Ontario Power Authority

Ontario

Ontario Energy Board

Commission de l'énergie de l'Ontario

JOINT REPORT TO THE MINISTER OF ENERGY: RECOMMENDATIONS ON A STANDARD OFFER PROGRAM FOR SMALL GENERATORS CONNECTED TO A DISTRIBUTION SYSTEM

March 17, 2006

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1. INTRODUCTION

To help achieve its objectives with respect to renewable and clean energy supply, the Ontario Ministry of Energy (the Ministry) has run a number of competitive procurement processes for clean energy supply[1] and renewable energy supply. Three of these processes are complete: the Clean Energy Supply Request For Proposals (RFP), the Renewables I RFP and the Renewables II RFP. The Renewables III RFP procurement process is currently underway. Although effective for large developers, these processes presented a number of barriers to participation that many proponents of smaller generation projects were unable to overcome.

In order to begin addressing these barriers, the Ministry of Energy commissioned a study by the Ontario Sustainable Energy Association (OSEA) on the design of a standard offer program for Ontario. The OSEA reported to the Minister in 2005 with a policy proposal for a standard offer program for small generators of renewable energy in Ontario.[2]

In a letter dated August 18, 2005, the Minister of Energy then requested the Ontario Power Authority (OPA) and the Ontario Energy Board (OEB, or Board) to work together to address the barriers through a standard offer program for small generators embedded in a distribution system[3] that use clean [4] or renewable resources.[5] The program should reflect the costs and benefits of renewable energy as well as the Government's stated objectives with respect to renewable energy. The Minister requested that the OPA and OEB consider the OSEA work, consult with stakeholders, and report by the end of 2005 with findings, recommendations and a proposed implementation plan for a standard offer program for electricity from clean or renewable sources in Ontario.

The Minister's letter identified the following barriers that the competitive RFP process presents to small generators:

1. Financial security requirements,;
2. Complexity of the contracting process;
3. High cost of proposal development relative to project size; and
4. Overall administrative burden of the RFP process.

[1] Clean energy supply was defined in the Clean Energy Supply (CES) RFP as energy from resources that do not burn coal, oil or municipal solid waste.
[2] Ontario Sustainable Energy Association, *Powering Ontario Communities: Proposed Policy for Projects up to 10 MW*, May, 2005. http://www.ontario-sea.org/pdf/PoweringOntarioCommunities.pdf Referred to as the OSEA Report.
[3] Small generators located close to consumption are often referred to as distributed generation, or DG.
[4] Clean energy projects, as seen in the CES RFP, are relatively complex due to the fuel price risk.
[5] Dwight Duncan, Ontario Minister of Energy, letter to Mr. Howard Wetston, Chair, Ontario Energy Board and Mr. Jan Carr, Chief Executive Officer, Ontario Power Authority, August 18, 2005.

In general, a standard offer process sets certain criteria for participation and makes a commitment that any potential project which meets the criteria will receive the terms as set out in the standard offer. The terms of the standard offer may differ for different circumstances, for example offering different prices for different kinds of resources, but they do not differ for potential projects which have the same characteristics.

The Minister's letter indicated that the OEB, in accordance with its authority, was to focus on changes to codes and connection requirements and on ensuring non-discriminatory access to the electricity system. In accordance with its authority to procure electricity supply and capacity, the Minister indicated that the OPA was to investigate the appropriate price and eligibility requirements for projects in the standard offer program.

1.1 OPA Responsibilities and Process

The OPA is recommending appropriate price conditions, eligibility requirements and contract terms for the standard offer program. The OPA will be responsible for payments under the contracts, and will be the agency ultimately responsible for the standard offer program.

The powers and objectives of the OPA are stated in legislation.[6] These include:

- Engaging in activities to support the goal of ensuring adequate, reliable and secure electricity supply and resources in Ontario; and
- Engaging in activities to facilitate diversification of the sources of electricity supply by promoting the use of cleaner energy sources, including alternative energy sources and renewable energy sources.

Regulations under the legislation make clear that the OPA is envisioned as a transitional agency and will look over time for more market-based solutions and to avoid paying a premium to procure new generation.[7] To accomplish these objectives, the OPA is given the power, among other things, to enter into contracts relating to the procurement of electricity using clean energy sources or renewable energy sources to assist the Government of Ontario in achieving its goals in respect of these energy sources.

The objectives of the OPA, therefore, relate to the function of the electricity supply system. The OPA is expected to ensure that the system is adequate to reliably meet the needs of Ontario consumers, and it is concerned with the sources of electricity supply. For example, it is not directly concerned with the economic development implications of electricity supply, in terms of whether it creates jobs in the province through the activity of providing electricity. In the development of the standard offer program, the OPA was guided by its objective to promote the use of alternative and renewable energy sources in a prudent manner on behalf of Ontario ratepayers.

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[6] *Electricity Act, 1998*, Statutes of Ontario 1998, c.15, Sched. A, section 25.2. http://www.e-laws.gov.on.ca/DBLaws/Statutes/English/98e15_e.htm#BK35

[7] *Integrated Power System Plan Regulation,* Ontario Regulation 424/04, sections 2(4) and 2(5). http://www.e-laws.gov.on.ca/DBLaws/Statutes/English/98e15_e.htm

The OPA released a discussion paper on November 2, 2005.[8] The paper reported on research into the experience of standard offer and similar programs in other jurisdictions and set out a series of questions for the consideration of stakeholders interested in the design of the Ontario standard offer program. The OPA then hosted a series of presentations by stakeholders from November 16 to 18. On November 16, the OPA held a plenary session with approximately 150 attendees and presentations from 26 parties, including representatives from a number of associations, utilities, energy marketers and First Nations. Over the following two days, the OPA held private sessions with 34 groups or individuals. In addition, the OPA received over 50 written responses to its discussion paper both from parties which did make presentations and from parties which did not. Most of the submissions to the OPA dealt with the issues raised in its discussion paper.

The OPA has considered this stakeholder input in the formulation of its proposed program and the specific recommendations contained in Chapters 1, 2, 3 and 4 of this Report. These final recommendations have been reviewed and endorsed by the OPA Board of Directors on December 13, 2005 and March 1, 2006.

1.2 OEB Responsibilities and Process

The Ontario Energy Board regulates the province's electricity and natural gas sectors in the public interest. Its mandate is determined by the provincial government, and is embodied in legislation and regulations. The Board acts through regulatory instruments such as orders, licences, and codes that are developed in open and transparent processes.

To facilitate implementation of the standard offer program, the OEB, in accordance with its authority over connection policies and delivery obligations of local distribution companies (distributors or LDCs), has focused on identifying the need for changes to its regulatory instruments, including codes and connection requirements, with a view to ensuring non-discriminatory access to the electricity systems of LDCs as required by their licences.

The OEB issued a Staff Discussion Paper on November 17, 2005. The Staff Discussion Paper solicited comment on a variety of issues relating to licensing requirements for generators, the process for connection to distribution systems and the application of certain distribution rates. The OEB received thirty-four written submissions in response to the Staff Discussion Paper. Most of the submissions dealt with issues raised in the Staff Discussion Paper, while some dealt with issues that are within the purview of the OPA's mandate.

The Board has considered these comments in the formulation of the recommendations contained in Chapter 5 of this Report. These recommendations were reviewed and endorsed by the Board at its meeting on December 13, 2005.

[8] Ontario Power Authority, "Discussion Paper on Small Generators Embedded in a Distribution System", November 2, 2005. Referred to as the OPA Discussion Paper.

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1.3 Guiding Principles of the Standard Offer Program

Given the OPA's and the OEB's responsibilities and the instructions from the Minister, several guiding principles were adopted for the development of the standard offer program:

- The program should be kept simple.
- The program design should focus on removing barriers to smaller developers.
- The program needs to strike a balance between the Government's renewable generation targets and the value of the electricity to the ratepayer.
- The program should consider the early efforts of the OSEA.

All stakeholders agreed that the standard offer program should be kept simple, to facilitate widespread participation and to reduce its administrative cost. It was generally felt that the relative complexity of competitive RFP processes contributed to the inability of small generators to participate in these procurement processes. Simplicity implies understandable criteria for participation, contracts that are relatively short and simple, and terms and conditions that are simple and readily understood.

The Minister's letter outlined several barriers that the standard offer program should address. In addition, all stakeholders agreed that open, fair and non-discriminatory access to distribution systems is crucial to the success of the standard offer program. To obtain such access consistent with the safe operation of distribution systems will require distributors to cooperate with prospective generators. Lack of access to distribution systems would create a significant barrier for smaller renewable generation.

The Ontario Government has announced a goal of having 2700 MW of renewable generation capacity installed in the province by 2010. The Government recognizes that this generation is likely, at least initially, to cost more than some conventional generation sources. Similarly, the design of the standard offer program needs to balance the interest of the Government in securing generation from renewable resources against the interests of ratepayers and the statutory objectives of the OPA and the OEB.

Development of the standard offer program considers the foundation provided by the OSEA Report. The recommendations of the OSEA Report are shown as part of the discussion leading up to the recommendations for the structure of the standard offer program.

1.4 Distribution System Considerations

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

Connection of generation to such a system in synchronous or parallel operation is neither simple nor trivial. Once power is sent into the system, the flows of electricity will be changed and even reversed from the design parameters and normal operation. This can lead to a number of technical problems that can affect the stability of the network and the quality of electricity supplied.[9] These include issues of voltage control, reactive power and protection of the system. Distribution connected generation may also create transmission constraints and any such impacts must be considered.

Given these conditions, a distribution system may not be physically capable of accepting all of the generation that developers might wish to offer under the standard offer program.

Additionally, because of the complexity of adding generation to a system and limited technical resources, distributors may at times be unable to react in a timely fashion to a large number of requests for connection assessments from potential standard offer program participants.

The capacity of the distribution and transmission systems, both physical and administrative, may therefore limit the distribution system's ability to absorb additional embedded generation.

1.5 Program Length and Review

The OSEA Report recommended a five year standard offer pilot program. Stakeholders generally did not comment on whether the program should be a pilot or a permanent program. However, making it a pilot program with a limited lifespan could produce a rush to secure contracts near the end of the pilot and uncertainty after its end. A pilot program could be expected to be relatively limited in size, in order to test program elements before too much is at stake. Many stakeholders do not want such a limited program.

The elements of the standard offer program will be subject to periodic review, as OSEA recommended and most stakeholders agreed. The elements to be reviewed could include total or annual program caps, the maximum and minimum size of eligible projects, other eligibility rules, the prices to be paid for new projects under the standard offer program, the length of new contracts, and other parameters that together set the terms of the standard offer program. The processing of applications for the standard offer program would continue during the review.

The period to the first review of these elements could vary by element. The initial period should be long enough for prospective program participants to be assured that important conditions, like price and eligibility, will not change suddenly while they are preparing their projects. It should also be long enough to allow for reasonable evaluation of the standard offer program itself. Not fixing a firm date for the review allows the OPA to continue to control the standard offer program and to adjust it when circumstances make adjustment necessary. To allow flexibility in program review, while still assuring potential participants of program stability, the time for the first review is not fixed, but rather specified as a preferred minimum period before the review. As part of the review, the OPA would consult with the Board on matters within the Board's purview.

In years when the program is not reviewed, its performance should be monitored and reported on, as the OSEA noted in its Report.

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[9] International Energy Agency, "Distributed Generation in Liberalized Electricity Markets", 2002, p. 73

Recommendation 1.1 ***The OPA recommends that the standard offer program be ongoing, with regular reviews. The first review of the standard offer program elements is not intended to occur before the end of the second year of the program. The OPA intends to report annually to the Minister on standard offer program performance.***

Rationale for the recommendation:

- A pilot program creates uncertainty and encourages hoarding.
- Having flexibility in the timing of the first review allows the OPA to address major initial problems, if they arise.
- The intended length of at least two years should allow enough time to assess program performance.
- Does not mandate a review at a specified time even if none is needed.

1.6 Contents of this Report

The next three chapters of this Report (Chapters 2, 3 and 4) deal with the OPA's recommendations under the headings, respectively, of Eligibility, Pricing and Terms and Conditions. Each set of recommendations is preceded by an introduction to the issue and a summary of feedback from the stakeholder consultation process, and is followed by a rationale. Chapter 5 sets out the OEB's recommendations with respect to the standard offer program. Each set of recommendations is preceded by appropriate background for the issues, information on stakeholder feedback, and rationale for the recommendations. The final chapter outlines a preliminary implementation plan.

1.7 Report Submittal

At the request of the Ontario Minister of Energy, this Report is submitted jointly by the Ontario Energy Board and the Ontario Power Authority.

Each entity is responsible for the recommendations made in this Report in relation to issues falling within its sphere of authority. Thus, the OPA, in accordance with its authority to procure electricity supply and capacity, has endorsed the recommendations to the Minister set forth in Chapters 2, 3 and 4 with respect to price, terms and conditions, and eligibility requirements for projects to qualify for the standard offer program, and the recommendation set forth in Chapter 1 with respect to the design of the standard offer program.

The OEB, in accordance with its authority over connection policies and delivery obligations of electricity distributors, has endorsed the recommendations to the Minister set forth in Chapter 5 of this Report, which reflect activities that the Board intends to undertake for reasons relating not only to implementation of the standard offer program but also to achieving objectives already set out in the Board's 2005 – 2008 Business Plan. The activities include proposing changes to its regulatory instruments and to connection requirements for distributors, in a manner consistent with the principle of non-discriminatory access to distribution systems.

2. ELIGIBILITY

The elements of eligibility are set out in the OPA Discussion Paper:

- Ownership;
- Size;
- Fuel Source;
- Location;
- Connection;
- In-Service Date; and
- Rehabilitation and Upgrading.

The criteria for eligibility to participate in the standard offer program will strongly shape the program. These criteria will determine what technologies and fuels will be prevalent in projects and what kinds of entities will own them. Many of these criteria are related to each other and to other conditions of the standard offer program. For example, there is a greater need to impose requirements for progress on implementation if there is a cap or limit on the total size or number of projects that can participate. Similarly, there may be less concern with what kinds of entities own the projects if each is limited to a small size.

This Chapter discusses each of the above elements in turn. The OSEA Report and the stakeholder consultations discussed these elements, and all comments are considered. Some of the elements have more than one dimension and may be placed into separate recommendations.

2.1 *Ownership*

The ownership issues considered included participation by local community groups, large organizations and government/Ontario Power Generation/distributors.[10]

The OSEA Report examined community-based renewable power projects, defining acceptable ownership as:

> Farmers and rural landowners, community-based organizations, co-operatives, First Nations, NGOs,[11] municipal entities, private individuals, small businesses, and combinations thereof.[12]

Most stakeholders were in favour of local ownership or participation in the standard offer projects, but they did not advocate either restricting the kinds of entities which could own projects or requiring local participation.

[10] Distributors are not allowed to own generation directly, but they may do so through an affiliate.

[11] Non-Governmental Organizations, often community or aid agencies, such as a community environmental action group.

[12] OSEA Report, pg. 29.http://www.ontario-sea.org/pdf/PoweringOntarioCommunities.pdf

Some stakeholders did favour limiting the size of each participant in the standard offer program or limiting the number of projects a company could participate in. However, ensuring local participation and banning large players (including limiting the size or number of projects a single owner can have) are both difficult and costly to track and enforce. Stakeholders noted that ownership restrictions can readily be evaded by opaque inter-corporate ownership.

It was noted by some stakeholders, primarily potential suppliers, that distributors and municipal governments have potential conflicts of interest if they are allowed to own standard offer projects. Both of them control key resources needed by program participants: distributors control access to their distribution systems and municipalities control zoning and some local permits. However, many stakeholders, including distributors, were in favour of allowing municipalities or their affiliates, or affiliates of a distributor, to own standard offer projects.

The process for connection assessment is described in the OEB's Distribution System Code. An objective of the OEB'S Affiliate Relationships Code for Electricity Distributors and Transmitters (the "ARC") is to ensure that there is no preferential access to regulated distribution services for affiliates of distributors. Enforcement of the ARC is within the Board's purview.

Almost all stakeholders favoured preventing Ontario Power Generation, Inc. (OPG) from owning projects in the standard offer program; most of the others felt a prohibition to be unnecessary because of market restrictions on OPG's generation development activities.

Recommendation 2.1 ***The OPA recommends that there be no restrictions on the nature or location of entities that can own standard offer projects. The OPA recommends that there be no restrictions on ownership, except for Ontario Power Generation, Inc., which should not be allowed to own all or any part of projects which participate in the standard offer program. Projects that include a distributor's affiliates, municipal government or municipal government's affiliate ownership should be allowed to participate in the standard offer program.***

Rationale for the recommendation:

- Simple to administer; enforcing local ownership requirements or banning certain kinds of entities is difficult to police.
- Local ownership may be desirable, but forcing it could preclude some economic projects.
- Supports the system benefits of widespread participation.
- Facilitates partnerships/cooperatives.
- Helps build community involvement and overcome "NIMBY" ("Not In My Back Yard") issues.
- Facilitates involvement of First Nations.

2.2 *Fuel Source*

The Minister's letter stipulated that the program address "clean or renewable resources." The Minister did not indicate a preference for any particular type of clean resources, such as cogeneration. Separately, the Minister has directed the OPA to procure 1000 MW of capacity from combined heat and power (CHP) developers.

The Clean Energy Supply RFP defined "clean" as any resources that do not burn coal, oil or municipal solid waste. The Renewables RFP defined a renewable generating facility as "a facility that generates electricity from one or more of the following sources: wind, solar, Renewable Biomass, Bio-gas, Bio-fuel, landfill gas, or water," (upper-cased terms are defined in the RFP). The OSEA Report dealt only with renewables, which it defined as wind, small hydro, biomass and solar PV. Stakeholders generally agreed with these definitions. Some had concerns about what would constitute biomass fuels, and several wanted to ensure that certain fuels were included.

The intention of the standard offer program is to facilitate participation by relatively small and simple projects which can be included using a standardized and simple contract. Contracts for clean energy resources, as seen in the CES RFP procurement process, are relatively complex, largely due to the natural gas price risks. Stakeholders generally agreed that the inclusion of clean generation would add complexity to the standard offer program.

The OPA therefore believes that the standard offer program is a suitable procurement mechanism for renewable projects as defined in the Renewables II RFP. However, because of the natural gas price risks inherent in clean projects, a procurement mechanism – other than the standard offer program – would be more appropriate for small clean energy projects. One such mechanism is the process for acquiring electricity from combined heat and power sources, as already noted.

The RFP definitions form a good basis for the standard offer program. Where necessary, the standard offer program recommendations should distinguish between "clean" and "renewable" resources using these definitions.

Recommendation 2.2 ***The OPA recommends that only generation resource types that qualify as renewable resources in the Renewable Energy Supply II RFP should be eligible for the standard offer program.***

Recommendation 2.3 ***The OPA recommends that any generation resource type that qualifies as a clean resource in the Clean Energy Supply RFP <u>not</u> be eligible for the standard offer program. Apart from the CES RFP and coincident with the implementation of this standard offer program, the OPA will undertake an investigation of alternative procurement mechanisms to facilitate development of small clean energy projects.***

Rationale for the recommendations:

- Consistent with Government policy as expressed in the RFPs.
- Consistent with the OPA's objectives for renewables including water, wind, solar PV, biomass, bio-gas and landfill gas.
- Consistent with the simplicity objective of the standard offer program.

The OPA Discussion Paper raised the issue of whether the standard offer program should impose environmental performance standards beyond those already required for each kind of generation. Stakeholders said that no additional restrictions are needed and that it is not the place of the standard offer program to impose environmental performance conditions beyond those established by federal or provincial statute and regulation.

Recommendation 2.4 ***The OPA recommends that standard offer projects be required to meet only environmental standards already established under federal or provincial statute or regulation.***

Rationale for the recommendation:

- Existing environmental standards represent current Government policy.
- Existing environmental standards are sufficient and additional requirements would only impose an unnecessary burden on small project developers.

2.3 Size

2.3.1 Maximum project size

The Minister's request was directed at small generators embedded in a distribution system. The OSEA Report suggested a maximum project size of 10 MW, but included the "last unit in;" that is, a unit that brought the total project size from below 10 MW to above it would be included. Several stakeholders endorsed this approach. Others suggested a maximum of 20 MW, 25 MW or no limit except that imposed by the physical limits of the applicable distribution system.

The 10 MW limit fits with the Independent Electricity System Operator's (IESO's) current registration rules. With no limit, the choice of whether to go ahead would be with the developer, who could decide if a larger project is worth accepting IESO registration. A 20 MW limit might allow a single project to take up all the connection capacity on a line. Leaving the limit to what the LDC can accept could let much larger projects in within the largest LDCs.

Note that generators that are greater than 10 MVA at the connection are required to register their facilities and operate within the IESO Market Rules. In the event that a generation facility greater than 10 MVA at the connection is also eligible under the standard offer program, the facility will be required to comply with all IESO regulations.

Recommendation 2.5 ***The OPA recommends that the maximum size of projects eligible for the standard offer program 10 MW.***

Rationale for the recommendation:

- Simple and easy to administer.
- Facilitates participation by many smaller suppliers.
- Consistent with registration rules set by the IESO.

2.3.2 Minimum project size

Setting a minimum size helps to control the administrative burden that results from a large number of small volume contracts.

The OPA Discussion Paper asked stakeholders whether a minimum size of 500 kW (the maximum size for net metered projects) would be appropriate. However, stakeholders pointed to several small (<150 kW) projects, such as on-farm anaerobic digesters, which might want to participate in the standard offer program. Most stakeholders favoured having no minimum size but did indicate concern about the consequent administrative cost burden on the OPA and/or distributors.

Also considered was the idea that minimum size might be established by a distributor's connection practices, which provide for a much simpler process for suppliers less than 10 kW.

Stakeholders commented on both sides of this issue. Those who preferred to have a minimum size were concerned with the potential administrative burden on the OPA. Any minimum size limit would be to some extent arbitrary.

Recommendation 2.6 ***The OPA recommends that there be no minimum size threshold for projects to be eligible for the standard offer program.***

Rationale for the recommendation:

- Provides the broadest access to the standard offer program to ensure all economic projects can be included.
- Project economics will drive the most reasonable floor, so no limit is set arbitrarily.
- Preserves simplicity.

2.3.3 Standard Offer Program Limits

The limit on individual project size reduces the risk of the total standard offer program being larger than desired. The concern for the total program size is its cost if prices prove to be too high and lead to the development of unsustainable projects. However, setting a total program limit could lead to hoarding of queue positions and other counter-productive behaviour.

Several stakeholders argued against an overall program cap, because it could lead to gaming and other negative behaviour. The OSEA Report recommended no cap during the pilot period. The ability to review and fine tune the standard offer program and the proposed conditions for contract award both help to minimize the risks from having no program cap.

Recommendation 2.7 ***The OPA recommends that there be no cap on the total capacity (MWs) accepted under the standard offer program.***

Rationale for the recommendation:

- Not having a program cap reduces the risk of participants hoarding queue positions.
- The overall size of the standard offer program could be self-limiting because of the small size of individual projects and the finite resources in Ontario.

2.4 Location

Two considerations with respect to location are whether to encourage projects in specific locations for community development or other purposes, and whether to limit the amount that can be located in any particular area.

Much of the discussion from stakeholders about locational issues was concerned with the technical limits of distribution and transmission systems. These are described further in Section 1.4 and dealt with in Chapter 5 of this Report. Some stakeholders did urge that the standard offer program be used as an instrument of economic development for communities.

Technical limits of distribution and transmission systems are a concern, which will in general be dealt with in the connection process. Transmission system capacity constraints, in addition to distribution system constraints may place limits on generation development in certain regions of Ontario.

The OPA Discussion Paper raised the question of whether the program should place a restriction on the total number of projects or amount of generation a single distributor should be required to take. Stakeholders indicated that the appropriate control is the physical limitations of the distribution and transmission systems.

Recommendation 2.8 ***The OPA recommends that the standard offer program should not place restrictions on the location of standard offer projects***.

Rationale for the recommendation:
- Simple and easy to administer.
- This recommendation is consistent with the power system planning objective of obtaining the most economic resources.
- This allows potential developers to propose optimal sites.
- Natural program limits will be determined by the available capacity of the distribution and transmission systems.

2.5 Connection

Non-discriminatory access to distribution systems is an essential component of a standard offer program. The ability to connect to sell power is crucial to the success of the standard offer program. The rules and process for connection come under the Distribution System Code (DSC), which the OEB proposes to amend as described in Chapter 5 of this Report.

The standard offer program can define the voltage at which the eligible suppliers, who will be embedded in distribution systems, can connect. In Ontario legislation, the stated demarcation separating distribution from transmission lines is 50 kV. Stakeholders agreed that connection should be at distribution voltage, which is typically 44 kV and below.

Some proponents pointed out that desirable projects which would otherwise qualify for the standard offer program might be located in relatively remote regions, far from any distribution system, but close to a transmission line. Including such projects in the standard offer program poses several problems, including the fact that they must become IESO market participants.

Recommendation 2.9 ***The OPA recommends that the maximum voltage for connecting standard offer projects should be 50 kV.***

Rationale for the recommendation:

- It is consistent with the Minister's request that the standard offer program target projects connected at the distribution level.
- It is simple to administer.
- It respects the ability of the standard offer program participant to locate where connection capacity is available.

Some projects which are otherwise eligible for the standard offer program might be embedded within larger distribution customers. Including such projects in the standard offer program raises several issues relating to metering and settlement, as well as issues relating to load displacement and gross and net billing. The only stakeholder comment on this point came from those with an interest in a project that is connected through a distribution customer.

Recommendation 2.10 ***The OPA recommends that only projects that are connecting directly to a distribution system be eligible for inclusion in the standard offer program. Exceptions to this recommendation would be the "Early Movers" as described in Section 2.6 below, whose distribution connection arrangements would be grandfathered under the standard offer program.***

Rationale for this recommendation:

- Including projects embedded in a distribution customer can add considerable complexity to the standard offer program.

2.6 *In-Service Date*

Existing projects cannot increase the amount of renewable energy in Ontario. Allowing them to participate in the standard offer program could simply increase their rate of return above the minimum necessary to maintain these projects. On the other hand, some existing projects may have been built in anticipation of market or other conditions which did not arise due to Ontario Government policy changes. Such projects may need the additional support that a standard offer program provides. Stakeholders who commented on this issue generally supported including "Early Mover" projects, meaning those which are already in service but would otherwise be eligible for inclusion in the standard offer program, and which were implemented in anticipation of a restructured Ontario market.

Accepting projects which have been brought into service since the anticipated restructuring of the Ontario electricity market would include those built in anticipation of a different market environment and would parallel the treatment of the early movers for clean energy supply. Setting an historical date for eligibility will also include projects currently under development. The original commitment for electricity restructuring in Ontario was for an unspecified date in 2000.

Recommendation 2.11 The OPA recommends that projects brought into service after January 1, 2000, which would otherwise qualify for the standard offer program, be eligible for the program. Any project which has a contract arising from the Ontario Hydro Non-Utility Generation or Renewables RFP processes will be excluded.

Rationale for the recommendation:

- The Ontario competitive electricity market was initially scheduled to open in 2000. Projects brought into service after that date may have been started in anticipation of characteristics of that market which, due to subsequent Government policy decisions, it now does not have.
- This treatment roughly parallels that accorded to the early movers in clean energy supply, who are being accorded an opportunity for a supply contract with the OPA similar to those awarded under the CES RFP process.
- Projects that have been, or are currently under, a power purchase contract with a Government agency have already received the benefits of fixed, long term contracts and should not be eligible for the standard offer program.

2.7 Phased Projects, Additions, Rehabilitation and Upgrading

Several conditions could result in a proposal to add new generation to an existing connection:

- Subsequent phases of a phased project;
- Incremental additions to existing projects;
- Rehabilitation of an existing facility; or
- Upgrading of an existing facility.

These conditions may be treated differently for the purpose of inclusion in the standard offer program, depending on their characteristics.

Several stakeholders described possible phased projects. Such projects are fully eligible for the standard offer program if the total project, including all phases, does not exceed the size limits. An issue for the standard offer program is how to treat them if a long lag is expected between phases. Giving an initial contract for the whole project will fix its terms long in advance of construction, while allowing a connection assessment for the entire project would in effect reserve capacity for the future phases, with no assurance that they will be built, and the potential that they will prevent other projects from using the connection capacity.

Recommendation 2.12 proposes a three-year time limit from contract signing to commercial operation of the generation. Phased projects which can be completed within that time need no special consideration. Beyond that, new phases of phased projects should be treated as new projects. The special consideration required for them is discussed below.

Recommendation 2.12 ***The OPA recommends that phased projects should be able to connect in phases, subject to limitations of system connection capacity and provided that all phases are completed and in-service within three years of the contract signing date. Once the first phase of the project is in service, the project is eligible to generate revenue.***

Rationale for the recommendation:

- Does not exclude economic projects.

Some existing or contracted projects may have unexploited economies of scale. Small additions to the existing project can take advantage of these economies. However, if the existing project already has a contract arising from the Ontario Hydro Non-Utility Generation or Renewables RFP processes, the available economies of scale have been realized through these contracts. Further, the proposed standard offer pricing reflects the costs of connection facilities. To the degree that projects are able to avoid these costs, yet realize the same price, allowing a marginal addition to participate in the standard offer program would provide the total project with returns beyond those expected from the earlier contracts. Most of the projects with such contracts are well beyond a size that would qualify for the standard offer program.

The discussion above, however, suggests that subsequent phases of phased projects which cannot be completed within three years would be treated as separate projects with separate contracts and separate connection assessments.

Recommendation 2.13 ***The OPA recommends that projects which connect through a generation project which has, or has had, a contract with an agency of the Ontario Government should not be eligible for the standard offer program, except for projects which are subsequent phases of an existing standard offer contract and which otherwise are eligible for standard offer program participation.***

Rationale for the recommendation:

- The standard offer program is designed to address barriers to the development of small generation projects. The projects addressed in this recommendation are able to leverage off the infrastructure of existing Government contract projects and do not have the same barriers.
- This prevents excessive profits on projects which already benefit from supply contracts with an agency of the Ontario Government.
- The recommendation still allows subsequent phases of standard offer projects to use the existing connection.

Many existing generation facilities can produce increased output with rehabilitation or with upgrades or additions to the existing equipment. Such upgrades and additions, if they would qualify for the standard offer program, should be included because they represent additions to the system. However, the eligibility conditions should prevent existing facilities from achieving greater returns. Similarly, there may be facilities that are now abandoned and which could be rehabilitated. Again, facilities which have been abandoned, but not those which have been operating within the last two years, should be eligible for the standard offer program.

Including incremental additions to existing projects in the standard offer program presents several issues. The incremental generation and the base generation will be separately priced, and therefore should be separately metered. This may not be possible where the incremental addition results from, for example, runner replacement for a hydroelectric project. Another issue is the definition of incremental generation and its eligibility. Extending the example, runner replacement is routine for hydroelectric projects at some point in their lives, and the new runners typically increase capacity of the facility. Such projects may not need pricing under the standard offer to proceed. These issues are best left to the implementation phase for more focused discussion with stakeholders.

This issue was not addressed in the OPA Discussion Paper. Stakeholders did comment on it though, noting that a rehabilitation of a facility that had been out of service for some time did add to the total generation capacity of the province. Some stakeholders agreed that a two-year total outage was a reasonable period of no generation to allow a project to be considered incremental.

Recommendation 2.14 ***The OPA recommends that projects which represent an incremental addition to the capacity of an existing project that does not raise the total project size above the limit for the standard offer program, and which would otherwise be eligible, should be eligible for participation in the standard offer program. The questions of definition and metering of such projects will be addressed in the implementation stage of the standard offer program design.***

Recommendation 2.15 ***The OPA recommends that projects which rehabilitate and return to service a facility that has not produced electricity for two consecutive years prior to August 18, 2005, the date the Minister requested the OPA and OEB to make recommendations on a standard offer program, and which would otherwise be eligible for the standard offer program, should be eligible for participation in the standard offer program.***

Rationale for the recommendations:

- Rehabilitation and upgrading projects can add to the electricity supply at relatively low environmental and financial cost.

3. PRICING FOR THE STANDARD OFFER

3.1 *Pricing for Renewables*

The OPA Discussion Paper asked several basic questions on how prices should be set for renewables:

- Should prices be based on the cost of the renewables or on their market value, or on some mix of these?
- Should the pricing be a fixed price for energy, or should it be a variable price?
- Should different technologies receive different prices?
- What should the base price be?
- Should there be tiered prices for wind projects with different wind regimes?
- Should prices be escalated, and if so by what escalator and for what fraction of the price?
- Should prices for new projects be adjusted over time, and if so how?

In the OSEA Report and in the stakeholder consultation sessions, there was active discussion of each of these questions. This Chapter will consider these questions and will include a discussion of the treatment of federal incentives.

3.1.1 Market-Based vs. Cost-Based Pricing

All commodities oscillate between the supplier's cost to produce and the end-use consumers "consumptive" value. Market-based mechanisms attempt to equilibrate between these supply costs and demand values to determine a price point. A true market-based pricing mechanism for renewable electricity would attempt to capture added value for location and use of renewable fuels. The absence of a traded market requires a valuation of these components to become price adders to the energy price

A market-based price would start with a competitive energy price. All stakeholders and the OSEA Report agreed that an IESO-administered market price, such as the Hourly Ontario Energy Price (HOEP), was not appropriate as a basis for standard offer prices. HOEP is too variable and too affected by various market forces, and would in any case not reflect the fact that there is a different market for renewables in Ontario. A price that does reflect the value of renewable fuels would be the prices from the Renewables RFPs in Ontario, namely Renewables I and Renewables II. These represent the prices at which sellers are willing to offer supply from renewable resources in Ontario.

Many stakeholders felt that the prices resulting from the competitive RFPs do not form a useful basis for standard offer pricing, primarily because most of the RFP projects have greater economies of scale, and therefore lower costs per unit produced than the standard offer program projects can achieve. Most stakeholders said, as did the OSEA Report, that the prices for renewable resources should be based on their costs, and should be set so as to produce an acceptable rate of return to the generation owner. Underlying many of these cost-based positions is the assumption that a purpose of the standard offer program is to promote community development, complete with the geographic dispersion of the facilities producing renewable power under the standard offer program.

Several other stakeholders suggested a combination of market- and cost-based pricing, for example by choosing a market-related base price and adding to it credits representing the value of distributed generation to the electricity system. Some stakeholders noted the difficulty of accurately analyzing the costs for different generation fuels and technologies, which would be necessary if prices are to be based on costs.

Recommendation 3.1 ***The OPA recommends that the price paid for renewable generation under the standard offer program be market-based and include adders for the value of distributed generation and lost economies of scale.***

Rationale for the recommendation:

- The basis for pricing is simple and readily understood.
- The results of the competitive RFP processes for renewables can provide a market-based value for renewable generation in Ontario.
- The OPA's objectives include the development of economic electricity supply for Ontario consumers, while supporting renewable electricity development. Cost-based pricing could support less economically sustainable generation.
- Basing prices on cost requires understanding and analyzing the range of costs associated with a broad array of possible projects, which is both complex and not readily understood.

3.1.2 Fixed vs. Variable Pricing

The standard offer price could be structured as a fixed payment for all output (e.g., $/MWh), a fixed payment in addition to a variable component, or a variable payment. The variable payment could be structured as a contract for differences where the supplier would be guaranteed a specific price. The OPA also considered a combination of fixed and variable payments, including a pricing option with a fixed floor price plus a payment based on generation performance or on market price.

Stakeholders and the OSEA Report were not in favour of a variable payment contract. These parties indicated that the certainty of a contract with a fixed price is needed to enable project financing. Variable pricing contracts are perceived to increase risk and add complexity. A combination of fixed and variable payments can address these concerns if the fixed component is sufficiently high to satisfy the financial backer.

Generation facilities which have, or can have, a generation profile that provides proportionately more of their output during peak periods may have a higher value to the electricity system. Proponents for some technologies, notably farm-based anaerobic digesters and certain small hydro-electric facilities, said that their generation can be available at all times, and with the addition of some storage could be designed to generate more at peak demand times. This raises the issue of whether and how to reward such facilities.

One way to address this issue is to give a reasonable base price to all forms of generation, while offering an incentive for generation that can commit to being available at times of peak consumption. This approach would differentially reward generation that can better time its output, while not penalizing those technologies which are less able to control the time of generation. It would give incentives for technologies which can shape their output so that generation occurs at the times when it has most value to the electricity supply system. If such projects can schedule generation to be on peak, they can help the IESO in its task of meeting demand at lowest cost.

Recommendation 3.2 ***The OPA recommends that the basis for pricing for renewable resources in the standard offer program be a fixed base price per unit of energy plus a performance incentive for projects that can demonstrate control over output to meet peak demand requirements.***

Rationale for the recommendation:

- Fixed pricing per unit of energy puts performance risks on the supplier, who is best able to manage these risks.
- Setting fixed pricing as the primary component of generator revenue is preferred as a basis for financing projects.
- Adding a variable component can reward generators for performance during peak demand periods, when the generation is most needed, and thus more highly valued.
- A relatively simple variable component keeps the cost of contract negotiation and administration relatively low and can be settled with existing market systems.

3.1.3 Pricing by Fuel

Generation from renewable resources is typically highly capital-intensive. Wind, water power and solar PV have no or low fuel cost,[13] while biomass facilities may be fuelled by waste products. The cost characteristics of these generation types therefore have some similarities in their degree of dependence on the structure and cost of their financing. The OSEA Report recommended differentiated prices only for solar PV, which clearly has much higher costs per unit of installed capacity than the other renewable fuels. Most stakeholders who advocated basing prices on costs expected that prices would be different for different fuels.

Recommendation 3.3 ***The OPA recommends that the base price under the standard offer program be the same for all electricity from renewable resources except solar PV.***

Rationale for the recommendation:

- This is a relatively simple approach; setting separate prices for each fuel would be complex.
- The value to the system is not solely based on fuel source, but also on when the generation can be available.

[13] Wind developers pay a rental to the land owners; hydro developers pay a water rental fee to the province after their first ten years of operation. These payments are considered to be like fuel costs, but are based not on a fuel market but on the value of the electricity generated.

3.1.4 Base Price

The OSEA Report and several stakeholders proposed that the price for generation from renewable resources be fixed at 13.3 cents per kWh[14] for at least the first five years of the standard offer contract. After that, the price would come down for wind turbines with the more productive regimes. For other resources, the Base Price would remain fixed at 13.3 cents per kWh. Other stakeholders proposed that the Base Price be determined as the price that would give specific technologies or projects a sufficient return to allow them to proceed. Both of these approaches are cost-based.

Following Recommendation 3.1, the OPA suggests that the price under the standard offer program for renewable generation in Ontario should be a market-based value. One market-based indicator of that value is the prices resulting from the recent Renewables II RFP competition, which can then form a baseline for pricing the renewables component of the standard offer program. The highest accepted Renewables II project price forms the upper limit of value as determined by the RFP process, and would represent a starting point for the assessment of the value of renewable generation in the standard offer program. That price must be estimated, because the range of bid prices was not made public.

The weighted average price for the winning projects was disclosed to be 8.64 cents per kWh. In the Renewables II RFP, the Ministry reserved the right to accept bids up to 15% above the weighted average price of the initial project stack. If the bid prices are roughly normally distributed and that range represents two standard deviations, the standard deviation of accepted bids would be just over 6 cents. Assuming that the highest accepted bid was within a 90% confidence interval of the mean, the highest accepted bid could be in the range of 9.4 cents per kWh. It is recommended that this be the starting point for setting the base standard offer price.

It is recognized that the price of 9.4 cents per kWh does not include the value of federal incentives like the first phase of Wind Power Production Incentive (WPPI) that is currently 1.0 cents per kWh for 10 years. Federal government officials have reported that the current budget allocation for the WPPI is nearly fully subscribed and may not be available for new projects. The future of the second phase of WPPI and the Renewable Power Production Incentive (RPPI) energy credit is still under consideration by the Federal government. In addition, developers have reported to the OPA that they found the cost and burden associated with accessing the credit to be significant and often not worth pursuing for smaller projects.

The OPA further recognizes that economies of scale are generally lost for smaller projects. Small renewable generators are disadvantaged by such lost economies of scale. In recognizing these challenges, the OPA proposes to provide the developer with a scale bonus.

Distributed generation (DG) projects can reduce system costs by reducing transmission losses. In a study done for Hydro One Networks Inc. and submitted to the OEB,[15] average transmission losses were estimated at about 2.5%. However, marginal losses can be up to three times higher than that. Since the DG projects can be considered to reduce the marginal demand at the times that they are running, they

[14] Provisions to compensate for inflation are discussed in Section 3.1.6 below.

[15] Navigant Consulting, "Avoided Cost Analysis for the Evaluation of CDM Measures," June 14, 2005.

can be credited with reducing marginal losses. This same study estimated average marginal losses over a year at about 7%.

Recommendation 3.4 ***The OPA recommends that the price for renewable resources offered under the standard offer program be based on the following formula:***

Base Price = R + S + T
= R +0.10R + 0.07R
= 1.17R
= 11.0 ¢/kWh

Where,

R = Estimate of the marginal accepted Renewables II RFP project price = 9.4 ¢/kWh
S = 10% Scale bonus = 0.10R = 0.94 ¢/kWh
T = 7% Avoided transmission losses credit = 0.07R = 0.66 ¢/kWh

Thus the Base Price is 11.0 ¢/kWh.

Although this is a market-based pricing formula, the OPA understands that, if the resulting price is not high enough to attract investment, the standard offer program will not be successful. Some informal analysis of its appropriateness has been done on the various renewable projects and concludes that a typical project will have a positive net present value if it receives this Base Price and annual CPI escalation on a proportion of the Base Price.

Rationale for the recommendation:

- This sets the price for electricity from renewable resources at a level that is based on its market value, but that also permits some renewable projects to earn a reasonable rate of return.
- The price is at a level that will not represent a large financial burden relative to other renewable resource procurement methods if there is a high rate of participation by renewable resources in the standard offer program.
- Price is based on value as provided by knowledgeable industry participants through competitive processes (i.e. RFPs).
- This price brings appropriate value to the end-use consumer who has to pay for the standard offer program.

3.1.5 Performance Incentive for Control of Output

The OPA has considered that an addition to the Base Price for performance can encourage renewable generators to schedule their output so that it is available at the time the system most needs it. The metering specifications in the DSC will allow for collection of data that can be used to determine a time-based payment for the standard offer generation. Time-based payments can be defined in several ways. The intention is to reward generation at peak times, but not to penalize those generators who cannot control their output shape. Recommendation 3.5 addresses this.

The amount of the incentive payment should be related to its value to the electricity system. Over the period since market opening, the average price during on-peak hours has been about 33-38% higher than the average price over the entire year. Transmission losses are expected to be highest during periods of peak demand and the incentive should be derived as a percentage of the Base Price plus the transmission credit. A premium of 35% of the total of the estimated successful marginal RES II RFP price plus the credit for the avoided transmission losses would reflect the value to the system of the shaped output. The incentive payment is therefore calculated at 3.52 cents per kWh.

Recommendation 3.5 ***The OPA recommends that generators under the standard offer program that are not intermittent and are able to demonstrate control of generation output receive an incentive payment of 3.52 cents per kWh for all output they produce in hours defined as on-peak for the purposes of the OEB's Regulated Price Plan.***

Rationale for the recommendation:

- This provides an incentive to those generators which can control the time of their output to focus it on those hours when it is most valuable to the electricity supply system, while not penalizing those who cannot.
- The OPA still receives a benefit when its contracted generation has a price lower than the spot market price.

3.1.6 Escalation

The OSEA Report and most stakeholders asked that at least part of the price be subject to escalation to compensate for future increases in costs. As already noted, for many renewable resources, most of the costs (which are capital costs) are fixed in monetary terms at the time the generation comes into service. This is the case for baseload or intermittent generators as well as for incremental capital costs required for generators that have the potential ability to shape their generation output to on-peak hours.

Some work has been done to quantify the approximate proportion of life-cycle costs for generators that are upfront capital related, and the proportion of costs that are on-going operations, maintenance and administration (OM&A) related. It is these latter costs that may be subject to future inflationary pressures and would be appropriate for escalation over time. Information from Government officials in Prince Edward Island and from other wind industry sources estimated that approximately 1.9 cents per kWh of a wind power development were attributable to ongoing OM&A costs.

The fraction of the price to be escalated can be fixed and related to the fraction of the total project cost that is likely to be subject to cost increases. For the highly capital-intensive renewable technologies, the only part of the costs that is subject to inflation is OM&A, including major capital refurbishments if necessary. As noted, these comprise about 1.9 cents per kWh or approximately 20% of the contract Base Price. This would support an escalation of the standard offer program Base Price at approximately 20% of the annual Ontario Consumer Price Index (CPI).

Recommendation 3.6 ***The OPA recommends that standard offer contract prices incorporate an escalation on 20% of the Base Price at the annual Ontario Consumer Price Index. Escalation will begin to apply after the first anniversary of the date of commercial operation.***

Rationale for the recommendation:
- Takes into account that renewable energy projects have a significant proportion of their cost as upfront capital costs.
- Provides developers with protection against inflation on the variable OM&A costs.

3.1.7 Solar Photovoltaic Production

At this point in time, solar PV is not technologically mature, and will not be as economic as other renewable energy sources. If the objective of the standard offer program is to obtain the most economic distribution-connected renewable projects in Ontario, then solar PV would not be successful under the standard offer pricing proposed. However, the Government's objective is to recognize the intrinsic value of solar PV, and use the standard offer program to support the growth and development of this technology, therefore an appropriate cost-based pricing model is considered.

In recommendation 3.3 above, the OPA has implicitly raised the issue of a different price for grid-connected solar PV. Stakeholders and the OSEA Report recognized that no pricing that was based either on representative cost for other technologies or on value would provide a price high enough to support solar PV. In the interests of promoting the technology, the OSEA Report recommended a much higher price for solar PV.

The necessary price for solar PV will be quite high – estimates range from 42 to 85 cents per kWh. The OSEA Report set it at five times the initial price for wind or other renewable resources. There is very little price discovery for solar PV in Ontario, however it is expected that system costs result in electricity prices at the high end of the range. One way to obtain more accurate information is to include solar PV in the standard offer program at a price that is estimated based on available information from the industry and other jurisdictions where standard offer contracts are available for solar PV projects. Prices from such a process are likely to be significantly higher than the prices to be paid to other renewable technologies. Selecting a price at the low end of the range will provide incentive to the early technology adopters but will not likely result in a proliferation of profitable projects for developers. The price discovery mechanism should be initiated with no escalation rate, since any variable costs associated with solar PV are likely to be negligible. This approach limits the impacts on ratepayers of such prices. The OPA will revisit this issue and adjust the Solar PV price as needed should actual results suggest the need to do so.

Recommendation 3.7 ***The OPA recommends that in order to undertake price discovery, solar PV should be included in the standard offer program, at an initial price of 42 cents per kilowatt hour with no escalation. The OPA will revisit this price, as well as the escalation stipulation, if price discovery reveals the need to do so.***

Rationale for the recommendation:

- Solar PV cannot compete at the same price as other renewable technologies.
- There is limited price discovery information about solar PV available for Ontario.
- Inclusion in the standard offer program addresses a Government policy objective.
- Recognizes the benefits that solar PV projects can bring to a distribution system, particularly in urban areas.

3.1.8 Tiered Pricing for Wind Generation

The OSEA Report, and several stakeholders, recommended that the prices received by wind generation vary according to the quality of the wind resource. Generators with the best wind resource would receive lower prices, to prevent them from making extraordinary profits. Generators with the poorest resources would receive the highest revenues, in order for them to earn a reasonable rate of return.

The OSEA proposal extends cost-based pricing to all wind generation. Like the other cost-based pricing proposals, it assumes that dispersing standard offer generation projects throughout the province is one of the objectives of the standard offer program. Like other cost-based pricing proposals, it would allow higher-cost projects to participate, with the extra costs paid by electricity consumers. These objectives however conflict with the OPA's responsibilities as discussed in Section 1.1.

Recommendation 3. 8 ***The OPA recommends that the price for all wind turbine generation be the same, regardless of wind regime, as set out in Recommendation 3.3.***

Rationale for the recommendation:

- It is simple to administer.
- Paying a uniform price does not encourage less economically-sustainable wind generation projects as part of the standard offer program

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3.1.9 Credit for Federal Incentives

Some renewable generation projects may be eligible for production incentives offered by the federal government for new generation from renewable resources. The current level of subsidy is a payment of 1.0 cent per kWh for the first ten years of operation of the generator. The OPA Discussion Paper raised the question of whether pricing for the standard offer program should take into account the potential revenue from federal incentive programs. The question is essentially whether any payments under the federal incentive programs are treated as additional revenues for the project or are used to reduce the amount that the buyer pays.

The OSEA Report suggested that the federal incentive payments should be used to reduce the payments that the OPA makes. Some stakeholders agreed that these payments should, in effect, belong to the party paying for the renewable generation; others felt that these payments are too uncertain, and the process of obtaining them too onerous, for them to be considered to belong to the buyer.

The availability of any federal or other government support (such as the Wind Power Production Incentive and Renewable Power Production Incentive) is uncertain, and the application process cost can be burdensome for small projects. As a result small projects cannot expect to benefit from these programs with a high degree of confidence. Therefore it is appropriate that any available incentive should be assigned to the OPA, on behalf of the Ontario ratepayers. The OPA would be in a better position to aggregate any credits and more efficiently pursue such credits on behalf of Ontario ratepayers.

Recommendation 3.9 ***The OPA recommends that any incentive payments available to standard offer projects from other government initiatives should accrue to the benefit of Ontario consumers through the OPA.***

Rationale for the recommendation:

- Provides greater certainty for developers by including the value of the credit into the price paid.
- Reduces the administrative burden for the small project developer.
- Access to payments from federal incentive programs has some cost and uncertainty. This provision makes it the responsibility of the OPA to pursue the value of any available credits.

3.1.10 Changing Prices over Time

Once a standard offer program participant has a contract, the prices and other terms contained in that contract cannot be changed except by mutual agreement, even if cost and other circumstances change.

However, as cost and market value conditions for renewable generation change over time, prices that worked well at one time may become too high or too low. After reviews of the standard offer program, the prices and other terms and conditions of the contracts might need to change in response to changing conditions. These changes would only affect new projects.

Stakeholders were very open to the idea that prices and other terms and conditions for new contracts might change over the course of the standard offer program, though they were all agreed that the changes should not affect contracts already in place. The OSEA Report placed the review and possible changes in the context of the five-year pilot program envisioned in that Report.

Recommendation 3.10 ***The OPA recommends that prices offered under new contracts in the standard offer program should be reviewed regularly and adjusted in response to changing market circumstances. The first review is intended to take place no earlier than two years after the start of the program.***

Rationale for this recommendation:

- Given planning and assessment lead times, potential developers will need assurance that prices offered will remain stable while they are preparing to obtain a contract.
- The OPA still needs the ability to monitor the prices and review the performance of the program, and to adjust the terms for future projects as necessary.

4. Standard Offer Program Terms and Conditions

4.1 *Tariff or Contract*

The OPA Discussion Paper raised the question of whether a reverse tariff, which would pay participants a guaranteed rate, would be preferable to a contract. Its main virtue is simplicity; its disadvantage is that proponents and financial institutions may be less likely to accept it as a basis for financing. Most stakeholders said that, given the uncertainty in Ontario's energy policy, they expected investors would be much more comfortable with a contract than with a commitment from the OPA to pay the agreed reverse tariff for the duration of the agreement. The OSEA Report assumed a contractual relationship.

Recommendation 4.1 ***The OPA recommends that the basic relationship for standard offer projects be established under a written contract between a supplier and a counterparty.***

Rationale for the recommendation:

- This is consistent with information from stakeholders and potential investors; a reverse tariff is perceived as more risky, and could present an unnecessary barrier to development of some projects.
- Other OPA procurement processes have resulted in a written contract between a supplier and counterparty.

4.2 *Administrative Counterparty*

The possible counterparties to the contract with the suppliers are the electricity distributor and the OPA. Most stakeholders, especially the distributors, said that they preferred the OPA as counterparty. However, some agreed that they would equally accept the distributors as counterparties if they were assured that the financial commitment was clearly backed by the OPA. Having the security of the OPA's superior credit rating would help secure financing and reduce the cost of that financing. The OPA believes, however, that distributors could be asked to act as an agent of the OPA for purposes of signing the contract.

The distributors must have a contractual relationship with the supplier in the form of a connection agreement. They also have relationships with customers and the ability to settle energy transactions with suppliers and customers. With the distributors as the signing agent, the standard offer contract could become a relatively simple two-part agreement: Part A as a connection agreement and Part B as the power purchase agreement. Part A would be signed by the distributor on its own behalf; for Part B, the distributor would be acting as agent for the OPA. This is similar to the structure for information requirements that the OEB suggests in conjunction with its Recommendation 5.2.

A disadvantage of having distributors as signing agents would be the wide disparity in the administrative capability of individual distributors. Allowing a distributor to assign the contract administration responsibility to another distributor or to a specialist company could help to alleviate this problem. The OPA should further explore opportunities for maximizing the efficient administration of the standard offer program.

Having a large number of standard offer projects embedded in a single distribution system could put an undue administrative cost burden on the distributor. The distributor's customers should not be required to bear these costs since customers across the province are expected to benefit from embedded renewable generation. Therefore, these costs should be considered part of the cost of the standard offer program and the distributors should be adequately compensated by the OPA for them.

The form of the contracts and the arrangements for the OPA to compensate distributors will be negotiated between the OPA and the OEB. In keeping with the guiding principle of simplicity, the OPA expects to arrive at a simplified form of standard offer program contract for each technology type which can easily be incorporated as part of the connection agreement with distributors. The OPA would also develop a master agreement to be entered into with each distributor that will spell out the responsibilities of each party and form the basis for the distributor's agency relationship with the OPA.

Recommendation 4.2 ***The OPA recommends that distributors be asked to act as agents for the OPA to manage the standard offer contracts and settle the related financial transactions. Distributors should have the ability to assign this function to another party.***

The OPA would provide funding to the distributor to cover costs incurred by distributors in conjunction with administering the standard offer program contracts. The OPA intends to work with the OEB and distributors to develop an agency agreement and determine a methodology to compensate distributors for their administrative costs.

Rationale for this recommendation:

- It is a simpler arrangement for the supplier.
- The distributor can best administer and settle the standard offer supplier transactions using the current settlement systems, as it does for other embedded suppliers.
- The distributor's customers should not have to bear the direct contract administration cost of embedded generation under the standard offer program because the program provides benefits to all customers in Ontario by using primarily environmentally benign technologies and reducing electricity losses across the transmission system. All customers across Ontario should therefore bear these costs equally.

4.3 Contract Term

The term of the contract should be long enough for the supplier to recover capital cost plus profit within the lifetime of the asset. Different generation assets have different lifetimes; for example, landfill gas resources may be exhausted by 15 years after the landfill closes. Most stakeholders suggested a 20-year term for the contracts.

The term could vary according to fuel type. In particular, hydroelectric projects typically have very long lives, often 100 years or more. The contract term could recognize this difference, but it is simpler to agree on a standard term.

Recommendation 4.3 ***The OPA recommends that the term for standard offer contracts be 20 years. Shorter terms should be considered based on technology constraints.***

Rationale for the recommendation:

- This term reflects an amortization period that is reasonable given the technologies eligible for the standard offer program.
- The term of the contract is critical to financing; twenty years is long enough for the supplier to recover the capital cost within the useful life of the project.
- This term does not obligate the OPA to longer than necessary funding commitments that may hinder the ability of these projects to move toward a competitive market.
- Some technologies, such as landfill gas, may not have sufficient fuel supply to deliver over a twenty year period.

4.4 Contract Prerequisites

Standard offer program participants need signed contracts before they can obtain financing and begin construction. The OPA can require the supplier to provide an indication of progress towards project implementation before the contract is signed.

Setting preconditions has several advantages. It helps to ensure that the proponents are serious about developing their project and that the conditions for project success are being met. It can help to prevent hoarding of contracts. It provides a better indication of the likely timetable for the project's completion. It reduces the need for contract security, which can be a financial burden for some projects. The preconditions can address some of the more likely stumbling blocks that can produce unwanted delays in project implementation.

The OPA Discussion Paper did not explicitly raise the possibility of setting rigorous preconditions for the award of contracts. In the discussions with stakeholders, however, many of them agreed that setting these preconditions would be reasonable and would help to ensure that the contracted projects are actually moving towards implementation.

Recommendation 4.4 ***The OPA recommends that, before a standard offer contract is awarded, the supplier must meet the following pre-conditions:***

- ***Demonstrated site control (e.g. ownership, long-term lease, or firm option);***
- ***Completed Connection Impact Assessment[16] with the distributor (to be further reviewed during implementation phase);***
- ***Evidence of local support (e.g. community ownership, or resolution or letter from local council);***
- ***Environmental assessment underway (as may be required);***
- ***Evidence of a commitment to fund the project by the lending institutions/investors; and***
- ***Demonstrated access to fuel sources, where appropriate.***

Rationale for the recommendation:

- This requirement balances simplicity with the need to bring power on line as soon as possible.
- This requirement reduces the chance that a proponent will hoard contracts.
- Achieving these steps ensures that the basic necessities of connection, fuel, and community support are present, making project completion more likely.
- Due diligence conducted by investors helps ensure project is viable and sustainable.

4.5 Project Schedule

Bringing a generation project into service requires coordinating schedules for multiple activities, including getting connection impact assessments, environmental assessments, local approvals, equipment purchases, and construction scheduling. All of these processes have some uncertainty around their duration, so suppliers need a reasonable length of time to complete their projects. Any timing requirements set by the OPA with respect to the contract should also harmonize with timing requirements set by the OEB with respect to the connection process.

The deadline for a project to be in service helps provide security for the buyer and prevent contract hoarding. The contract pre-conditions specified in Recommendation 4.4 would mitigate these concerns and would help ensure that projects have proceeded far enough that proponents can better estimate project timing. A firm deadline for the project prevents feeder capacity from being held indefinitely.

Participants in the stakeholder consultations agreed that a two-year deadline from contract signing to project in-service is reasonable. The OEB's Recommendation 5.9 has a one-year validity period from the Offer to Connect (which is issued after the connection impact assessment process and the detailed cost estimate process) to the execution of a connection agreement. The schedule should take that deadline into account. Recommendation 5.9 requires that a connection agreement be executed within one year of the issuing of an Offer to Connect. Because the connection agreement will require some engineering and other work, to specify the equipment details and other technical aspects of the proposed connection, the likely sequence would be that the proponent receives the Offer to Connect towards the end of its preparation for the contract. Once the supplier meets the connection and other preconditions,

[16] More information available from the Hydro One guide entitled: "Connecting New Generation to Hydro One's Electricity System"

it will get a standard offer contract, which it can then use as a basis for financing the engineering work leading to a connection agreement.

Most stakeholders, and the OSEA Report, agreed that a two-year period from contract signing to project in-service is reasonable, with possible exceptions for some projects. Projects most likely to need exceptions were small hydro and any project on Crown land, especially on First Nations reserves. To preserve simplicity in the schedule, and to allow greater margin for unavoidable delays, the OPA is recommending a three-year period.

Recommendation 4.5 ***The OPA recommends that the standard offer contract should require a project to be in service within three years from the contract execution date. A project whose in-service date misses that deadline will forfeit the contract right.***

Rationale for the recommendation:

- The contract preconditions require that some of the processes which can delay implementation will have been completed before the contract is offered.
- This schedule is consistent with the timing for the connection process, as proposed by the OEB.
- Project proponents should not be allowed to hold contracts indefinitely without implementing the project – this recommendation mitigates gaming activities.
- Provides sufficient time to complete project construction as indicated by stakeholders.
- Force majeure will mitigate against the risk of unforeseen events.

4.6 Security requirements

Security requirements protect the buyer from supplier default and can be used to prevent contract hoarding. The cost to the buyer of a default is the administrative cost related to management of the contract.. Failure to generate can also impact electricity supply in the province and the OPA's Integrated Power System Plan. These concerns are mitigated by the contract preconditions in Recommendation 4.4 and the schedule requirements in Recommendation 4.5.

The Minister's letter identified the requirement for a security deposit as one of the barriers the RFP process created for small embedded generation. Stakeholders generally did not think that security deposits were necessary. The loss of revenue incurred by a supplier which fails to perform was considered sufficient penalty.

Recommendation 4.6 ***The OPA recommends that project proponents not be required to provide security to the OPA.***

Rationale for the recommendation:

- The contract preconditions give assurance that the project has made some progress before signing the contract, and the project schedule gives some assurance that the project will continue to completion.
- Not requiring security simplifies the administrative process.

- Security deposits were identified as a barrier in the competitive processes.

4.7 Ownership of Emission Credits

Generation from renewable resources contracted under the standard offer program may be eligible for emission credits relating to greenhouse gas (GHG) or other emissions. The Canadian Government has indicated that there will be some (as yet undefined) mechanism by which electricity supplies which do not emit GHGs are eligible for emission offset credits which can be sold to emitters, who will have obligations to reduce GHG emissions. Owners of such renewable electricity supplies would have to establish the amount of thermal generation and therefore GHG emissions that they displace.

The value of the emission credits is unknown, but the proposed plan allows emitters to purchase as many offset credits as they need at $15 per tonne, at least until 2012. The upper limit to the emission credit value is therefore $15 per tonne until that date. There are many other uncertainties with respect to emission credits. These include the cost and difficulty of registering for and receiving the credits and the difficulty and cost of establishing the amount of GHG emissions avoided.

Credits accruing to participants in the standard offer program could remain with the supplier or could be transferred to the buyer. In the RES II contracts, the buyer, the OPA kept the rights to all environmental attributes including any emissions credits. If they remain with the buyer, suppliers would expect that the contract price should reflect this transfer in value. Given the standard offer program contract price is based on the market value of renewable electricity as underpinned by the RES II RFP prices, it would be appropriate to have these credits retained by the buyer as they are in the RES II RFP. The OPA will investigate whether to retire these credits or sell them for the benefit of electricity ratepayers of Ontario.

Recommendation 4.7 ***The OPA recommends that the buyer retain, for the benefit of Ontario consumers, the rights to any emissions credits generated through the standard offer program, , including credits for avoided emissions of GHGs or any other substance.***

Rationale for the recommendation:

- This approach is consistent with the RES II RFP, and the market price component of the standard offer program contract price is derived from the successful RES II RFP prices.
- The OPA retains the rights to the environmental attributes on behalf of the ratepayers of Ontario, and the OPA can review options for dealing with any credits as their value becomes more certain.

4.8 Force Majeure Events

Force majeure events are events that are beyond the control of a party. A force majeure event typically excuses non-performance by the defaulting party without any financial or other penalties against the defaulting party for as long as the event continues to prevent or delay performance.

Since, as indicated below in Recommendation 4.9, the OPA recommends having no default provisions in the contract, only force majeure events occurring during the three-year project development period would be relevant because they could lead to the consequence of loss of contract. The force majeure clause should therefore spell out conditions which would constitute a force majeure during that period. Stakeholders suggested that regulatory changes be included as events of force majeure.

Recommendation 4.8 ***The OPA recommends that force majeure provisions be included in the standard offer contract. These provisions will only apply to events that occur up to the in-service date.***

Rationale for the recommendation:

- Prior to in-service, the supplier can lose the standard offer contract if it is unable to put the project into service within three years of contract sign date - force majeure provisions are required to cover this period.
- After in-service, there is no additional financial penalty for non performance other than loss of revenue – standard offer contracts are not "take or pay", as indicated below in Recommendation 4.10, therefore force majeure provisions would not be helpful.

4.9 Default Provisions

Default provisions in supply contracts typically identify the rights of the buyer in the event that a supplier defaults on the contract. The primary provision in most contracts is the ability for the buyer to terminate the contract and demand an early termination penalty from the supplier. A default by the supplier can have consequences for the OPA. If the payments are front-loaded, a default removes the period of lower prices at the end of the contract period. The loss of supply could also impact the Integrated Power System Plan. However, given the small size of each project, the impact from any one default is not expected to be material. Several stakeholders agreed that the consequences of default to the supplier are simply the loss of expected revenue.

Recommendation 4.9 ***The OPA recommends that the standard offer contract have no provisions for penalties to the project developer in the event of supplier default, beyond the loss of revenue from the sale of electricity.***

Rationale for the recommendation:

- The supplier does not have a contractual obligation to provide power, so it cannot be held liable for such failure.
- The buyer has no material risk if the supplier does not perform.

4.10 Take or Pay Provisions

Under certain conditions, a distribution system may not be able to accept output from standard offer suppliers. The DSC gives distributors the right to take actions to maintain the security and reliability of their systems; these actions could include disconnecting the generator. These potential conditions can be part of the contractual arrangements between the generators and the distributors as contained in their connection agreement. Compensation for foregone production is not included in the DSC. The conditions causing the generators to be forced off are not within the purview of the OPA.

Recommendation 4.10 ***The OPA recommends that the standard offer contract have no provisions for take or pay arrangements for suppliers who are constrained off the distribution system in which they are embedded.***

Rationale for the recommendation:

- The conditions causing the constraint are not the responsibility of the OPA.
- Distributors are responsible for the safety and security of their distribution systems and have the right under the DSC to disconnect generators in emergency situations.

5. OEB RECOMMENDATIONS

5.1 *Obligation for non-discriminatory access*

Section 26 of the *Electricity Act, 1998* states that a distributor shall provide generators (and others) with non-discriminatory access to its distribution system in Ontario in accordance with its licence. With very few exceptions,[17] the licence issued to each distributor also requires it to provide generators (and others) with non-discriminatory access to its distribution system and to convey electricity on the generator's behalf. The distributor, therefore, does not have a legal ability to discriminate between standard offer generators and any other generator requesting connection to its system.

Section 6.2 of the Board's Distribution System Code (DSC) sets out a distributor's responsibilities to generators. It requires the distributor to make "all reasonable efforts...to promptly connect" a generation facility to its distribution system. It does not give the distributor grounds for refusing to connect a generator provided that the generator requests connection and all relevant requirements are met.

5.2 *Licensing*

5.2.1 Application

In its Staff Discussion Paper, the Board requested comments on its generation licensing process and on associated fees. Among the issues raised were whether the licensing process or requirements are too onerous; whether coordination of the licensing process with associated OPA and distributor processes would be helpful; and whether the fees associated with licensing are an economic barrier for smaller generators.

Based on the comments received from stakeholders, it is evident that the Board's licensing processes and the requirements that it imposes in relation to connections are not well understood. For example, certain stakeholders appeared to be unaware of the Board's performance metrics for the processing of licensing applications or of the fact that the Board's website has a page where active applications can be tracked. Because all standard offer generators will require a generation licence and need to be aware of connection requirements imposed by the Board, it is important that an understanding of these matters be facilitated as much as possible.

It is clear from the comments received that the Board needs to make information regarding its processes more easily and readily available. Generators need easily understandable information about applicable Board requirements.

[17] Where the distributor is exempt by regulation from the obligation to provide non-discriminatory access.

Recommendation 5.1 ***The Board intends to develop a web-page for distributed generation giving plain language descriptions of the Board's requirements regarding licensing and other matters, with links to the appropriate documents (such as legislation, codes, and forms). The web-page will also include a high level description of the authority of other entities (distributors and the OPA) and of the need for the generator to meet the requirements of those other entities.***

Comments received from stakeholders in relation to the coordination of applications reveal that most would consider some degree of coordination between the OPA, the OEB and distributors to be helpful. Some stakeholders indicated a desire for the centralized administration of these processes, while others identified areas where the three entities could share information or eliminate duplication. The sharing of confidential information was not seen as a barrier in this regard.

The Board does not believe that centralization of the processes is necessary. Each of the OEB, the OPA and distributors has its own internal requirements and no one entity should be reliant on another for satisfying those requirements (including as to timeliness). However, the Board does see considerable merit in working with the OPA and distributors to develop a common multi-part form using consistent nomenclature, parts of which could then be sent by the generator to each entity. For example, the multi-part form could consist of:

- Part A – Common Project and Applicant Information
- Part B – Information to OEB for Application for Electricity Generation Licence
- Part C – Information to Distributor for Request to Connect to the Distribution System
- Part D – Information to OPA for Standard Offer Contract

Recommendation 5.2 ***The Board intends to work with the OPA and distributors to develop a common element for "tombstone" information requirements.***

The OPA agrees that there should be a simplified, multi-part contract to implement the standard offer program. Chapter 4 of this Report has further discussion and recommendations.

A number of stakeholders suggested that the Board's licence application process could be simplified by eliminating the request for certain financial and personal information. In developing applications for electricity generator licences, the Board was concerned with the financial viability and integrity of the applicant and with the energy industry experience of the key individuals involved.

The Board is interested in requesting only information that is relevant to the decision it is being asked to make in any given case. The Board recognizes that the nature of the information requested for generator licensing purposes may need to be updated in light of recent changes to, among others, the electricity marketplace and the development of new initiatives.

Recommendation 5.3 ***The Board intends to review its Application for Electricity Generator Licence with a view to removing what may have become extraneous information requirements and developing consistent nomenclature with the OPA and distributors.***

At the present time, the application fee for a generation licence is $800.00. In addition, the Board currently has an annual registration fee of $800.00 for licence holders. In a November 11, 2005 letter to licensees, the Board decided to exempt generators of less than 0.5 MW in capacity from the fee for the 2005-2006 fiscal year based on their submissions of financial hardship.

Application and annual registration fees were identified by stakeholders as barriers for smaller projects, although comments tended to focus more on the registration fees than on the application fees.

The Board's licence application fee is designed to recover a portion of the costs involved in processing licence applications. The Board believes that it is appropriate for all licence applicants, regardless of size, to make a contribution towards the cost of processing their licence applications.

The annual registration fee serves two purposes: (1) to provide incentive for efficient use of the Board's services by licensees not charged under the General Cost Assessment, and (2) to confirm that licensees with multi-year licences are active and operating. The annual registration fee forms part of the Board's Cost Assessment Model, which is intended to allocate the costs of regulation among licensees. The Board intends to re-examine the assessment of the annual registration fees on smaller generators. While the Board's costs in regulating generators that are part of the standard offer program are not known at this time, there is potential for reduced fees consistent with the level of oversight provided.

Recommendation 5.4 ***The Board intends to re-examine fees for smaller generators.***

5.2.2 Reporting and Record Keeping Requirements

At the present time, generators that have a capacity of less than 25 MW and that are not market participants are exempt from regular reporting under the Board's Reporting and Record Keeping Requirements (RRR). Most stakeholders acknowledged that generators that are part of the standard offer program would likely fall within the scope of this exemption and that therefore annual RRR reporting was not likely to be required. Therefore, no action is required in this regard.

The Board does consider it desirable to monitor how distributors are handling connection assessment requests from potential participants in the standard offer program. This will allow the Board to be more responsive to the need for further regulatory action should the need arise.

Recommendation 5.5 ***The Board intends to propose amendments to its Reporting and Record Keeping Requirements to require distributors to keep records of information on requests by generators for connection assessments, including the time taken for each step as defined in the DSC and the costs charged to the generator.***

5.3 Connection

5.3.1 Process

The DSC sets out the minimum conditions that an electricity distributor must meet in carrying out its obligations. It also sets out the requirements for connecting generators to distribution systems. All licensed electricity distributors in the province must comply with the provisions of the DSC as a condition of licence.

Appendix F of the DSC includes provisions to allow for standardization, consistency and clarity with regards to procedures and requirements for facilitating connection of new generation facilities to distribution systems. These provisions were developed largely through amendments to the DSC that were introduced in December, 2003 and that:

- defined four generation categories by size (see Table 1 below);
- prescribed connection processes and the related time frames for connection to distribution systems for each size category;
- standardized, to the extent possible, technical requirements, including system operations, reliability, power quality, safety and measurement issues as well as introducing broader standardization of similar technical requirements involving federal and other Ontario standards; and
- included a standard form contract for micro-embedded load displacement generation.

The four size categories were developed by a working group including distributors, generators and Board staff. The different size categories stem from the technical impacts of each category on the distribution system. To facilitate connection of generation to distribution systems, the DSC allows flexibility to shift a project from a larger size category process requirement to a smaller one. This helps a generator, upon mutual agreement with the distributor, to follow a process that is shorter and with fewer requirements.

Table 1: Embedded Generation Size Categories for Which the DSC Prescribes Connection Processes		
Size	Name-Plate Rating	Distribution kV
Micro-	10 kW or less	n/a
Small a) b)	 500 kW or less and more than 10 kW 1 MW or less and more than 10 kW	 Less than 15 kV 15 kV or greater
Mid-sized a) b)	 Less than 10 MW and more than 500kW Less than 10 MW and more than 1 MW	 Less than 15 kV 15 kV or greater
Large	10 MW or greater	n/a

There is an expedited connection process for the micro category (10 kW or less for own use). As this size of generation is mainly renewable or alternative in nature, the micro-sized connection process is geared to promote the addition of new generation which predominantly utilizes cleaner energy sources, including alternative and renewable energy sources. The connection agreement for micro-generation is a one-page, standard form.

The connection process for embedded generation outlines standardized processes for connection. This includes setting time lines, filing and technical requirements and obligations on distributors in reviewing applications. For example, a distributor may be obligated to complete its activities to connect micro-sized generation within a total of 20 days of receiving a generator's application to connect.

Stakeholder feedback on the standard offer program indicates that distributors generally favour the DSC requirements as they pertain to connection processes. While some generators tend to the view that distributors are using those processes to impose barriers to connection, those familiar with it were generally supportive of the DSC connection process.

A number of individual elements relating to the connection process were highlighted in the Staff Discussion Paper and in comments received by the Board on that Paper. These are dealt with separately below.

5.3.2 System Information

In its Staff Discussion Paper, the Board raised the issue of disclosure of distribution system information to potential generators. It noted the tradeoffs between the cost to the distributor of providing and updating information and the need for potential generators to have adequate information to enable them to evaluate potential points of connection.

Comments received from stakeholders reveal that distributors are concerned that information publishing requirements may be too onerous, could leave the system open to sabotage and may reveal sensitive commercial data on large consumers. Most generators did not comment on the need for generally available information. This may reflect the fact that many potential standard offer generators have little discretion over siting. Wind farms have some ability to choose a site within favourable wind areas. Anaerobic digesters, small hydro, and other generators locate at the fuel source and have little or no choice for siting.

The DSC already contains provisions that require distributors to make information available to generators on request. There is, however, the potential for considerable variation across distributors in terms of the quality of the information and the timeliness with which it is provided. The Board believes that it is reasonable to require distributors to make certain key information available to allow generators who have some discretion on siting to compare sites between distribution service areas and within a given service area. In the Board's view, the information proposed to be made available is not such as to give rise to increased risks of sabotage or to require the disclosure of confidential consumer information. This approach should benefit distributors as well, since the alternative would be to field many individual inquiries from generators for essentially the same information.

In terms of costs, some of the information should be made available free of charge while other information can be provided conditional on payment of a reasonable fee. The distributor would be permitted to recover reasonable costs for providing hardcopy information and providing information on more than 3 connection points.

Recommendation 5.6 ***The Board intends to propose amendments to the DSC to require each distributor to make the following information, updated annually, readily available:***

- ***a contact for distributed generation inquiries (name, telephone number and e-mail address); and***
- ***a description of the distributor's system with an up-to-date system schematic map showing:***
  - ***major distribution and sub-transmission lines;***
  - ***transformer and distribution stations, noting what voltages are used for distribution in different parts of the system; and***
  - ***sufficient geographic references to enable a generator to correlate circuits with a municipal road map.***

The Board sees benefit to having this information publicly available by posting it on the distributor's web-site, having it available at the distributor's public offices and making it available through a request to the distributor's customer service center or representative.

Many distributors will get relatively few requests for connection under the standard offer program. The Board therefore does not believe that increasing the level of information that is required to be updated and made publicly available beyond the level referred to in the above Recommendation is warranted at this time. Those distributors that expect to see a significant number of requests for connection, such as those whose service areas include good wind areas (such as Hydro One Networks Inc.), may choose to exceed the minimum information disclosure requirements referred to above to avoid being inundated with multiple individual requests for the same information.

As the information referred to in Recommendation 5.6 will not be enough information for a generator to make a preliminary connection assessment, the Board is also proposing that distributors be required to provide certain specified additional information to generators that embark on the connection process. Under Appendix F of the DSC, step 1 of the connection process is for the generator to request information from, among others, the distributor. Step 2 is for the distributor to provide information, described as the "Information Package" in Appendix F, within a specified timeline. Certain key information necessary for a generator to make a preliminary connection assessment should be provided as part of the "Information Package".

Recommendation 5.7 ***The Board intends to propose amendments to the DSC to require each distributor to provide voltage levels, fault levels and minimum/maximum feeder load (subject to confidentiality concerns) for up to 3 locations free of charge. The information would be provided as part of the Information Package required by the DSC within the 15 days already allotted to respond to the request for information. Additional requests from the same generator would be supplied at reasonable cost within the same timeline.***

5.3.3 Technical Standards

The DSC also defines the technical requirements to be met to connect generators to distribution systems. The technical requirements address system operations, reliability, power quality, safety and measurement issues. To benefit from existing industry knowledge and experience, the DSC has references to other existing codes and standards, where applicable. This approach allows for faster and less costly generation connections to a distribution system. As well, it introduces broader standardization of similar technical requirements involving federal and other Ontario standards.

There is no single recognized standard for connection design. Most generators feel that explicit technical standards will remove many of the points of contention between distributors and generators. Many want the OEB to oversee development of specific, Ontario standards. Others point to emerging CSA standards. Distributors, for their part, want to maintain the flexibility to specify their own standards to account for individual regional requirements.

Appendix F of the DSC sets technical requirements for connection of embedded generation, since there were no recognized standards when the DSC was amended in 2003. The Board has, in the past, undertaken standards development through industry task forces where no standard exists (a good example is the development of Electronic Business Transaction standards). However, it is neither feasible nor desirable for the Board to act as a standards body in areas where work by other recognized consensus-based agencies is progressing.

The Board sees value in converging distribution practice on national and international standards where available. Specific technical requirements aid design and application. Recognized and authoritative standards allow equipment manufacturers to design to universal requirements, thereby reducing costs.

Recommendation 5.8 ***The Board intends , as part of the DSC amendment process referred to above, to review the technical requirements in the DSC against changes in standards since 2003 and to propose updates to those requirements to reflect those changes as required. The Board intends to continue to monitor development of IEEE and CSA standards for future application to generator connections.***

5.3.4 Queuing

Under the DSC, distributors in most cases have up to 90 days to make an Offer to Connect after receipt of payment from a generator for a detailed estimate. The DSC does not state how long an Offer to Connect must be valid, nor how an outstanding Offer to Connect will affect subsequent requests to connect. In its earlier work on connections, the Board had identified the development of a queuing process as a next step. The Board recognizes that, in the context of the standard offer program, the issue of queuing is closely linked to the standard offer terms and conditions being articulated by the OPA.

In their comments on the Staff Discussion Paper, most stakeholders agreed with a basic first-come/first-served queuing process. Many also indicated that Offers to Connect, which occur at the completion of the connection assessment process, should be good for at least 12 months. This would mean that the generator has 12 months from the date of the Offer to complete a connection design, have it reviewed by the distributor and sign a connection agreement. Construction could then begin. Some stakeholders suggested that projects should be required to meet pre-determined milestones in order to maintain their place in the queue. There were suggestions for specific situations that would need more time than others (e.g., projects over crown lands).

The Board believes that, at least initially, a first-come/first-served queuing process should be adequate, and benefits from simplicity of administration for distributors. As experience with the standard offer program progresses, and where necessitated by the volume of prospective standard offer participants, a more complex queuing process may need to be considered. The Board would, in that case, look to the experience of the Independent Electricity System Operator and in other jurisdictions with a view to developing a more elaborate queuing mechanism.

The Board favours a time-based approach rather than an approach based on completion of project milestones such as "construction begun" or specific permits received. In the case of generator connections to a distribution system, the only milestone of substance from the perspective of a distributor is the satisfaction of the requirements of the Electrical Safety Authority for energization. Some projects may face more regulatory requirements than others (e.g., projects involving aboriginal lands owing to the need to obtain federal approvals, or projects involving hydro technology owing to the need for water use permits and environmental assessment data requirements), making "one size fits all" project milestones difficult to identify. Monitoring the completion of project milestones for queuing purposes would, in the Board's view, be an onerous requirement for many distributors, who should not be responsible for keeping a generator's project on track.

Recommendation 5.9 ***The Board intends to propose, as part of the DSC amendment process referred to above, a first-come/first-served queuing process with specific time deadlines, and a requirement that an Offer to Connect remain valid only for twelve months. The DSC should specify that, if a connection agreement is not signed with the distributor within those twelve months, the Offer to Connect expires.***

5.3.5 Dispute Resolution

Under the DSC, distributors are required to include a dispute resolution process as part of their publicly available Conditions of Service. In accordance with their licences, distributors must ensure that their dispute resolution processes deal with disputes in a fair, reasonable and timely manner.

The process used by most distributors is to try to resolve the complaint through internal investigation and follow-up with internal escalation as required. Unresolved complaints are referred to the Board. None of the larger distributors refer complaints to third parties.

A number of stakeholders indicated that there has not been sufficient experience in terms of disputes with distributors to enable them to ascertain the adequacy of the existing dispute resolution process. A number of stakeholders agreed that third party dispute resolution would be valuable. They did not usually specify the third party. It was noted that smaller generators in particular will not have the resources to engage in formal, protracted dispute resolution processes. Some suggested that the Board oversee dispute resolution if the process can be streamlined and economical.

It is noted that disputes can arise either before or after a connection agreement is signed. With respect to disputes arising before a connection agreement is signed, existing rules stipulate that those disputes are to be resolved through the distributor's dispute resolution process as described in its Conditions of Service. In many cases, these disputes will involve questions of compliance by the distributor with its regulatory obligations. Where that is the case, the matter can be referred to the Board's compliance office for review. It has been the Board's experience to date that most complaints referred to the compliance office are resolved on a timely basis. For the time being, the Board believes that this approach remains adequate. The Board will monitor this matter as experience with implementation of the standard offer program progresses. In the event that pre-contract disputes relating to generator connections become a significant issue, the Board will consider mandating that an independent third party dispute resolution process be put into place by distributors. This process is currently contemplated in each distributor's licence, where it is stated that as of a date determined by the Board the distributor must "subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board".

Where a dispute arises after a connection agreement has been signed, the dispute is a contractual matter. The Board believes that it is appropriate to include third party dispute resolution as a term of the standard form contract that the Board recommends be developed (see section 5.3.6), as it has done in the standard form connection agreement that forms part of the Transmission System Code.

Recommendation 5.10 ***The Board intends to monitor disputes arising between generators and distributors prior to the signing of a connection agreement to ensure that they are not a significant problem for generators. The Board intends to include, on the distributed generation web-page referred to in Recommendation 5.1, a link to information on the Board's compliance process. The Board intends to include a dispute resolution process in the standard connection agreements referred to in Recommendation 5.11.***

5.3.6 Agreements

At the present time, the DSC includes a standard form contract only for micro-embedded load displacement generation, although it does contemplate the possibility that others could be included at a later date.

The Staff Discussion Paper included a list of elements that could be included in a contract with a standard offer program participant. Many stakeholders agreed with that list, although a common theme was that any contract should be as short as possible and be in plain, easy to understand language.

The Board believes that development of a mandatory standard form connection agreement is desirable and should exist for all sizes of generator eligible for the standard offer program.

Standard form agreements are necessary so that parties know what is common and expected. If the terms of connection agreements are not mandatory, there is a risk that they will not be used, in whole or in part. The existence of standard form agreements also eliminates potentially lengthy contract negotiations that can act as a barrier to implementation of generation projects and provides consistency of treatment across all distributors. The standard form agreements should be modular so that provisions or schedules that are not applicable to a particular project need not be included but are available for use when appropriate. The Board will consider available and relevant precedents in developing the standard form agreements, including a simplified form of the connection agreement that forms part of the Transmission System Code.

Recommendation 5.11 ***The Board intends to develop modular, mandatory standard-form connection agreements for small and mid-sized generator, to be proposed as part of the DSC amendment process referred to above.***

5.3.7 Meters

The current metering standard under the DSC is to require a four-quadrant interval meter for all licensed generators.

From their comments, it appears that most stakeholders accept this requirement. Those who object feel that it is more than is required by the situation.

It is observed that the cost of a four-quadrant interval meter is comparable to the alternative of two interval meters (to measure flow in each direction). Interval meters are necessary in case the standard offer program offers time-differentiated prices, now or in the future, or if the generator ever intends to settle at market prices. The net metering standard is two three-phase meters, and will remain the same until Measurement Canada has approved a single net meter.

Recommendation 5.12 ***The Board does not propose to change the DSC metering standard that requires a four-quadrant interval meter for all licensed generators.***

5.4 Rates and Costs

5.4.1 Costs Associated with Connection

The costs of connecting a generator to a distribution system are usually differentiated as shallow charges that are directly or solely applicable to the customer, or as deep charges that are reinforcements to the larger system beyond the connection point. Under the DSC, a generator is required to pay all costs (whether shallow or deep) associated with its connection, although there is provision for a refund of system reinforcement costs where a subsequent generator connection obtains the benefit of reinforcements paid for by the earlier generator.

Generators argue that deep costs should be socialized, usually on a provincial basis, because the benefits accrue to all system users in a way that is difficult to fully allocate. Some stakeholders suggested specific mechanisms for shared costs such as a standard price limit over which the generator is required to pay costs. This would be analogous to load connections where a basic connection is provided free of charge.

The current model of distribution rates, like the distribution systems themselves, was developed when the purpose of the system was to bring remote, transmission-connected generation to dispersed loads. Distributors invested in infrastructure on behalf of the customers that they served and customers were charged fixed and variable rates to cover the distributor's revenue requirement that included operating costs and a return on that investment. Distributed generation, since it was relatively rare, paid full connection costs, paid for any energy drawn from the system in the same manner as a load customer and did not pay for use of the system to inject energy. As the connections were funded by capital contributions from customers, the distributor did not include the assets in rate base and did not make a return on these assets. The increase in distributed generation is one of many drivers putting pressure on this model of distribution rates.

The rate structure (customer groupings, one-time charges, fixed and variable tariffs) must recover the costs of distribution in a way that simply and fairly recovers costs for use of the system and properly motivates growth of the system for both generation and load. In 2006, the Board will begin a comprehensive review of rate design models for Ontario distributors.

Economic siting of generation is one issue for design of the rate model. One option is to make the generation model similar to the load model: put into rate base more costs of connection while requiring generators to pay more use-of-system charges. Another option is to allow distributors to pay for and add to rate base reinforcement costs when the generation connection that triggered the reinforcement is an alternative to network investment. An example is a project to reinforce a line that delays the need for a more expensive transformer station. These are illustrative of approaches that could be taken, and others may well be identified and examined by the Board in its rate redesign review.

The Board has undertaken significant work in terms of setting the regulatory framework for revenue requirement and is in the midst of an exercise to review cost allocations. The Board has already made many adjustments to the levels of distribution rates to accommodate rates of return, rate harmonization of amalgamated utilities and recovery of extraordinary costs (regulatory assets) and new ongoing costs.

The benefit in a proactive approach to rate restructuring is that the Board can take a thoughtful and measured approach to the issues and get information from Board-engaged consultants and stakeholders. It is not expected that the Board's distribution rate design project will be finished within the timelines expected for implementation of the standard offer program.

In the meantime, the Board does not propose to make significant changes to the DSC regarding connection costs. Until there is a rational replacement balancing investment and charges for use of the system, the current mechanism allows proponents to prioritize projects with the lowest connection costs and therefore the highest cost/benefit. The Board is concerned that removing the obligation on generators to pay all connection costs will result in uneconomic projects going forward. If costs are socialized, the generator has no incentive to look for economic siting or connection. Also, the distributor who recovers costs in rates has no incentive to design economic connections. The ratepayer is at risk for projects of questionable economic value. As well, the distributor has no basis for applying different policies for connection costs to standard offer program generators than to others. Under the principle of non-discriminatory access, the same rules must apply to all generation.

While the Board believes that there is value in reviewing the question of the appropriate allocation of connection costs, this should be done on a more global basis for all generators and should not be limited to considerations particular to the standard offer program. The Board's upcoming rate design review is the more appropriate forum for consideration of this issue.

Recommendation 5.13 ***The Board intends to consider the issue of the allocation of connection costs in relation to all generators, including those that may be eligible for the standard offer program, as part of its broader examination of electricity distribution rate design to commence in early 2006.***

5.4.2 Standby Charges

Under the existing distribution rate structure, many load customers with load displacement generation behind the meter currently pay standby charges to compensate the distributor for the ability to accommodate, at any time, the customer's total load. At the present time, 16 Ontario distributors have standby charges, billed on the basis of a variety of determinants.

Distributors that have standby charges generally defended them as representative of costs. Generators often felt that standby rates would cause many projects to be uneconomic.

It is likely that few standard offer participants will be load displacement generators. There may be some co-generation. Farm anaerobic digesters may be behind the existing meter.

The issue of standby charges is before the Board in the context of the 2006 electricity distribution rate proceeding, where the Board concluded that standby charges should be determined on a case-by-case basis through a distributor-specific analysis (and in some instances on a case-specific analysis). The Board remains of the view that the 2006 electricity distribution rates applications are an appropriate forum in which to address specific standby charges. The larger issue of treatment of load displacement generation will be examined as part of the Board's distribution rate design project referred to in the previous section.

Recommendation 5.14 ***Standby rates, including those that apply in relation to standard offer program participants, will be addressed on a case-by-case basis in the context of each applicable distributor's 2006 distribution rates application.***

5.4.3 Limit on Distributed Generation Capacity

Although not raised as an issue in the Staff Discussion Paper, a number of generators agreed in their comments to the concept of imposing limits on the number of standard offer projects per distribution service area or per transformer station.

Although not raised as an issue in the Staff Discussion Paper, a number of generators agreed in their comments to the concept of imposing limits on the number of standard offer projects per distribution service area or per transformer station.

Appendix L of the <u>Renewables II RFP</u> noted that certain transmission lines have capacity constraints. There would be difficulties in managing the system if flow out of the adjacent distribution system were to exceed these limits. The DSC connection process makes provision for adjacent transmitters or distributors to be given advance notice of the proposed connection of small, mid-sized and large embedded generators. This allows the notified transmitter or distributor to make its own assessment. This process should allow projects to be managed as they approach transmission capacity constraints.

The amount of distributed generation that can be accommodated is limited by physical system constraints of the distribution and transmission systems. Amounts beyond a system's limitations will likely be uneconomic to connect.

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The standard offer program will not be primarily load displacement. As such, there should not be much effect on distributor revenues. The electricity produced will be delivered to load within the distributor's system.

Therefore, in relation to matters falling within the Board's sphere of authority, at this time there appears to be no reason to impose a cap on the total amount of distributed generation capacity that can be accommodated within a given service area or to a given transformer station.

Recommendation 5.15 ***The Board does not recommend specifying a limit on distributed generation capacity within a given distributor's service area or to a given transformer station.***

6. IMPLEMENTATION PLAN

The following is a high-level outline of an implementation plan for the standard offer program. More detailed implementation planning is one of the first steps of the implementation plan itself.

6.1 Schedule

The expectation is that the standard offer program will be ready for initial implementation by the fall of 2006. The timetable assumes that the Minister of Energy approves the joint Report, amended as necessary, in early 2006.

One activity that has a minimum time for completion is the proposed change to OEB codes, which requires a statutory notice and comment process. The other required implementation processes, including proposed working groups, can take place in parallel with the Board's code amendment process. The communications and other preparatory steps can be started shortly thereafter.

6.2 Coordination and Cooperation between OEB and OPA

Implementation will be the responsibility of two agencies, the OEB and the OPA. Each will function within their own defined areas of responsibility, as indicated by the Minister's letter and the areas addressed in this Report. There are also interdependencies between the implementation work to be performed by the OEB and that to be performed by the OPA. Some of the issues are linked to one another, and the timing of one agency's work may depend on the timing of the work of the other. Therefore, coordination and cooperation between the OEB and the OPA will be required in relation to implementation processes, including scheduling and issues management.

Inter-agency coordination could be best handled by a high-level inter-agency Coordinating Committee to which a number of working groups would report. The Coordinating Committee would only be responsible for issues which affect both agencies; the management of each agency would be responsible for implementation of its own tasks.

The primary function of the Coordinating Committee, therefore, will be to oversee the work of the multi-party working groups which will be formed to address these implementation issues. The working groups will consist of representation from the two agencies and stakeholder groups as required. For example, a working group addressing issues related to the standard offer contract could include representatives from the OPA, the OEB, the distributors, and generators. Also, both the OEB and the OPA have agreed that they will work together to develop a multi-part contract. This process is likely to include stakeholders. Other working groups will be struck as necessary, under the direction of the Coordinating Committee. Membership will be determined for each working group, as appropriate for its assigned tasks.

6.3 Tasks

The first task for both agencies is to develop and agree on a more detailed implementation plan. Such a plan would confirm a schedule and include an initial outline of the number, membership and mandate of the working groups.

The primary tasks for the Ontario Energy Board include:

- Participating in the Coordinating Committee, including finalizing implementation plans,
- Drafting proposed amendments to applicable regulatory instruments,
- Approving processes for the amendments,
- Undertaking applicable amendment processes,
- Establishing the distributed generation web page,
- Participating in working groups, as required,
- Ensuring that certain standard offer issues are referred to other relevant OEB processes, and
- Communicating with the distributors.

The primary tasks for the OPA include:

- Participating in the Coordinating Committee, including finalizing implementation plans,
- Finalizing standard offer terms and conditions, including all details of the eligibility rules, pricing, and contract terms and conditions,
- Developing contracts,
- Participating in working groups, as required, and
- Developing and implementing a communication strategy.
- Establishing a clearinghouse of renewable energy information