Independent Electricity Market Operator

18-Month Outlook:

An Assessment of the Adequacy of the Ontario Electricity System

From October 2000 to March 2002

November 17, 2000

Independent Electricity Market Operator

Executive Summary

This report presents an assessment of the generation and transmission adequacy of the Ontario electricity system for the 18-month period from October 2000 through March 2002. The assessment is based on a forecast of electricity demand and available supply combined with current information on the configuration and capability of the transmission system. The most recent known outage plans of generators and transmitters are incorporated in the assessment.

Resource Margins in Ontario are forecast to be manageable for the entire period.

Detailed Margin analysis was conducted in accordance with the Transitional IMO License – EI-1999-0450..

Ontario Power Generation has declined to give the IMO permission to publish these resource adequacy details for as long as Ontario Power Generation has the obligation to supply the Ontario Electricity System. The IMO is required to respect Ontario Power Generation's position as a condition of the Transitional IMO License.

Ontario Power Generation will manage the Margins through a combined use of its own generation, load management, rescheduling of outages and supply from interconnected control areas.

The transmission outage plan has been reviewed for system impacts. Results of this assessment indicate the following:

Although the forecast available generation margins are generally manageable in the study period, any outages that may affect interconnection support or generation access to the IMO-Controlled Grid should be coordinated closely between the transmitter and the generators involved. The analysis highlighted a few outages with this potential impact. In addition, the impacts of some forced outages have been noted.

System voltage concerns during times of extreme summer peak demands, will limit the flexibility for planning outages in the Toronto and Windsor areas in 2001.

Restoration of the reactive power output capability of Darlington and Pickering units could reduce the stated voltage concerns in the Toronto area.

Caution and Disclaimer

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1.0 Introduction

When put in force in 2001, the Ontario Electricity Market Rules (Chapter 5) will require that the Independent Electricity Market Operator (IMO) provide forecasts and assessments of the adequacy of the existing and committed generation and transmission facilities after market opening. Until that time, a condition of the Transitional License for the IMO (Section 18.1) requires the IMO to monitor the state of electricity demand and available supply in Ontario.

To meet these obligations, the IMO published[1] the first 18-Month Outlook in March 2000 and the first 10-Year Outlook in August 2000.

In October, 2000, the IMO updated the original 18-Month Outlook to cover the period from October 2000 until March 2002. This is a public version of the 18-Month Outlook, derived the IMO's detailed analysis by eliminating all the information that, in the opinion of stakeholders, is commercially sensitive. The IMO is prevented from publishing this information under Section 19 of its Transitional License.

Section 2 of this report provides an 18-Month forecast of electricity demand for Ontario. The generation capacity that is expected to be available during the study period is summarized in Section 3, and an assessment of the adequacy of the generation capacity under the current generation maintenance outage program is presented in Section 4. The transmission system that is expected to be available is described in Section 5 and the current transmission outage plan is assessed in Section 6. The findings and conclusions of this assessment are contained in Section 7.

Readers are invited to provide comments on this report or to give suggestions as to the content of future reports. To do so, please call the IMO Help Centre at 416-506-2836 or send an email to forecasts.assessments@theIMO.com.

[1] IMO Website www.theIMO.com (Months and Years Ahead)

2.0 Forecast of Ontario Electricity Demand

The Ontario Primary Demand is the sum of coincident load demands plus the losses on the transmission and distribution systems. Ontario Primary Demand does not include loads that are supplied by embedded generation.

Section 2.1 describes the process used to forecast electricity demand for this report. Section 2.2 looks at the factors that shape the demand for electricity. Section 2.3 summarizes the current energy demand forecast, while Section 2.4 summarizes the peak demand forecast. A detailed forecast of total demand and demand by transmission zone is shown in Appendix A.

2.1 Forecasting Process

The forecast of Ontario electricity demand used in this assessment was produced by the IMO utilizing information provided by Ontario Power Generation Inc (OPGI). Both the methodology and the OPGI supplied information are consistent with the 10-year demand forecast found in the IMO's current 10-Year Outlook. Recent actual energy demand shows stronger growth than the trend in the IMO's current 10-Year outlook. For this reason, a scenario with higher peak demand is included in the assessment discussed in Section 4.

The demand for electricity in Ontario was analyzed for the Northwest portion of the province separately from the remainder of the province. This separation is necessary due to the difference in scale and behaviour of the two systems. The Northwest system accounts for roughly 5% of the total energy demand on the system, and the climate and mix of end-uses make the Northwest system profile significantly different from that of the remainder of the province.

Demand is divided into three large and distinct blocks for each subsystem identified above. These blocks are identified as cooling load, heating load and base load. Each of these blocks was forecast individually, then summed to derive the system electricity demand. Growth projections were derived for each of the blocks or components based on historical relationships and future trends. Each of these components is shaped by the same environmental factors however the impacts of these factors vary by demand component.

Forecasts of peak demands were calculated using historical peak-to-energy demand relationships. Statistics were also produced for variance of the peak demands in each week to reflect the impact of weather.

For input into the assessment study, the following forecasts were developed:

Separate forecasts of the 20-minute peak demand for the Northwest and the remainder of the province, as well as the coincident total system peak demand (under Weather Normal conditions);

hourly energy demand by region (under Weather Normal conditions);

statistics on the variance in the peak and energy demand in each week to reflect the impact of weather.

For the purposes of the forecast, weather is not explicitly forecast; rather a "Weather Normal" forecast of electricity demand is produced. Combining the current economic model and a sample of representative weather conditions generates Weather Normal numbers. This sample is comprised of weather conditions for the same period over the last 30 years. This results in a distribution of potential values for the period in question. The median value of the distribution is termed the Weather Normal.

The process of forecasting will continue to evolve at the IMO as experience is gained and the energy modeling increases in sophistication. After market opening, a range of new forces will come into play that will change the dynamics of Ontario's electricity demand and the IMO forecasting process will evolve with these changes. With very few registration applications received to date from price-responsive loads, it is too soon to include estimates of their impact on overall Ontario demand.

2.2 Forecast Drivers

The consumption of energy is driven by a variety of factors, from weather to the behaviour of homeowners to changes in technology. Weather has by far the greatest impact on consumption, but great volatility and unpredictability also characterize it. For this reason, modeling is done on a weather normal basis. Without weather as an explanatory variable, economic, end-use and technology factors shape the growth of consumption. The key drivers shaping the underlying trends for each of the demand components are discussed below.

Cooling Load is primarily comprised of space cooling or air-conditioning demands which are highly sensitive to heat and humidity. Aside from variations due to weather conditions, growth in cooling load will depend on the end-user. Unlike some other end-uses, electric air-conditioning does not yet have a viable non-electric competitor. Therefore, demand grows with additions to housing stock and commercial floor-space, as well as with increased manufacturing activity.

The increased penetration of space cooling in the residential market means that the cooling load will grow faster than the housing stock. Although commercial development has mostly languished since the late 1980's, economic activity over the last several years has led to a rebound in growth in floor-space – particularly in the "Big Box" retail segment.

Over the last three years (1997-99) Ontario built 163,000 new homes and is expected to add an additional 210,000 over the 2000-02 time frame. With new housing activity remaining strong over the forecast period and commercial construction activity picking up, cooling load is expected to experience strong growth (2.0% per annum) throughout the 18 month forecast.

Heating Load is weather-sensitive winter load. Aside from weather variations, the growth in heating load will also be determined by the end-user. Unlike cooling load, heating load is subject to strong competition from other energy sources, in particular natural gas. Over the late 1980's and early 1990's, natural gas prices were falling as electricity prices were increasing, triggering a decade long phase of fuel switching. At the same time prices were changing, the efficiency of oil and natural gas equipment was increasing, adding further incentive to switch fuels. Therefore, as space-heating equipment reached the end of its useful life or the payback justified it, electric heating equipment has been replaced by natural gas or oil fired equipment. Electric heating is rare in new homes and fuel switching of existing customers will continue.

Despite its competitive price disadvantage, electricity does still have a significant heating load. Due to technological issues, some fuel switching is not economical – in particular; baseboard heaters do not have an economic substitute. Natural gas is limited to the area served by its distribution system. As well, the price advantage enjoyed by oil and natural gas has eroded recently. The loss of customers to fuel switching has slowed and, combined with modest heating additions, heating load will remain flat over the forecast.

Base Load represents the non-weather sensitive portion of demand. Contributing factors include lighting, water heating and industrial machinery. Since this load is not weather dependant, growth will be driven by economic activity.

Currently, the strong U.S. economy, combined with the low Canadian dollar, has been a boon to Ontario's exporters. Energy intensive industries such as transportation equipment, pulp & paper and steel have seen their competitive advantage increase with the dollar's decline. Domestic demand has continued to strengthen on the back of strong employment growth and relatively low interest rates. Despite a recent slowing of U.S. economic growth, domestic demand and international competitiveness will ensure robust growth in manufacturing activity over the forecast period. Offsetting some of the increased load from economic expansion will be base load lost to self-generation and fuel switching. Despite the addition of 435,000 jobs over the 2000-02 time frame, load loss will keep base load growth at 1.0% per annum over the forecast period.

2.3 Forecast of Energy Demand

Actual primary energy demand has averaged annual growth of 1.4% over the period 1986-1999. Although this report is for an 18-Month forecast (Oct-2000 to Mar-2002), a figure for 2002 is provided in order to calculate annual growth. The predicted energy demand and corresponding growth rates are detailed in Table 2.1. Figure 2.1 graphically displays energy demand on a monthly basis. As Table 2.1 indicates, energy demand is expected to grow by 1.16% over the forecast period. The growth comes from the combined effects of the projected cooling, heating and base load growth. The impact of recent higher trends in energy demand will be captured in the next update. Base load growth from economic activity and cooling load growth from increased air-conditioning penetration are the reasons for the growth in energy demand.

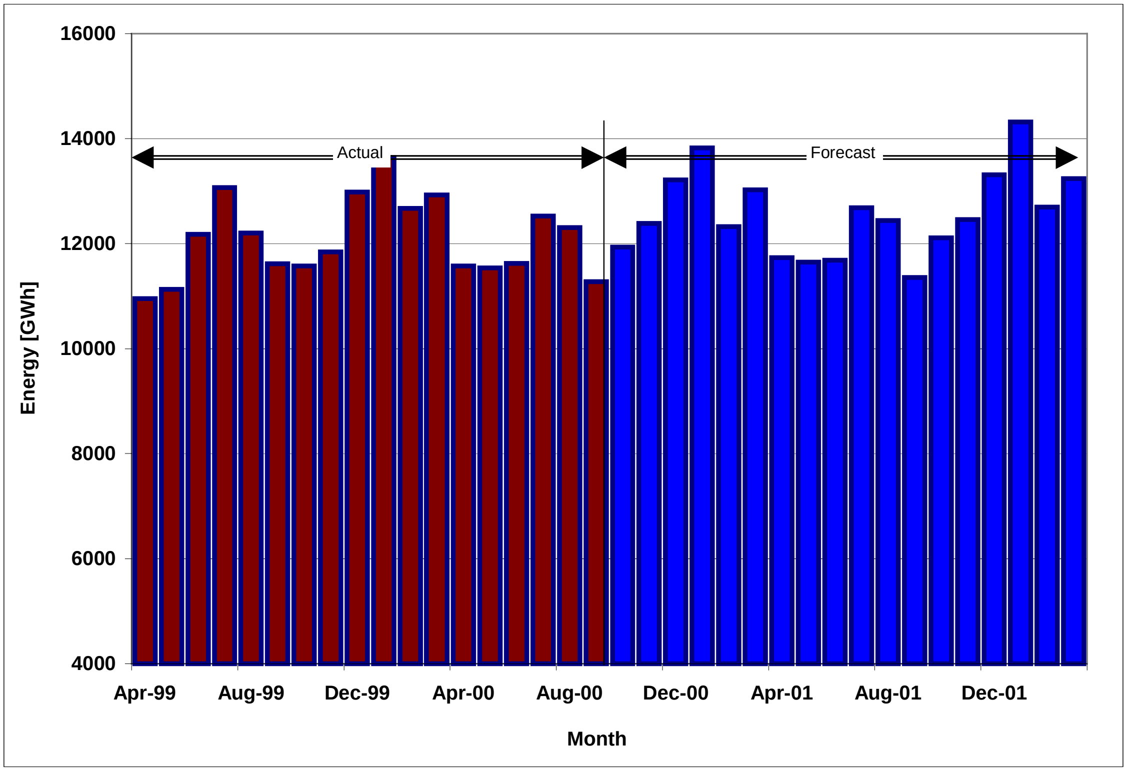
Table 2.1 Ontario Energy Demand

Year	Weather Normal Energy Demand (TWh)	Actual Weather[2] Energy Demand (TWh)
1995	137.5	137.0
1996	138.8	137.4
1997	139.7	138.4
1998	141.6	139.9
1999	144.8	144.1
2000	147.6 (forecast)	
2001	148.6 (forecast)	
2002[3]	149.9 (forecast)	
Average Annual Growth 1999-2002 is 1.16%		

[2] For the years 2000 to 2002 , the forecast energy for Actual is the same as the forecast for Weather Normal since weather is not forecast for the planning period.

[3] The forecast only extends to Mar-02, however an annual figure is provided.

Figure 2.1 Monthly Total System Primary Energy Demand Forecast Weather Normal



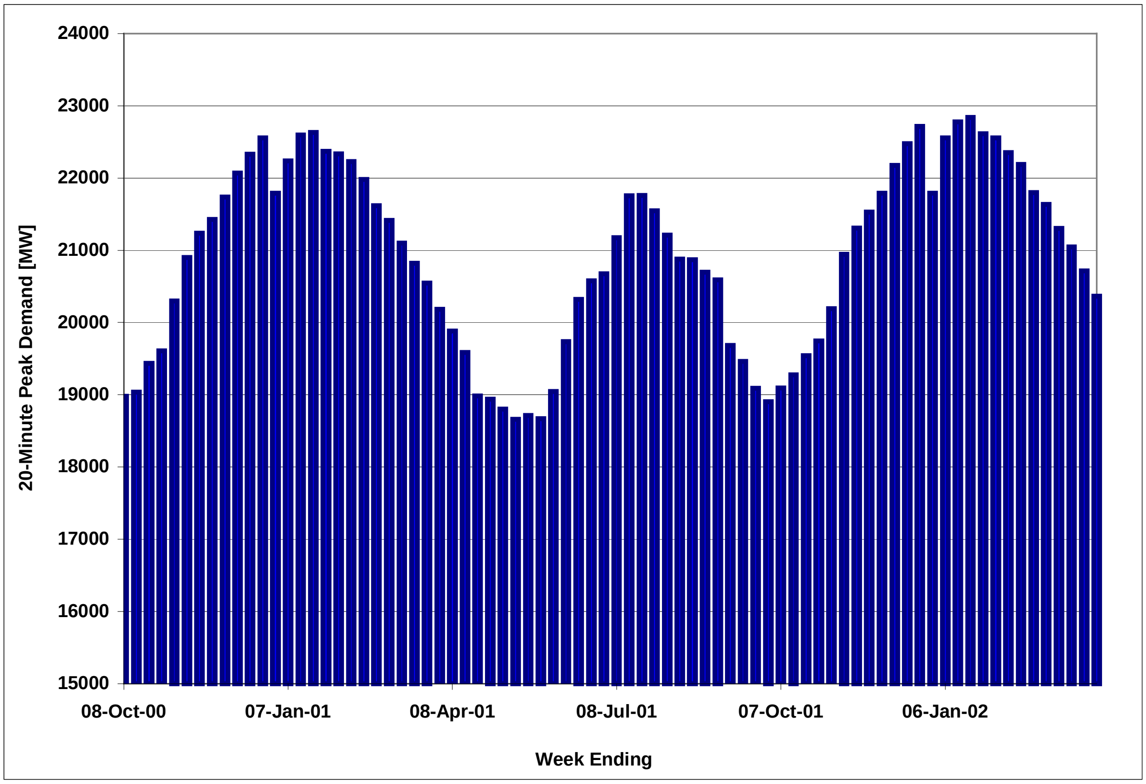
2.4 Forecast of Peak Demand

Historically, Ontario's electricity peak demand has occurred during the winter, usually in the months of December through February and between the hours of 5 p.m. to 7 p.m. Exceptions to this were in 1998 and 1999, when the annual peak demand occurred during the afternoon of early to mid-July. The occurrence of this summer vs. winter peak demand is attributed to a warmer than normal winter and unusually hot summer weather as a result of El Nino and La Nina. The actual Ontario all-time 20-minute peak demand reached 24,007 MW in January 1994 and the highest summer peak was 23,435 MW in 1999. The actual 20-minute winter peak demand in 2000 was 23,428 MW (Monday, January 17) and the actual summer peak demand in 2000 was 23,222 MW (Thursday, August 31). Recent higher energy demand is not reflected in a higher actual peak demand, mainly due to moderate weather during the past year. However, a scenario of about 300 MW higher peak demand, in winter and summer, is included in the assessment of resources.

The winter and summer peak demands are very weather dependent and usually coincide with extreme weather conditions. The growth in the summer peak is determined by the growth in base load and cooling load. Conversely, the growth in the winter peak is determined by the growth in base load and heating load. Based on the discussion under section 2.2, it is not surprising that we have seen a lower response for energy during periods of cold temperatures and a higher response for energy during periods of hot temperatures. Over the 1986-1999 time frame, the winter peak demand has averaged annual growth of 0.9% while the summer peak demand has averaged annual growth of 2.6%, testimony to the underlying trends affecting the two.

Although the system will remain winter peaking throughout this forecast, the summer peak demand will grow faster than the winter peak demand in this forecast. Figure 2.2 displays the forecast weekly peak demand measured over a 20-minute period. Further details of the peak forecast are included in Appendix A.

Figure 2.2 Forecast of Weekly 20-minute Total System Peak Demand Normal Weather



3.0 Resources

This section describes the generating resources that are forecast to be available over the 18-Month assessment period from October 1, 2000 to March 31, 2002.

Section 3.1 describes the declared net capacity of the generation resources and Section 3.2 describes the bilateral external transactions (imports and exports). Section 3.3 provides an overall summary of the available resources that are included in the assessment after taking into account various reductions and external transactions.

3.1 Generating Capacity Included in the Assessment

Generation from Ontario Power Generation Inc. (OPGI)

The OPGI generation included in the study is shown in Appendix C, Table C1.1. The generation mix includes nuclear, coal, oil and gas-fuelled generation, as well as hydroelectric and wind-powered stations. Also shown in Appendix C are the OPGI generators that are not included as resources in this assessment.

Bruce Power will assume control over the Bruce plants after it is granted an operating license by the Canadian Nuclear Safety Commission and the Ontario Energy Board. These approvals are expected by late spring or early summer 2001.

Committed Additional OPGI Resources

Over the next several years, OPGI plans to undertake a number of upgrades at various hydroelectric stations, in order to increase the output of their units. Only 30 MW of planned upgrades (after Year 2000) have been committed at this time.

Generation from Contract Generators

Contract Generators are generators that have contracts with the Ontario Electricity Financial Corporation (OEFC) to deliver defined amounts of capacity and energy. This generation includes hydroelectric generation as well as waste-fuelled and natural gas-fuelled thermal generation as shown in Appendix C. The installations range in size from about 1 MW to 165 MW resulting in a total capacity of 1,766 MW at winter peak. The production forecast for Contract Generators was provided by Hydro One Networks Inc.

3.2 External Transactions

OPGI has existing contracts for the purchase of up to 1000 MW until December 31, 2000 and 200 MW until October 31, 2003.

No capacity backed sales to other Control Areas have been identified to the IMO.

3.3 Summary of Available Resources

Table 3.1 shows a snapshot of the total available generation capacity at the time of winter peak demand in 2001 and 2002. The available generation (not accounting for planned outages) is forecast to be 26,104 MW at winter peak of 2001 and 26,560 MW at the winter peak of 2002.

Changes from the current 10-Year Outlook

The available generation (no planned outages) was forecast to be 26,680 MW at winter peak of 2001 and 27,195 MW at winter peak of 2002 in the current 10-Year Outlook. The reduction to available generation included in this 18-Month Outlook is mainly due to a new hydroelectric forecast from OPGI and reductions in capacity due to transmission limitations. The latter reductions were not previously included in stating the Available Resources but were included in the margin calculations.

3.4 Potential New Generation Sources

There are no new generation sources in the assessment period. A status summary of the requests for new connection assessments is available on the IMO's website.

Table 3.1 Summary of Generation Assumed Available at Winter Peak

Notes	Year	2001	2002
	Net Capacity		
1	OPGI Declared Net Capacity	27,794	27,794
2	Committed OPGI Generation	30	30
3	Contract Generators	1,766	1,766
4	Firm Import	200	200
5	Total Declared Net Capacity	29,790	29,790
	Reductions to Net Capacity		
6	Unavailable Capacity	2,312	1,857
7	Hydro Plant Reductions	1,268	1,268
8	Locked-in Capacity	106	105
9	Available Generation Capacity	26,104	26,560

Notes to Table 3.1:

1. OPGI Declared Net Capacity
   This is the total capacity available from OPGI owned generation units, as declared by OPGI in Table C1.1. This capacity does not include Bruce A.

2. Committed OPGI Generation
   OPGI has committed projects to upgrade some of their facilities. The reported quantity is the expected improvement from these projects. Additional planned upgrades were reported, but these are less certain and have not been included here.

3. Contract Generators
   Hydro One administers Contract Generators on behalf of Ontario Electricity Financial Corporation. The reported amount is the net declared capacity available from the Contract Generators.

4. Firm Import
   At the present time, there is only one firm contract for the import of 200 MW of energy and capacity. This contract ends on October 31, 2003.

5. Total Declared Net Capacity
   This is the sum of net declared generating capacity (MW) from all sources.

6. Unavailable Capacity
   The reported values include the amount of long term outages and the currently known temporary deratings to the Declared Net Capacity (line 5), and are based on information provided by the resource owner (OPGI and Contract Generators).

7. Hydro Plant Reductions
   Reductions to Hydro plants, from the declared net capacity, will vary from month to month. The in-service capacity of OPGI's hydroelectric generation is about 7,280 MW. This number reflects the maximum output from all such stations and, in this report, is reduced by an amount that reflects the expected hydro peak hour production and forced outage reductions, as provided by the owner. Ontario 25 Hz locked-in generation capacity has also been accounted for as a further reduction in this estimate.

8. Locked-in Capacity is the estimated generating capacity locked into local areas due to Operating Security Limits, excluding 25 Hz locked-in generation in Item 7.

9. Available Generation Capacity
   This is the generation capacity available to supply the forecast demand, after all known reductions have been accounted for. It is the net declared capacity less the known deratings and hydroelectric reductions. This quantity does not include any generator outages (planned or unplanned). Planned outages take place mainly in the spring and fall, when the demand is low.

4.0 Resource Assessment

This section provides an assessment of the adequacy of the available generating resources described in Section 3 to meet the forecast demand as described in Section 2. The methodology used to carry out this assessment is summarized in Section 4.1. and is described in more detail in Appendix C. A summary of the adequacy assessment is provided in Section 4.2. All detailed Margin analysis has been removed to meet the conditions of the Transitional Licence of the IMO, Section 19.

4.1 Methodology to Assess Resource Adequacy

4.1.1 Generation Reserve Requirement

Generation Reserves are required to ensure that the forecast demand can be supplied with a sufficiently high level of reliability. The Generation Reserve Requirement is calculated based upon the NPCC Generation Adequacy Standard. The Required Generation Capacity, is therefore, the amount of generation capacity required to supply the peak demand and meet the Generation Reserve Requirement.

The IMO, as a member of the Northeast Power Coordinating Council (NPCC), is expected to demonstrate that it can achieve the following Generation Adequacy Standard:

> "…after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years".

The Generation Reserve Requirement in MW was calculated, for each week in the assessment period, based on the Generation Adequacy Standard described above using the IMO's Load and Capacity Program (see Appendix C for further details). The forecast excess or shortfall (between the Available Generation Reserve and the Generation Reserve Requirement) is termed the Margin. The Margin does not include the additional support that may be available from interconnection assistance or from the dispatching-off of price sensitive loads. The amount of such support will vary depending on price and availability; this variability and range of support is described in the final assessment of adequacy. As mentioned earlier, the explicit values of the Margin are not shown in this version of the report due to the commercial sensitivity of this type of information.

Changes from the current 10-Year Outlook

The Generation Adequacy Standard is now based directly on the NPCC standard, which is described above. In the previous report the Generation Reserve Requirement was a percentage of the Peak Demand for the period 2000 to 2002. All future assessments will be based on the NPCC standard.

4.2 Summary of Resource Adequacy

The forecast weekly Gross Margin is shown in Figures 4.1 and 4.2. Gross Margin does not include the effect of planned or forced outages to generation resources. It is calculated from information available in the public domain or forecast by the IMO.

Forecast Margins (after accounting for outages) in Ontario are expected to be manageable for the entire period. Ontario Power Generation will manage the Margins through a combined use of its own generation, load management, rescheduling of outages and supply from interconnected control areas. If made necessary due to resource shortfalls, the IMO will implement Emergency Operating Procedures.

Figure 4.1 18 - Month Forecast of Gross Resource Adequacy

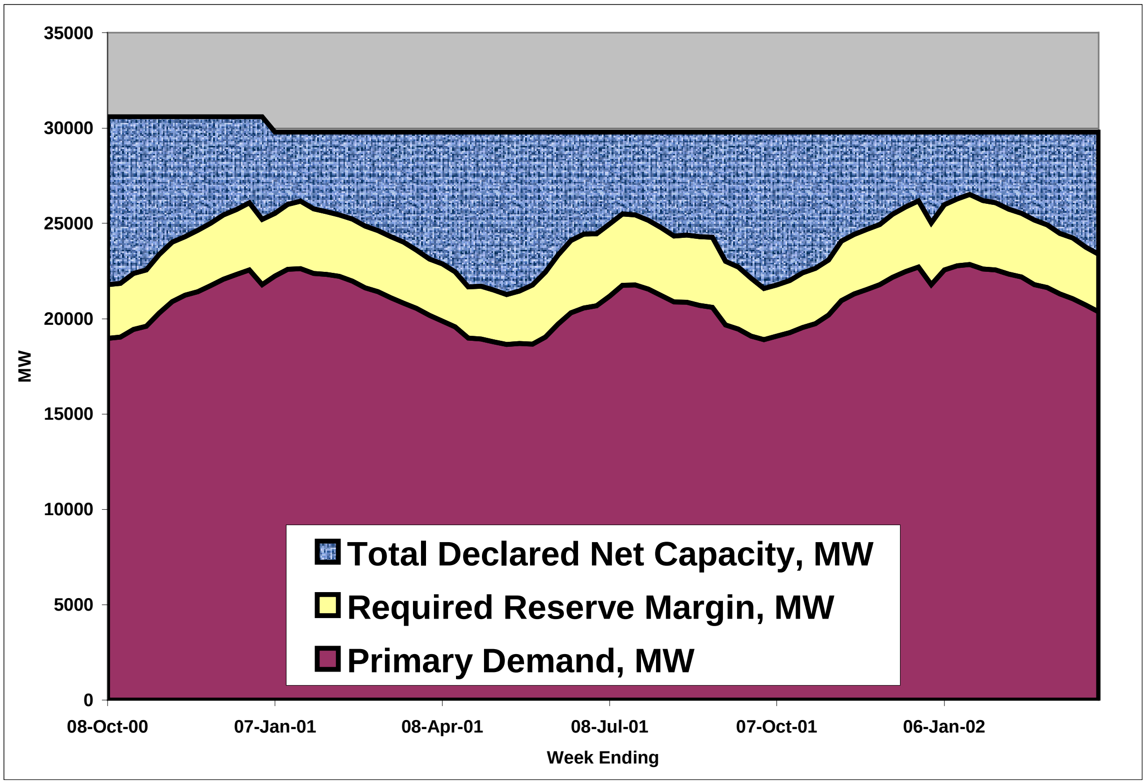
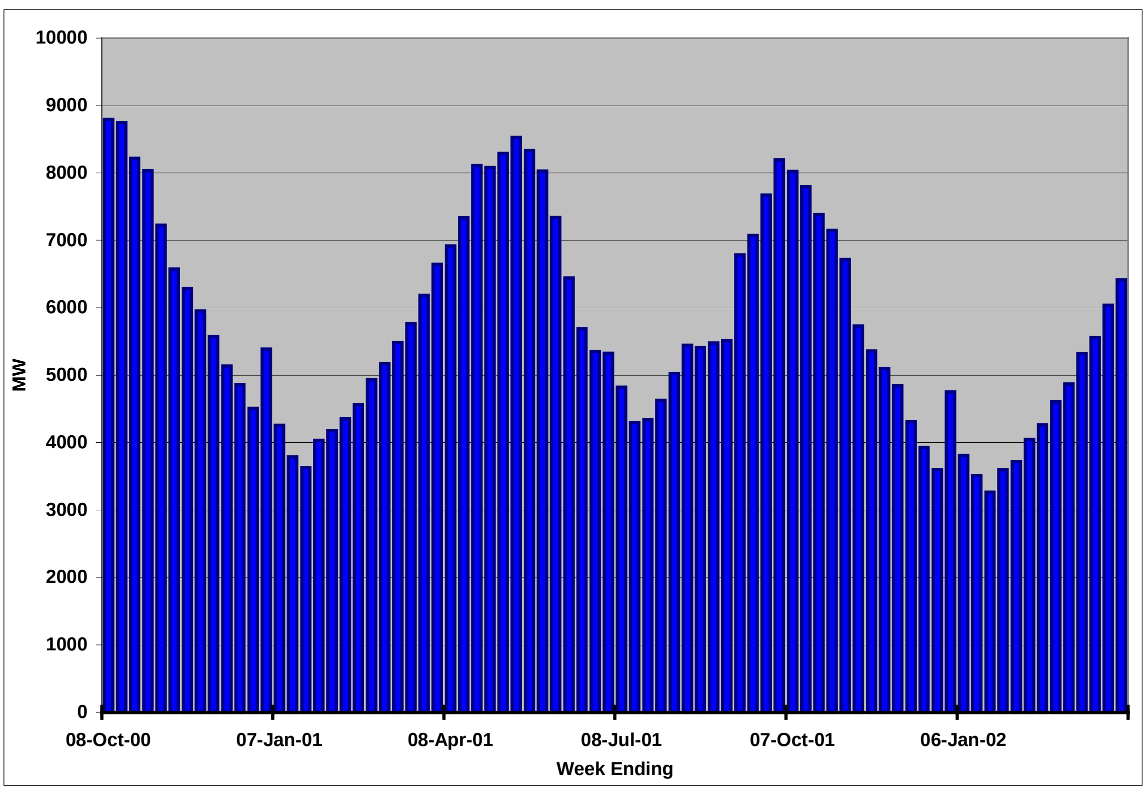


Figure 4.2 Gross Margins



5.0 The Ontario Electricity System

5.1 Current Configuration of the Transmission System

The existing and committed 500, 230 and 115 kV transmission network is shown in Appendix B (Maps) and Appendix D (Details). Figure 5.1 provides a geographic depiction of Ontario's internal transmission zones, between which there are stated transfer limits, and the points of interconnection with other jurisdictions.

5.1.1 Changes to the Committed Transmission Plan from the Previous Report

Committed transmission facilities are summarized in Appendix D, Section 4. Of special note are construction activities, which are underway to implement the following modifications to the Michigan-Ontario interconnections, with a target completion date of June 2001:

Ontario Facilities:

Parallel the existing two 345/230 kV autotransformers T7 and T8 for connection on the interconnection circuit L4D;

Install two 230 kV, 845 MVA phase shifting transformers, one on the interconnection circuit L4D and one on interconnection circuit L51D.

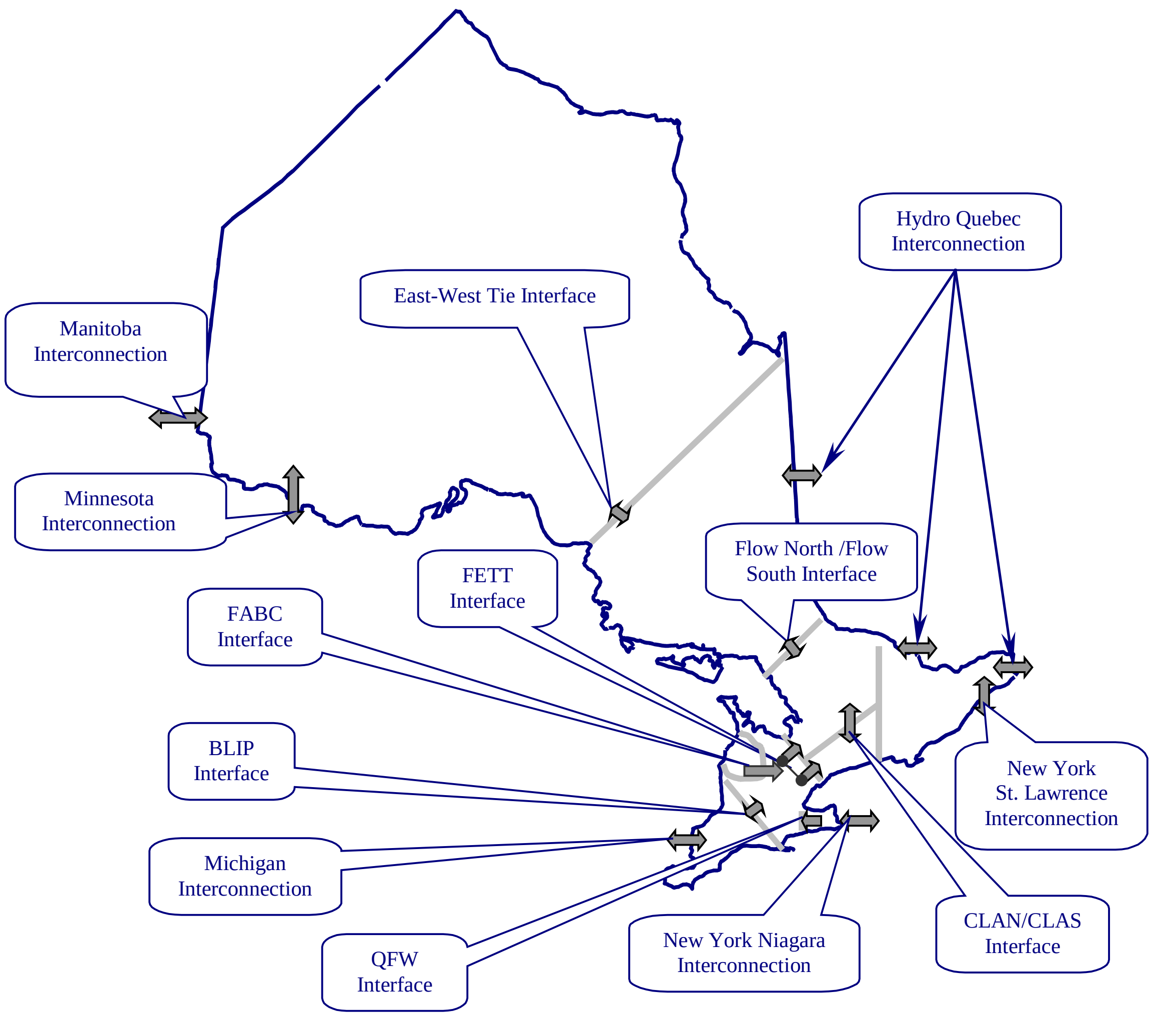
Michigan Facilities:

Install a 345/230 kV, 1000 MVA autotransformer on the interconnection circuit L51D;

Install a 230 kV, 675 MVA phase shifting transformer on the interconnection circuit B3N.

All of the above facility installations were completed in June 2000 with the exception of the L4D phase shifter which is scheduled to be completed by June 2001. These modifications will increase the Ontario-Michigan interconnection capability as shown in Appendix D, Table D3.1. The new phase shifting transformers, with an effective phase angle control range of ±40 degrees under full load will provide the capability of controlling Lake Erie Circulation (LEC) by approximately 500 to 600 MW. Details are provided in Appendix D, Section 1.4.

Figure 5.1 Significant Internal Ontario Transmission Interfaces and Points of Interconnection With Neighbouring Areas



Major Interface Capability

Manitoba Interconnection *	288 in or out Summer / 300 in or out Winter
* limited to 163 summer, 190 winter until December 2001	
Minnesota Interconnection	100 in, 150 out
East-West Tie	325 E, 350 W
Flow North Interface	1900
Flow South Interface	1400
CLAN Interface	2000
CLAS Interface	1000
FABC Interface	5200, normally not limiting
HQ Interconnection	1394 in, 530 out Summer / 1408 in, 530 out Winter
New York Interconnection	1850 in, 2350 out Summer / 2150 in, 2450 out Winter
Michigan Interconnection	1500 in, 2350 out Summer / 1600 in, 2400 out Winter
Buchanan Longwood Input (BLIP)	3500
Negative BLIP	1500
Queenston Flow West (QFW)	1800 Summer / 2000 Winter
Flow East to Toronto (FETT)	5700

6.0 Transmission Adequacy Assessment

The principal purpose of this transmission adequacy assessment is to identify any transmission limits of concern in the next 18 months and to highlight transmission outages that should be rescheduled or coordinated with generation outages to mitigate system reliability concerns.

Planned transmission outages have been provided by Hydro One for the calendar year 2000. Planned transmission outages for 2001 are currently being developed by Hydro One and will be available for the next 18-Month Outlook. The transmitters and generator owners are expected to have a mutual interest in developing an ongoing arrangement to coordinate their outage planning activities. The IMO has an obligation to review the integrated plans of generators and transmitters to identify situations that may adversely impact the operation of the system and to notify the affected participants of these impacts. Prior to this report, the IMO has identified to Hydro One certain planned outage situations that could potentially impact the reliability of the system. Hydro One has responded to this information with appropriate changes in their outage plan. The latest transmission outage plan has been provided by Hydro One for this assessment.

The scope of the transmission assessment for this report is outlined in Section 6.1. The primary assessment is contained in Section 6.2, while voltage and other concerns that may impact on system operation in the study period are outlined in Sections 6.3 and 6.4. A summary of the adequacy of the transmission system is provided in Section 6.5.

6.1 Planned Transmission Outages

Hydro One's Transmission Outage Plan is shown in Appendix D, Section 5. The outage plan includes outages for voltage levels of 115 kV and higher and with a duration longer than 5 days. The following items are listed for each outage, with the first and third item having been provided by Hydro One:

1) Description of the outaged transmission element
2) Transmission Zone (as defined in Appendix D, Section 1.3 of this report)
3) Start & Finish Dates, Outage type (continuous or otherwise) and Recall Time,
4) IMO's statement about any reduction in the Interface Limits (defined in Appendices D, Sections 2 and 3) or a reduction in a limit internal to the Transmission Zones.
5) A qualitative statement from the IMO about the impact of any reduction in transmission limits including any impact on generation.

6.2 Assessment of Transmission Outage Plan

The IMO's assessment of the impact of the Transmission outage plan provided by Hydro One is shown in Appendix D (Tables D5.1 to D5.9). In these tables, each element in Hydro One's outage plan is assessed individually and the reduction in transmission limits and possible impacts are noted. A further analysis of overlapping outages did not result in the identification of any further impacts other than those outlined in this section.

Given that the available generation margins are low at times in the study period, outages that may affect interconnection support or generation access to the IMO-Controlled Grid should be coordinated with the generator owners involved. The analysis highlighted a few outages with potential impact as summarized below:

Northwest and Northeast Transmission Zones

Several outages are scheduled in the above zones but only the following outage may limit generation in the Northwest system due to the identified reduction of 105 MW to the limit in the transfer capability between the Northwest and the Northeast system:

Item #110 circuit P26W between Mississagi and Wawa

Toronto Transmission Zone

One outage to the 500-kV system, listed below, will reduce interconnection transmission capability from the USA:

Item #80 Circuit B560V from Bruce A to Claireville will reduce the Negative BLIP[4] limit which in turn will reduce import capability from the USA, coincident with negative Generation Margins in October 2000.

West Transmission Zone

The following transmission outages will reduce interconnection transmission capability with Michigan for a number of weeks in November and December 2000. These outages raise minimal concerns since generation margins are adequate but could become impactive if generation outages in October are not completed as planned:

Item #104 Circuit J5D, Keith to Waterman, 230kV

Item #111 Circuit B563L, Bruce B to Longwood, 500kV

East Transmission Zone

Some 115kV outages will require careful coordination with generation schedules to limit bottling of generation:

Items #23, #87 and #88 impacting Eastern Ontario 115kV circuits

Item 129 Interconnection circuit B31L between Ontario and Quebec will limit the import capability from Quebec during the winter peak period although the generation margins are forecast to be adequate.

In summary, only a few of the planned outages will potentially impact the generation system. The outages with the highest impact are listed above.

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[4] Buchanan Longwood Input - BLIP

6.3 System Voltage Concerns

Low system voltage concerns particularly in the Windsor and Greater Toronto Area will limit the generation and transmission outages that can be planned during summer peak demand periods. The various system voltage concerns are described below:

In the Windsor area, load growth is stressing the capability of the existing system under extreme-weather, summer peak conditions, when voltages are expected to be near the low end of the acceptable range. Voltage control is acceptable but may require restrictions on the use of the J5D interconnection for exporting power to Michigan. Planned outages to generating units or transmission circuits in the Windsor and Sarnia area should therefore be avoided during the summer peak period.

Studies conducted for summer 2000 are applicable to the summer 2001 forecast period and indicate that voltage control in the Greater Toronto Area (GTA) is acceptable but with little or no margin for contingencies. The planned outage of one Pickering B generating unit can be accommodated but system voltages are expected to be at or near their acceptable minimum values, and require the availability of the remaining four Lakeview, three Pickering B and four Darlington units. Planned outages to these units should be scheduled outside the summer peak periods. These studies assumed that all but two Darlington units can supply their designed reactive output capability at rated MW output, and that all other reactive sources and transmission elements in the GTA are available. Above the forecast extreme-weather 2001 summer peak demand (of 24,254 MW), voltages in the GTA can be expected to drop 1.5 kV for each additional 100 MW of demand (at 0.9 power factor). This means that precontingency actions may be necessary to manage the risk of the loss of an additional large generating unit. The historical, lower-than-rated equipment performance, of some Pickering and Darlington units in providing rated reactive power during hot weather further erodes any available voltage control margins in the area. Restoration of the rated reactive output capability of these units will reduce the stated voltage concerns.

At least one of the three generators at Thunder Bay is required to be in-service, most of the time, to maintain minimum voltages in the area, at times of normal industrial demand.

6.4 Forced Outages

The following ongoing forced outages will affect outage planning:

Manitoba-Ontario tie K22W is currently unavailable due to the forced outage of the phase-shifting transformer. This has reduced the transfer capability between Manitoba and Ontario, and has somewhat restricted the flexibility for Manitoba Hydro and OPGI in their existing interchange agreements. The outage also reduces the East-West tie capability, in the order of 50 to 100 MW, further reducing dispatching flexibility in the Northwest zone and requiring more coordination in planning transmission and generation outages

Lennox T52 autotransformer is unavailable due to a forced outage. The most significant impacts of the outage are reductions to the flexibility to dispatch Lennox and reduced ability to plan outages to the remaining Lennox T51. Under summer conditions, with heavy imports from Beauharnois, and reduced output at Darlington, transformer T51 can be loaded up to its continuous rating and may require one of Unit 3 or 4 operating at Lennox to reduce flows.

Outages to T51 make the Lennox reactors unavailable and may require Lennox unit operation to control voltages at Lennox.

6.5 Summary

The transmission outage plan has been reviewed for system impacts. Forecast generation reserve margins are such that any outages that may affect interconnection support or generation access to the IMO-Controlled Grid should be coordinated closely between the transmitter and the generators involved. Some of these outages are highlighted in the body of this report; the remainder are addressed in Appendix D. Several other locally impactive transmission outages, that require careful coordination with local generators, are also identified. In addition, the impact of forced transmission outages has been noted.

System voltage concerns during times of expected summer peak demands, will limit the flexibility for planning outages in the Toronto and Windsor areas. Restoration of the reactive power output capability of Darlington and Pickering units would reduce the stated voltage concerns in the Toronto area.

7.0 Overall Findings and Conclusions

An assessment of the generation and transmission adequacy of the Ontario Electricity System has been carried out for the period from October 2000 through March 2002. The assessment is based on a forecast of electricity demand and available supply combined with current information on the configuration and capability of the transmission system. The most recent known outage plans of generators and transmitters are incorporated in the assessment.

Forecast Margins in Ontario are expected to be manageable for the entire period.

Ontario Power Generation will manage the Margins through a combined use of its own generation, load management, rescheduling of outages and supply from interconnected control areas.

If necessary due to resource shortfalls, the IMO will implement Emergency Operating Procedures.

The transmission outage plan has been reviewed for system impacts and the results of this review indicate the following:

Although the forecast available generation margins are generally manageable in the study period, any outages that may affect interconnection support or generation access to the IMO-Controlled Grid should be coordinated closely between the transmitter and the generators involved. The analysis highlighted a few outages with this potential impact. In addition, the impacts of some forced outages have been noted.

System voltage concerns during times of extreme summer peak demands, will limit the flexibility for planning outages in the Toronto and Windsor areas in 2001.

Restoration of the reactive power output capability of Darlington and Pickering units could reduce the stated voltage concerns in the Toronto area.