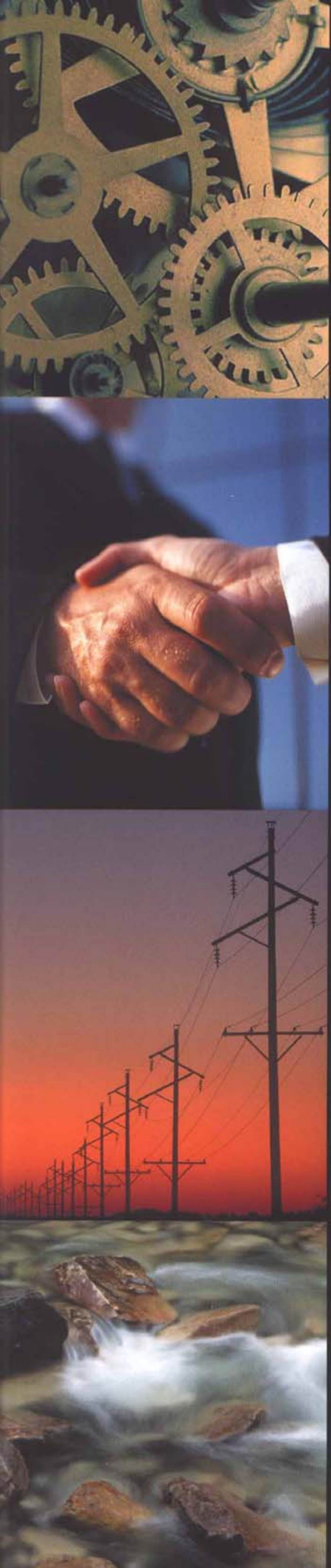

EES Consulting

Discussion Paper on Distributed Generation (DG) and Rate Treatment of DG

June 2007

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Executive Summary

Introduction

The Ontario Energy Board (OEB) requested the assistance of EES Consulting, Inc. (EESC) to provide policy-related recommendations to streamline the deployment of distributed generation (DG) and to explore DG-related rate design, especially standby rates. EESC conducted a survey of DG policy in selected jurisdictions throughout the world using published sources from regulatory agencies in Canada, USA, Australia and Europe to determine their policies used to promote DG. EESC further focused on a specific class of DG, industrial generation (also called load displacement generation). EESC also provided a discussion of standby rate design issues for DG and a review of OEB standby unit costs.

Policy Implications

The interest level in DG has significantly increased in recent years due to a variety of industry changes, including: utility industry restructuring, increasing system-capacity needs, technology advancements, social policy and greenhouse gas emission reduction. Distributed generation differs fundamentally from the traditional model of central generation and delivery, thus creating a new set of policy issues to be resolved. One of the key differences is the wide range of possible sizes of (and markets for) DG technologies. Examples include a single solar panel on a residence or a large natural gas fired generator capable of displacing load at an industrial facility.

In order to resolve the primary barriers to DG, the following policy issues need to be addressed:

- System Interfaces (e.g., access, net metering, dispatch)
- Interconnection Standards
- Stranded Costs
- System Investments
- Standby Charges

Survey of Worldwide DG Energy Policy

A survey was conducted to better understand how other countries or jurisdictions are addressing each of the potential DG barriers. It is generally agreed that DG should not be subsidized if not economically viable. However, some DG systems, primarily renewables (wind and solar) and combined heat and power (CHP), are receiving subsidies in order to support environmental policy. The surveyed countries are all working at some level to streamline DG implementation by reducing the barriers.

System Interfaces

System interfaces handle the interaction between the DG facilities and the distribution system. Policy issues include access to the distribution system, net metering and dispatch capabilities. Australia has established standardized access arrangements for DG to the network. Net metering is being addressed by most of the surveyed countries. Within the United States, 41 of the 50 states offer at least some form of net metering. In general, if dispatch capabilities are considered, they are limited to large DG systems and typically impose the same market participation requirements as central power generators. Implementing full access would require development of bidding, scheduling and dispatch protocols that account for DG.

Interconnection Standards

Interconnection is a significant policy issue and the general trend is to develop standard interconnection guidelines. Without standard interconnection guidelines, each connection to the distribution system must be designed on a case by case basis. The Netherlands has adopted standardized interconnection guidelines. The European Union and United States are both promoting interconnection standards by developing a template for member countries or states to adopt on an individual basis. In the US, California, New York and Texas have all adopted standard interconnection guidelines. In Denmark, network operators have developed connection specifications based on the size of DG plant, with less stringent requirements for smaller plants.

Stranded Costs

Deciding whether or not DG users should pay the utility for stranded investment costs, such as an underutilized distribution system, is a significant DG barrier. Several of the surveyed countries are actively addressing this issue in theory; however, Denmark is the only country where the exposure to stranded assets has been significant due to the high quantities of DG. In Denmark, stranded costs are shared among all ratepayers as the shift to DG is considered a change for the common good. Additional methods for addressing stranded costs include exit fees, competitive transition charges or covering these costs in the fixed standby charge. From the LDC perspective, stranded costs should be covered by the standby charge.

System Investments

One benefit of DG is the potential to delay or avoid transmission and distribution system investments. System investment policy should address a methodology to determine cost-effective system planning and the inclusion of DG in the analysis. The United Kingdom employs locational transmission charges based on where the DG is located, determined by the forward looking long run marginal cost of providing incremental capacity at different points on the network. However, in Denmark, the initial benefit created by avoided transmission and distribution costs is being replaced by an increase in transmission and distribution costs due to the increased quantity of wind generation located in low load areas.

Standby Charges

The appropriate methodology for calculating the standby rates for DG facilities, including reliability considerations, is also a significant issue. Standby charges in California are developed for three categories:

- Supplemental – a portion of customer load is not covered by the customer's DG. The portion of the load served by the distribution company is at the applicable tariff.
- Backup – used for unanticipated load resulting from an unplanned DG unit shut-down. These costs are higher as the utility will have to plan for available system capacity during peak times.
- Maintenance – DG system outages are scheduled at time of utility low demand, therefore the costs should reflect this flexibility.

Standby Rate Design

In order to review the standby rates in Ontario, the rate setting objectives, rate design options and issues surrounding the design of standby rates must be discussed.

The local utility typically provides standby service to a customer that generates all or most of its electricity requirements with generation facilities located on its own premises. There are three common types of standby service: backup, maintenance and supplemental. Backup service is electrical energy delivered by the utility during unscheduled outages of the customer's onsite generator. Maintenance service is electrical energy delivered by the utility during a scheduled outage of the onsite generator. Supplemental service is electrical energy delivered by the utility when the output of the onsite generator is less than the customer's maximum demand. The load characteristics of each service are different, resulting in different load shapes and, therefore, different service costs.

Rates can take many forms, but ultimately they should reflect the costs that the utility incurs (demand, energy and customer related costs), and collect the desired level of revenues. The process of developing standby rates requires greater consideration of fundamental economic and pricing theories. For example, economic theory dictates that the price of a commodity must roughly equal its cost, if equity among customers is to be maintained. In general, the standby rate should include:

- Monthly contract demand rate ($/kW) to collect cost of having the distribution and local transmission system available when needed;
- Monthly customer charge to collect administrative and service costs; and
- The standby rate should be utility specific, although the methodology used to calculate the rate should be consistent across utilities.

In addition to determining the standby charges, it is also important to develop a process for determining the additional benefits and credits of a specific DG unit, such as transmissions and distribution savings due to the customer's DG unit; avoided losses; and provided ancillary services.

Review of Current Standby Unit Costs in Ontario

Standby rates should reflect the costs that the LDC incurs serving the standby customer. The rate should incorporate, to the extent possible, both the costs and the benefits of adding the DG customer to the distribution system. In practicality, the costs and benefits can be difficult to determine. In Ontario, interim standby rates have been implemented using various methods and assumptions across LDCs. However, a standardized cost of service study, benefit calculation and rate design can provide useful guidance towards improved standby rates.

Cost allocation filings as submitted and/or standby rates as reflected in the 2006 Tariff of Rates and Charges were reviewed for this report. As part of OEBs Cost Allocation informational filing, several LDCs submitted fully allocated expenses for DG customers in a new and separate standby rate class. The allocated expenses (including customer-related costs) were used to calculate a monthly unit cost ($/kW) based on the non-coincident peak demand (NCP) and compared to the demand charges applicable to DG customers under their current rate schedule. Total revenues paid by the DG customer under current standby rates were compared to fully allocated costs as well. This exercise was undertaken to determine whether DG customers were paying their full cost to serve.

Based on the initial analysis of the data provided by the cost allocation filing, there is a very small difference in unit cost when separating the standby customers from the existing classes. In addition, a comparison of benefit-cost ratios shows that the standby rate customers pay close to their allocated cost of service. In general, there are concerns over the reliability of the data gathered for modelling the standby rate classification. Therefore, any results are very general and may not be accurate for individual LDCs.

While the cost allocation filing provided information on the unit costs of serving DG customers, the filing did not generally provide information on the potential benefits provided by DG customers to the distribution system. As discussed, further in this report, there are generally two different conceptual methods that can be used to determine benefits of DG. The marginal cost approach determines the marginal cost of capital investments and avoided operating expenses. The incremental approach calculates the LDC’s revenue requirement with and without the DG customer. Any cost savings between the two scenarios would represent the benefit of DG and are attributed to the DG customer. In general, a detailed calculation should be performed for large DG customers.

However, for the smaller DG customers a methodology that is straightforward, consistent, and easy to change over time should be implemented. This simpler methodology could include the marginal distribution unit costs calculated for the CDM programs. Another option would be to base the benefit (credit) on the credit assigned to a large DG customer.

Recommendations

Based on the review of policy decisions in other jurisdictions, understanding of OEB’s standby unit cost allocation and the current DG policy, it appears that the development of fair and balanced policies for distributed generation is on the right track in Ontario. EES Consulting provides the following recommendations for OEB to establish a standard methodology across utilities for implementing DG.

System Interfaces

1. Recognize the obligation to support net metering for renewable and DG resources.

Interconnection Standards

2. Continue to implement interconnection standards for the four generation classes as per the Distribution System Code (DSC).

Stranded Costs

3. Stranding may be moot with proper cost allocations where DG customers are viewed as a load by the LDC.

4. If proper cost allocation to DG customers is not achieved, a separate report on stranding is suggested.

Standby Charges

5. Specific considerations for setting and designing standby rates include the following:

    - Rates should be designed to reflect the costs, net of any offsetting benefits;

    - Standby rates should reflect the various gradations of services (i.e., voltage levels) provided;

    - Rates should not create artificial barriers to DG;

    - The rate structure should be simple and easy to understand by the DG consumer and to administer by the LDC;

    - Rate design should encourage the following:

        - Reduced redundancy of installed capacity;

        - Operation of DG plant during on-peak hours; and

        - Utilization of excess grid capacity during off-peak hours.

6. Create a separate class for DG customers with generation capacity above 500 kW and where a DG customer generates more than 10% of its total load. Exempt customers (e.g., generation less than 500 kW, or greater than 500 kW but make up less than 10% of the customer's total load) would remain on current rate schedules. Information on customers could be obtained from the interconnection applications and other customer information available. The 500 kW threshold allows for special treatment of the large DG customers, while limiting the administrative burden of identifying all DG customers.

7. Calculate and adopt standby rates that properly reflect the costs of service customers with DG. The standby rate should include:

   - Monthly contract demand rate based on billed historical demand and ratchet ($/kW) to collect the costs of having the local transmission and distribution system available when needed;

   - Monthly customer charge to collect administrative and service costs; and

   The standby rate should be utility specific, although the methodology used to calculate the rate should be consistent across utilities.

8. Develop a process for determining the additional benefits and credits of a specific DG unit. This process should be initiated during the development of the connection agreement between the LDC and the DG customer. The process would determine and credit the DG customer for:

   - Transmission and distribution savings due to the customer's DG unit;

   - Avoided losses; and

   - Provided ancillary services.

   While the process to determine benefits can be consistent across LDCs and customers, the actual benefits for larger DG customers must be determined on a case by case basis for each customer. Smaller DG customers should have a generic crediting process. The benefit provided to the DG customer would be paid for by all customers based on their standard cost allocation of similar costs.

Distributed generation is being more widely implemented worldwide as countries and local jurisdictions work to reduce the barriers. Working to streamline the process and adopt fair, cost-based standby rates for DG is a good starting point for Ontario.

1.0 Introduction

1.1 Overview

The Ontario Energy Board (OEB) requested the assistance of EES Consulting, Inc. (EESC) to develop a survey of the policy treatment of distributed generation (DG) in selected jurisdictions throughout the world and to formulate recommendations to support DG.

Distributed generation is defined as the placement of small-scale electricity generation units close to load sites with the option of feeding back into a centralized network. Normally, DG is under 25 MW in size and connected to the distribution system at relatively low voltages. As part of this project, EESC used published sources to survey regulatory agencies in North America, Australia, Japan and Europe to determine the methodologies used to support DG. EESC also reviewed the current OEB DG regulation. In Ontario, the terms used are generally load displacement generation (LDG), which is installed to meet a portion of a customer's load, and embedded generation (EG), which may provide power to both the customer and to the distribution system.

EESC was also asked to explore DG-related rate design, especially standby rates. The results of the current Ontario standby unit cost calculations were also reviewed. Finally, EESC provides a recommended best practice for future treatment of DG.

1.2 Objective of the Report

The objective of this report includes the examination of the methodologies used by other entities to regulate the implementation of DG. Based on available data, EESC provides a summary of practices and policies utilized by each jurisdiction surveyed. The issues explored include the following:

- Current DG Approach, Incentives and Tariff Treatment – includes the current policies, incentives and tariffs, and any methods currently in place for dealing with avoided costs, net metering, interconnection, and standby rates.
- Regulatory and Market Issues – includes key issues being considered at the surveyed regulatory agencies, open regulatory proceedings, and associated working group activities.
- Pilot Program Results – includes case studies of DG installations and pilot programs.

Special attention was paid to load displacement generation systems, standby rates and the method of allocating costs. Key policy issues were identified that will need to be considered as Ontario addresses DG.

1.3 Report Organization

This report is divided into nine sections. Following this Introduction, the next three sections provide background information on Distributed Generation, Policy Consideration and the current Status of DG in Ontario. The survey profiles are located in Section 5 - Survey of DG Policy, followed by a section focused on a specific class of DG, load displacement or industrial generation. The next section (Section 7) discusses the Standby Rate Design Issues. A review of the current allocated standby costs in Ontario is provided in Section 8. The Summary and Conclusions section contains recommended best practices and highlights policy issues that should be considered. Appendix A contains additional details on available distributed generation technologies. Appendix B contains the complete survey results summarized in Section 5, including summary tables by country. A bibliography of references is located in Appendix C.

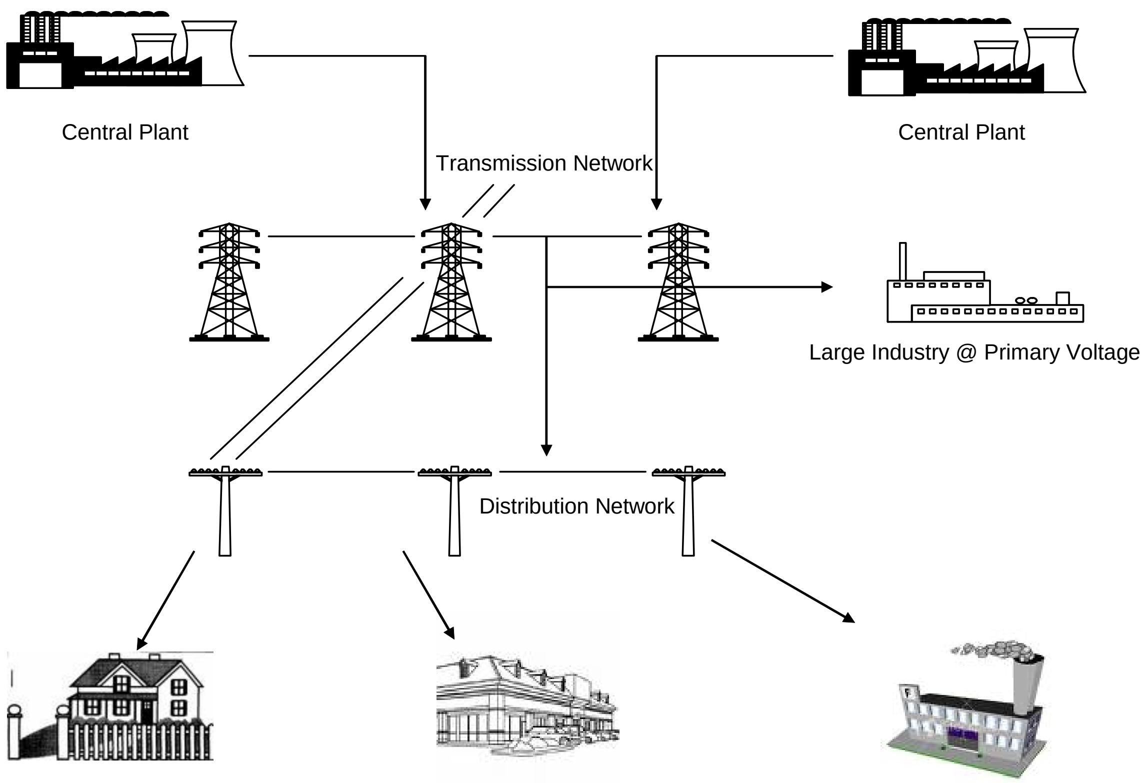
2.0 Distributed Generation

This section introduces the currently available distributed generation technologies, including a summary of performance characteristics and typical applications.

2.1 What is Distributed Generation (DG)?

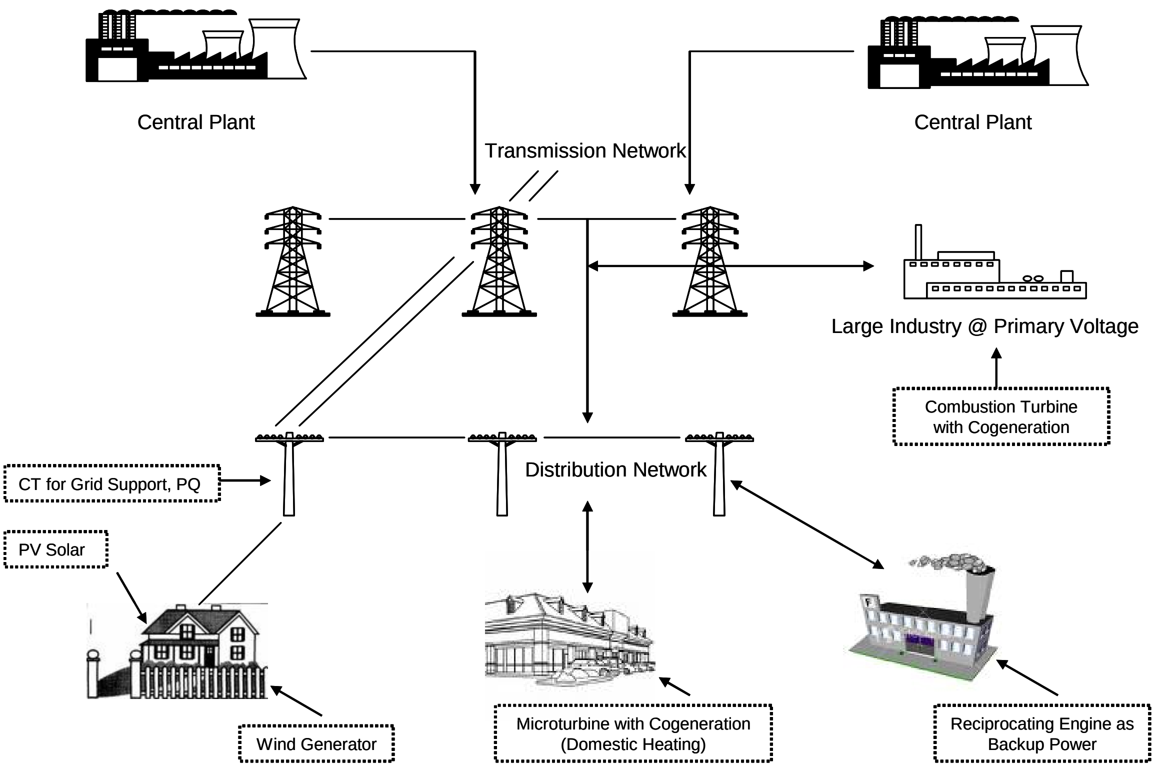
Typically generation resources are located far from load sources as shown in Figure 1. The power generated at large generation facilities is transported, first over high voltage transmission lines, and second over distribution lines to homes and businesses in the service area.

Figure 1
Central Generation



Distributed generation includes parallel and stand-alone electric generation units located within the electric distribution system at or near the end user. Figure 2 provides an illustration of a system which includes distributed generation.

Figure 2
Distributed Generation



Distributed generation is defined as electric power generation equipment located near the customer that will use it and generally ranges from a few kW to 25 MW in generation capacity.

Distributed generation projects can take many forms, ranging from small-scale generation projects that typically use natural gas or renewable energy sources designed specifically to supply electricity to the local utility or to the wholesale market, to electricity produced by companies or individual customers who have generators installed within their facilities. This type of self-generation is created primarily to meet the customer's own electricity needs, although the producer may choose to sell extra power to its utility or the wholesale market.

The following outlines the different applications of DG:

- **Cogeneration**, or combined heat and power (CHP) systems use waste heat for thermal applications, such as space heating and cooling, or to generate additional power with a steam generator.
- **Peak shaving** units operate during times of high demand to reduce the high utility demand charges associated with the peak.
- **Net metering** allows a customer to send excess electricity from an on-site DG unit back to the electric grid for a credit toward energy costs.

- **Standby or emergency generation** systems are typically used in situations where the failure of critical devices would result in property damage, threaten health and safety, or possibly result in a high outage cost, such as lost production time. These systems typically only operate a few hours a year when the electric grid is unavailable.
- **Premium power systems** are located at a site to improve both power quality and power reliability. Typical premium power customers include banks, semiconductor manufacturers, grocery stores, hospitals and other industrial and commercial sites. Premium power systems operate continuously and are often backed up by the electric grid.
- **Remote power systems** are installed at a site located far away from the existing transmission and distribution system. These customers avoid the cost of connecting to the grid and eliminate any potential problems associated with being the last customer on a distribution line, such as power outages and reduced power quality.
- **Green power systems**, also known as renewable technologies, have very low emissions and or environmental impacts; typically attract customers that are concerned about the environment and willing to pay a slight premium for this power.

2.2 Distributed Generation Technologies

DG encompasses a wide variety of technologies and fuel types, as summarized in Table 1. DG technologies include renewable energy, such as solar and wind, however, large renewable projects, such as wind farms, are not considered DG. Large wind farm (greater than 5 MW) and solar arrays (greater than 100 kW) are typically operated as a central generation site.

The DG technologies listed in the table are divided into two groups, mature and emerging technologies. The mature technologies are currently commercially available and well suited for DG applications. Mature technologies continue to undergo new advancements to improve their performance and reduce costs. Emerging technologies are generally in the demonstration phase and have not been adopted commercially. These products are not commonly promoted through DG policy incentives aimed at wide-scale adoption.

More detailed information on the available DG technologies is located in Appendix A.

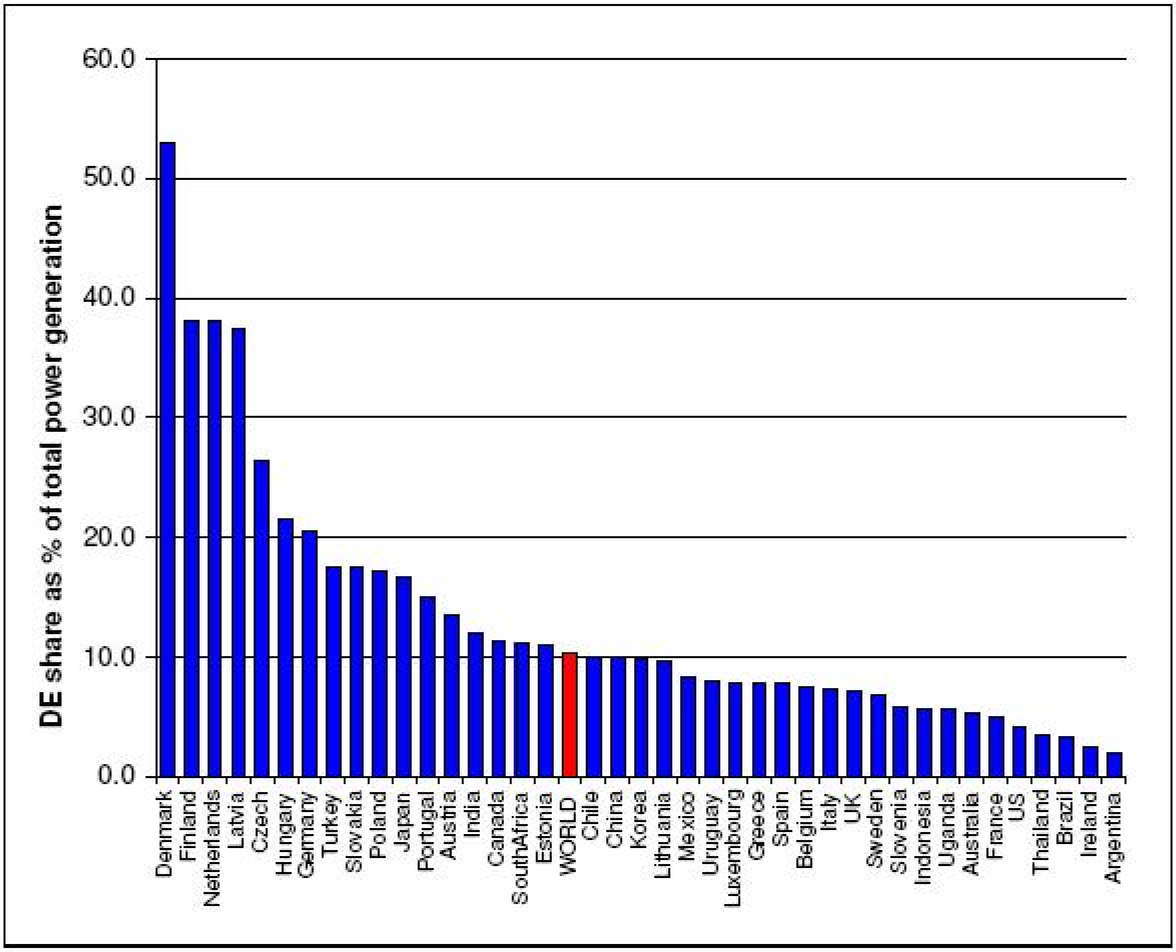
Table 1 Summary of DG Technologies				
DG Technology	**Sizes Available**	**Fuel**	**Efficiency**	**Cogeneration**
Mature Technologies				
Combustion Turbine	500 kW – 25 MW	Natural gas, liquid fuels	20 – 45%	Available as steam
Reciprocating Engine	5 kW – 7 MW	Natural gas, diesel, landfill gas, digester gas, biogas	25 – 45%	Available as steam
Microturbine	25 kW – 500 kW	Natural gas, hydrogen, propane, diesel	20 – 30%	Available as 50 – 80 °C water
Small-Scale Hydro Power	500 kW – 25 MW	Water	65 – 70%	N/A
Photovoltaics*	< kW to 100 kW	Sunlight	5 – 15%	N/A
Wind Turbine*	Several kW – 5 MW	Wind	20 – 40%	N/A
Emerging Technologies				
Molten Carbonate Fuel Cell	250 kW – 10 MW	Natural gas, hydrogen	45 – 55%	Available as hot water, LP or HP steam
Phosphoric Acid Fuel Cell	100 kW – 200 kW	Natural gas, landfill gas, digester gas, propane, biogas	36 – 42%	Available as hot water
Proton Exchange Membrane Fuel Cell	3 kW – 250 kW	Natural gas, hydrogen, propane, diesel	25 – 40%	Available as 80 °C water
Solid Oxide Fuel Cell	1 kW – 10 MW	Natural gas, hydrogen, landfill gas, fuel oil, biogas	45 – 60%	Available as hot water, LP or HP steam
Stirling Engine	<1 kW – 25 kW	Natural gas	12 – 20%	Available as hot water

* Does not include large installations with many units.

2.3 Distributed Generation Share of Total Energy Output

Figure 3 provides the proportion of total energy production from DG by country. Worldwide, distributed generation totals roughly 10 percent of the total power generated. The highest share of DG is observed in Denmark, which produces over 50 percent of its energy with distributed generation technologies including large CHP. Denmark's DG is primarily due to the high volume of large wind generation. In other jurisdictions, the actual energy from DG facilities may be higher than reported in the figure due to lack of data and reporting requirements. For example, DG accounts for only 4% of energy produced in the United States; however this number does not include CHP generation facilities. As a comparison, Canada produces approximately 12% of total energy from distributed generation.

Figure 3
Proportion of Total Power Generation from DG[1]



Source: WADE, *World Survey of Decentralized Energy*, 2006

[1] The WADE chart may include CHP, regardless of size. Data relies on reported figures which may not be considered across all countries.

3.0 Policy Considerations

Based on a jurisdictional survey, this section provides a discussion of the benefits of adopting DG technologies as well as the barriers to implementation of the technologies, and outlines the policy decisions that will help to remove the barriers.

Increased availability and decreased cost of DG presents new regulatory challenges to distribution utilities. A key requirement is to understand the cost of the distribution system and the costs that may be incurred or avoided in the presence of additional DG. Because the decision to install DG is largely made by individual customers, it is important to reveal the costs and benefits of DG to a wide range of stakeholders. It is equally important for regulators to set appropriate policy goals and regulations such that implemented DG provides more benefits than costs.

3.1 Benefits of Distributed Generation

DG technologies can provide a variety of benefits to both electricity customers as well as the electric utility.

Customer Benefits

- More reliable power, especially for those in areas where outages are common.
- The variety of DG equipment allows customers to choose the best solution for an individual location or application.
- Some DG equipment is able to provide high-quality, premium power for sensitive applications.
- DG equipment efficiency improvements are achieved when used in combination with combined heat and power equipment for heating, cooling, and dehumidification applications.
- Cost savings can be realized by reducing the peak demand at a facility, therefore lowering demand charges.
- DG equipment can provide power to remote applications where traditional transmission and distribution lines are not an option.
- Environmental benefits of DG solutions include a reduction in emissions for some technologies (e.g., solar, wind, fuel cells, biogas, water).

System Benefits

- Delay or eliminate the need to build new large central generating plants or transmission and distribution lines.
- Reduce the utility peak demand.

- Reduce transmission losses by placing small generation close to the end use location.
- Improve system security by reducing reliance on a single energy source.
- Improve reliability to customers, improving the quality of service.

3.2 Potential Barriers to the Further Development of Distributed Generation

The benefits of DG are offset by the potential barriers to DG adoption, including both real and perceived risks. The following key barriers to the adoption of DG are common issues, and not all are applicable to Ontario.

Regulatory Barriers

- Individually negotiated contract terms may be more complex that if standardized.
- Interconnection procedures are geared toward large systems, generally too complex for small systems.
- Regulatory burden may be equal to that of a central generation facility.
- Wholesale market access. DG resources have limited access to the wholesale power and ancillary services markets due to current supply market and regional transmission organization (RTO) rules.
- Retail market access. Direct retail wheeling of DG resources is not allowed in some jurisdictions.

Cost Barriers

- Electric rate structures:
    - Low rates for residential or small commercial customers can discourage development of small DG. Often, artificially low rates can be due to shifting away from cost-based rates in order to provide a subsidy for a specific rate class. This subsidy may reduce any customer incentive to build DG.
    - High reliability costs are included in utility rates regardless of DG use.
    - No rate reduction for benefits DG provides to utilities (such as deferred distribution investments, voltage support and possibly reactive power, improved reliability).
- Payment for ancillary services may be cost prohibitive.
- DG customer carries the burden of payment for utility stranded costs.
- Utility perception of potential lost revenue to DG projects serving customer load.
- No credits for avoided transmission and distribution losses.

Operational Barriers

- Operating characteristics vary drastically over size range (e.g., a small residential system operating as a backup generator versus a large industrial facility using large DG equipment as base load power generators).
- Lack of experience. The traditional electric industry was built around central power generating stations delivering power to customers via the transmission and distribution system.
- Customer perception that DG is uneconomical.

- Price volatility for DG fuel.
- Economies of scale. Many DG units are expensive on a dollar per kW basis, as the units are not being produced at an efficient manufacturing scale.
- Difficulty in obtaining financing for DG technologies due to the high risk of transaction costs.

Many of these issues can be addressed through changes in policy; discussed further below.

3.3 Policy Issues

The interest level in DG has significantly increased in recent years due to a variety of industry changes, including: utility industry restructuring, increasing system-capacity needs, technology advancements, social policy and greenhouse gas emission reduction. DG technology differs fundamentally from the traditional model of central generation and delivery, thus creating a new set of policy issues to be resolved by decision makers. In addition, there are several sizes of DG facilities. The smallest size could be a solar panel on a residence, while the largest size could include a natural gas fired generator at the site of an industrial facility intended to displace load. In order to address and resolve the barriers discussed above, the following policy issues should be addressed:

- System Interfaces
    - Access
    - Net Metering
    - Dispatch
- Interconnection Standards
- Stranded Costs
- System Investments
- Standby Charges

System Interfaces

The system interface is the interaction between DG facilities and energy infrastructure. The considerations related to system interfaces include policy regarding safety, protocols, system impacts, reliability, standards and metering, dispatching, tariffs, price signals, and operational decisions.

Access

A major consideration regarding DG is that access to the energy system, in general, is designed for large, centralized generation units connecting at transmission voltages. As a consequence of adding more complexity by including several DG plants, system operation and transaction costs may increase. In addition, technical requirements may hinder the access to the market by individual units if DG must meet the same standards as large centralized units.

Net Metering

Net metering allows small customers to offset their electricity consumption by sending extra energy generated to the interconnected utility. A bi-directional meter registers electrical flow in both directions. This type of metering enables a monetary exchange based on net customer generation and consumption.

A net metering customer uses DG to generate part of their load and the utility for the remaining load requirements. However, issues arise with the possibility of the customer generating more electricity than they use. The primary question is how this excess energy should be valued if it is returned to the interconnected utility. Opinions range from a minimum rate based on the cost for the utility to purchase wholesale power to a maximum rate based on the full retail energy rate to the customer. Issues associated with net metering, include:

- The energy portion of the utility tariff may contain fixed charges and costs. If so, the full retail rate may over-compensate the customer for the energy delivered back to the utility and, in turn, hurt the utility's non-participating customers.

- The energy rate is an average rate over the whole year; therefore it may not correctly value the energy. Wholesale energy rates vary throughout the year and the retail energy rate accounts for these fluctuations. This means that the customer could be providing power to the utility during high or low value times.

Dispatch

Proponents of DG encourage regulators to allow DG operators to bid generation directly into the power market. In this case, DG would increase in value as increased access and flexibility would allow for energy sales in periods of high market prices. However, implementing full access to the market would require the development of bidding, scheduling, and dispatch protocols that take DG into account. Some jurisdictions allow this for larger DG plants, but require the owner to register as a market participant with the attended increase in associated responsibility and costs.

Policy decisions about system interfaces must weigh the cost of increased complexity against the DG owner's benefit of operational flexibility and access to the energy market.

Interconnection Standards

One of the significant issues facing anyone planning to install a DG technology is the interconnection of the device to the electric utility system. The lack of common standards for interconnecting DG devices into the utility system is considered a barrier to the wide acceptance and installation of DG technologies.

The installation and interconnection of DG devices requires a transfer switch. During a power outage, the transfer switch ensures that there is no backfeed of electricity from the DG device into the utility's electric distribution system. Backfeed creates a dangerous situation for utility line workers and may also damage equipment. In addition, backfeed may create instability potentially impacting other utility customers.

In the US, the Institute of Electrical and Electronics Engineers, Inc. (IEEE) has developed the *Standard for Interconnecting Distributed Resources with Electric Power Systems* (IEEE 1547). This standard establishes criteria and requirements for interconnection of DG systems with the electric power system. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. The standard is not mandatory and is generally left to be adopted by individual states, however, the U.S. Energy Policy Act of 2005 called for state commissions to consider certain standards for electric utilities. Under Section 1254 of the act: "Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time."

Policy should address designing interconnection policies in a balanced manner to address size of generation facilities and the unique capabilities of DG. In addition, policy in this area needs to address uniform standards across transmission systems.

Stranded Costs

The stranded costs include the cost associated with an underutilized system. From the utility perspective, they made an investment in generation, transmission and distribution with the assumption that they would receive a fair return on those investments. From the DG user perspective, the bulk of the transmission and distribution system has been paid for and the ongoing maintenance expense is covered by fixed charges (customer charges) in the tariffs. Therefore, a customer reducing load will still pay the fixed charges. Methods that have been used to recover stranded costs include the following.

- Competitive Transition Charges (CTCs) for power supply stranded costs. CTCs have, for example, been used in California during restructuring; CTC's pay for stranded generation assets no longer economic in an open market.

- Exit fees are used to collect transmission and distribution stranded costs. Exit fees allow the utility to collect for investments made in the system on behalf of the customer reducing load or leaving the system entirely.

Additional arguments are that as long as DG installations are not growing faster than load growth, the underutilized assets are available to support the growth in demand. These types of fees and charges may discourage the adoption of DG and will result in limitation on competition from different and possibly more efficient sources.

System Investments

One of the posited benefits of distributed generation is the potential delay or avoidance of distribution and transmission investments. The benefit, however, depends on the timing of the installation of DG facilities, as well as the location of the facilities. The highest benefit of DG occurs in areas where the total load is at or near capacity of the substation or feeder. In addition, the area must be one with a slow growth of load. Otherwise, the deferral of investments is very short timeframe and the benefit of DG much lower.

Policies that support the use of DG would encourage utilities to explore the option of DG in conjunction with the analysis of system upgrades. In addition, areas with low growth and system constraints could potentially be encouraged to development DG by rate incentives, similar to economic development rates. These rate incentives should be based on the benefit estimate of deferred system investments.

Although potentially increasing regulatory burden somewhat, regulators could adopt a reporting scheme designed to highlight opportunities for more cost-effective choices, rather than the traditional options considered by utility system planners. These reports could include forecasts of distribution projects over a long period to explore the opportunity of installing DG projects, rather than upgrading the system.

Policy in this area needs to address the methodology used to determine cost-effective system planning and how to include the option of DG in the analysis.

Standby Charge

Standby charges are rates paid by customers to receive power from the grid only at times when their DG system is unavailable (during routine maintenance or unplanned outages). The standby delivery charge significantly affects the economic viability of DG technologies in instances when the customer cannot choose to disconnect from the grid entirely. In order to disconnect entirely, a customer will need to supply its own backup power source and follow its own load precisely.

It is generally accepted that standby rates should reflect the cost to the utility of providing standby service. However, determining a cost-based rate has proven difficult. Data regarding the impacts that standby customers have had on utility systems has been inadequate and opinions on the best application of that data have differed. Most of a utility's cost for providing standby service is associated with the fixed cost of the transmission and distribution system. The standby charge is usually in the form of a monthly $/kW demand charge.

The policy implications of standby charges are very important. If utilities charge too high a standby charge, the development of DG could be disadvantaged. On the other hand, if the standby charge is not high enough, DG customers are subsidized by other customers. Policy makers need to address the appropriate methodology for calculating the standby rates for DG facilities, including the consideration of reliability.

4.0 Status of DG in Ontario

This section summarizes the current status of DG in Ontario including current DG approaches, incentives and tariff treatments, as well as identified regulatory and market issues.

Ontario's government is actively encouraging new energy solutions because of the Province's considerable potential for electricity supply shortfall. According to the Ontario Power Authority (OPA)[2], Ontario had 30,631 MW of generation capacity in 2005 and consumed a total of 157 TWh. The OPA estimates that electricity consumption in the province will grow at an annual rate of 0.9%. After accounting for Conservation and Demand Management (CDM) programs, net demand is forecasted to be 179 TWh in 2025[3].

Ontario's Industry Task Force on Distributed Generation estimates approximately 300 MW[4] of DG is in service in Ontario. The Task Force projects an additional 200 to 300 MW could be available in the near term.

Ontario is at a critical juncture for its future electricity needs. This challenge stems both from an anticipated growth in demand and the expected retirement of existing coal and nuclear supply resources. The potential for the resource gap is approximately 24,000 MW by 2025[5] (see Figure 4).

As part of pursuing new options for meeting future load, Ontario is in the process of investigating the benefits of additional implementation of DG resources. Some of the potential benefits that additional DG could bring to Ontario are the following.

- Shorter construction and installation lead-time
- Delay or avoid transmission upgrades
- Increased fuel diversity
- Reduce peak electricity prices, line losses and transmission charges
- Enhance system security and reliability
- Encourage alternative fuel use

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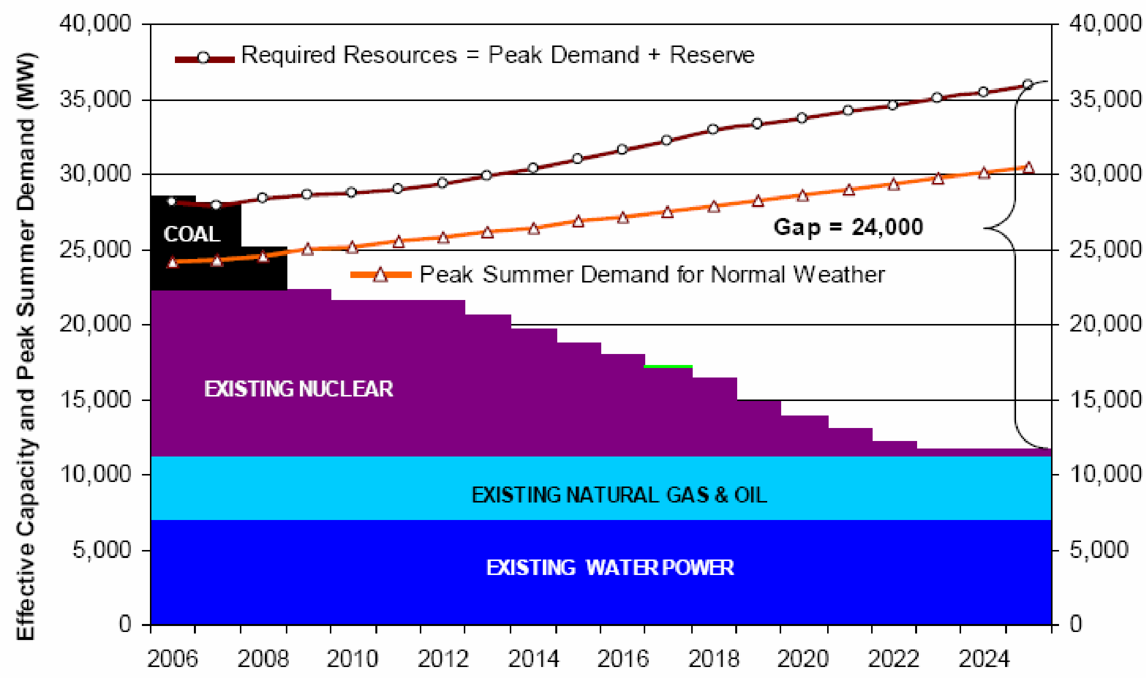
[2] Ontario Power Authority, *Ontario's Integrated Power System Plan: The Road Map for Ontario's Electricity Future.* Preliminary February 2007.

[3] Cogeneration and On-Site Power Production, *Canadian cases: analysis of decentralized energy using the WADE economic* model, article.

[4] Industry Task Force on Distributed Generation, *Distributed Energy Resources: Bringing Energy Closer to Home*, Presentation, July 28, 2005.

[5] Ontario Power Authority, *Supply Mix Advice Report*, December 9, 2005.

Figure 4
Demand Growth and Generation Retirements in Ontario



Source: Ontario Power Authority

4.1 Current DG Approach, Incentives and Tariff Treatment

The Province is actively encouraging renewable DG by streamlining the process for connecting the generating systems to the grid. Recent requirements, such as smart meters for all customers and the Renewable Energy Standard Offer Program (RESOP) favour DG development.

While a DG operator will need a generator license from the OEB, this requirement has been waved for small units less than 500 kW. The DG provider will have to pay for any additional connection or meter costs required to connect to the system. The connection process for DG is separated into four categories: Micro, small, mid-sized and large, based on the size of the generation facilities. The process becomes more complex as the generation unit size increases.

DG providers may take advantage of "net metering", an initiative of the Ministry of Energy. Net metering allows small generators to send electricity from renewable sources to the distribution system for a credit toward energy costs. The net-metering program allows the local distribution companies (LDCs) to receive renewable electricity from the customer as long as technical and metering requirements set out in the Distribution System Code (DSC) are met. Net-metering provisions allow customers to receive credit for excess energy from renewable sources for all eligible projects that produce up to 500 kilowatts.

A DG provider can also provide electricity to the wholesale market and, depending on the flexibility of the timing and amount of output; the DG provider can also receive payments to provide operating reserve. There are, however, additional costs associated with registering and participating in the wholesale market. Under the Standard Offer Program (SOP), which is administered by the OPA, eligible small generators can sign a contract for up to 20 years to provide electricity under contract with the OPA and receive a guaranteed price per kilowatt hour. Among other eligibility criteria, projects must be 10 megawatts or less; and must generate electricity from a renewable resource.

While many challenges still exist, Ontario is working towards removing some of the barriers facing distributed generation. The DSC was amended in 2003 to include standard processes and technical requirements for the connection of new generation to the distribution system and a Micro-Embedded Load Displacement Generation Connection Agreement as a standard contract agreement for connection to the distribution system of all micro generation (under 10 kW). Further amendments in 2006 provided, among other "connection friendly" amendments, a standardized connection agreement for small and mid-sized generation facilities and a queuing process for available distribution capacity.

4.2 Regulatory and Market Issues

Ontario Ministry of Energy identified in the 2004 paper, "Electricity Transmission and Distribution in Ontario – A Look Ahead", several specific barriers to distributed generation in Ontario and requested comments from stakeholders on these issues.

Some of the challenges listed in the report by the Ministry were the following.

- Efficiency of fuel use in smaller conventional gas-burning facilities may not compare favorably to large plants;
- If not located carefully, distributed generation could worsen transmission load factors; and
- Many natural sources of distributed generation (e.g. landfill gas, wind, tidal, geothermal) may not be located near loads, thus limiting the possibility of avoiding transmission.

The Ministry of Energy wanted answers to the following questions:

1. What are some key concerns, particularly for distributors and transmitters, arising from the emergence of, and expected increased reliance on, distributed generation in Ontario?
2. Are there any specific legislative, regulatory or institutional gaps or inconsistencies that might need to be addressed in order to facilitate distributed generation?
3. In light of increased deployment of distributed generation, are there longer-term strategies necessary to ensure safety and reliability, and efficient system planning?

Based on the stakeholder response, two key changes were recommended by the Ministry:

1. Allow the developer of a DG project to capture upstream savings. I.e., DG Projects should get credit for local transmission and distribution (T&D) savings.
2. DG should be valued in the same manner as DSM and load reduction. DG currently is valued less than other forms of load reduction.

5.0 Survey of DG Policy

EESC conducted a survey of regulatory bodies to determine the methodology used by each to promote DG through use of policy decisions. The survey includes regulatory agencies from eight countries and the European Union. The surveyed countries and their status include the following:

- Australia – actively addressing DG issues
- Canada – various stages by Province
- Denmark – established DG and renewable policies
- European Union – actively addressing DG issues
- Japan – actively addressing DG issues
- The Netherlands – established DG, CHP, and renewable policies
- New Zealand – requires retail companies to establish fair DG terms
- United Kingdom – actively addressing DG issues
- United States – actively addressing DG issues, varies by state

The following discussions summarize how the different regulatory entities surveyed address the policy issues identified above. It is generally agreed that DG should not be subsidized if not capable of providing an economical solution. However, some DG systems like renewables (wind and solar) and CHP are receiving subsidies in order to promote environmental intangibles.

5.1 System Interfaces

System interfaces handle the interaction between the DG facilities and the distribution system. Policy issues include access to the distribution system, net metering and dispatch capabilities. In general, if dispatch capabilities are considered, they are limited to large DG systems and typically impose the same market participation requirements as central power generators. Implementing full access would require development of bidding scheduling and dispatch protocols that account for DG. Table 2 describes how several nations are providing DG system interfacing.

Table 2 **System Interface Survey Results**	
Australia	National Energy Rules establish access arrangements for DG to the network. Units less than 5 MW are exempt from registering as a generator. Units between 5 MW and 30 MW register as a non-scheduled generator. Units above 30 MW are required to register as a market generator (energy sold into the market) or as a non-market generator (energy sold to the LDC or another customer).
Canada	Net metering is at various stages of development across Canada; British Columbia and Ontario have developed net-metering programs; New Brunswick and Nova Scotia have recently introduced net-metering programs; Quebec is about to launch a program; and Prince Edward Island is developing a net-metering program. Manitoba has a long-established net-metering program, but participation levels have been low in part due to the low electricity rates in the province. The remaining provinces are in the preliminary stages of DG policy consideration. In addition, the Government of Canada's Budget 2003 included funding toward researching the integration of large blocks of intermittent power and DG into the grid.
Denmark	Due to issues with power quality, spinning reserves and power overflows, the transmission system operator is allowed to curtail certain DG facilities in exchange for financial compensation. Large DG facilities are centrally dispatched, while smaller units operate under self-dispatch.
Japan	Allows net metering for any solar installation.
The Netherlands	Generation plants > 5MW must provide ancillary services, excluding uncontrollable sources of energy, such as wind. Plants < 60 MW ancillary requirements are less stringent than those > 60 MW.
New Zealand	The LDC must have standard terms and conditions on which it will offer to pay for electricity exported to a distribution network from equipment capable of generating no more than 40,000 kilowatt hours of electricity over a year. Units < 10 MW typically do not have to bid into the market on a day-ahead basis.
United Kingdom	The Government is reluctant to introduce net metering due to potential complications in paying and refunding the value added tax that is associated with electricity. Pilot programs are under way in some areas.
United States	Most states (41 of the 50) offer at least some net metering. The larger and more active states such as California allow for a wide range of sizes (e.g., up to 10 MW) to be net metered. However, most of the states limit net metering to renewable technologies, especially solar and wind.

Source: EESC and surveyed regulatory agencies

5.2 Interconnection Standards

Interconnection is a significant policy issue and the general trend is to develop standard interconnection guidelines. Without standard interconnection guidelines, each connection to the distribution system must be designed on a case by case basis. Several of the surveyed countries are actively addressing this issue as shown in Table 3.

Table 3
Interconnection Survey Results

Australia	Established working group to address barriers to DG, such as interconnection contract negotiations between utilities and customers.
Canada	The Government of Canada's Budget 2003 established funding to remove institutional barriers to grid interconnection of DG by 2010. Interconnection standards vary by province. For example, Ontario's *Distribution System Code* specifies the process and technical requirements to connect embedded generation facilities to the distribution system.
Denmark	Danish network operators have developed connection specifications based on size of plant, with less stringent requirements for smaller plants. In addition, the Transmission Systems Owners are allowed to temporarily cut production to certain CHP's to maintain system stability in exchange for financial compensation of the lost revenues. DG owners pay "shallow" connection charges, i.e., they pay only the cost of connecting to the grid at 10 kV. Any upstream costs are paid by the LDC, and as a result, paid by the LDC's rate payers.
European Union	Promoting standards for interconnection to member countries.
The Netherlands	Standardized interconnection in place. Grid code, system code and tariff code take into account different sizes of generators, although no distinction is made between DG and centralized generators.
United Kingdom	DTI published Technical Guide to the Connection of Generation to the Distribution Network.
United States: California	California has adapted IEEE Interconnection Standard 1547 and called this standard Rule 21. A Rule 21 working group was established and the group continues to address specific details of the standard.
United States: New York	The New York Public Service Commission (PSC) has approved standardized interconnection requirements for DG units 2 MW or less connected in parallel with the utility distribution system. The PSC also publishes a list of pre-certified interconnection equipment to streamline the process.
United States: Texas	The Public Utility Commission of Texas (PUCT) has adopted Substantive Rules §25.211, *Interconnection of On-Site DG*, and §25.212, *Technical Requirements for Interconnection and Parallel Operation of On-site DG*. The PUCT published a DG interconnection manual in 2002 to guide the inclusion of DG in to the Texas distribution system.

Source: EESC and surveyed regulatory agencies

5.3 Stranded Costs

Deciding whether or not DG users should pay the utility for stranded investment costs, such as an underutilized distribution system, is a significant DG barrier. Several of the surveyed countries are actively addressing this issue in theory (see Table 4); however, Denmark is the only country where the exposure to stranded assets has been significant due to the high quantities of DG. In Denmark, stranded costs are shared among all ratepayers as the shift to DG is considered a change for the common good. Others are discussing whether or not stranded costs should be included as exit fees and competitive transition charges or if these costs are covered in the fixed standby charge.

Table 4
Stranded Cost Survey Results

Denmark	The large number of DG units has lead to the decommissioning of central plants that were operational and regulated. The shift to DG is considered a change for the common good; therefore stranded costs are shared by all rate payers.
European Union	The general philosophy is that DG should get credit for the full cost and benefit of access to the system. Therefore, the EU is considering pricing such that an accurate price signal can be provided to DG developers to place DG units where they would provide the most benefit, minimizing stranded costs.
United Kingdom	Stranded costs are addressed in modeling used to calculate Transmission Use of System (TUoS) and Distribution Use of System (DUoS) charges.
United States: California	The California Public Utility Commission (PUC) has approved tariffs designed to collect a surcharge from customer generation departing load (see Rulemaking 03-09-029).
United States: New York	In New York, exit fees are assessed to departing load that will be served by DG systems in order to recover stranded costs. Exit fee exemptions are in place for loads that are replaced by clean on-site generation, such as CHP and renewables.
United States: Texas	Recovery of stranded costs through competitive transition charges (CTC's) have expired in Texas. The CTC was calculated such that the stranded costs for each utility was amortized over the average remaining life of the generation asset(s) underlying the stranded costs, and allocated to each class. The rate design of the CTC for each class was to be consistent with the rate design used to recover the costs of the generation assets underlying the stranded costs in the utility's last rate proceeding.

Source: EESC and surveyed regulatory agencies

5.4 System Investments

One benefit of DG is the potential to delay or avoid transmission and distribution system investments. System investment policy should address a methodology to determine cost-effective system planning and the inclusion of DG in the analysis. Several countries are beginning to address system investment issues (see Table 5).

Table 5
System Investments Survey Results

Australia	Addressing method to quantify the benefits of DG on the distribution system, such as delaying or avoiding system upgrades. Currently, utilities are required to pay DG operators for network support services and avoided transmission charges, if the DG unit is connected directly to the distribution network. Network support services include frequency regulation, operating reserves, reactive power supplies and other ancillary services.
Denmark	Denmark has seen an increase in transmission and distribution costs recently due to the increased quantity of wind generation located in low load areas. Initially transmission and distribution improvements were avoided.
European Union	Addressing avoided costs and benefits of DG.
United Kingdom	Employs locational transmission charges based on where the generation is located, determined by the forward looking long run marginal costs of providing incremental capacity at different points on the network.
United States	Rulemaking 04-04-025 was opened in California to determine a methodology for quantifying avoided costs that are both time and region specific.

Source: EESC and surveyed regulatory agencies

5.5 Standby Charges

The appropriate methodology for calculating the standby rates for DG facilities, including reliability considerations, is also a significant issue. Several of the surveyed countries are actively addressing this issue as indicated in Table 6.

Table 6
Standby Charge Survey Results

Australia	Addressing pricing issues, such as standby charges that incorporate the benefits of DG on the system and the utility cost for maintaining excess capacity when the DG system is not in use.
Denmark	Priority generation is exempt from the usual balancing mechanism applied to all other market participants. Deviations between the forecast and actual production are paid for by the transmission system operator. This cost is shared across all system users.
Japan	Established capacity charge that is high only when the utility power is actually used as a backup. The capacity charge (kW charge) is 110% of normal when power is used and only 30% of normal when not in use. The energy charge is 110% of normal if the use is planned and 125% of normal if the use is unplanned.
United Kingdom	Standby charges are assessed based on the distribution system costs through a Generator Distribution Use of System (GDUoS) charge, modeled by region within a utility's territory.
United States: California	If a DG unit in California is down and the customer is able to immediately reduce its load, standby costs are minimal. Standby rates were recently updated by the three private utilities. Standby charges are divided in to three categories: ■ Supplemental – portion of load not covered by DG is at the applicable tariff. ■ Backup – unanticipated load results in increased costs. ■ Maintenance – scheduled at times of utility low demand, costs should reflect this flexibility.
United States: New York	New York agreed on a standard method to compute standby charges containing two demand charges. ■ Contract demand – based on dedicated facilities applicable primarily to the DG customer. ■ Daily as-used demand – based on shared facilities and the customer's daily maximum kW demand.

Source: EESC and surveyed regulatory agencies

6.0 Industrial Distributed Generation

Large industrial DG systems include those systems greater than 500 kW. The majority of these systems are load displacement generation units. The load displacement generator (LDG) provides generation for self-service with no significant generation above the customer's load. These customers often require backup service from the local distribution company and are generally charged standby rates for any backup service required. In addition, these customers may need service to meet load that exceeds maximum generation potential. Typically, these systems are grouped with central power stations for requirements, such as siting, permitting and other regulations.

6.1 Survey Results for Industrial DG

Based on the survey of distributed generation policies around the world, it is clear that smaller renewable DG resources get the most attention from regulators. In general, if a DG program is in place, the program targets units less than 10 MW using renewable fuels, such as wind, solar and biogas. These DG resources are the ones that qualify for specialized programs.

A few countries address the larger DG facilities. For example, in the Netherlands, DG units between 5 MW and 60 MW have less stringent connection and permitting requirements. In addition, these units can choose whether to provide backup, while it is mandatory for larger units to have reserves available. In Denmark, units less than 25 MW are not required to have a license, and in the UK generators under 50 MW are allowed a "class exemption" to the license requirements.

In general, unless the unit is renewable and/or small, policy makers are not attempting to dramatically reduce the barriers to the development of DG.

6.2 Ontario's Policy for Industrial DG

Ontario has developed a Renewable Energy Standard Offer Program (RESOP) for eligible renewable DG units of 10 MW or less. This program makes it easier for owners of DG facilities to sell power that will be distributed through the distribution system. The owner of the DG facility is required to pay for the necessary connection and meter upgrades and enter into a 20 year contract with the OPA. However, the owner is not required to post any security deposits or provide credit information to the OPA.

Units over 10 MW or those not participating in the special programs for renewable and clean generation are treated as specified for their size category in the DSC. A generator must be a registered market participant if the output is to be sold through the wholesale electricity market.

The OEB reviewed standby charges in the generic decision RP-2005-0020/EB-2005-0529 (March 21st, 2006). In this decision, OEB stated that the current standby rates do not have “a proper cost foundation due to lack of available data”. The Cost Allocation Review (RP-2005-0317) reviewed the appropriate methodology to use in developing standby rates and treating LDG customers. The report discussed the option of creating a separate customer class for LDG customers. In addition, the methodology for determining standby rates was discussed. As part of the review, OEB required licensed distributors to provide a cost allocation filing, which explored the issue of creating a separate customer class for LDG customers and the estimation of standby rates for this class. The result of these filings will be reviewed in the section titled Distributed Generator Cost Allocation and Rate Design Review in Ontario.

6.2.1 Recommendations for Industrial DG

If the OEB determines that the benefits of larger, non-renewable DG resources warrant additional support, there are several changes that could be made to the current programs. Contracts for DG resources could be set up with terms between 5 years and 20 years depending on the needs of the local utility and those of the DG owner.

The current connection policy requires that the DG owner pays all interconnection costs for the LDC including study costs and equipment costs. While this policy addresses payment of all incremental costs, stranded costs to the utilities may still occur depending on any unused upstream costs due to the installation of the distributed generation facility.

As customers install self-generating facilities, they have commented that utilities are requiring customers to pay a variety of fixed charges to cover standby or back-up service, stranded costs or other fixed costs of the system. Those costs discourage installing DG by making self-generation more costly and in some cases uneconomic. On the other hand, some charges are necessary to ensure the utilities collect sufficient revenues for the services they provide, while preventing cost shifting between customer classes. The general goal for utilities is to try to ensure that the charges on each customer’s bill reflect the actual cost of serving that customer.

Because the utilities are obligated to deliver all the power required by the customer, the utility can not plan for average load, but must plan to meet peak loads. Therefore, the transmission and distribution system must be build large enough to serve the customer’s peak load. This implies that a LDG customer requiring back-up service will have to pay for the full share of the distribution system that is ready and available to provide power, even if the customer self-generates for the majority of the time.

Determining the true cost of serving a LDG customer is further complicated because these customers are currently included in the commercial and industrial customer classes. In order to explore the issue of cost of service for LDG customer, OEB directed utilities to file a cost allocation filing, which examines the impact of a separate customer class for LDG customers. The result of this analysis is further discussed in Section 8.

7.0 Standby Rate Design Issues for Distributed Generation

This section provides a brief discussion on the purpose of rate setting for standby service provided by utilities. In addition, several rate design options and issues surrounding the design of standby rates are provided. For this report it was assumed any energy use by standby customers will be billed at the usage charge of similar customers for both transmission and generation service.

7.1 Standby Charges

A customer that generates all or most of its electricity requirements with distributed generation facilities located on its own premises has a need for the local utility to provide standby service.

There are three common types of standby service: backup, maintenance and interruption. Backup service is electrical energy delivered and guaranteed by the utility during unscheduled outages of the customer's onsite generator. Maintenance service is electrical energy delivered on a predetermined basis by the utility during a scheduled outage of the distributed generator. Interruptible service is electrical energy delivered by the utility when the output of the distributed generator is not running and the serving utility has surplus capacity.

As these descriptions demonstrate, the load characteristics of each service are different, resulting in different load shapes and, therefore, different service costs. Backup service, for example, is characterized by intermittent and unpredictable loads that reflect the random nature of unscheduled distributed generator outages. In contrast, maintenance service is characterized by predictable loads associated with the scheduling of generator maintenance, usually during low cost off-peak periods. Finally, interruptible service is intended to meet the energy needs of distributed generators only when the serving utility can do so at a convenient time.

The different service options could affect the standby rate design and the components included in the standby rates.

- Backup
  - A portion of the LDC local transmission and distribution system is being held available to provide standby service.
  - Established based on a pre-set reserved demand level. This pre-set billing demand level is generally based on the maximum load placed on the serving utility.
  - The standby rate is designed to recover fixed costs of dedicated facilities.
- Maintenance

- Similar to the back-up charge, except for the cost to recover fixed costs of dedicated facilities.
- Because maintenance back-up is pre-scheduled, usually during off-peak periods, the cost of the dedicated facilities is generally lower than the cost of reserving standard back-up capacity.

■ Interruptible

- Should be charged at a lesser rate.
- Only available if convenient for the serving utility—no guarantees.

Most costs associated with the provision of transmission and distribution services to distributed generation customers are fixed. Thus, recovering these costs through fixed reservation charges, also referred to as contract demand charges, would appear to be consistent with providing accurate price signals to customers. Another option for charging standby costs is through usage-based, volumetric charges. However, in the case of distributed generation facilities which are designed to run continually, such as a combustion turbine, only a small fraction of the customer's electricity requirements will be supplied by the utility. In this case, usage-based volumetric charges may result in the under collection of fixed costs. For other systems, such as wind, solar, and some biomass generating facilities which do not to run continually, usage-based, volumetric charges may collect sufficient revenue to cover fixed costs.

Sometimes charges for standby service reflect two additional factors: diversity among customer loads and the reliability of the distributed generators. The costs associated with transmission and distribution service is related to the overall level of diversity between customers on the system. When utilities design the local distribution system, system planners do not assume that all customers use power at the same time. Customers use power during different periods and a certain level of diversity is built into the distribution and transmission system. The level of diversity among individual loads defines the total load placed on the system at one time.

Since not all distributed generators will require backup service at the same time, generators often state that load diversity exists and should be taken into account when determining the costs of standby service. Utilities typically respond by distinguishing between transmission and distribution diversity. While load diversity may exist at the transmission level, they argue that because of the radial design of many distribution systems, and the relatively small number of distributed generators connected at distribution voltages, there is virtually no load diversity benefits on individual distribution circuits.

Regarding the second factor, reliability of the generator, generators with high reliability place less demand on a utility's system than do unreliable generators. As a result, the rates for standby service are sometimes expressed as the product of a demand charge and an estimated forced outage rate for onsite generators. For example, a generator that is always unavailable will require the utility to provide standby service at all times including during the peak hours. Thus, such a generator would be billed the full demand charge. In contrast, a generator that is always available will never request utility service and, hence, would pay nothing. However, the costs of constructing facilities to stand ready to serve standby customers are the same regardless of whether the customers use those facilities one time each year or a hundred times a year.

Backup and maintenance delivery services are distinguishable by the fact that backup loads are random and unpredictable, whereas maintenance loads are predictable. Thus, utilities offering backup service are required to reserve distribution, transmission and generation capacity at all times in order to ensure that backup loads are fully met. This suggests that customers requesting backup service should be required to contract for the service in advance and pay a reservation charge that recovers the associated backup service costs. Tariff provisions that allow the reservation capacity to be re-set in the event of a change in demand are known as demand ratchets and are often found in general service tariffs for large commercial and industrial customers.

In contrast to backup service, maintenance service is generally scheduled by the customer during off-peak periods and therefore should not require the utility to build or reserve capacity to serve it. Thus, maintenance service is likely to be significantly less costly than backup service.

There are also differing views on whether standby rates should reflect embedded or marginal costs. Proponents of embedded cost based rates generally argue that a standby charge that reflects the marginal costs of providing distribution, transmission and generation services to onsite generators must be reconciled to the standby class revenue requirement in order to avoid the under recovery of embedded costs. The same entities also argue that the rates for standby service should reflect embedded costs, particularly if the charges for all other retail service classifications reflect embedded cost. Proponents of embedded cost-based rates also tend to be opposed to standby rates that reflect geographic distinctions, on the grounds that averaging utility rates across a service territory fairly spreads the costs of system improvements to all customers. However, marginal cost-based pricing, including localized transmission and distribution rates, sends more efficient price signals, and includes all the costs that planners use when making investment decisions.

7.2 Standby Rate Design Objectives

Rates can take many forms, but ultimately they should reflect the costs that the utility incurs (demand, energy and customer related costs), and collect the desired level of revenues. The process of developing standby rates will require greater consideration of fundamental economic and pricing theories. For example, economic theory dictates that the price of a commodity must roughly equal its cost, if equity among customers is to be maintained.

One important consideration is that the wires cost component is fixed and does not vary with usage, although distribution system investment does vary with the number of customers. These factors must be given consideration in designing rates if the utility is to recover its costs properly and fairly.

Prudent rate administration requires that several viewpoints be considered in setting electric rates for wires service. These views balance the needs of the consumer, the utility, and society as a whole. All three need to be considered when designing rates.

Based on these overall viewpoints for setting rates, the specific considerations that need to be kept in mind for standby rates are the following:

- Rates should be designed to reflect the costs, net of any offsetting benefits
- Standby rates should reflect the various gradations of services provided
- Supply charges should remain the same for all customers
- Rates should not create artificial barriers to DG
- The rate structure should be simple and easy to understand by the consumer or generator, and it should also be easy to administer by the LDC
- Rate design should encourage the following:
    - Reduced redundancy of installed capacity
    - Operation of DG plant during on-peak hours
    - Utilization of excess grid capacity during off-peak hours

7.3 Rate Considerations

In general, utilities must consider the same issues for standby rate schedules as for any other rate schedules. There are several approaches to the design of standby rates, and customer characteristics such as size, technology, timing of use, and service requirements affect the rates calculated.

Customer Size

Because standby rates are based on the facilities reserved to meet demand, utilities often design different standby rate schedules depending on the size of the customer. Several jurisdictions exempt smaller DG facilities from standby rates. On the other hand, it is fairly common to establish more comprehensive standby charges as the size of the DG facility increases.

Another option used is to exempt DG resources from a standby charge if the maximum output of the DG resource makes up a small percentage of the customer's load. In this instance, it is assumed that the customer pays for the cost of the distribution system through the regular tariff and that the additional standby requirement does not have a material cost impact on the utility.

DG Technology

It is very common for renewable DG resource to get preferential treatment and avoid all or some of the standard standby charges. Several jurisdictions recognize that DG facilities that are cleaner with low-emissions may provide significant public benefit and therefore should be exempt from certain charges.

Timing of Use

Another consideration is the inclusion of time differentiated charges on the standby rate schedule. Some jurisdictions assess charges that depend on the season. For example, the tariff could reflect, to the extent practical, seasonal variation in distribution demand charges. Another option would be to include an actual time-of-use component on the standby rate design to address the differential in distribution charges between time period, i.e., on-peak and off-peak.

Service Requirements

As discussed previously there are several different levels of service requested by customers with distributed generation. The tariff treatment of these different services depends in a large part on the distribution system and how constrained it is during certain peak times. Some jurisdictions allow different charges based on the level of service, while others argue that the cost of building and maintaining distribution facilities for standby customers does not differ based on the portion of load served by DG or whether an outage is scheduled or unscheduled.

Billing Determinants

Billing determinants are used to calculate the total payment paid by customers. There are many options to consider when deciding on the billing determinants to use for the standby rate. In general, the standby tariff would consist of the following charges:

- A demand (or capacity) charge to collect localized delivery costs, and
- Monthly customer charge to recover administration and service costs.

However, the billing determinant for the demand charge can take many forms. Some jurisdictions base the billing determinant on a pre-set contract demand (kW) for the customer. This pre-set billing determinant can be determined either as the maximum capacity of the DG resource or more often based on the 12-month historical billing demand of the customer. Often the tariff would include a penalty for exceeding the contract demand set for the customer.

Another option used is to use a billing determinant based on actual non-coincident peak demand within a given period. Some jurisdictions also add a daily or monthly "as-used" component or ratchet as a billing determinant.

7.4 Calculation of Standby Rates

This section of the report describes the standard methodology for calculating standby rates. For customers with DG in Ontario, the potential costs and benefits affect up to three different entities:

- Ontario Power Authority – commodity and costs;
- Hydro One – transmission costs and benefits; and
- LDC – local transmission and distribution costs and benefits.

While the same guiding principles would apply to regional transmission and OPA costs and benefits, this section only addresses the methodology of determining the costs and benefits to the LDC of DG.

The calculation of standby tariffs that properly reflect the costs and benefits of service customers with distributed generation is generally based on data provided by a utility's cost of service study. If the utility uses an average embedded cost of service analysis approach, the standby rates should be based on average embedded costs. On the other hand, if a marginal approach is used to set general rates, then marginal costs should also be used to set standby rates.

The standby rate should include:

- Monthly contract demand rate ($/kW) to collect cost of having the distribution and local transmission system available when needed;
- Monthly customer charge to collect administrative & service costs;
- The standby rate should be utility specific, although the methodology used to calculate the rate should be consistent across utilities; and
- Any benefits to the distribution system attributable to the DG should be reflected in the final rate.

The monthly contract demand charge represents the cost of reserving an amount of distribution and local transmission capacity on the system. The charge is calculated based on the allocated wires costs divided by the billing determinant. As discussed previously, the billing determinant is usually based on a pre-set contract demand (kW) for the customer. This pre-set billing determinant can be determined as the expected capacity need of the DG customer. In many jurisdictions, the contract demand is agreed upon in the first year and then increased in the following year if the customer exceeds the set contract demand.

The monthly customer charge is calculated based on the allocated administration and services costs from the cost of service analysis. It is generally a cost per customer per month charge.

7.5 Calculation of Potential Local Transmission and Distribution Benefits

In addition to determining the standby charges, it is also important to develop a process for determining the additional benefits and credits of a specific DG unit. This process should be initiated during the development of the contract between the LDC and the DG customer. The process would determine and credit the DG customer for:

- Transmissions and distribution savings due to the customer's DG unit;
- Avoided losses; and
- Provided ancillary services.

While the process to determine benefits can be consistent across LDCs and customers, the actual benefits must be determined on a case by case basis.

The benefits of a DG unit on the local transmission and distribution system are in a large part related to the potential deferral of system improvements or additions. For example, in a slow growing area with excess capacity, the local transmission and distribution benefits are likely to be minor. On the other hand, in a fast growing area with a constrained distribution system, the addition of DG can provide great benefits to the utility and the other customers.

One approach that can be used to determine the potential local transmission and distribution benefits of DG facilities is the following four step approach:

- Determine the benefits in $/kW per year of deferred transmission capacity,
- Identify transmission and distribution investments over a historical (or forecast) period of time,
- Identify peak demand growth over the same period, and
- Calculate the annual carrying charge of investments based on assumptions on taxes, financing costs, operational expenses and other recurring costs.

The benefit of deferred local transmission and distribution capacity can be determined based on the incremental investment that occurs over time due to load growth divided by the load growth over the same period of time. In general, a longer term period (both historic and forecast years) is recommended given the lumpiness of transmission and distribution investments.

The peak demand growth used to determine the $/kW benefit needs to be weather normalized and use the appropriate point of measurement (i.e. transmission peak for the transmission calculation and distribution peak for the distribution calculation).

7.6 Exemption Examples from Standby Charges

In general, net metering programs do not include additional standby charges. In a simultaneous buy-sell arrangement, it is assumed that the customer will pay for the commodity and wire usage based on a common rate schedule available to all similar customers. In addition, some jurisdictions exempt “clean” and smaller DG resources from standby rates.

Below are a few examples of exemptions from standby rates in different jurisdictions.

Table 7
Exemptions from Standby Rates

California	Exempts “ultra clean resources” up to 5 MW from standby charges, this exemption is set to expire 2011.
New York	Exempt are DG with nameplate rating less than 15% of customer max demand, Renewable resources, CHP < 1 MW, fuel cells, after 2007 standby rates will be transitioned in again.
Connecticut	Exempts clean DG from standby rates.
Massachusetts	Exempts DG of 250 kW or less, DG 250 kW – 1,000 kW that usually meet less than 30% of customers load, renewable resources, except fuel cells only up to 2 MW and 10 MW max exempted in service area.
Rhode Island	Exempts DG less than 30 kW and DG powered by “eligible renewable resources”. Max 3 MW of DG exempted in service area, Renewable systems, less than 25 kVa, and eligible for net metering less than 25 kVa do not count towards the 3 MW.

Source: EESC

8.0 Distributed Generator Cost Allocation and Rate Design Review in Ontario

This section provides a review of the Ontario practice in the area of cost allocation and rates for DG. These rates are typically referred to as "standby" rates. This section also comments on the quantification of cost-based cost allocations and unit costs (i.e., $/kW and $/customer) as provided in the recent LDC cost allocation filing requirements, and provides an analysis of how the cost-based unit costs compare with the standby tariffs currently charged by several LDCs in Ontario. This section will also discuss benefits provided by DG. Finally, this section will summarize any differences between the recommended standby rate methodology and existing standby charges, and will identify any modifications needed to implement OEB's cost-based standby rates in Ontario.

8.1 Standby Cost Allocation and Unit Costs in Ontario

OEB is exploring the issue of whether Ontario should implement a standardized methodology for setting standby rates for DG or whether a utility-specific approach to standby rate design is preferable. At this time, several LDCs in Ontario have standby rates for their DG customers. These rates have been developed based on different approaches and incorporate a variety of billing determinants across LDCs.

There are several issues surrounding standby rates for DG that need to be addressed as the standardized methodology for standby cost allocations and rates in Ontario is explored. Standby rates:

- Should reflect the costs of serving a customer with DG
- Should reflect benefits provided by DG such as:
  - reduced losses
  - avoided power supply, transmission and distribution costs
  - improved reliability/black start capability

As such, there are several issues that complicate the design of standby rates for DG in Ontario. While most stakeholders agree that standby cost allocation and rates should be determined as part of the generic cost allocation review and filings, it is not clear that all the necessary information is available to ensure the resulting standby rates reflect the appropriate costs and benefits of DG customers.

In particular, benefits associated with DG to include avoided power supply, transmission and distribution costs are best determined outside of a traditional cost allocation framework. This is because the cost allocation framework allocates average costs across customer classes based on system-wide allocators. Unless avoided power supply, transmission and distribution costs are directly assigned to a standby class within the cost allocation process, the additional benefit of DG will not be properly quantified. As a result, the standby cost allocation and unit costs identified below represent the cost of serving standby customers, but may not necessarily reflect all benefits associated with DG customers.

While this section discusses impacts of DG on the distribution system, it is important to acknowledge actions in the area of supply and backbone transmission which may impact the costs and benefits related DG installation. Some DG providers sell power through the OPA's RESOP and receive revenues from this transaction. Depending on the pricing for this power, the DG may already receive payment for some of the benefits provided on the distribution system. This payment must be considered when analyzing the costs and benefits of DG so as not to "double credit" DGs for any system benefits they might provide.

Deciding whether or not DG users should pay the LDC for stranded investment costs, such as an underutilized distribution system, is a significant issue that should be addressed in a policy setting as well. Theoretically, if the standby rates are designed based on cost causation, the utilities should experience no stranded costs. As long as the DG customer pays reservation charges based upon the maximum load they place on the LDC, the DG customer pays for the share of the LDC system standing ready and available to serve.

Another issue that needs to be addressed is interconnection costs. In general, DG customers pay the cost of hooking up to the local distribution system. Any additional costs to the backbone system due to the addition of the DG customer are generally paid by the LDC, and as such by all customers.

8.2 Cost Allocation Filings

In its decision RP-1999-0034, the OEB indicated that "LDCs will be required to undertake cost allocation studies to better align rates among customer classes with cost causation in second generation PBR" (paragraph 2.1.13). LDCs filed updated cost allocation information that is being used by OEB to consider the need for adjustments in the current share of distribution costs paid by various classes of customers.

OEB has established a common cost allocation methodology for use by Ontario LDCs. This cost allocation methodology calculates the revenue to cost ratios and rates of return for each rate classification of an LDC. All LDCs were required to submit cost allocation informational filings to OEB starting in the fall of 2006. These filings are used as the basis for the standby cost allocation and rate analysis contained in this section of the report.

Cost allocation filings as submitted and/or standby rates as reflected in the 2006 Tariff of Rates and Charges were reviewed for the following 20 LDCs:

- Barrie Hydro Distribution
- Brantford Power
- Burlington Hydro
- Canadian Niagara Power–Port Colborne
- Chatham-Kent Hydro
- Enersource Hydro Mississauga
- EnWin Powerlines Ltd.
- Essex Powerlines Corp.
- Greater Sudbury Hydro
- Grimsby Power
- Haldimand County Hydro
- Horizon Utilities Corp.
- Hydro One Brampton Networks
- Hydro One Networks
- Hydro Ottawa Ltd.
- Kingston Electric Distribution Ltd.
- Kitchener-Wilmot Hydro
- London Hydro
- Orillia Power Distribution Corp.
- Toronto Hydro-Electric System Ltd.

A number of the distributors in this list have an approved standby rate but have no customers to which it is applicable.

The cost allocation filings contained updated and useful information that is helpful in accessing the cost of service basis for all current retail rates. The rate design portion of this generic review will examine the need for, and implications of:

1. Adding a new rate class for scattered unmetered loads and DG customers,
2. Adding a new rate class for embedded distributors served by host distributors, and
3. Eliminating the legacy rate class identified as "Time of Use".

Item 1 is the focus of this section's analysis where the need for a separate category for DG customers is reviewed.

Each LDC has been required by the OEB to complete a minimum of two and possibly three cost allocation runs using version 1.2 of the Cost Allocation spreadsheet model provided by OEB. These runs are explained below:

- **Run 1** is the mandatory base cost allocation. It reflects the 2006 EDR rate classifications based on the methodology approved by OEB.
- **Run 2** is a mandatory run that allows a limited number of rate classification changes that are of interest to OEB (e.g., separate standby rates for DG customers).
- **Run 3** is an optional run to permit certain LDC-initiated rate classification changes.

The following text provides more detail on the treatment of DG customers in the two model runs[6].

> "For the purposes of **Run 1**, a [LDC] with a currently approved "standby" rate, including interim standby rates, is to model its DG customers. Two approaches are employed in the filings:

[6] Ontario Energy Board, *Cost Allocation Informational Filing Guidelines for Electricity Distributors*, November 15, 2006.

i.) Treatment as part of a standard rate classification, or
ii.) Treatment as a stand-alone DG rate classification.

Based on the rate design in the 2006 EDR for DG, the [LDC] must carefully choose the appropriate treatment. If the rates for standby service in the 2006 rate order are equivalent to, or derived from one of the standard rate classifications, then approach i.) should be followed. Otherwise, approach ii.) will likely be more appropriate. The [LDC] is to include in the Filing Summary an explanation if the [LDC] wishes to use approach ii.). The [LDC] is to do one of the following:

- A [LDC] using i) is to gather specific information as described in the Model to determine an [DG] charge or credit.

- A [LDC] using ii) is to separate the load data for [DG] into a separate classification for proper allocation of demand and customer related costs."

(Section 2.2.3)

For **Run 2**, "a [LDC] is to model a single and separate class for customers with load displacement facilities having displacement loads equal to or greater than 500 kW in the 2006 EDR test year. If a [LDC] has concerns about the reliability of the load data gathered for modeling the separate [DG] rate classification, then these concerns should be identified in the Filing Summary. If no reasonable load data is available, the [LDC] must explain why in the Filing Summary and is to use the Run 1 approach (which does not require separate load data for these customers) again for Run 2." (Section 2.3.6)

8.3 Analysis of Ontario LDC Standby Cost Allocation and Unit Costs for DG Customers

As discussed in this report's Standby Rate Issues Section, a standby rate for DG should include:

- Monthly contract demand rate ($/kW) to collect cost of having the distribution and local transmission system available when needed;

- Monthly customer charge to collect administrative and service costs;

- The actual standby cost allocation and rate should be LDC-specific, although the methodology used to calculate the rate should be consistent across LDCs; and

- Any benefits provided by the DG.

Each LDC noted above submitted fully allocated expenses for DG customers in a new and separate standby rate class. For this section's analysis, the allocated expenses (including customer-related costs) were converted into a monthly unit cost ($/kW) based on the non-coincident peak demand (NCP) and compared to the demand charges those same DG customers receive under their current rate schedule. Total revenues paid by the DG customer under current standby rates were compared to fully allocated costs as well. This exercise was undertaken to determine whether DG customers were paying their full cost to serve.

In order to compare the allocated standby rates in the most recent cost allocation filing to current rates on an equal basis, it was assumed that all rate classes paid the fully allocated revenue requirement (100 percent revenue to cost ratio for each rate class). The revenue requirements for all LDCs were generally comprised of the components in Table 8.

Table 8
Summary of LDC Revenue Requirements

	Distribution Costs
	Customer Related Costs
	General and Administration
	Depreciation and Amortization
	Payments in Lieu of Taxes (PILs)
	Interest
Σ =	**Total Expenses**
+	Direct Allocation
+	Allocated Net Income
Σ =	**Total Revenue Requirement**
-	Miscellaneous Revenue
Σ =	**Total Revenue Requirement from Rates**

The revenue requirement less miscellaneous revenue is then converted to a demand-based unit cost ($/kW/month) by dividing the revenue requirement by the non-coincident peak of the DG customer class. This analysis was performed twice, as 1 NCP and 12 NCP. Customer-related costs would typically be included in a customer charge ($/customer/month). However, for this analysis, these costs are included in the standby unit demand cost calculation.

Similarly, the allocated distribution revenue is also converted to a demand-based unit cost ($/kW/month) by dividing the revenue by the 1NCP and 12 NCP of the DG customer class.

When customers with differing consumption patterns are pooled into a customer classification, this results in the sharing of the benefits of the diversity of their consumption patterns. These benefits arise because the classification's peak will be lower than the sum of the individual customer peaks. This means that the demand allocation of costs to that classification will be lower than if the allocator were based on the sum of the individual customer peaks. For the unit cost calculation, each "rate classification" (i.e., class or subclass) was treated as independent and separate for cost allocation modeling and load data requirement purposes. Diversity was shared within each separate rate classification (e.g., GS<50 kW and CG>50 kW) and not between any rate classifications. For the standby rate class, diversity was shared among those customers and the main classification with which they share demand costs.

8.4 Benefits

While the cost allocation filing provided information on the unit costs of serving DG customers, the filings did not generally provide information on the potential benefit provided by DG customers to the distribution system.

As discussed, there are generally two different conceptual methods can be used to determine benefits of DG:

- Marginal Cost Approach

  This approach determines the marginal cost of capital investments and avoided operating expenses. This value can then be used to calculate the benefit of the reduced capacity needs or operating costs by the DG customer. Because a marginal cost of service study may not be performed on a regular basis by Ontario LDCs, the marginal power supply, transmission and distribution unit costs calculated for the CDM programs may serve as an available proxy for local marginal costs.

- Incremental Approach

  This approach calculates the LDC's revenue requirement with and without the DG customer. Any cost savings between the two scenarios would represent the benefit of DG and be attributed to the DG customer.

Once the benefits have been identified, the methodology used to credit the DG benefits needs to be examined. There are three different ways to provide credits to DG customers for system benefits they provide.

- Separate Rate Class

  If DG customers are separated into a unique customer class, the cost calculation and charge determination, including crediting of benefits, are fairly straight forward and simple. This customer class would be directly assigned any benefits attributable to DG,

- Credit to Standard Unit Costs

  If DG customers are not separated into a unique customer class, a credit for system benefits could be calculated based on cost of service and used to off-set the standard demand unit cost for non-DG customers. This treatment would be similar to that where a customer receives a credit for providing his own transformer.

- Reduce Revenue to Cost Ratio by a Certain Percent

  Finally, an option that can be used to simplify the benefit calculation would be to determine that since DG customers bring some form of benefit, rates could be set not at 100% revenue to cost ratio, but, for example, at 90% or 95% revenue to cost ratio. This option could be used for small DG customers, in conjunction with a detailed analysis for larger DG customers. Based on the site specific analysis of the larger DG customers, an approximate level of benefits could be determined for the smaller DG customers. This crediting approval would require a separate rate class for DG customers.

For all these methodologies, any benefits paid to the DG customers are expenses to the LDC and should be paid by all customers. Costs should follow benefits; therefore as a DG customer provides benefits to the entire distribution system, the entire distribution system and customers are responsible to pay for the benefit.

8.5 Preliminary Results

The preliminary results of the comparison of current DG charges versus those from the cost of service filings are located in Tables 9 through 11. Only those LDCs that provided a study with DG customers in a new and separate standby rate class (i.e., LDCs that provided Run 2 data) are included in the results. Several LDCs did not separately report DG customers. In addition, for this preliminary analysis those LDCs with missing or unusual data were not included. These miscellaneous data deficiencies can be addressed after the preliminary reviews of DG standby rates results are completed.

Some version of Non-Coincident Peak (NCP), i.e. peak demand for a customer classification regardless of the time of occurrence, is generally used to allocate most demand related distribution costs. In general for any given rate classification, this load data is obtained from load shapes applicable to customers embodied in the specific rate classification. The challenge in obtaining load data that is a true representation of standby customers is that by definition standby charges are triggered only when the customer is on standby, i.e. the load is zero as the customer's load is being supplied by self-generation.

The following tables show unit costs under both cost allocation runs, assuming 1NCP and 12NCP, respectively, are used to calculate unit costs ($/kW/month). For this analysis, the 9 LDCs were divided into three groups based on density. Density is defined as the number of customers per kilometers of distribution line. Within each group, the resulting unit costs were averaged and presented in the summary tables. The groups are defined per the following definition:

- Small = density less than 30 customer/km
- Medium = density between 30 and 60 customers/km
- Large = density greater than 60/customers/km

Table 9 Summary of Monthly Unit Costs for DG Customers Using 1 NCP Method ($/kW/month)			
LDC	**Run 1**	**Run 2**	
	Allocated Revenue Requirement Less Miscellaneous Revenue	**Original Class Revenue Requirement Less Miscellaneous Revenue**	**Standby Class Revenue Requirement Less Miscellaneous Revenue**
Small	$4.44	$4.62	$3.34
Medium	$3.12	$3.15	$3.36
Large	$3.39	$3.42	$2.17

Table 10 Summary of Monthly Unit Costs for DG Customers Using 12 NCP Method ($/kW/month)			
LDC	**Run 1**	**Run 2**	
	Allocated Revenue Requirement Less Miscellaneous Revenue	**Original Class Revenue Requirement Less Miscellaneous Revenue**	**Standby Class Revenue Requirement Less Miscellaneous Revenue**
Small	$5.25	$4.90	$6.54
Medium	$3.80	$3.80	$5.34
Large	$3.82	$3.83	$2.69

Table 11 Summary of Revenue to Cost Ratios for DG Customers*		
LDC	**Run 1 – Original Class Total Revenue to Cost Ratio for the Class**	**Run 2 – Standby Class Total Revenue to Cost Ratio for the Class**
Small	1.56	0.85
Medium	1.13	1.14
Large	1.11	1.11

* Results vary by individual utility.

8.5 Observations Regarding DG Standby Cost Allocation and Rates

A summary review of the tables above can be enlightening and productive. Some initial observations follow:

- The numbers of LDCs actually being compared in the tables are limited due to data deficiencies in the LDC's cost allocation filings as noted earlier, as well as by the fact that some of the LDCs have no actual standby customers. Of the 20 LDC filings reviewed nine provided adequate information to compare standby cost allocations and rates for DGs, albeit the nine analyzed were some of the larger LDCs.

- The Interim Standby Rates are generally lower than the fully allocated standby unit costs per the recent cost allocation filings. This observation may be somewhat misleading as the recent cost allocation filings may have fully reflected the allocated costs to DG customers but not fully reflected all benefits DG customers bring to the LDC's system.

- The differences in standby unit costs between the 1NCP method and the 12NCP method are significant. The 1NCP unit costs are generally lower than in 12NCP which indicated DG customers have a relatively poor load factor. This relatively poor load factor supports in the imposition of a minimum monthly contract demand or high demand ratchet within the standby rate design process.

- The difference in unit costs for the remaining (non-DG) customers associated with separating out DG customers into a distinct rate class is minimal.

- The difference in standby rate unit costs for DG customers as a separate class is generally small.

- The instructions provided by the OEB to LDCs with respect to submitting Run 2 load data for customers with substantial DG facilities states "load data must be based on the actual metered usage of such load displacement customer(s)". The correct standby load is the difference between the metered load when the DG is not operational and when the LDG is operational. There is at least one instance in the group of DGs reviewed, where the standby monthly 1NCP provided by the LDC exceeded the sum of the name plate ratings of all LDG's in the distributor's territory. This could be caused by the distributor misinterpreting the OEB's instructions and/or the distributor's DG customer(s) bringing on additional load when its generators are not operational compared to when they are operational. This appears counter intuitive as it is more likely for additional load to be brought on when on-site generation is operational compared to when it is not.

- In general, there are concerns over the reliability of the load data gathered for modelling the standby rate classification. There are instances where there is no meter at either the distributor end or the generator end to record the generator's output. Data is obtained by using the generator on/off times provided by the customer to the LDC. The LDC is unable to verify whether or not the customer generated at full capacity or not. While consumption changes sometimes match the generator's capacities, other times they do not. This may be as a result of the customer bringing on more load when a generator comes on (flip of the situation described above), thus masking the impact of the generator. As well, it appears that customers can connect their generators and not produce for considerable periods. This is evident by sudden consumption changes that do not match an on/off report by the customer. These sudden consumption changes could be as a result of a generator coming on or off or as a result of load coming on or off. Thus, the LDC is sometimes not able to distinguish between these situations. Also, the customer's generator on/off reports is based on an honor system. It is also possible that the customer can forget to advise of a change of state of the generator that results in the sudden change of the consumption profile. Consequently, it is not always possible for a distributor to accurately determine to what extent the customer is displacing load. Many of these concerns can be mitigated by the LDC viewing the DG as a load, and billing the DG based upon the maximum load it places on the LDC.

Based on the aforementioned observations, the following recommendations regarding LDC cost allocation and rate treatment for DG customers are offered:

- Each LDC should establish a separate rate category for all DG customers greater than 500 kW. While the allocated unit costs for standby rates for DG customers do not change dramatically between Runs 1 and 2, the allocation of unique benefits to DG customers likely dictates a separate customer class for the larger DG community. A separate rate for DG customers will facilitate a "one off" analysis of benefits or a more generic benefit crediting such as reducing the DG's class's required revenue to cost ratio.

- Within the LDC cost allocation process, this separate DG class should have a standby rate calculated with a customer charge and demand charge. The demand charge should vary depending on delivery voltage to the DG customer (i.e., secondary, primary or subtransmission).

- Within the cost allocation process, care should be taken in calculated demand allocators for DG customers. If the LDC uses 4 NCP for the allocation of distribution demand costs, the DG's actual monthly demands may need to be reviewed to make sure all distribution costs are being allocated to the DG class. If 1 NCP is used, no additional review will likely be necessary.

- Within the rate design for these DG customers, consideration should be given to using an annual contract demand or high demand ratchet for collecting demand-related costs due to the DGs relatively low load factor. This addition in rate design will ensure all DG customers within a separate rate class pay their fair share of the total LDC costs allocated to the DG customer class, and that the LDC has a stable and predictable revenue stream from the DG class.

- Given that all legitimate LDC costs are allocated to the DG customer class through this separate standby rate category, all legitimate local benefits should also be reflected. These benefits may include reduced line losses, deferred capital investment and overall reliability improvements. These potential benefits are typically too situational-specific for a larger DG to quantify generically but should be quantified specifically based upon good faith negotiations between the LDC and DG customer. A more generic benefit approach such as reduced revenue to cost ratios for the DG class should also be considered.

- A standard methodology for determining any benefits provided by DG customers should be developed. Generally two different conceptual methods can be used (as discussed in Section 7):

    - Marginal cost approach.

      This approach determines the marginal cost of capital investments and avoided operating expenses. This value can then be used to calculate the benefit of the reduced capacity needs or operating costs by the DG customer. Because a marginal cost of service study may not be performed on a regular basis by LDCs in Ontario, the marginal power supply, transmission and distribution unit costs calculated for the CDM program could be used as a reasonable proxy.

- Incremental approach.

  This approach calculates the LDC's revenue requirement with and without the DG customer. Any cost savings between the two scenarios would represent the benefit of DG and be attributed to the DG customer.

- The aforementioned recommendations deal with the costs/benefits of a DG customer as related to the LDC only. Any additional system benefits/costs (i.e., generation through OPA and backbone transmission through Hydro One) need to also be considered in a separate undertaking. It should also be noted that DG customers should not receive credit twice for any benefits.

- Finally, there have been concerns expressed regarding the ability to identify all DG customers for separate rate treatment. It should be noted that this separate rate for DG customers is only being recommended for the larger DG customers (>500 kW). As such, the larger DG customers should be readily identifiable by the LDC for separate rate class treatment from the DG's initial request to interconnect.

8.6 Conclusions

Standby rates should reflect the costs that the LDC incurs serving the standby customer. The rate should incorporate, to the extent possible, both the costs and the benefits of adding the DG customer to the distribution system. In practicality, the costs and benefits can be difficult to determine. However, a standardized cost of service study, benefit calculation and rate design can provide useful guidance towards improved standby rates.

The first issue that must be addressed is the customer classification of a DG customer. Some LDCs create separate standby or DG customer classes, while other LDCs combine these customers with other non-DG customers. The DG customer should be viewed by the LDC as a customer with load. As such, standard cost allocation is an appropriate methodology to use when determining the cost of service both for a standby rate class and when combined with other non-DG customers. However, it is important to ensure that the demand allocator appropriately reflect the potential usage of the distribution system by the DG customer. As such, results may need to be examined under several demand allocation methodologies, such as 1 NCP, 4 NCP or 12 NCP.

Based on the initial analysis provided in this section, there is a very small difference in unit cost between Runs 1 and 2 and between the existing classes. In general, there are concerns over the reliability of the data gathered for modelling the standby rate classification. Therefore, any results are very general and may not be accurate for individual LDCs.

While the cost allocation filing provided information on the unit costs of serving DG customers, the filing did not generally provide information on the potential benefits provided by DG customers to the distribution system. As discussed, there are generally two different conceptual methods can be used to determine benefits of DG. The marginal cost approach determines the marginal cost of capital investments and avoided operating expenses. The incremental approach calculates the LDC's revenue requirement with and without the DG customer. Any cost savings between the two scenarios would represent the benefit of DG and are attributed to the DG customer. In general, a detailed calculation should be performed for large DG customers.

However, for the smaller DG customers a methodology that is straightforward, consistent, and easy to change over time should be implemented. This simpler methodology could include the marginal distribution unit costs calculated for the CDM programs. Another option would be to base the benefit (credit) on the credit assigned to a large DG customer.

For all these methodologies, any benefits paid to the DG customers are expenses to the LDC and should be paid by all LDC customers. Costs follow benefits, therefore as a DG customer provides benefits to the distribution system, the distribution customers are responsible to pay for the benefit.

Finally, the rate design must incorporate the same billing basis across LDCs. The billing determinant should be based on either the greater of actual load on LDC, the maximum contract demand along with a demand ratchet. This rate design promotes intraclass equity and revenue stability.

9.0 Conclusion and Recommendations

Based on the review of policy decisions in other jurisdictions, understanding of OEB's standby unit cost allocation and the current DG policy, it appears that the development of fair and balanced cost allocations for DG is on the right track in Ontario. One area that needs to be further developed is the treatment of benefits provided by the DG community. EES Consulting recommends that the OEB use the following tasks to establish a standard methodology across utilities for these customers.

System Interfaces

1. Recognize the obligation to support net metering for renewable and DG resources.

Interconnection Standards

2. Continue to implement interconnection standards for the four generation classes as per the DSC.

Stranded Costs

3. Stranding may be moot with proper cost allocations where DG customers are viewed as a load by the LDC.

4. If proper cost allocation to DG customers is not achieved, a separate report on stranding is suggested.

Standby Charges

5. Specific considerations for setting and designing standby rates include the following:

   - Rates should be designed to reflect the costs, net of any offsetting benefits;
   - Standby rates should reflect the various gradations of services (i.e., voltage levels) provided;
   - Rates should not create artificial barriers to DG;
   - The rate structure should be simple and easy to understand by the DG consumer and to administer by the LDC;
   - Rate design should encourage the following:
     - Reduced redundancy of installed capacity;
     - Operation of DG plant during on-peak hours; and

- Utilization of excess grid capacity during off-peak hours.

6. Create a separate class for DG customers with generation capacity above 500 kW and where a DG customer generates more than 10% of its total load. Exempt customers (e.g., generation less than 500 kW, or greater than 500 kW but make up less than 10% of the customer's total load) would remain on current rate schedules. Information on customers could be obtained from the interconnection applications and other customer information available. The 500 kW threshold allows for special treatment of the large DG customers, while limiting the administrative burden of identifying all DG customers.

7. Calculate and adopt standby rates that properly reflect the costs of service customers with DG. The standby rate should include:

   - Monthly contract demand rate based on billed historical demand and ratchet ($/kW) to collect the costs of having the local transmission and distribution system available when needed;

   - Monthly customer charge to collect administrative and service costs; and

   The standby rate should be utility specific, although the methodology used to calculate the rate should be consistent across utilities.

8. Develop a process for determining the additional benefits and credits of a specific DG unit. This process should be initiated during the development of the connection agreement between the LDC and the DG customer. The process would determine and credit the DG customer for:

   - Transmission and distribution savings due to the customer's DG unit;

   - Avoided losses; and

   - Provided ancillary services.

   While the process to determine benefits can be consistent across LDCs and customers, the actual benefits for larger DG customers must be determined on a case by case basis for each customer. Smaller DG customers should have a generic crediting process. The benefit provided to the DG customer is paid for by all customers based on their standard cost allocation of similar costs.

Distributed generation is being more widely implemented worldwide as countries and local jurisdictions work to reduce the barriers. Working to streamline the process and adopt fair, cost-based standby rates for DG is a good starting point for Ontario.