permit development of design and operating alternatives that would not have been considered by the distributor.

Information already exists in most distributors' records.

Much of the information that would be useful for evaluation of generation opportunities and other customer interests is presently prepared in one form or another by distributors for internal use. Publication would entail some effort to assemble and collate the information into a standard format but this is not expected to be an undue hardship given the potential benefits of disclosure.

Information is valuable for distributor management.

For those distributors that do not currently record system data, the requirement will represent an opportunity to organize recordkeeping and derive the benefits of longer-term planning that such records permit. At the least, a comprehensive summary of a distributor's system is desirable for good utility management and for responding to customer inquiries.

The type of information needed by generators to properly evaluate the best (and worst) locations for a generator is usually spread among various departments of a distributor and may not be easily assimilated into a coherent system document. Some information may not be collected by a utility at the level of detail required by a generator and special data collection efforts might have to be made to acquire it. In addition, the varying complexity of urban vs. rural distribution systems might dictate different information requirements. At the same time, some consistency in content and format is desirable to make the system usable by generators. A balance between the cost of collecting and publishing information and the value it has to the end user needs to be struck.

Information must be updated.

Distribution systems are dynamic networks that change frequently. Changes can be daily as feeder interconnect points are adjusted to balance loadings or they can be longer term as residential and commercial developments prompt new station and feeder construction. Any system plan would have to be updated regularly to be useful and the burden of doing so might become significant particularly in utilities experiencing rapid growth.

How often should distribution system information be updated?

3.4 Connection Processes

3.4.1 Standardized Process

Section 6.2 of the DSC deals with generation connections. The DSC provides connection processes for four generation categories differentiated by size (see Table 1). The different size categories stem from the technical impacts and requirements of each category on the distribution system. Where feasible, and to facilitate connection of generation to distribution systems, the DSC allows flexibility to shift a project from a larger size category process requirement to a smaller one. This helps a generator, upon mutual agreement with the distributor, to follow a process that is shorter and with fewer requirements. The DSC includes an expedited connection process for the micro category of DG including a standard contract for micro load displacement generation.

Table 1: Embedded Generation Size Categories for Which the DSC Prescribes Connection Processes

Size	Name-Plate Rating	Distribution kV
Micro	10 kW or less	n/a
Small a) b)	 500 kW or less 1 MW or less	 Less than 15 kV 15 kV or greater
Mid-sized a) b)	 Less than 10 MW and more than 500kW More than 1 MW and less than 10 MW	 Less than 15 kV 15 kV or greater
Large	10 MW or greater	n/a

Appendix F prescribes connection processes for connection to local distribution systems for each size category. The DSC puts a timeframe on the distributor for responding to the generator at various stages of the process.

3.4.2 Dispute Resolution

In Ontario, distributors are required to include a dispute resolution process as part of their publicly available Conditions of Service. These Conditions of Service are filed with the Board although the Board does not review or approve them. Further, when any person believes that a distributor is not abiding by legislation, the terms and conditions of its licence or any other of the Board's regulatory instruments, the person can make a complaint to the Compliance Office of the Ontario Energy Board who will investigate on behalf of the Board. The Board can compel compliance including assessing administrative fines.

Given the lack of consensus on connection standards, the Massachusetts Distributed Generation Collaborative identified a third-party dispute resolution process as aiding generation projects.

Is the current process adequate to resolve disputes?

3.4.3 Queuing

According the DSC, distributors have up to 90 days to make an Offer to Connect after receipt of payment from a generator for a detailed estimate. This step is fairly late in the process. This offer includes detailed design work and an estimated cost, based on the distribution system configuration. The DSC does not specify how long the generator has to proceed or how long the Offer to Connect must be valid.

The DSC does not contemplate how this outstanding Offer will affect subsequent requests to connect. Determining a queuing process would allow a generator that applies to be connected to the distribution system to secure a position or a priority to connect over other future applicants. The concern is that developers might tie up economic sites whether intentionally or not. Stakeholders have indicated that need to develop fair and transparent queuing requirements that would account for the different generation types and sizes as well as distributor needs.

In its previous work on connection, the Board identified the determination of a queuing process as a next step. Ofgem is developing a queuing process for two or more connection applications involving the same assets[16].

Is a queuing process necessary for the SOP to proceed? Should the distributor develop new offers assuming that the existing offer will or will not proceed? Is the first generator guaranteed the cost in the Offer despite a subsequent project moving more rapidly through the process?

3.5 Sample connection agreements

The requirement to negotiate individual connection agreements is a barrier to DG. It is a benefit to make the contract terms as simple and transparent as possible[17]. The Board intends to develop a sample connection agreement to be included in Appendix E of the DSC having adequate and clear details on the obligations and requirement of each party so as to provide the basis for contract negotiations.

Appendix E of the DSC includes a standard contract for micro-embedded load displacement generation i.e. under 10 kW.

The DSC Appendix F contains detailed technical requirements for generation connection on the distribution system. Appendix F also contains a detailed process for the connection of generators including the requirement for commissioning and testing.

Comparison of Connection Agreements

See Appendix 3 to this paper for a comparison of eight DG connection agreements from other jurisdictions both existing and proposed.

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[16] Distributed Generation Coordinating Group, Ofgem, “Interactive Connexion Applications”, November 2003.
[17] OSEA, “Powering Ontario Communities”, 2005, p. 45.

The length of the agreements ranges from three pages to 91 pages. Connection agreements supported by a complete and detailed connection requirement document required less declaration to clarify points of the agreement.

Appendix F of the DSC contains detailed technical requirements for generation connection on the distribution system. Appendix F also contains a detailed process for the connection of generators included the requirement for commissioning and testing. A generator cannot be connected onto the distribution system unless all commissioning and testing has been completed to the satisfaction of the distributor and the Electrical Safety Authority (ESA). When the distributor and ESA are satisfied that all of the connection requirements are met, the ESA will issue an "Authorization to Connect" giving the generator authorization to connect on the distribution system. Therefore, if a generator receives the Authorization to Connect, it must be assumed that that all technical requirements have been met.

Because technical requirements and the process for commissioning and testing are defined in Appendix F of the DSC, they need not be included in the agreement itself.

A connection agreement is established between the distributor and the generator to provide for the safe and orderly operation of the connection facility. Based on all the sample agreements reviewed, the agreement should likely include, but not be limited to the following:

- Names and addresses of the parties;
- Recitals;
- Term – commencing upon receipt of Authorization to Connect. A temporary connection agreement may be required to allow commissioning and testing;
- Description of the connection facility;
- Reference to Appendix F for the technical requirements;
- Reference to Appendix F for the commissioning and testing;
- Description of the connection point;
- Process for notification of modifications to the facility;
- Representations and warranties;
- Indemnification;
- Cost Responsibility/Responsibilities/Maintenance;
- Access to Facility;
- Disconnection for repairs (planned outage);
- Disconnection without notice;
- Default;
- Notices;
- Amending process;
- Assignment;
- Signatures; and
- Attachments:
    - Single line diagram
    - Contact list

- Safety procedures and work protection

A DSC sample connection agreement can be derived from the sample connection agreements studied to date. The connection agreement developed by the Interstate Renewable Energy Council could be used as the basis.

Are the points suggested appropriate to form a connection agreement for plants under 10 MW?

3.6 Metering

Section 5.1 of the DSC governs metering requirements for generating facilities. This would require SOP generators to install four-quadrant interval meters. These meters measure consumption and reactive power in both directions over preset intervals, usually 5 or 15 minutes.

Is a four-quadrant meter a reasonable requirement for SOP generators, given the power flows, charge determinants and Measurement Canada requirements?

4. Distribution Rates

In 2006, the Board will begin a larger examination of distribution rate models in light of the many recent changes to the electricity industry and the role of distributors. Distribution rates to accommodate distributed generation will be one of the issues in that project.

4.1 Standby Charges

The OPA is determining eligibility criteria for the SOP. It may include load displacement applications such as co-generation (or combined heat and power) plants. If these generators are eligible, it raises the issue of standby charges.

The purpose of standby charges is to compensate the distributor for maintaining the ability to accommodate, at any time, the total load of a customer with load displacement facilities behind its meter. It is the responsibility of the Board to regulate rates such that the recovery of costs associated with the distributor's facilities that must be available to meet the customer's total demand is not inadvertently subsidized by the rest of the distributor's customers and, at the same time, the customer with load displacement facilities is not unduly burdened by higher than reasonable charges.[18]

[18] OEB. 2006 Electricity Distribution Rate Handbook, Report of the Board, May 11, 2005, p. 95.

Ofgem, in the United Kingdom, currently has each distributor set "distribution use of system (DUoS)"charges based on the distributor's assessment of system costs. These assessments are fed into a charging model to determine the cost of additional load at each level of the distribution system and an appropriate cost recovery split between customer groups. The models assess reinforcement costs, and exclude costs which are recovered from the customer in full (connection charges or transactional charges). The fact that capacity was found to be the key driver of costs on the distribution system, would support the argument in favour of standby charges.[19]

In the context of the 2006 Electricity Distribution Rate proceeding, the Board concluded that the standby rate should be determined through a distributor specific analysis (and in some instances a case specific analysis) of the distribution costs that need to be recovered through the standby rate.[20] At present, 16 Ontario distributors have standby/cogeneration facility charges. These charges are billed on a range of determinants, such as:

- actual or anticipated maximum demand;
- per kW reserved;
- capacity reserved;
- kVA rating; manufacturer's rated output of the co-generator;
- various measures of demand; or
- a monthly service charge.

The Board's regulatory instruments indicate that where a distributor currently has a standby charge, it should be continued for 2006. Any modifications or new charges are to be requested as part of the distributor's 2006 rate application.[21] A sample methodology and framework that might be used as a basis for such an application were included in the 2006 Electricity Distribution Rate Handbook.[22]

The distributor is permitted to charge an amount to cover the incremental cost of monitoring, billing and administration related to providing this service.

Are standby charges a barrier to generators who would be eligible for the standard offer program?

4.2 Rate Classes

All generators draw some power either directly as a result of the generator starting or incidentally as station load while the generator is not running. In either case for merchant generators (as opposed to the load displacement generators described above), the amount of power used is usually not more than 1% to 2% of station capacity rating. For the sizes of most SOP generators, this will be on the level of a residential account.

There is a lack of consistency in the rate class applied to merchant distributed generation among the distributors in Ontario. Some distributors charge volumetric tariffs only either

[19] Ofgem. Structure of electricity distribution charges, Consultation on the longer term charging framework, May 2005, pp. 7, 16.
[20] Ibid., p. 80.
[21] OEB. 2006 Electricity Distribution Rate Handbook, May 11, 2006, p. 95.
[22] Ibid., p. 102 – 3.

on a consumption or demand basis but no fixed customer charges. Others apply a fixed customer charge. Hydro One Networks has some holdover rates for previous Ontario Hydro direct customers where commercial rates are being charged.

As an interim solution, Hydro One Networks has proposed creating a separate rate class for this customer segment to allocate the costs of providing services. This interim charge will be reviewed as part of Hydro One Networks 2006 distribution rate case.

4.3 Connection Costs

The cost of connecting a generator to a distribution system can often involve significant system reinforcements and operating changes. Connection charges are usually differentiated as shallow charges that are direct or solely attributable to the customer, or deep charges that are reinforcements to the larger system beyond the connection point. In the UK, DG developers pay the full cost of connection, both shallow and deep costs, up front. This approach factors in location-based prices and in principle allows for discounts to these charges for the value of generation deferral. Partially as a consequence, DG does not pay any charge for use of the distribution system but also does not receive any additional charges or credits from the distributor for losses or ancillary services. Ofgem is leading the network system operators in a comprehensive rate re-design exercise to develop charging models that include use-of-system charges for generation[23].

By contrast, in the Netherlands, DG pays only the shallow connection costs for distribution. Distributed generators larger than 10 MVA also pay costs for using the system[24].

There are advantages to both systems. The UK system sends stronger "locational" signal but can be a barrier for DG, as connection costs can amount to a large percentage of installation costs. OSEA has proposed that the developer be responsible for costs to the point of connection but that network upgrades, if required, be borne by the system.

Chapter 6 of the Transmission System Code covers generators connecting to the transmission network. Generators pay for their connection and upgrades to any transmitter-owned connection facility. The connection extends to the nearest station on radial lines. However, changes to network facilities are socialized except in exceptional cases with approval of the Board. This recognizes the general benefit of network upgrades and the large pool of transmission customers amongst whom these costs will be spread.

If TSC-type definitions of connection were used in a distribution system, how would that affect the cost responsibilities?

Under Chapter 3 of the DSC, the generator pays all costs. System reinforcement, however, usually provides more capacity than a single generator needs and this leaves

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[23] Ofgem, "Structure of electricity distribution charges: Consultation on the longer term charging framework", May 2005.

[24] International Energy Agency, "Distributed Generation in Liberalised Electricity Markets", 2002, p. 83.

open the likelihood that subsequent generators attaching to the same system become free riders at the expense of the initial investor. Being the first generator on a system can be a handicap.

Chapter 3 has addressed this by providing for charges to subsequent generators attaching to the system to refund a portion of the reinforcement costs to the original generator. This approach allocates the costs more equitably among the generators causing them, avoids cross subsidization issues and provides incentives for generators to look for the most economical connection points. It can be administratively awkward and still forces the first generator to provide a potentially large capital contribution without any guarantee that an offsetting rebate will materialize in the future. It also lacks incentives for distributors to minimize costs, placing the onus for this feature on generators.

Connection cost policies do not fully recognize the benefits of embedded generation. Avoided costs of both distribution and transmission system capacity upgrades can be an example of unrecognized benefits. System security and improved reliability is another benefit that accrues to all ratepayers from having generation embedded at the distribution level. Reduction in system losses is a benefit to the ratepayer, yet neither the DG nor the distributor will be rewarded for a reduction in losses. Where the cost of connection is high compared to the overall cost of the generation project, the project might not proceed and these benefits would not be realized.

In fact, embedded generation will, in some cases, displace distributor capital investment limiting rate base growth and the revenue that goes with it. For example, if generation is added to a distributor's system that resolves a transformation capacity constraint, the distributor might forego building a new transformer station. This investment would have been added to ratebase providing a rate of return to the distributor.

The market-based rate of return on assets would compensate the distributor for its investment and the costs of connection would be spread over all ratepayers in the territory. A problem with this approach is that it would remove any incentives from generators and distributors to choose the most economical connection points and minimize connection costs. Without some accountability for costs, prudence will have to be more closely scrutinized. The Board would have to take care that the connection cost policy was not unfairly inducing distribution level connection over transmission level connection. The same situation arises with demand response. If a load shifts use to periods with lower demand and lower prices, all consumers benefit.

Socialization of some connection costs might be desirable to facilitate distributed generation. "Any unusual or extraordinary costs should be borne by the system and ultimately Ontario's ratepayers."[25] One proposal to address this issue would be to have connection costs borne by the distributor and allow them into ratebase. In Germany, the costs associated with connecting plants generating electricity from renewable energy sources including the cost of metering are borne by the generator. However, the costs

[25] OSEA, "Powering Ontario Communities: Proposed Policy for Projects up to 10 MW", 2005, p. 46.

associated with upgrading the system are borne by the distributor and added to ratebase for determining rates[26].

To spread connection costs over all the consumers in the province would require a mechanism like the rate protection for rural or remote consumers in s. 79 of the OEB Act.

Is it appropriate for generators to pay both direct and reinforcement costs? Should some of these costs be borne by the ratepayer? Should costs be paid by ratepayers of the specific distribution system or all Ontario consumers? How can economic connection be encouraged?

5. Next steps

Board staff is inviting written comments on the issues raised in this paper or to do with the Board's jurisdiction over the SOP.

Any stakeholder who wishes to make a written comment **must** file seven (7) paper copies of the comments, and an electronic copy in Adobe Acrobat (PDF) with the Secretary of the Ontario Energy Board at the address above and by e-mail to BoardSec@oeb.gov.on.ca **by 4:30 p.m. on November 30, 2005**. You **must** quote Board file number EB-2005-0463 and include your name, address and e-mail address.

The Board and the OPA will issue a report on their work on the Standard Offer Program to the Minister by the end of 2005. Any necessary amendments to the Board's regulatory instruments to implement the final program will begin in early 2006. Options for rate design models will be examined starting in 2006.

[26] Article 13: Grid costs, The Renewable Energy Sources Act, The Bundestag, proclaimed August 1, 2004.