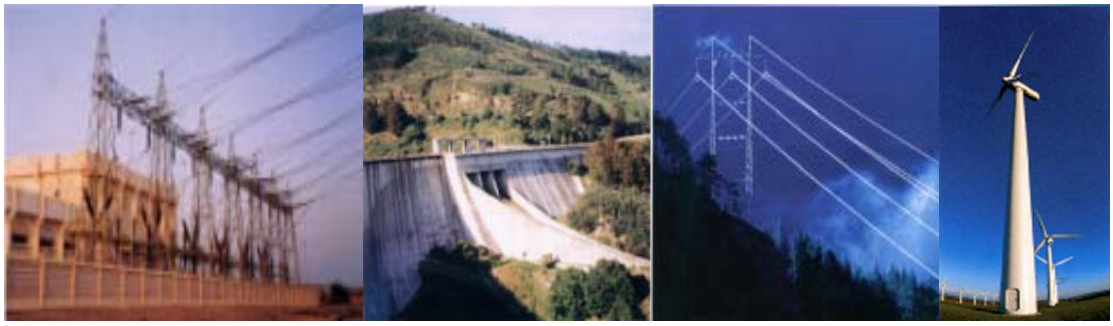
Ontario Country Report



Innovative Electricity Markets to Incorporate Variable Production

to

IEA – Renewable Energy Technology Deployment

May 2008

IPA Energy + Water Consulting

COWI A/S

SGA Energy

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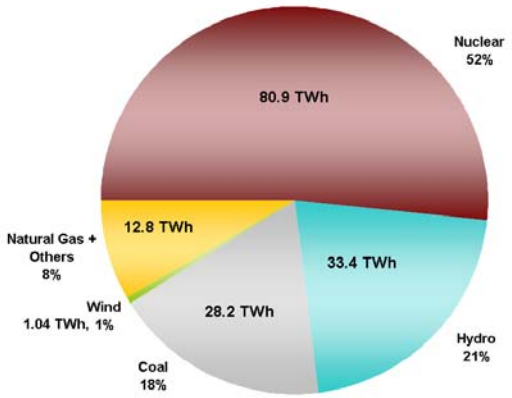
1 MARKET MECHANISMS

This section provides an overview of the operation of variable renewable generation within the Ontario market.

1.1 Renewable Generation Capacity

Ontario currently has over 31 GW of capacity on its system. In 2007 generation was made up of a combination of nuclear, fossil fuel, and hydro as well as a minor amount of other renewable energy as shown in the figure below.

Chart 1: Ontario generation mix for 2007



Source: IESO Press Release, 10 Jan 2008.

- **Nuclear Energy**

  In 2007, nuclear plants accounted for 52% of Ontario's electricity production. There are three nuclear power plants in Ontario: Pickering Generating Station, Darlington Generating Station and Bruce Power. All Ontario's Nuclear Power Generating Stations are publicly owned. The Ontario government is the sole shareholder for Ontario Power Generation which owns all of the nuclear power plants in Ontario. Bruce Power, a privately owned company, is licensed to operate the Bruce nuclear plants under a lease agreement with Ontario Power Generation.

- **Hydroelectric Energy**

  In 2007, hydroelectric generation accounted for 21 per cent of Ontario's generating mix. There are currently about 190 hydroelectric stations (of which 68 are connected to the transmission grid) in Ontario, the size and power of which vary considerably. The smallest stations produce less than one megawatt of power, while Ontario's largest, Niagara Falls' Sir Adam Beck 2 Generating Station, produces almost 1,500 megawatts of electricity.

- **Fossil Energy Generation**
  - ***Coal***

    Ontario currently has four coal-fired fuel stations: Nanticoke, Lambton, Thunder Bay, and Atikokan. In 2007, they accounted for 18% of Ontario's production.

    The government has directed the Ontario Power Authority to plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electricity system reliability in Ontario. Currently this date has been set as 2014.

  - ***Natural Gas and Oil***

    Natural gas and oil accounted for 8% of Ontario's generation in 2007. There are currently about 60 natural gas stations of varying sizes, of which 21 are connected to the grid.

- **Renewable Energy Sources (excluding large hydro)**

  In 2004, the Ministry of Energy set a target for the province to produce five per cent (1,350 megawatts) of its electricity from renewable sources by 2007 and 10 per cent (2,700 megawatts) by 2010.

  In April 2004, the government began initiating a series of renewable energy Requests for Proposals (RFPs). By the end of 2005, the OPA had contracted for over 1,300 megawatts of renewable energy from land-based wind, water, landfill gas and biogas projects. The vast majority of these are wind.

  Current renewable energy projects approved under 2 RFP processes since 2004 include 12 wind projects, 3 hydro projects, 2 landfill gas projects and one biogas project. Of these, only the wind projects and one small run-of-river hydro station would be considered to be "variable generation" sources. Hydro projects incorporate enough storage in the main to at least predict generation on a day-ahead basis and the biomass projects can be regulated to predict generation.

  Of the 12 wind systems 471 MW are now operational (2007) and 865 MW are at various stages of completion.

1.2 Institutions

The restructuring of Ontario's electricity sector in the mid-to-late 1990s saw the elimination of Ontario Hydro, the integrated power system planning and operation function, that had played a central role in the development and management of Ontario's power system from 1906 to 1998 and a move to a market based approach to generating and distributing electricity. To deliver electricity within the Ontario market there are now at least a number of main actors.

- **Ministry of Energy (MOE)**

  The Ministry of Energy is the public, government agency with ultimate responsibility for the electricity system. The Ministry of Energy's responsibility is to ensure that Ontario's electricity system functions at the highest level of reliability and productivity. It is also focused on promoting ingenuity and innovation in the energy sector.

- **Ontario Energy Board (OEB)**

  An independent adjudicative tribunal responsible for regulating Ontario's natural gas and electricity sectors. Part of the OEB's mandate is to protect the interests of consumers with respect to prices and the reliability and quality of electricity service.

- **Ontario Power Authority (OPA)**

  The OPA is responsible for ensuring an adequate, long-term supply of electricity in Ontario, which is critical to the province's continued growth and prosperity. It is responsible for the planning of the system, the issuance of RFPs, and approvals, as well as contract management to ensure adequate generation and transmission capability. This process also assists in furthering government policy by for instance tendering renewable energy generation or demand management projects.

- **Independent Electricity System Operator (IESO)**

  The Independent Electricity System Operator (IESO) is the hub of the electricity wholesale marketplace, connecting all participants - from the generators and suppliers who sell electricity to wholesale consumers. Its responsibilities include: overseeing the IESO-administered wholesale markets; ensuring the reliability of the integrated power system; and forecasting supply requirements.

- **Hydro One**

  A provincially-owned company that operates the majority of Ontario's transmission lines, Hydro One also serves as an electricity local distribution company in some rural areas of the province.

- **Ontario Power Generation (OPG)**

  A provincially-owned electricity generation company – their hydroelectric, nuclear and fossil fuel stations generate approximately 70% of Ontario's electricity.

1.3 Renewable Generation Size

In recent years Ontario system agencies have evolved a number of mechanisms by which renewable generators can participate in the system. These mechanisms are useful in defining renewable energy generating capacity.
http://www.energy.gov.on.ca/english/pdf/renewable/NetMeteringBrochure.pdf

First, the Net Metering program is available to any Hydro One customer who generates electricity primarily for their own use from renewable energy source (wind, water, solar radiation or agricultural biomass) using equipment with a total nameplate rating of 500 kW or less.

Net metering allows a customer to send electricity generated from Renewable Energy Technologies (RETs) to Hydro One's distribution system for a credit toward their electricity costs. Excess generation credits can be carried forward for up to 12 months to offset future electricity costs.

Second, in November 2006 the OPA established the Renewable Energy Standard Offer Program (RESOP). The intent of the Program is to make it easier for the operators of small renewable energy generating facilities to feed in to their Local Distribution Company. The OPA will establish a 20 year PPA contract with dedicated renewable generators under 10 MW. Transmission grid constraints may impose certain restrictions. An eligible renewable energy project must be located in Ontario, must have a Gross Nameplate Capacity of no more than 10,000 kW, must be connected (directly or indirectly) to an OEB-licensed Distribution System, must have a connection voltage of no more than 50 kilovolts and must be metered at the Generator's expense in accordance with Distribution System Code requirements.

A market-based price system has been established for all technologies except solar photovoltaic (PV), that provides a Base Rate of $0.11/ kWh plus a performance incentive of $0.03/kWh for generators who can control their output to meet peak demand requirements reliably over time. It also provides for price escalation to the Base Rate paid to some Generators, linked to the Consumer Price Index in Ontario. PV Projects will be paid $ 0.42 kWh but will not be eligible for inflation indexation or the peak-hour premium. By way of comparison current IESO wholesale average electricity rates range from $0.032 / kWh to $0.071 / kWh.

Both net metering (applying to under 50 kW) and the Standard Offer Program (applying to under 10 MW) may be considered to be aimed at "embedded" renewable energy generators at this stage in market system development. Largely they provide a negative demand load on local distribution systems. This is always the case, however, as wind generators sometimes need to connect through the distribution system to transmission as their night-time peak output exceeds the load at that hour on the distribution system. Generators under net metering interact only with the LDC Hydro One to balance their electricity bill based on input and take-off to the distribution grid. Generators under the RESOP do not interact with the IESO nor are they compensated under market trading. Their contracts provide direct return from OPA based on energy generated. These generators have not had a negative or positive impact on the system overall. As the number of distributed generators increases on the Ontario system impacts will have to be monitored closely.

Projects connected to the transmission system must become customers of the IESO. As such, these projects will be subject to more comprehensive connection requirements and require settlement through the IESO and OPA rather than the local distribution company. Thus, connection to the transmission system typically requires higher cost voltage equipment along with more metering, control, relaying and protection.

The remainder of this document focuses on those generators greater than 10 MW that are subject to market interaction through the IESO. These generators sell power through the IESO on the spot market or negotiate a long term contract with OPA, Ontario Government or another private consumer.

1.4 Renewable Generation and Power Markets

Electricity generated by developers of renewable generation may be sold through the IESO controlled spot market or through long-term financial contracts with the OPA or another private consumer. In either case the IESO controls power to the market through its management system.

Long term financial contracts (typically 20 years) signed by the OPA require the generator to sell its output in the market. The OPA will then provide a top-up to cover any shortfall between market prices and the agreed contractual price. This is not, technically speaking a Purchase Price Agreement because the contractor, in this case the OPA, is not agreeing to pay for electricity. The OPA acts more like a market-maker, ensuring that generators have sufficient incentive to participate in the Ontario electricity market.

The OPAs competitive tender RFP process has been responsible for Ontario's significant increase in renewable capacity. The contractual price paid to each generator may be different dependent on bids made by the individual proponents. In the future the market for "green" electricity (and hence more consumer PPAs with renewable generators) shows promise for expansion with the advent of carbon credit markets. In the absence of a North American market for carbon credits and with the advance intervention of OPA programs there has been little of private consumer contracting activity to date in Ontario.

The IESO controls the marketing of electricity through a spot market as well as the access of all generators to the Ontario grid. The wholesale market price for electricity is based on supply and demand. Suppliers submit offers to sell electricity and wholesale buyers submit bids to buy electricity. The IESO then uses these offers and bids to match electricity supply with demand, and establish the Hourly Ontario Energy Price, or HOEP. Large industrial customers with interval meters must purchase electricity from the market based on HOEP.

From the IESO perspective the supply of energy comes from two sources:

- Dispatchable resources such as large generators
- Non-dispatchable generators such as wind facilities

Dispatchable participants market energy they have available by submitting offers. Offers tell the IESO how much power the participant wishes to sell and at what price.

Non-dispatchable generators can be of two types: self-scheduling (such as small CHP facilities) and intermittent (such as wind). Variable generation is by definition

non-dispatchable and intermittent. On the Ontario system non-dispatchable generators don't enter offers, and they don't receive dispatch instructions. Instead, they provide the IESO with schedules (self-scheduling generators) or forecasts (variable generators) indicating:

- The quantity of energy they expect to produce
- The hours during which they expect to produce it
- A price at which they reasonably expect to reduce their output to zero rather than sell into the market

Non-dispatchable generators then produce energy and are accepted onto the grid in real-time, according to their submitted schedules without receiving dispatch instructions.

1.5 Degree of Centralization

Currently control of variable renewable generation in Ontario is mixed with elements of both central control and decentralization. As discussed in previous sections the OPA has been given sole responsibility for implementing government policy by issuing RFP for the development of PPA with private variable generation developers according to government targets. These offers have catalyzed the private sector to develop over 1000 MW of variable generation (notably the public generating utility OPG is not eligible to compete in the process). Further RFP offerings are expected. The identification, development and management of all variable generation, on the other hand, is the responsibility and risk of private industry.

1.6 Support Mechanisms

Several support mechanisms exist for variable generation:

- The provision of provincially sponsored renewable generation targets with attendant RFP for new capacity to meet the targets. Resulting PPA with the OPA at better than spot market rates assure development. (see section 1.4)
- IESO guarantees of taking electricity as-generated (section 1.4)
- The Canadian federal government ecoEnergy program. ecoENERGY for Renewable Power provides an incentive of $0.01 / kilowatt-hour for up to 10 years to eligible low-impact, renewable electricity projects (including wind) greater than 1 MW constructed over the next four years, April 1, 2007 to March 31, 2011. Currently the OPA requires developers to share the program incentive 50/50 when setting up a PPA.

1.7 Trading

There are two basic types of bids and offers on the IESO system.

First, daily bids and offers apply for only one day. The window for entering daily bids and offers opens at 6 a.m. the day before the energy will flow (i.e. the day before the 'dispatch day'). Second, there are also standing bids and offers. Standing bids and offers apply for more than one day. They stay in the IESO system until changed or withdrawn, or until participants enter an expiry date. Standing bids and offers convert to daily bids and offers at 6 a.m. the day before the dispatch day.

Participants can adjust their daily or standing bids and offers as more information about the specific hour becomes available.

Dispatchable facilities are expected to respond to dispatch instructions that are determined every five minutes. The market clearing price (MCP) used for dispatchable facilities is set every five minutes, matching each dispatch interval.

Non-dispatchable facilities such as wind or run-of-the river generators or local distribution companies (LDC) are different. They are 'price takers' and offer into the market at a price that ensures they will be dispatched (for example at $0/ MWh). They set their own generation or demand levels without dispatch instructions. Non-dispatchable facilities are paid for their production or pay for their consumption based on the Hourly Ontario Energy Price (HOEP). This price is the average of the twelve five-minute prices during the hour. By definition then non-dispatchable generation is the least expensive available supply. Therefore, IESO use electricity available from these sources first, as a block, before considering energy available from dispatchable facilities.

Under this system of trading variable generation is assured of a market for all generated power in which it receives the HOEP. This price is rarely high or secure enough by itself to induce building of wind generators. Experience has shown wind is dependant on PPA side agreements for financial security. A PPA provides a guarantee of income by paying the increment of Contracted Purchase Price less the HOEP. Markets for trading variable generated electricity are decidedly illiquid under this arrangement.

The IESO wholesale market allows embedded generators as small as 1 MW to participate in trading so relatively small generators can in theory trade. Because of market trading rules, however, there is no trading as such of variable generation. All available electricity is accepted by the grid but is settled at a predetermined average price derived from the spot-market.

1.8 Dispatch

Once market participants have submitted their bids and offers, the IESO run these through an optimization program referred to as the 'dispatch algorithm'. The dispatch algorithm determines the settlement price and dispatch instructions to meet demand for each 5 minute interval. The algorithm considers not only bids and

offers but also physical constraints such as ramping capabilities of the counterparties or transmission system constraints.

As discussed in 1.7 variable generators are essentially a priority dispatch; that is they will always run.

1.9 Notification

Notification of generation from non-dispatchable sources is made to the IESO through schedules and forecasts. These are entered for non-dispatchable generators between 6:00 a.m. and 11:00 a.m. day-ahead.

The revision timeline schedule has three periods:

- **The unrestricted window.** This closes two hours before the dispatch hour and allows changes or submission of schedules and forecasts without restriction.
- **The mandatory window.** This runs from two hours before the dispatch hour to ten minutes before the dispatch hour. Only schedule changes are permitted and must be made if the variable generator cannot produce +/- 10 MW or +/- 2% of the submitted forecast schedule. Variable generators under 10 MW do not have to report changes but are encouraged to do so.
- **The dispatch hour.** This is the hour during which the energy is actually being produced. Generators cannot change their forecast schedule but must report variances.

1.10 Imbalance Settlement

Non-dispatchable generators do not participate in imbalance settlement. As discussed in Section 1.7, variable generation is not subject to imbalance settlement rules in the way that dispatchable generators are. Variable generators simply take the Hourly Ontario Energy Price determined by supply and demand. Settlement of PPA for increments above the HOEP is made outside the purview of the IESO and in the case of Ontario wind directly with the OPA.

The imbalance settlement process allows for financial penalties to be applied to participants for failing to balance their position. This is applied through a compliance process in the case of imbalance between a market participant's notified commercial position and the physical output over the contract hour. The process is used judiciously and sanctions normally occur only in cases of consistent misrepresentation and after attempts at amicable resolution of the imbalance. Variable generators would never be subject to imbalance settlement as they are ‘price takers’ and offer on the market at $0/ MWh on the basis of their forecasts only. They set their own generation or demand levels without dispatch instructions.

Settlement of other physical imbalances is largely made through the Hourly Uplift Charge which is settled supplementary to the Hourly Ontario Energy Price (HOEP). Uplift charges are applied to Load and Export customers only. An uplift

charge results from a number of factors most of which are unrelated to variable generators and include:

- Transmission losses accounted for as the imbalance between generated input and demand on the system. Charges also apply for costs related to operating the grid.
- Congestion management credits given to dispatchable market participants as a result of having to operate outside the market schedule.
- Operating Reserve Payments to dispatchable market participants for providing power (or curtailing consumption) on short notice.
- Imbalance costs for imports. The intertie offer guarantee holds importers whole to their offer price if the HOEP ends up lower than their offer. This happens because imports are scheduled hour-ahead, based on a projected price. Real-time price can end up being lower, which means price-risk to scheduled imports without the guarantee.

With regard to imbalance settlement for bilateral contracts for wind; currently in Ontario all variable generators have PPA signed with OPA. The IESO therefore pays the HOEP to the OPA for the generation into their system and in turn the OPA pays the generator the contracted rate. The difference between the market revenues received and the contract payments made is claimed by the OPA via the global adjustment mechanism. The global adjustment mechanism is located within the OPA as a fund to support special projects such as regulated renewable energy generators and demand management programs within local distribution companies (LDC). The global adjustment mechanism is calculated each month and is allocated back to the market as a charge against all loads. It can be positive or negative.

1.11 System Balancing

Balancing supply and demand is the responsibility of both the IESO and the market participants. The IESO has responsibility for balancing the system after gate closure (10 minutes ahead of real time). The IESO does its own forecasting to determine the size of the overall block based on submitted schedules of the participants or counterparties. Participants assist system balancing through accurate forecasting up to gate closure. Market participant balancing can also occur through bilateral contracts (or PPA). Day Ahead Commitment Process (DACP) exchanges are allowed with dispatchable generators and imports to assist with system balancing. DACP is not available to non-dispatchable, variable generators. In fact, in day ahead planning variable, intermittent generators are credited with 0 MW no matter what the forecast they might have provided. In this manner the IESO can plan contingencies based on rampable dispatchable generation and reserves. The IESO together with the Canadian Wind Energy association (CANWEA) are considering ways to give firm dispatch to variable generation such as improved forecasting methods and siting with geographic diversity. More experience is required with wind before capacity credits or anything but shallow penetration is permitted.

1.12 Summary

Ontario's electricity system is a mix of centrally planned and market operated principles. These provide opportunities and barriers for variable generation development. On the one hand publicly formulated targets for renewable energy generation have stimulated dramatic growth in generation. The targets supplemented with concessionary rates in long term PPA with public agencies have been successful in stimulating growth in capacity. The "green" rate margins paid to renewable generators which supplement the market rate mean the incremental tariff is shared amongst Ontario taxpayers. On the other hand, the growth of renewable generation is dependant on political will and bureaucratic influence rather than more predictable market influences. Although ambitious future targets have been set for renewable generation these are vulnerable to changes in government policy.

Intermittent or variable generators in Ontario are assured of market uptake of their electricity as "first in" to the supply mix. They are given preferential treatment over dispatchable generators in this regard. They are required to simply provide a forecast of generation and do not provide a marginal bid cost price. They are then provided the 5 minute average price over the hour.

2 CROSS BORDER TRADING

Currently Ontario is connected to electricity systems in five jurisdictions: two interprovincial – Quebec and Manitoba, and three with the USA – New York, Michigan and Minnesota. Electricity exports and imports to and from these markets are permitted under the Market Rules of the IESO; however, compliance with foreign laws is also necessary. Cross border electricity traders must therefore become familiar with general access rules, regional regulatory bodies and the regulatory structures in each jurisdiction. For example, imports and exports in Ontario bid / offer only once in an energy market for open access to transmission at the interties. US markets require dealing in a dual market of both energy and transmission.

2.1 Current Cross Border Flows

There is significant trade between Ontario and neighbouring jurisdictions, especially on the New York and Michigan interfaces. Traditionally, Ontario is a large exporter to New York and a large importer from Michigan. As Table 1 shows, Ontario was a net exporter in aggregate in winter peak months in 2005/2006 although imports were slightly greater than exports on-peak in December 2005. It should be noted that Ontario's position as a net exporter in this period is a complete reversal from the previous six months, May through October 2005, where it was a net importer.

Table 2 shows Intertie capacities and energy flows for imports and exports with each jurisdiction. At the Quebec border there are 9 interties with 500 MW export and 1400 MW import capacity; at the Manitoba border there are 3 lines with 300 MW export and 339 MW import capacity; at the New York border there are 9 interties with 2500 MW export and 2050 MW import capacity; at the Michigan border there are 4 interties with 2100 MW export and 1750 MW import capacity; at the Minnesota border there is 1 intertie with 150 MW export and 100 MW import capacity.

Annually Ontario is generally a net exporter to the US. Table 3 shows in 2006 Ontario annually as a net exporter to the US particularly New York which more than offsets imports from Minnesota and Michigan.

Table 1: Net Exports from Ontario On-Peak and Off-Peak (MWh), November-April

	Off-peak		On-peak		Total	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
November	(267,649)	148,094	(329,824)	25,506	(597,473)	173,600
December	(8,289)	200,714	(139,370)	(13,734)	(147,659)	186,980
January	45,765	192,403	25,133	228,771	70,898	421,174
February	91,037	373,280	176,943	269,661	267,980	642,941
March	180,736	433,664	138,701	246,164	319,437	679,828
April	(187,057)	671,257	(207,975)	372,724	(395,032)	1,043,981

Table 2: Ontario Intertie Capacities

Intertie:	**ON to Quebec**	**Quebec to ON**	**ON to Manitoba**	**Manitoba to ON**	**ON to NY**	**NY to ON**	**ON to Michigan**	**Michigan to ON**	**ON to Minn.**	**Minn. to ON**
Capacity (MW):	500	1400	300	369	2500	2050	2100	1750	150	100
Energy Flow (2007) (GWh)	953	1,158	181	585	8,654	944	2,244	4,308	255	212
No. Lines / Capacity (kV)	4 / 115, 5 / 230		2 / 230, 1 / 115		2 / 69, 1 / 115, 4 / 230, 2 / 345		1 / 120, 1 / 230, 2 / 345		1 / 115	
Owned by:	Provincial or State Transmission Operating Authority									

Table 3: Ontario – US Cross Border Energy Flow Summary: 2006

Export Destination / Import Source	*EXPORT (MWh / year)*	*IMPORTS (MWh / year)*	*Net Exports (MWh/ yr)*
Connecticut	428	866	-438
Indiana	30,498		30,498
Massachusetts	43,453	3,571	39,882
Michigan	357,046	2,473,613	-2,116,567
Minnesota	316,781	2,558,348	-2,241,567
Missouri	2975	10	2,965
New England	4299		4,299
New York	7,745,722	621,560	7,124,162
Ohio	844,370	225,034	619,336
Pennsylvania	31,796	102,023	-70,227
Vermont	19,729	1574	18,155
Illinois		150	-150
Total	***9,397,097***	***5,986,749***	***3,410,348***

2.2 Cross Border Capacity Mechanisms

The Ontario energy market has been designed to allow market participants to import power from and export power to other jurisdictions. Market rules also permit wheeling of power through the province. Wholesalers may bid and offer blocks as small as 1 MW for import / export in contrast to internal market participants who may bid / offer in 100 kW blocks. At the same time reliability standards must be maintained and adjacent market protocols followed, which results in a complex, time consuming coordination process. Imports and exports are therefore scheduled an hour in advance and for an hour at a time, rather than for the five-minute intervals used for internal dispatchable facilities. This means that an import that is to take place between 11:00 and 12:00 will actually be locked in shortly after 10:00, during the hour-ahead pre-dispatch run of the scheduling algorithm. Since 2006 imports and exports have been able to bid / offer in a day ahead commitment process (DACP) using the same IESO pre-dispatch process as other dispatchable generators. For scheduling purposes imports and exports are treated as non-dispatchable participants (i.e. intertie zone price takers – see below) who are given priority dispatch over their scheduled hour. A non-compliance charge is automatically applied for failure to deliver. Participants are monitored for delivery performance and regular failure to deliver may result in ISO sanctions.

While there is one uniform price, the 5 minute Market Clearing Price (MCP), used for all transactions inside the province, the market design allows for different prices at each transborder intertie zone. At pre-dispatch, an hour beforehand, a

projected price is determined for Ontario and all of the intertie zones based on bids and offers. In theory and to the extent that energy can flow to and from the intertie zone and Ontario, the price at an intertie should be the same as the Ontario price. There are, however, risks to importers and exporters since they are locked-in based on hour-ahead pre-dispatch prices, but settled based on real-time prices, which may be different mainly due to system congestion.

When the capacity of the intertie is insufficient to meet all the economical offers and bids it is "congested" and the intertie zone price will be different than the Ontario price. To ameliorate this risk the Intertie Congestion Price (ICP) has been established. The difference between the intertie zone price and the real time Ontario price is called the ICP. The price used to settle imports and exports in real-time is the sum of the real-time Ontario Market Clearing Price (MCP) and the ICP determined during the hour-ahead pre-dispatch run. MCP for intertie transactions, therefore, is the market clearing price in the intertie zone.

If for any reason congestion on the IESO-controlled grid restricts the ability of the grid to accommodate a scheduled import or export transaction then a physical Congestion Management Settlement Credit (CMSC) can also be applied. The CMSC is provided to any market participant, including importers and exporters, when dispatch schedules differ from market schedule due to IESO directions in the case of physical limitations on the grid. The CMSC returns the participant to their market schedule operating profit. Linked wheel-through transactions are not eligible for CMSC.

In the event that the MCP for intertie transactions is insufficient to return the expected operating profit of an importer an additional mechanism is meant to ameliorate risks for imports only. The Intertie Offer Guarantee (IOG) ensures that, over the course of the hour, an importer will receive at least the average price of their offer, i.e. they will not suffer a negative Operating Profit (OP). The IOG is calculated as follows:

$$IOG = -1 \times ((\text{Intertie Zone MCP} - \text{Offer}) \times \text{Market Schedule Quantity})$$

All settlement mechanisms (ICP, CMSC and IOG) are accounted for in hourly uplift charges applied to load (including exporter's) tariffs.

The IESO currently administers one financial market, the Transmission Rights Market, which addresses the financial risks of congestion when importing and exporting electricity on the interconnection lines between Ontario and its surrounding markets. When loading on the interconnection lines reaches the capacity limit of the lines, energy prices can differ significantly between Ontario and its surrounding markets. The Transmission Rights Market allows participants who import or export power to buy financial protection ahead of time to hedge their prices for power across the interconnections.

2.2.1 Potential Future Interconnector Capacity

Ontario has been consulting with other provinces about reinforcing and expanding east-west provincial interconnections. In November 2006, the

governments of Ontario and Quebec announced the signing of an agreement on a new transmission interconnect that will provide the potential to move 1,250 MW of additional power between the two provinces by 2010. The lines will help meet power needs in Ontario, with access to the predominately hydropower-generated electricity of Quebec, while reducing its reliance on importing electricity from the U.S.

In addition, Ontario and Manitoba continue to negotiate a contract to secure some of the output from Manitoba's planned Conowapa hydroelectricity development. If these negotiations are successful Ontario will begin planning and construction of an east-west transmission line to transport this energy to the demand centre in Southern Ontario. This will allow for the flow of clean hydroelectric power to the Ontario market, while assisting in the Ontario government's efforts to phase-out coal-fired generating stations thereby reducing carbon dioxide emissions.

The National Energy Board (NEB) has also recognized the conditions are ripening for investment in an east-west grid on a national scale. In its June 2005 Outlook for Electricity Markets, the NEB noted:

"While there are important interprovincial power transfers in some regions, the historical tendency for provinces to supply their own markets has limited the extent of interprovincial transfers. The concept of expanded east-west interconnections, or an 'East-West Grid' in Canada, was raised a number of times in the past, but typically was not considered economically attractive. Recent regional developments, such as the Clean Energy Transfer Initiative (CETI), between Manitoba and Ontario, and other potential interprovincial projects, suggest that specific opportunities may now exist."

2.3 Cross Border Trading

Ontario, through its electricity market offers non-discriminatory access to its transmission system, thereby satisfying the FERC reciprocity requirement. Ontario electricity market participants have open and equal access to the US, Manitoba and Quebec grids. Although Ontarians may use foreign grids, electricity trades must be uniquely negotiated in each bordering market.

Ontario wholesale electricity market participants who export or import electricity must use North American Electricity Reliability Council (NERC) tagging. The Market Rules specifically require NERC tags as do bordering American jurisdictions. Market Rules for the Ontario intertie zones, whether in Canada or at the US border, have been established setting the hour ahead, 1 MW blocks, as a standard for offers. NERC has further reinforced these regional standards by establishing these as North American intertie standards for all Regional Transmission Operators and the 8 Regional Reliability Councils. In other words exports and imports amongst all North American utility jurisdictions are all ruled by a universal trading format.

Ancillary services are provided through IESO contracts for an Emergency Demand Response Program (EDRP), black-start capability, regulation service as well as reactive support and voltage control. IESO establishes these services through RFP for contracts lasting 18 months and possibly 36 months. Ancillary services are by definition required from dispatchable loads and generators and are not available to imports and exports.

The IESO created an operating reserve (OR) market to efficiently purchase OR from market participants and subsequently activate it, when needed, to quickly restore the balance between supply and demand. Market participants can offer OR to the IESO-administered markets at the same time that they bid or offer energy. To offer operating reserve, there must be an energy bid or offer of at least as many megawatts. The IESO determines the price for this reserve every five minutes, based on the offers in the market. To participate in the operating reserve market, participants need to be dispatchable market participants thereby eliminating the efficacy of imports / exports providing this service.

With the exception of New York, electricity markets bordering Ontario are not deregulated and are less open to broad based competition. Trade with these jurisdictions is possible but requires an appreciation of their different regulatory structures. A summary of these systems follows:

New York

New York is a deregulated electricity market with competitive wholesale and retail markets. The wholesale market is divided into 11 local markets where energy suppliers and purchasers make bids and offers. Local clearing prices are determined by the market neutral New York Independent System Operator ("NYISO"). The NYISO plays the same role as the IESO in Ontario. In fact, much of Ontario's electricity market is based on the New York market.

Ontario market participants, once registered to participate in the New York market, may buy and sell electricity in New York through an open and continuous multi-party market. Specific counter-parties with which to trade power need not be found nor are uniquely negotiated bilateral electricity trade contracts necessary.

Michigan

Michigan does not have a fully deregulated wholesale electricity market, however, limited retail deregulation was completed in 2002. The Michigan market consists of several large local utilities which monopolize transmission and distribution and control access to retail customers. Ontario market participants may sell power into or draw power out of Michigan, however, no neutral market operator oversees such transactions. Bulk electricity trades are executed by negotiated bilateral contract.

Minnesota

Minnesota is researching deregulation but has not opened any part of its market to competition. Similar to Michigan, the market is made up of several large local utilities with transmission and distribution monopolies. Bulk electricity trades are by negotiated bilateral contract. Direct sales to retail customers are not possible.

Manitoba

Under the Manitoba Hydro Act, Manitoba Hydro has exclusive authority over electricity matters in the province. Limited wholesale electricity competition is sanctioned under the Act, however, Manitoba Hydro controls all transmission and most generation and distribution in the province. Sales or purchases of bulk power are controlled by Manitoba Hydro and the utility is the only entity which regularly trades wholesale power. Bilateral contracts for the trade of power may be completed with Manitoba Hydro and less commonly, with other entities in the province. No retail competition exists.

Quebec

Quebec has adopted a limited form of deregulation. Hydro Quebec, the dominant electric utility in the province must supply a "Heritage Pool" of power for domestic consumption at a set price. Competitive tenders may be made by any electricity supplier to meet the province's needs beyond the Heritage Pool. Ontario market participants may participate in the Quebec market by making tenders to supply power beyond the Heritage Pool or entering into bilateral electricity contracts with Hydro Quebec or a handful of other smaller wholesale electricity traders. There is no competition in the retail market.

2.4 Renewable Support Mechanisms

The most significant barrier currently for variable generation in export/import is the NERC system-wide requirement that all imports and exports be negotiated with participants one hour ahead and for one hour blocks of time. Although import / export markets are open to any bidders the risks associated with hour ahead bidding decrease the likelihood of non-dispatchable variable generators bidding into the import/export market. Imports / exports of course can be made under bilateral contracts. As well, there is leeway for smaller increment spot market import / export (even up to 5 minutes) given the approval of submissions to the NERC. To take advantage of the opportunity Ontario would require a coordinated submission from the 6 jurisdictions involved and these changes are currently not contemplated.

Earlier documentation outlined 3 support mechanisms for renewable energy and specifically variable generators such as wind:

1. The provision of provincially sponsored renewable generation targets that are being met through the RFP (Request for Proposal) or RESOP (Renewable Energy Standard Offer Program) process for new capacity. The resulting OPA contracts provide remuneration at better than spot market rates to help secure renewables development. The OPA contracts allocate all "green" or carbon credits attached to the energy generated to the OPA and not to the generator.

   In theory OPA would be free to export credits across borders either attached to purchases of renewable generated electricity or separately. In practice, the trade of electricity at trans-border locations is highly illiquid. Power must committed an hour before for a full hour due in part to individualized transactional arrangements amongst non-market based

utilities. Under these conditions variable generators could not hope to participate in trans-border exchanges except under bilateral contracts.

2. IESO guarantees the taking of non-dispatchable electricity as-generated on a forecast basis and guarantees the HOEP in return. Bilateral contracts might in theory be possible between trans-border agents for variable generation. A more flexible arrangement would allow the trans-border flow of credits attached to green generation credits rather than electrons.

3. The Canadian federal government ecoEnergy program. ecoENERGY for Renewable Power provides an incentive of $0.01 / kilowatt-hour for up to 10 years to eligible low-impact, renewable electricity projects (including wind) greater than 1 MW constructed over the next four years, April 1, 2007 to March 31, 2011. Currently the OPA requires developers to share the program incentive 50/50 when setting up a PPA.

   The ecoEnergy program is somewhat restrictive in that is available only to wind energy generated and used within Canada. Interprovincial transfers would therefore only receive support.

2.5 Utilisation for Variable Generation

There is no evidence that wind or other variable generation currently makes use of any interconnectors.

2.6 Summary

Overall, the trade in variable renewable generation into and out of Ontario is limited by market conventions established by the responsible agencies on all sides of regional interconnection.

The Ontario energy market has been designed to allow market participants to import power from and export power to other jurisdictions. As required by NERC membership the transmission system is provided to all market participants including exporters and importers on an open and equal basis. Wholesalers may bid and offer blocks as small as 1 MW for import / export committed at H-1 for the next hour. The IESO applies an automatic failure charge for non-compliance and monitors participants to apply sanctions or penalties for regularly failing to comply with market instructions.

Ontario has 5 transborder regions; interprovincially at Quebec and Manitoba and internationally with the US at New York, Minnesota, and Michigan. Each has an inherent interest in promoting import and export potential between jurisdictions and each therefore conforms to NERC regulations. Import and export regulations at each transborder region must be uniquely negotiated in each bordering market except New York which, like Ontario, uses a central electricity exchange.

3 GRID PLANNING

3.1 Grid Investment

In Ontario the Ontario Power Authority (OPA) is responsible for long term planning and the Independent Electricity System Operator (IESO) is responsible for managing the operational short term planning and connection process with transmission facility owners (TFO). With the exception of a series of dedicated merchant owners, the Ontario TFO is the regulated transmission monopoly Hydro One.

The OPA is responsible, through its Board of Directors, to the Minister of Energy of Ontario for the planning of the electric system, the issuance of RFPs, and approvals, as well as contract management to ensure adequate generation and transmission capability. The OPA is established as the single entity in Ontario with a mandate to develop an Integrated Power System Plan (IPSP), which includes identifying transmission requirements for the Integrated System. The first IPSP has been submitted for official and public scrutiny to the Ontario Energy Board OEB), the provincial regulator, in August 2007. The OPA planning process encompasses an integrated approach for the most cost effective and feasible options to meet demand projections. These include conservation and renewables as primary considerations based on targets established by Ontario's Ministry of Energy. Environmental and social considerations also play a role. With particular reference to Ontario's plans to accommodate more renewable generation, planning for transmission follows from a set of interrelated factors including:

- the existing transmission infrastructure;
- necessary transmission reinforcements and upgrades to access remote renewable resources;
- necessary bulk transmission reinforcements and upgrades to deliver renewable energy;
- timelines for approving and making transmission reinforcements and upgrades;
- the all-inclusive costs of developing these renewable resources (which included transmission-related costs including transmission losses); and,
- the regulatory and commercial requirements for making the necessary transmission reinforcements and upgrades.

The OEB is conducting a full and transparent review of the Plan to ensure it is economically prudent and cost effective. Stakeholders involved in discussions will include Ontario's transmission companies (the main transmission facility owner (TFO) being Hydro One a regulated monopoly), the Independent Electricity System Operator (IESO), and individual LDC of municipalities. The OEB and, potentially, the National Energy Board (NEB) also have roles in plan approvals, and approvals of specific projects to implement those plans. First Nations have been accorded a role in the review because they may be affected by rights of way

of transmission facilities and are potentially affected by or may be proponents for development of new generation facilities as well, including wind and hydroelectric power.

At the transmission project level the IESO's connection assessment process examines transmission proposals to determine the impact on the reliability of the IESO-controlled grid, and provides approval of the proposed facility under the Market Rules.

3.1.1 Planning the system

When planning the system, studies will be carried out to assess the impact of proposed developments. The study period depends on the purpose of the assessment.

- For proposed Load, Generation or Transmission developments, the study period runs up to 10 years into the future.
- For NPCC transmission reviews, the study period covers a 4 to 6 year period from the report date. These reviews are of three types: a comprehensive or full review, an intermediate or partial review and an interim review. Refer to NPCC document B-04, "Guidelines for NPCC AREA Transmission Reviews" for details.
- For NPCC resource adequacy reviews, the study period covers a 5 year look ahead period.
- Stability of the bulk power system shall be maintained during and following the most severe of the contingencies stated below. The following contingencies are evaluated for the bulk power system portion of the IESO-controlled grid:
- A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing.
- Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent circuits of a multiple circuit tower, with normal fault clearing.[1]
- A permanent phase-to-ground fault on any transmission circuit, transformer or bus section with delayed fault clearing or a permanent phase-to-ground fault on a circuit breaker with normal fault clearing
- Loss of any element without a fault.
- Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault.
- The failure of a circuit breaker to operate.

The above conditions are evaluated under various weather and generation conditions

[1] If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, this condition is an acceptable risk and therefore can be excluded.

- ***Wind Power***

  For the purposes of transmission system adequacy and connection assessments, wind powered generators are to be treated as non-dispatchable (intermittent) units which are operating up to their maximum output.

  For connection assessments, transmission line ratings will be calculated using 15km/h winds, instead of the typical 4km/h, within the vicinity of the wind farm and, with the approval of the transmission asset owner, out to a 50 km radius.

3.1.2 Offshore

Ontario borders on the Great Lake system, the largest body of fresh water in the world. The shores of four of the five lakes (Lakes Ontario, Erie, Huron and Superior) lap at Ontario's borders. The province also surrounds Georgian Bay, a major off-take of Lake Huron. In January 2008 the Ontario government lifted the deferral[2] on existing proposals for offshore wind power projects and began accepting new onshore and offshore applications for Applicant of Record status. Applicant of Record is the designation of acceptance given to a proponent by the Ministry of Natural Resources, the provincial Ministry concerned with the protection and management of all public, "crown" land in Ontario. Besides onshore crown land all submerged land is deemed crown in Ontario and is subject to Ministry scrutiny. Applicant of Record status then allows offshore developers to pursue the approvals required to construct and operate a wind power facility.

Once MNR grants Applicant of Record status under Site Release rules, the proponent can begin Environmental Assessment work under the Ontario Ministry of the Environment Guide to Environmental Assessment Requirements (MOE-GEAR) for Electricity Projects. Issues of aquatic ecosystem impacts are of high importance, and determining whether the Project would result in a Harmful Alteration, Disruption or Destruction (HADD) of aquatic habitat is the biggest issue, but certainly not the only one. Recreational use, aesthetic value, terrestrial species impacts and historical/ cultural issues will all come into play.

Environmental Assessment under the Canadian Environmental Assessment Act (CEAA) will be required if federal funding is involved or if the project appears to involve a HADD (and therefore Federal Fisheries Act approval). The data generated for the Ontario MOE-GEAR for Electricity Projects will be similar to that needed for the federal process, and these EA process can be managed as one requirement.

[2] The Ministry of Natural Resources put a halt to all offshore development in November 2006 to give the government more time to study the potential environmental impact of such projects on bats, butterflies, aquatic species and bird migration routes.

Other Permits and Approvals include: location and Plan Approvals under the Ontario Lakes and Rivers Improvements Act: and Approval of Works under the Navigable Waterways Protection Act.

3.2 Planning & Security Standards

The IESO imposes specific grid code requirements which affect all grid entrants including variable generators such as wind and hydro:

- Turbine reactive power control;
- System voltage control;
- Fault ride through capability;
- Frequency tolerance;
- Information provision – fixed data and operational metering.

Wind has separately defined grid code standards.

The IESO is involved in connection assessments and imposing grid code requirements for wind systems 10 MW and greater. Smaller systems are treated as embedded and connected through local distribution grids. Similar, but generally not as rigorous, connection assessments and grid codes are required of wind systems less than 10 MW.

Reliability standards are set beyond the jurisdiction of the Ontario Power Authority by reason of Ontario's membership in the North American Reliability Council (NERC). NERC has been established across North America as a standards regulator to ensure continental grid security and stability (see Annex D). NERC develops and maintains reliability standards, including regional reliability standards, which apply to bulk power system owners, operators, and users. Regional reliability standards, when approved by the Federal Energy Regulatory Commission (FERC) in the U.S. and in Canada the National Energy Board (NEB) along with provincial regulatory authorities, are made part of the body of NERC reliability standards. These are enforced upon all bulk-power system owners, operators, and users within the regional entity's region, regardless of membership in the region.

3.3 Transmission Access & Charging

In Ontario the IESO controls access to the grid through its dispatch instructions. When dispatched a dispatchable or import provider receives automatic access to the grid. Grid congestion is of course a factor when deciding access. With IESO policy favouring renewable generation, variable generators, by virtue of being non-dispatchable price-takers, have first automatic access to the grid. Currently the low penetration of variable generation in the Ontario system permits such a policy.

Transmission charges are levied against load and export participants only. Transmission losses (accounted for as the imbalance between generated input and demand on the system) and grid operating costs are integrated into an hourly uplift charge applied against energy transactions supplementary to the hourly energy price. Uplift charges also account for transmission congestion management credits given to dispatchable market participants as a result of having to operate outside the market schedule. Load and export participants alone pay uplift charges.

3.3.1 Transmission Access and Connection

All generators whether or not variable must complete the connection assessment process if they intend to:

- Connect a new facility to the grid;
- Significantly modify a facility connected to the grid;
- Connect a generator larger than 10 MVA to a distribution system.

The IESO conducts an initial assessment of the impact of the connection on the reliability of the integrated power system. If they expect the project to have a significant impact on the grid, they will require a formal assessment study. If the impact is minimal, they will require a less rigorous Expedited System Impact Assessment.

Issues of concern include:

- The appropriate voltage at connection; and
- The preferred point of termination of the incorporation facilities. This is especially important in situations where system constraints might influence the connection arrangement or where new equipment needs to be installed within facilities owned by the transmitter.

Customers may not gain access until grid capacity is assured and any required grid reinforcement is done. Access is managed according to queue position.

Transmission access currently poses difficulties for the development of variable generation sources (mainly wind and run of river hydro). In some cases, transmission access is lacking in remote areas having promising wind or hydro resources. In others, transmission capacity is congested due to large dispatchable generators such as nuclear generation or import from neighbouring provinces.

Generally the RFP process of the OPA, which to date has provided the only entry point for large scale economic renewable systems, has meant, by virtue of the selection process, that projects are distributed throughout the province in zones with available transmission access. Generators are of course free to plan and build dedicated transmission services but the

competitive RFP process means that bids which require high transmission costs are liable to be less competitive. The Transco, Hydro One, is publicly owned and buffered from direct market influences.

The Ontario wind industry is working with government and market regulators on wind integration issues. A 2006 jointly managed study by GE Wind identified opportunities and constraints to wind integration and made recommendations for the future. The majority of the conclusions focused on technical, non-market issues such as:

- Regulation of wind additions up to 10 GW would not be problematic;
- Incremental load following requirements and operating reserve over 5 GW of wind would require system reconfiguration because of wind variability;
- For all wind penetration scenarios the variability due to wind on an hourly or extended hourly basis would not tax the system. However at high wind penetration ramping due to extreme net load changes was significant;
- At high penetration scenarios, low system load could pose a significant problem. Solutions considered include wind shedding or controls at wind farms, increasing wind export potential, load modification with the addition of loads, and developing an accommodating supply mix to provide ramping capability.

The OPA has just released its first IPSP for review by the provincial energy regulator. In the sections regarding transmission, the OPA considered: the existing transmission infrastructure; necessary transmission reinforcements and upgrades to access remote renewable resources; necessary bulk transmission reinforcements and upgrades to deliver renewable energy; timelines for approving and making transmission reinforcements and upgrades; the all-inclusive costs of developing these renewable resources (which included transmission-related costs including transmission losses); and, the regulatory, and commercial requirements for making the necessary transmission reinforcements and upgrades.

3.3.2 Connection Charging

A new or modified generator is required to pay for the “deep” or “semi deep” costs of connection. The costs attributed to new or upgraded facilities are be allocated to the specific generator causing these costs[3]. An exception to this rule provides assurance that customers will not be required to pay costs beyond those for which they are responsible, which would otherwise be incurred by the transmitter to accommodate normal growth on its system[4]. (The same requirement exists for load customers.)

[3] Section 6.3 of [1]
[4] Section 6.3.6 of [1]

Generators are therefore responsible for the design, construction payment and ownership of any line and transformation facilities required, as well as any costs for modifications to the existing transmission facilities required in order for the generator to connect. They are not required to pay for those expenses that would have been part of the TSOs general process of maintenance of the network. A transmitter may require a capital contribution or a load guarantee from new transmission customers.

As discussed earlier a new generator must also conduct a connection assessment study which can cost from $30,000 to $70,000 for a larger project in the 10 MW range.

In 2008, the Ontario Energy Board launched a process to review connection cost responsibility for generators connected to the transmission grid. The OPA's IPSP has proposed socialized costing for new transmission infrastructure that enables clusters of renewable energy in certain areas [2].

3.3.3 Transmission Charging

A generator does not pay for either the transmitter's ongoing operation and maintenance costs or the transmission losses. These costs are recovered from load.

Transmission losses and grid operating costs are integrated into an hourly uplift charge applied against energy transactions supplementary to the HOEP. Transmission losses are accounted for hourly as the imbalance between generated input and demand on the system. Load and Export market participants pay the uplift charge based on their withdrawals.

ANNEX A – ABBREVIATIONS

Acronym	Definition
B.C.	British Colombia
CANWEA	Canadian Wind Energy Association
CEAA	Canadian Environmental Assessment Act
CETI	Clean Energy Transfer Initiative
CfD	Contract for Difference
CMSC	Congestion Management Settlement Credit
EA	Environmental Assessment
FERC	Federal Energy Regulatory Commission
GEAR	Guide to Environmental Assessment Requirements
GW	Gigawatt = 1,000,000 kW (unit of power/ capacity)
GWh	Gigawatt hour = 1,000,000 kWh (unit of energy)
HADD	Harmful Alteration, Disruption or Destruction
HOEP	Hourly Ontario Energy Price
ICP	Intertie Congestion Price
IEA	International Energy Agency
IESO	Independent Electricity System Operator
IOG	Intertie Offer Guarantee
IPSP	Integrated Power System Plan
kW	Kilowatt = 1,000 Watts (unit of power/ capacity)
kWh	Kilowatt hour = 1,000 Watt hours (unit of energy)
LDC	Local Distribution Companies
MCP	Market Clearing Price
MOE	Ministry of Energy
MW	Megawatt = 1,000 kW (unit of power/ capacity)
MWh	Megawatt hour = 1,000 kWh (unit of energy)
NEB	National Energy Board
NERC	North American Electricity Reliability Council
NTC	Net Transfer Capacity
OEB	Ontario Energy Board
OP	Operating Profit
OPA	Ontario Power Authority

Acronym	Definition
OPG	Ontario Power Generation
OR	Operating Reserve
PPA	Power Purchase Agreement
PTR	Physical Transmission Rights
RESOP	Renewable Energy Standard Offer Program
RET	Renewable Energy Technology
RETD	Renewable Energy Technology Deployment
RFP	Request for Proposals
SK	Saskatchewan
SO	System Operator
TFO	Transmission Faculty Owners
TSO	Transmission System Operator
TWh	Terrawatt Hour = 1,000 MWh (unit of energy)

ANNEX B – GLOSSARY

Term	Definition
Bilateral	Trades or other contracts between two participants, for example a generator and supplier.
Capacity	Cf. Energy, Power. The maximum ability of a generating station to generate an amount of electricity in a given time. Measured in units of power (kW). The actual energy generated is dependant on the load factor.
Clip Size	The minimum size of interconnection capacity contracts.
Credit Cover	The cash or other financial security that must be provided.
Day Ahead	The day prior to the day that is being traded for or balanced.
Deep Connection Costs	Cf. Shallow Connection Costs. The costs of reinforcing and upgrading the wider network to enable additional generation or demand to be connected.
Energy	Cf. Power, Capacity. Formally defined as the ability for a system to do work. In the case of an electrical energy this is measured in kWh. Energy cannot be stored in the transmission network, so at any given time the total energy generated must equal the total energy demand and total losses (due to heating of wires etc.) This is known as balancing the system.
Gate Closure	The last time at which energy can be traded before the markets are closed. Balancing trades may take place closer to real time on a separate balancing market.
Group Processing	This means that the grid operator puts applicants into a queue and groups them into areas or zones. Reinforcement is then carried out on selected zones to accommodate the applicants in that zone. There is no guaranteed timescale for connection.
Intraday	Within the day that is being traded for or balanced.
Load Factor	Also may be known as a capacity factor. The ratio of the actual energy output of a power plant over a period of time and its energy output if it had operated a full capacity of that time period. For example, an onshore wind farm might have a load factor of 30-40%. This means that on average it generates at 35% of its capacity, although at any given time it may be generating anywhere between 0% and 100% of its total capacity.
Locational	Cf. Postage Stamp. Differentiated by geographical location. For example, in the case of transmission charging, this typically will mean higher charges further from demand centres.
Long	Cf. Short. Where a participant has more generation than is required to balance their demand (including losses where applicable)

Term	Definition
Main Price	Cf. Reverse Price. The balancing price where a participant is out of balance in the same direction as the market, for example a participant that is "short" when the market is "short".
Merit Order	The order that a system operator will place generators in based on the costs to deliver a certain quantity of generation. Those generators that will allow the forecast demand to be met at the lowest costs (subject to system constraints) are described as being in the merit order and are despatched.
Postage Stamp	Cf. Locational. Uniform, equal throughout the network.
Power	Cf. Energy, Capacity. Power is the ability to create energy in a given time, and can be expressed in the following equation: $Power(kW) = \frac{Energy(kWh)}{Time(h)}$
Price Maker	Cf. Price Taker. In the context of an electricity pool, a price making generator will submit a number of bids/offers indicating how much electricity they would be prepared to despatch at a given price. The system operator will place the generators in order of cost to determine which plants will be despatched.
Price Taker	Cf. Price Maker. In the context of an electricity pool, a price taking generator will not submit a bid or will submit a bid at zero. This means it will always be despatched (subject to system constraints) and will receive the pool price. Price taking generators include variable generators with low marginal costs, such as wind.
Real Time	The actual time period that energy is being traded for or balanced.
Reverse Price	Cf. Main Price. The balancing price where a participant is out of balance in the opposite direction to the market, for example a participant that is "short" when the market is "long".
Shallow Connection Costs	Cf. Deep Connection Costs. The costs of physically connecting a generator to the nearest appropriate point in the transmission network, this may typically be the closest substation. This does not include costs associated with any required reinforcements to the wider transmission network.
Short	Cf. Long. Where a participant has less generation than is required to balance their demand (including losses where applicable)
Supplier	Normally used to describe a retail electricity supplier that sells electricity to final consumers, this can include domestic, commercial and industrial consumers
Vertical Integration	Vertical integration is the degree to which a firm owns its upstream suppliers and its downstream buyers. For example, within the electricity industry this can be used to describe the situation where a parent company owns both an electricity retail supplier and generator.

ANNEX C – REFERENCES

Number	Reference
1	Transmission System Code (TSC)
2	Transmission Connection Cost Responsibility Review (EB-2008-0003)
3	IESO, Ontario Transmission System June 23, 2006
4	Review of Wind Power Results in Ontario: May to October 2006, Tom Adams, Energy Probe, November 15, 2006
5	IESO Ontario Resource and Transmission Assessment Criteria, Issue 5.0, August 22, 2007
6	IESO website www.ieso.ca
7	OPA website www.powerauthority.on.ca

ANNEX D - THE NORTH AMERICAN ELECTRICITY RELIABILITY COUNCIL (NERC)

The North American Electricity Reliability Council (NERC) is responsible for aspects of an international electricity system that serves 334 million people, and has some 211,000 miles (340,000 km) of high-voltage transmission line throughout North America. The certification of NERC in 2006 has been the result of concerns for maintaining a high level of reliability throughout the North American grid.

NERC develops and maintains reliability standards, including regional reliability standards, that apply to bulk power system owners, operators, and users. Regional reliability standards, when approved by the Federal Energy Regulatory Commission (FERC) in the U.S. and in Canada the National Energy Board (NEB) along with provincial regulatory authorities, are made part of the body of NERC reliability standards. These are enforced upon all bulk-power system owners, operators, and users within the regional entity's region, regardless of membership in the region. As of Sept 2006 the NEB recognized NERC's role in Canada as Electric Reliability Organization for a North American interconnected system. The National Energy Board signed a Memorandum of Understanding promoting reliability standards for international power lines under the NEB's jurisdiction which covers all international bulk power exchanges. This agreement recognized the role of NERC in developing reliability standards for North America's bulk power grid. Although the NEB will continue to regulate international power lines that fall under its jurisdiction, NERC will monitor these lines in Canada to ensure compliance with its reliability standards. The NEB receives regular reporting from NERC concerning NEB regulated power lines. These reports are used to identify international power lines that are non-compliant with NERC's reliability standards.

Important standards developed by FERC and promoted through NERC relate to reciprocity principals for all members requiring non-discriminatory access to transmission lines within a member's jurisdiction. Members therefore enjoy open and equal access to each others transmission systems. NERC holds no legal enforcement power, however, the system is based on very strong reciprocity. Not supporting NERC policies could result in reduced openness by other systems. In practical terms Canadian provincial utilities must comply with the decisions of regional councils. NERC policies are, however, based on strong consensus and do not create onerous compliance requirements for competently run systems.

NERC works with eight Regional Reliability Councils to improve the reliability of the bulk power system. The members of the regional councils come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. NERC's proposal to delegate enforcement authority to eight regional entities is pending before the Federal Energy Regulatory Commission. These eight councils are as follows:

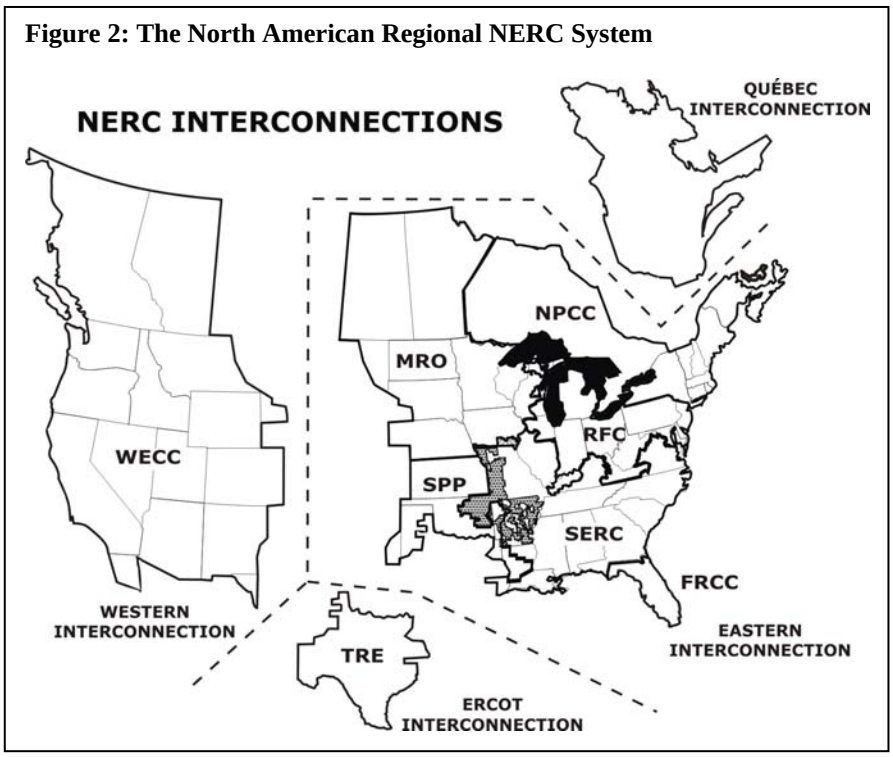
Regional Reliability Councils
Florida Reliability Coordinating Council (FRCC)
Midwest Reliability Organization (MRO)
Northeast Power Coordinating Council (NPCC)
Reliability*First* Corporation (RFC)

SERC Reliability Corporation (SERC)
Southwest Power Pool, Inc. (SPP)
Texas Regional Entity (TRE)
Western Electricity Coordinating Council (WECC)

The figure below positions each Regional Council geographically. Ontario falls within the NPCC, Alberta within the WECC.

A significant development for member imports and exports intra and inter regions is NERC tagging. Implemented in July 1997 long before full certification of NERC, tagging requires bulk electricity transfers between systems to be "tagged". A tag is an electricity transmission schedule with a specific path, for a specific duration, over a specific time frame. Copies of the tag are distributed to all systems that could be affected by the electricity transfer. These systems must apply their non-discriminatory transmission access rules to either approve or deny the path requested in the tag. A central agency collates the results. If all affected systems approve the transaction, the electricity transfer takes place as scheduled in the tag.

Figure 2: The North American Regional NERC System



The NERC Compliance Monitoring and Enforcement Program works to ensure compliance by all bulk power system owners, operators, and users with NERC reliability standards approved by applicable governmental authorities. Bulk power system owners, operators, and users are required to register with NERC and comply with all approved reliability standards and report all violations of the reliability standards to their regional entity. NERC also actively monitors registered entities for compliance with a select number of reliability standards. Through delegation agreements, each regional entity carries out the NERC compliance monitoring and enforcement program. NERC oversees each regional entity's compliance monitoring and enforcement process; each region is responsible for reviewing and enforcing compliance with all registered entities within the region.