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.

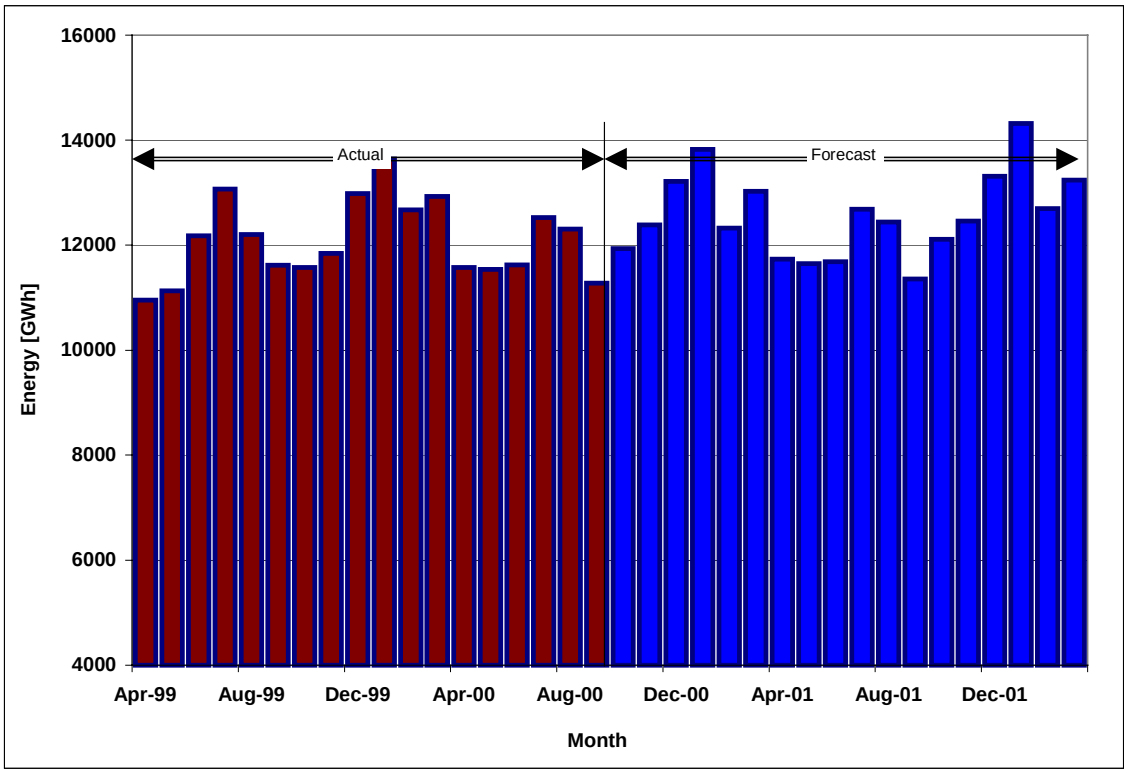
Table 2.1 Ontario Energy Demand

Year	Weather Normal	Actual Weather[2]
	Energy Demand (TWh)	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

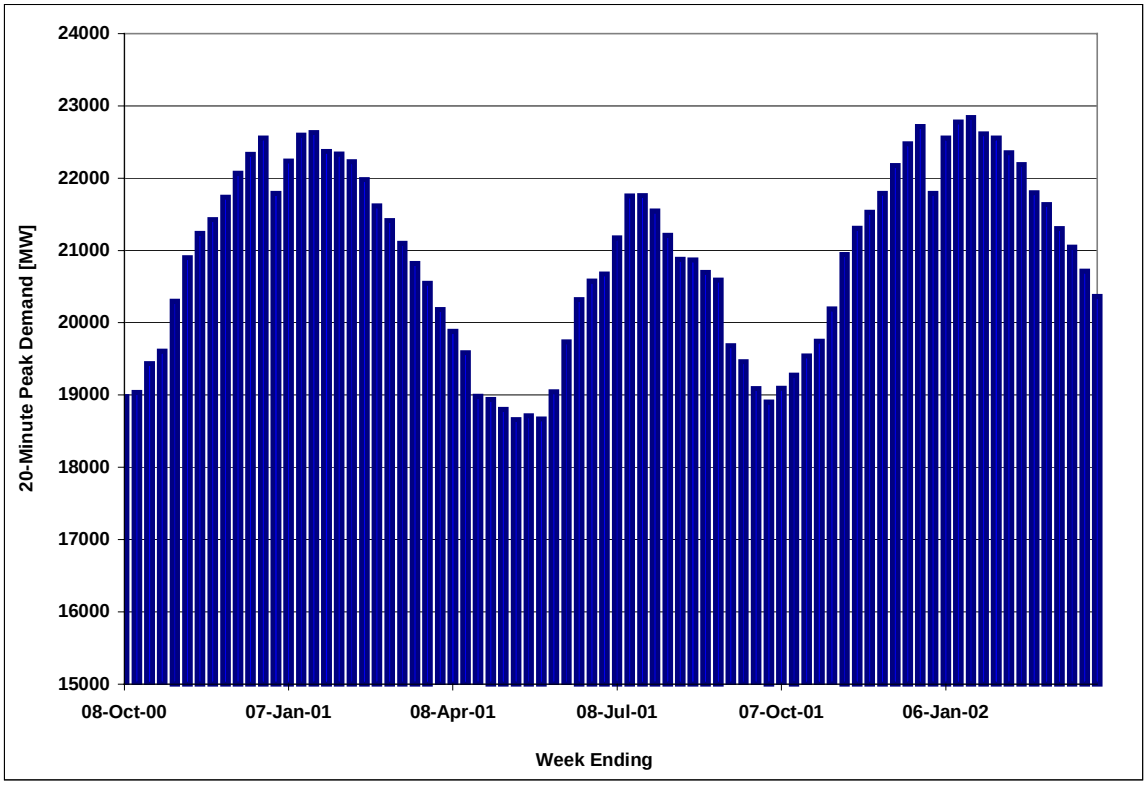
Historically, Ontario's electricity peak demand has occurred during the winter, usually in the months of December through February and between the hours of 5 p.m. to 7 p.m. Exceptions to this were in 1998 and 1999, when the annual peak demand occurred during the afternoon of early to mid-July. The occurrence 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

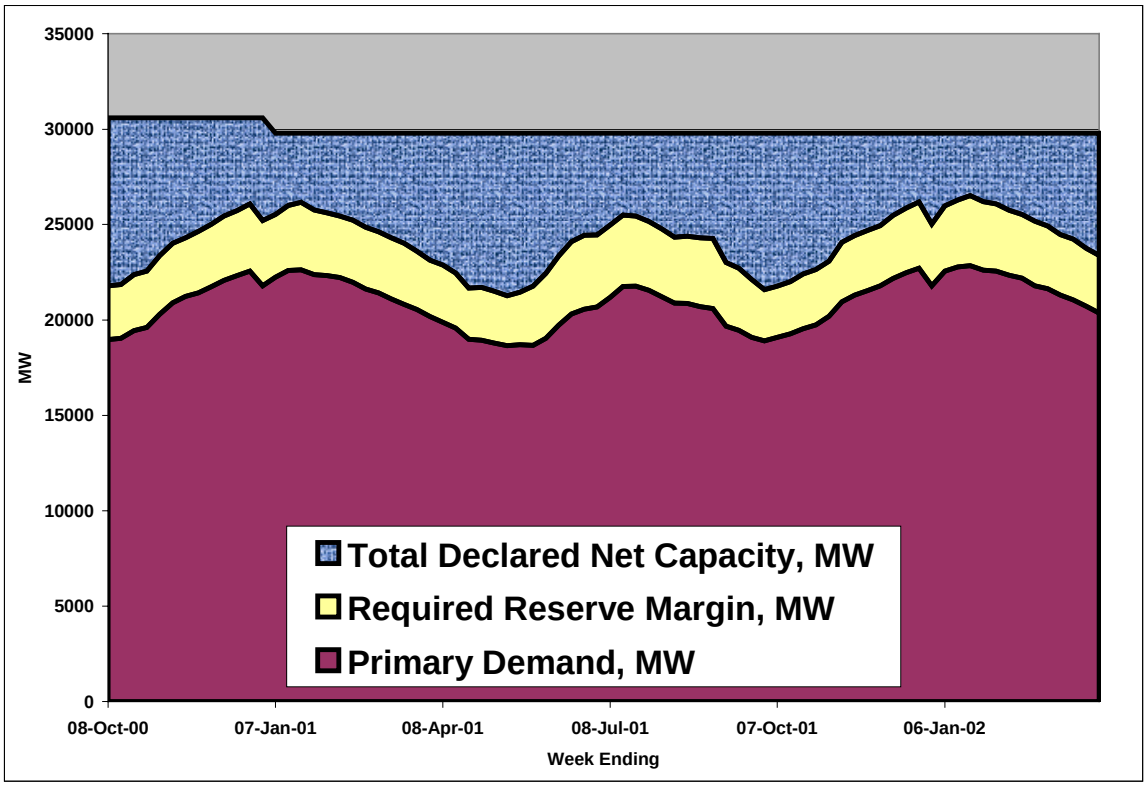
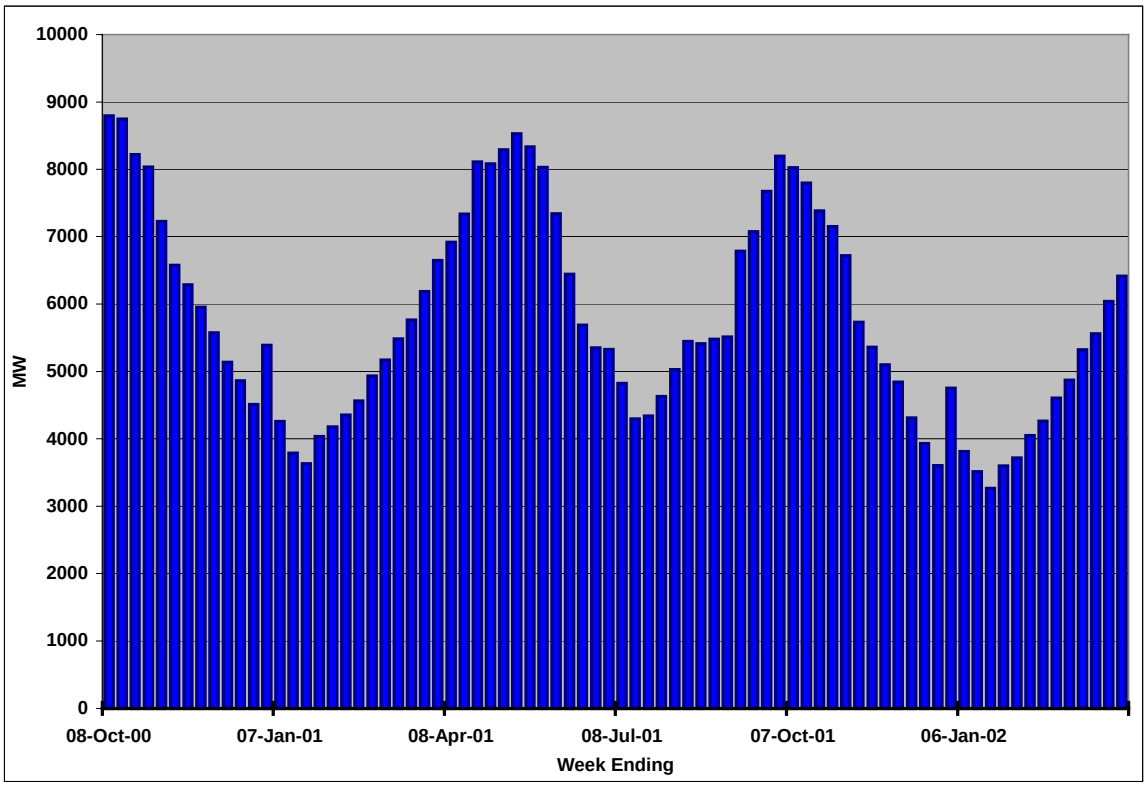


Figure 4.2 Gross Margins



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.

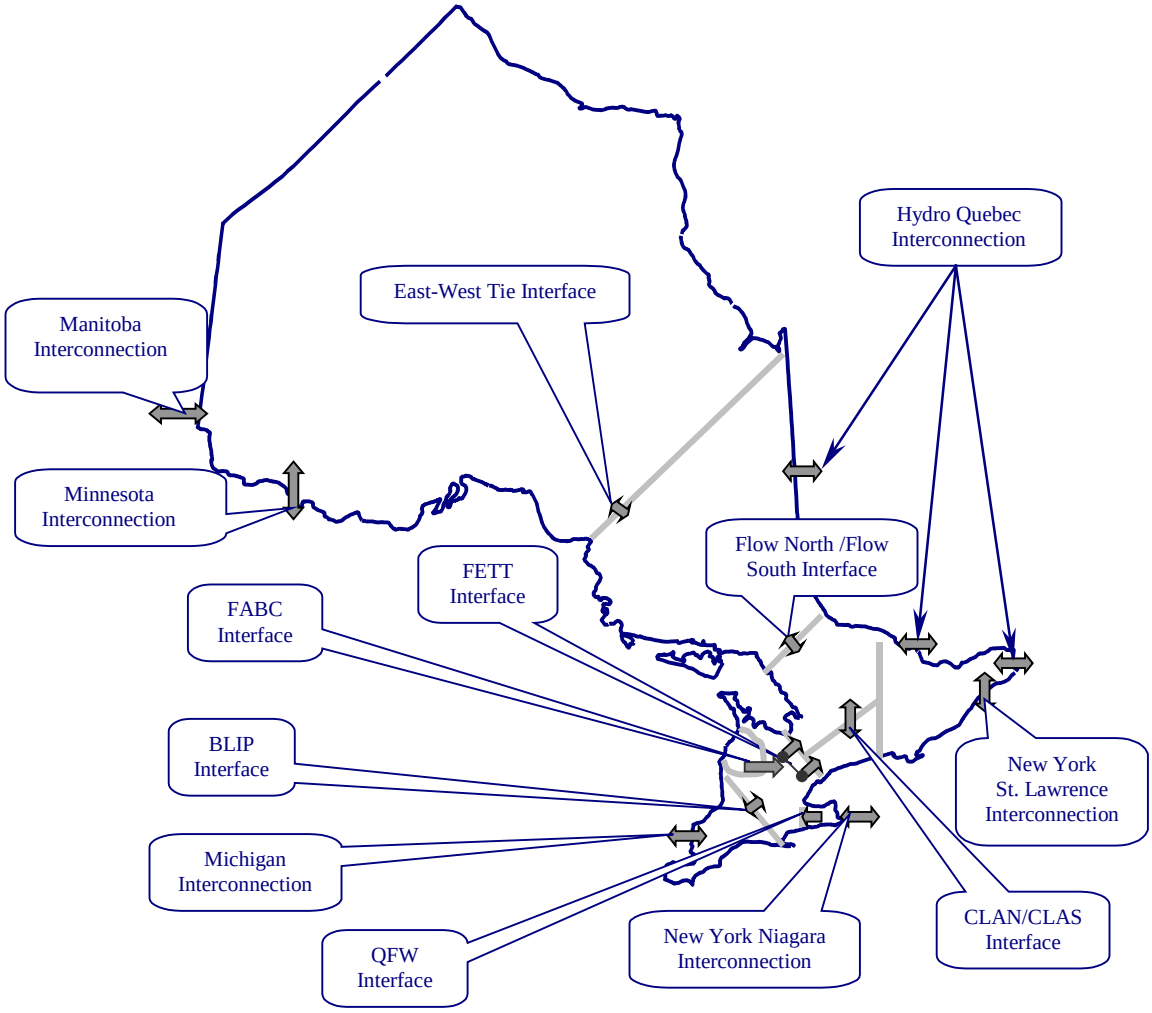
Michigan Facilities:

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.

[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.

Appendix A – Electricity Demand Forecast Details

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Figure A1 – Transmission Zones Used to Derive the Peak Demand Forecasts

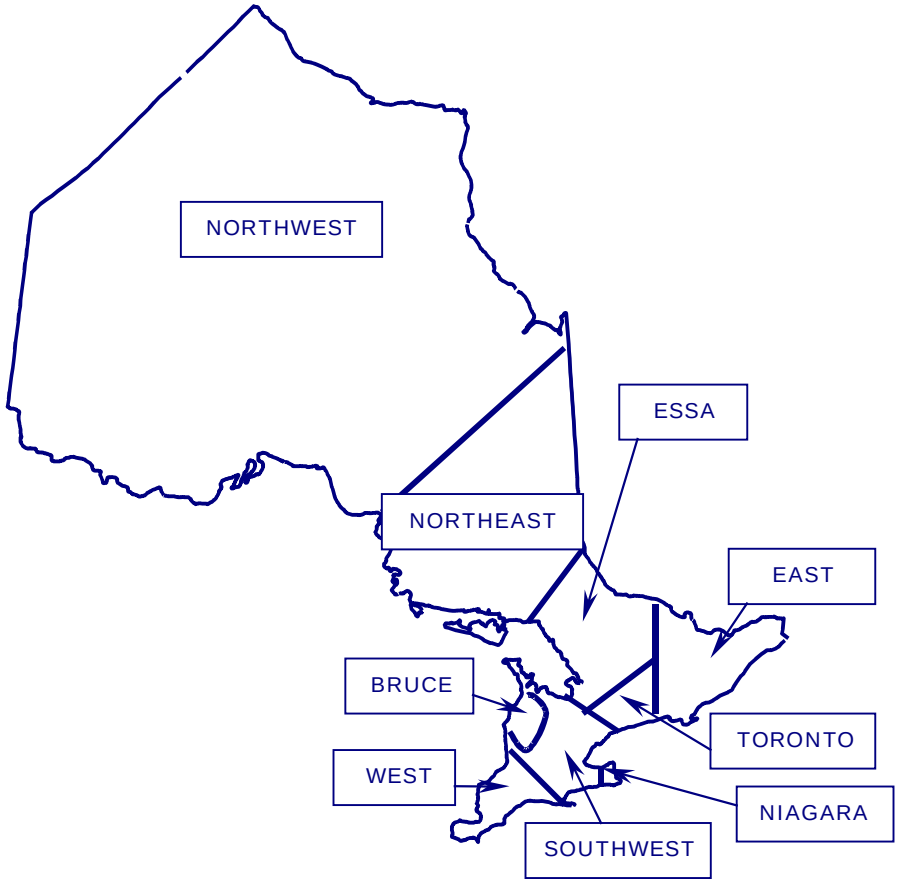

Table A1 Electricity Demand Forecast

Week Ending Day	20-Minute Peak Demand by Transmission Zone – Normal Weather Conditions - MW									Total System 20-min. Peak Demand MW – Various Weather		
	Northwest	Northeast	East	Essa	Toronto	Southwest	Niagara	Bruce	West	Normal Weather [1]	Normal +1 Standard Dev. Weather[2]	Extreme Weather[3]
8-Oct-00	974	1606	3227	798	5450	3659	803	344	2121	18980	19417	19854
15-Oct-00	974	1611	3237	800	5466	3670	806	345	2128	19037	19499	19961
22-Oct-00	974	1647	3308	818	5586	3751	823	353	2175	19434	19926	20418
29-Oct-00	974	1662	3339	825	5639	3786	831	356	2195	19605	20124	20643
5-Nov-00	1048	1717	3449	853	5825	3911	859	368	2268	20297	20869	21441
12-Nov-00	1048	1771	3558	879	6008	4034	886	379	2339	20901	21459	22017
19-Nov-00	1048	1801	3618	894	6109	4102	901	386	2378	21237	21712	22187
26-Nov-00	1048	1818	3652	903	6169	4141	909	389	2401	21427	21984	22541
3-Dec-00	1101	1841	3698	914	6244	4193	920	394	2431	21736	22361	22986
10-Dec-00	1101	1747	3925	1139	6576	4243	931	126	2281	22069	22837	23605
17-Dec-00	1101	1768	3974	1153	6656	4296	943	127	2309	22327	23081	23835
24-Dec-00	1101	1787	4016	1165	6729	4342	953	129	2334	22556	23394	24232
31-Dec-00	1101	1723	3873	1123	6488	4187	919	124	2251	21790	22587	23384
7-Jan-01	1080	1745	3943	1155	6677	4274	938	127	2295	22235	23029	23823
14-Jan-01	1080	1775	4011	1175	6790	4347	954	129	2334	22596	23478	24360
21-Jan-01	1080	1778	4017	1177	6803	4355	956	129	2338	22632	23624	24616
28-Jan-01	1080	1756	3968	1162	6718	4301	944	128	2310	22367	23249	24131
4-Feb-01	1080	1753	3962	1160	6708	4294	943	128	2306	22333	23100	23867
11-Feb-01	1063	1746	3945	1156	6679	4276	939	127	2296	22227	22957	23687
18-Feb-01	1063	1726	3899	1142	6601	4226	928	125	2269	21979	22774	23569
25-Feb-01	1063	1696	3831	1122	6487	4153	912	123	2230	21618	22420	23222
4-Mar-01	1063	1679	3794	1111	6424	4112	903	122	2208	21415	22160	22905
11-Mar-01	1007	1658	3745	1097	6341	4060	891	121	2180	21100	21835	22570
18-Mar-01	1007	1634	3693	1082	6252	4003	879	119	2149	20818	21555	22292
25-Mar-01	1007	1612	3642	1067	6166	3948	867	117	2120	20545	21152	21759
1-Apr-01	1007	1582	3574	1047	6053	3874	850	115	2081	20183	20802	21421
8-Apr-01	978	1671	3375	841	5757	3837	842	361	2221	19884	20480	21076
15-Apr-01	978	1645	3321	828	5666	3776	829	355	2186	19584	20192	20800
22-Apr-01	978	1592	3214	801	5483	3655	802	344	2116	18985	19482	19979
29-Apr-01	978	1587	3206	799	5468	3645	800	343	2110	18936	19457	19978
6-May-01	978	1575	3181	793	5428	3617	794	340	2094	18798	19207	19616
13-May-01	924	1568	3166	789	5400	3599	790	339	2084	18659	19160	19661
20-May-01	924	1572	3175	792	5416	3610	792	340	2090	18711	19428	20145
27-May-01	924	1569	3167	790	5403	3601	791	339	2085	18669	19587	20505
3-Jun-01	937	1600	3232	806	5513	3674	807	346	2127	19042	20073	21104
10-Jun-01	937	1256	3596	874	6025	3906	857	150	2134	19735	20966	22197
17-Jun-01	937	1295	3708	901	6212	4027	884	155	2200	20319	21691	23063
24-Jun-01	937	1312	3757	913	6295	4081	896	157	2229	20576	21978	23380
1-Jul-01	937	1318	3776	918	6326	4101	900	158	2240	20675	22020	23365
8-Jul-01	947	1351	3869	941	6483	4203	923	162	2296	21174	22527	23880
15-Jul-01	947	1390	3981	968	6669	4324	949	166	2362	21756	23005	24254
22-Jul-01	947	1390	3982	968	6672	4325	949	167	2362	21760	22965	24170
29-Jul-01	947	1376	3941	958	6603	4281	940	165	2338	21548	22721	23894
5-Aug-01	951	1353	3876	942	6494	4210	924	162	2300	21211	22340	23469

[1] The values shown are under 'normal' conditions which covers 50% of time weather conditions in that week from a normal distribution of the demand in that week. (This bell curve is used in the calculation of the generation reserve requirement in each week.) Total demand may not match the sum of the zones due to rounding.

[2] The values shown are under 'normal plus one standard deviation' conditions which covers 84.1% of time weather conditions in that week. Such a demand could be expected to occur on some days over a season. The maximum value over a season is provided to the Northeast Power Coordinating Council for seasonal assessments.

[3] The values shown are under 'normal plus two standard deviations' conditions which covers 97.7% of time conditions in that week. Such values are used to assess the adequacy of the transmission system.

Week Ending Day	20-Minute Peak Demand by Transmission Zone – Normal Weather Conditions - MW									Total System 20-min. Peak Demand MW – Various Weather		
	Northwest	Northeast	East	Essa	Toronto	Southwest	Niagara	Bruce	West	Normal Weather [1]	Normal +1 Standard Dev. Weather[2]	Extreme Weather[3]
12-Aug-01	951	1331	3812	927	6386	4140	909	159	2262	20877	21916	22955
19-Aug-01	951	1331	3811	926	6384	4139	909	159	2261	20870	21955	23040
26-Aug-01	951	1319	3777	918	6328	4103	901	158	2241	20696	21881	23066
2-Sep-01	956	1311	3756	913	6292	4079	895	157	2228	20588	21838	23088
9-Sep-01	958	1251	3582	871	6001	3891	854	150	2125	19682	20802	21922
16-Sep-01	958	1236	3540	860	5931	3845	844	148	2100	19462	20449	21436
23-Sep-01	958	1211	3468	843	5811	3767	827	145	2058	19088	19909	20730
30-Sep-01	958	1199	3433	834	5752	3729	819	144	2037	18904	19427	19950
7-Oct-01	974	1602	3235	806	5518	3678	807	346	2129	19095	19531	19967
14-Oct-01	974	1618	3266	814	5572	3714	815	350	2150	19273	19713	20153
21-Oct-01	974	1641	3314	826	5654	3768	827	355	2182	19541	20054	20567
28-Oct-01	974	1659	3350	835	5716	3809	836	359	2205	19744	20259	20774
4-Nov-01	1048	1692	3417	852	5830	3885	853	366	2250	20193	20724	21255
11-Nov-01	1048	1759	3552	885	6059	4038	886	380	2338	20946	21509	22072
18-Nov-01	1048	1791	3616	902	6169	4112	903	387	2381	21308	21815	22322
25-Nov-01	1048	1810	3656	911	6237	4156	912	391	2406	21527	22051	22575
2-Dec-01	1082	1831	3697	922	6306	4203	923	396	2433	21791	22413	23035
9-Dec-01	1107	1738	3927	1150	6648	4256	934	126	2286	22173	22880	23587
16-Dec-01	1107	1763	3983	1167	6744	4317	948	128	2318	22475	23226	23977
23-Dec-01	1107	1783	4028	1180	6821	4366	958	130	2344	22715	23533	24351
30-Dec-01	1107	1706	3855	1129	6527	4179	917	124	2244	21788	22586	23384
6-Jan-02	1107	1754	3983	1177	6810	4328	950	131	2323	22555	23356	24157
13-Jan-02	1081	1775	4029	1191	6880	4378	961	132	2350	22778	23613	24448
20-Jan-02	1081	1780	4041	1195	6901	4391	964	133	2356	22840	23827	24814
27-Jan-02	1081	1761	3998	1182	6827	4345	954	131	2332	22611	23548	24485
3-Feb-02	1081	1757	3988	1179	6809	4333	951	131	2326	22555	23364	24173
10-Feb-02	1063	1742	3954	1169	6751	4297	943	130	2306	22354	23099	23844
17-Feb-02	1063	1728	3923	1160	6699	4263	936	129	2288	22189	22960	23731
24-Feb-02	1063	1696	3851	1139	6576	4185	919	127	2246	21801	22654	23507
3-Mar-02	1063	1683	3820	1129	6524	4151	911	125	2228	21634	22379	23124
10-Mar-02	1007	1660	3769	1114	6436	4096	899	124	2198	21302	22045	22788
17-Mar-02	1007	1639	3722	1100	6355	4044	888	122	2170	21048	21795	22542
24-Mar-02	1007	1612	3659	1082	6249	3977	873	120	2134	20713	21314	21915
31-Mar-02	1007	1583	3595	1063	6138	3906	858	118	2096	20365	21028	21691

Table A2 Actual & Forecast Summer and Winter 20-Minute System Peak Demand

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Summer Peak Demand / Winter Peak Demand Ratio
1990	20,453	22,311	0.917
1991	21,150	23,212	0.911
1992	19,857	23,487	0.845
1993	20,806	21,951	0.948
1994	20,923	24,007	0.872
1995	21,766	22,855	0.952
1996	21,428	22,321	0.960
1997	21,667	22,197	0.976
1998	22,443	22,067	1.017
1999	23,435	23,308	1.005
2000	23,222	23,428	0.991
2001[1]	21,761 (f)	22,633 (f)	0.961
2002[2]	22,088 (f)	22,841 (f)	0.967

(f) = forecast

[1] The forecast is based on normal weather.

[2] The summer 2002 peak is not within the scope of this forecast. This estimate is provided in order to illustrate the relative changes in summer and winter peak

Appendix B – Ontario Electricity System – Maps

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1.0 The Ontario Electricity System 230 & 500 kV Geographical Layout Map[1]

Figure B1.1 – Southern Ontario

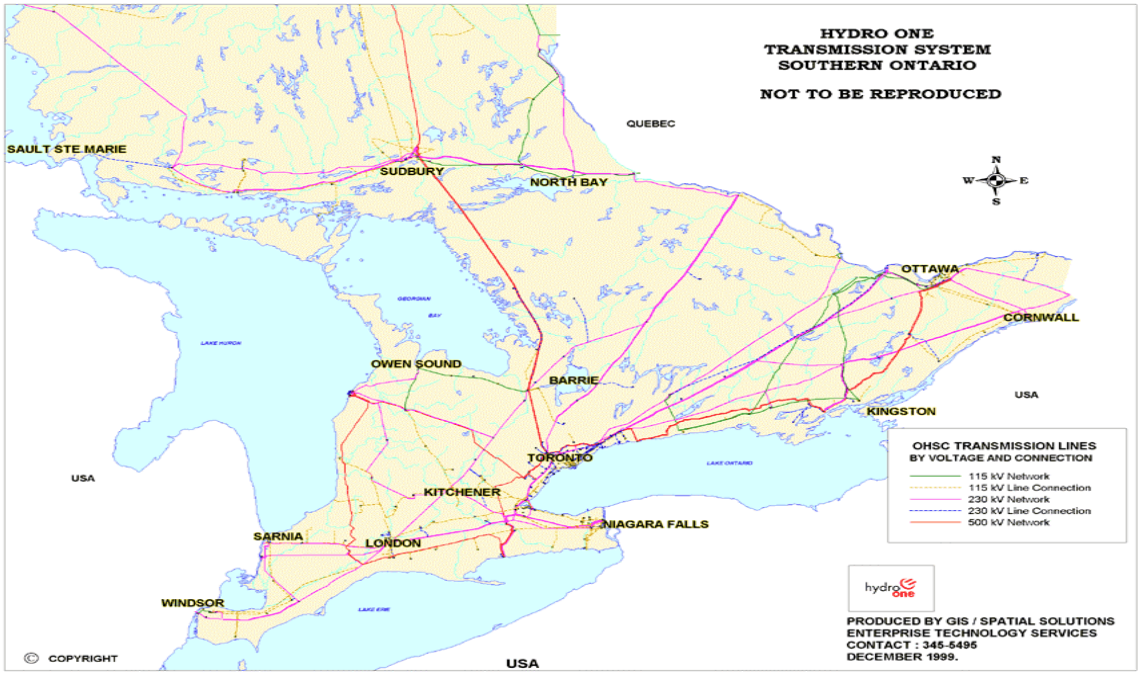
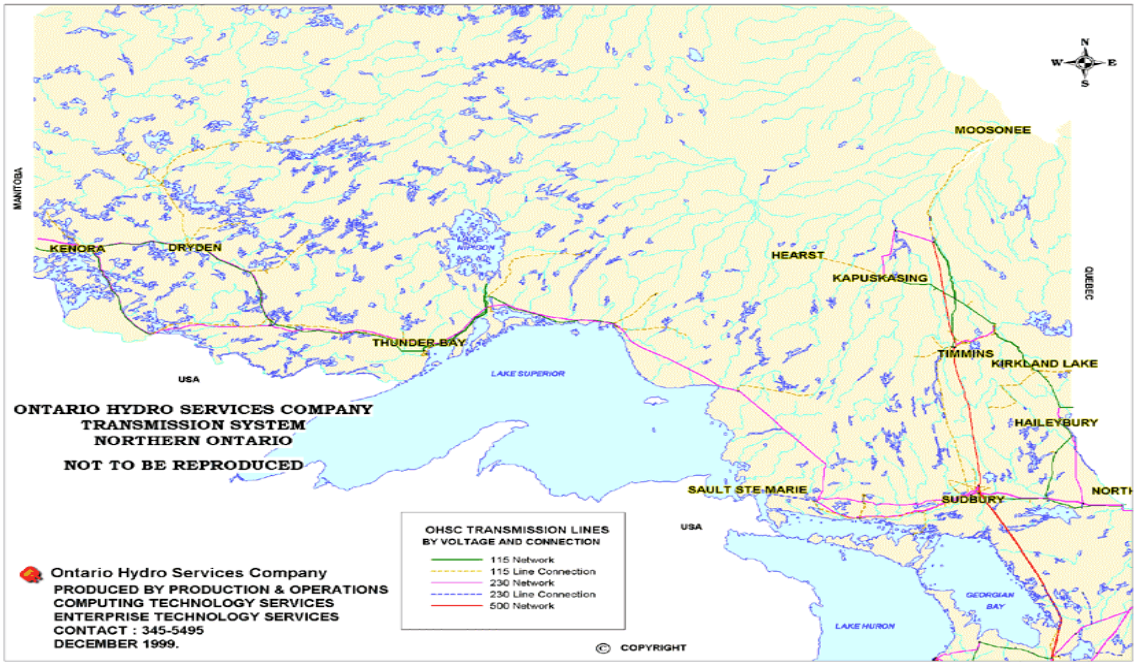


Figure B1.2 – Northern Ontario



[1] Maps are provided with the permission of Hydro One Networks Inc.

2.0 Load Centres

Figure B2.1 – GTA

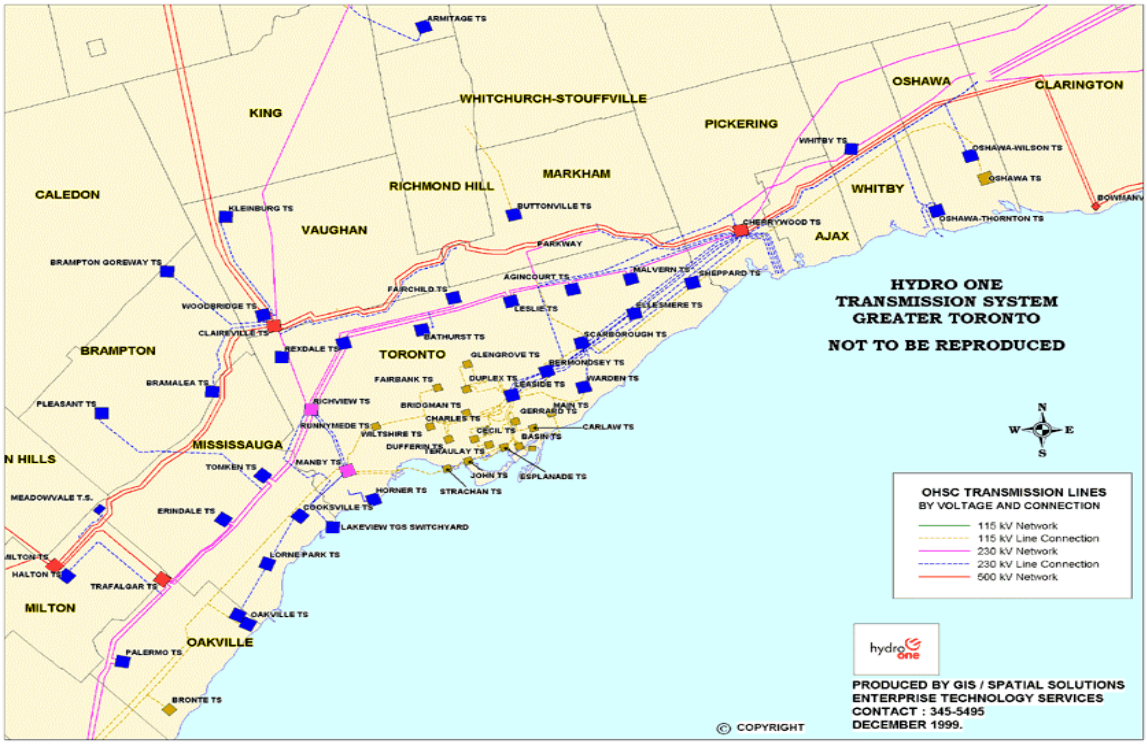


Figure B2.2 – Hamilton

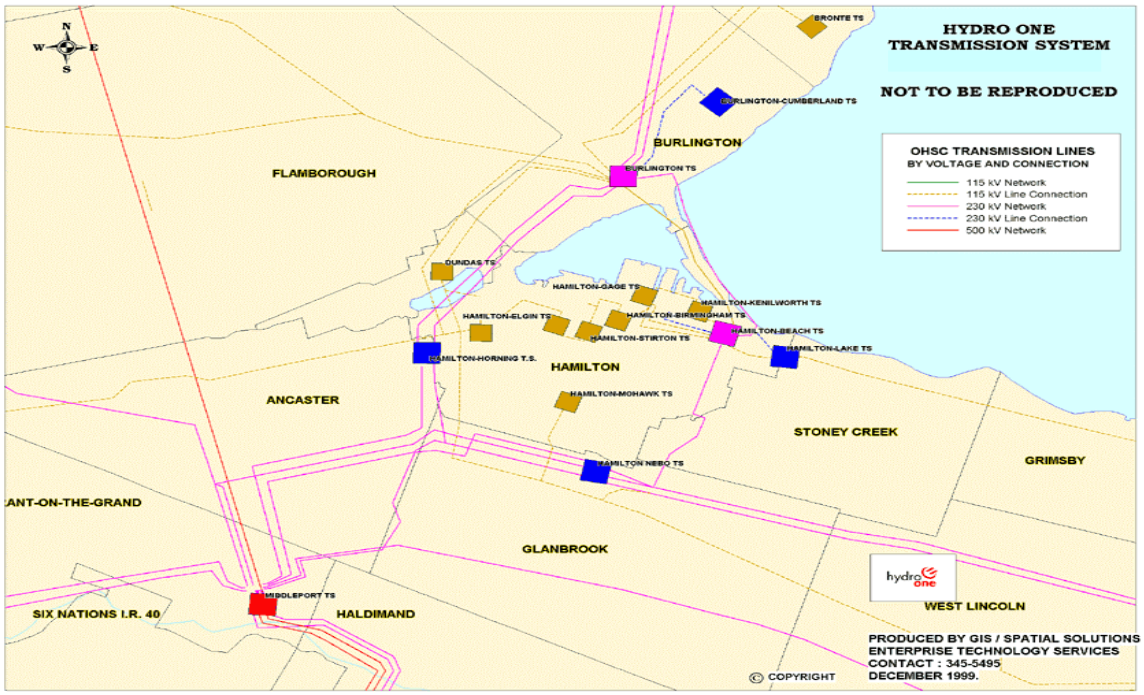


Figure B2.3 – Niagara

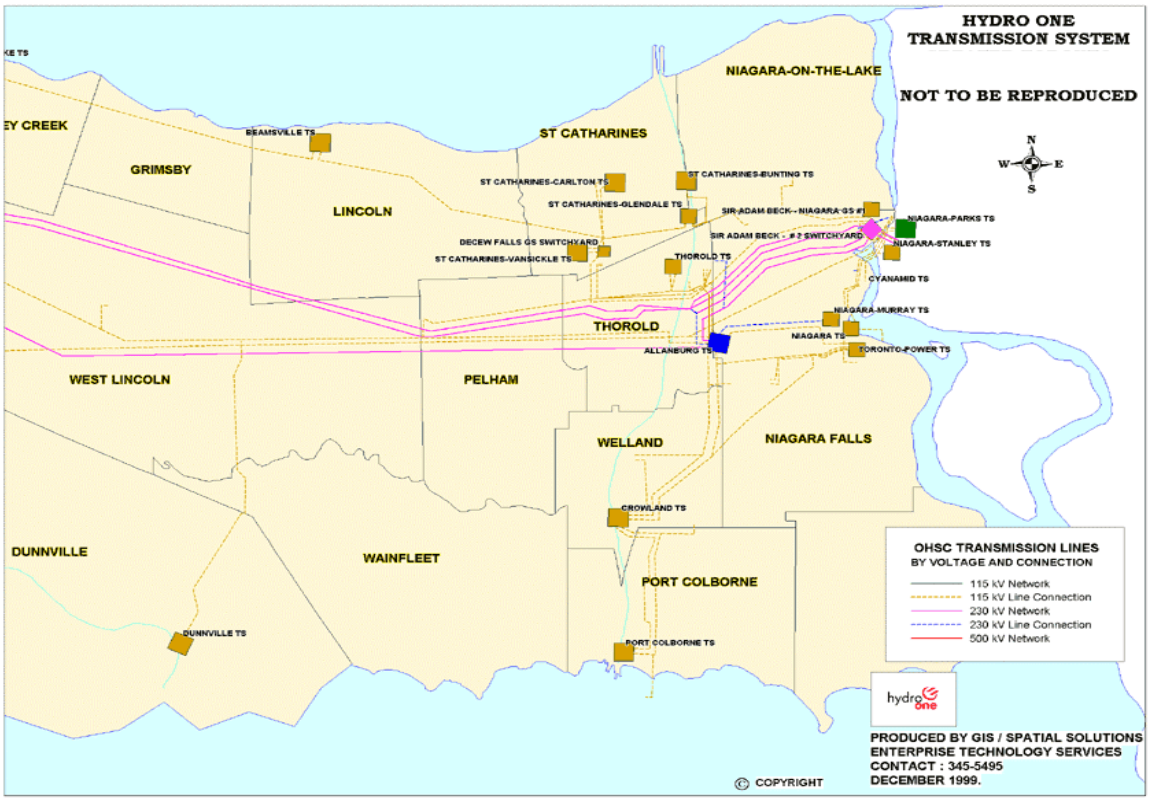


Figure B2.4 – Sarnia

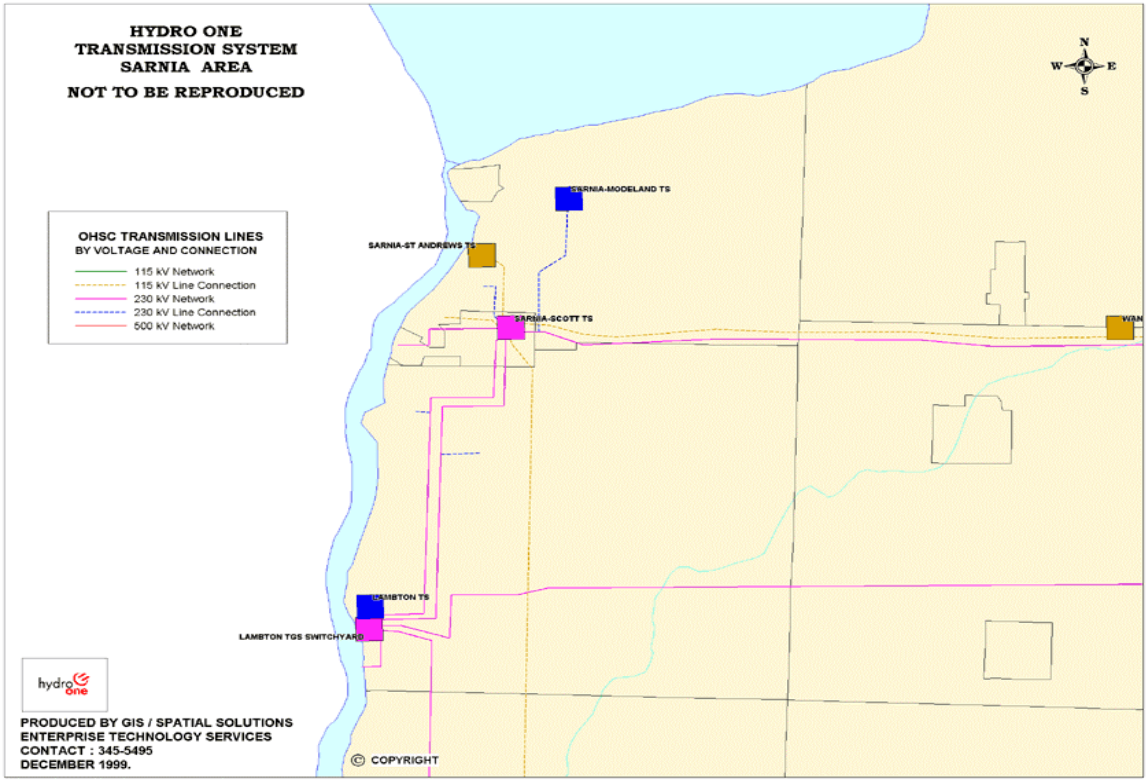


Figure B2.5 – Windsor

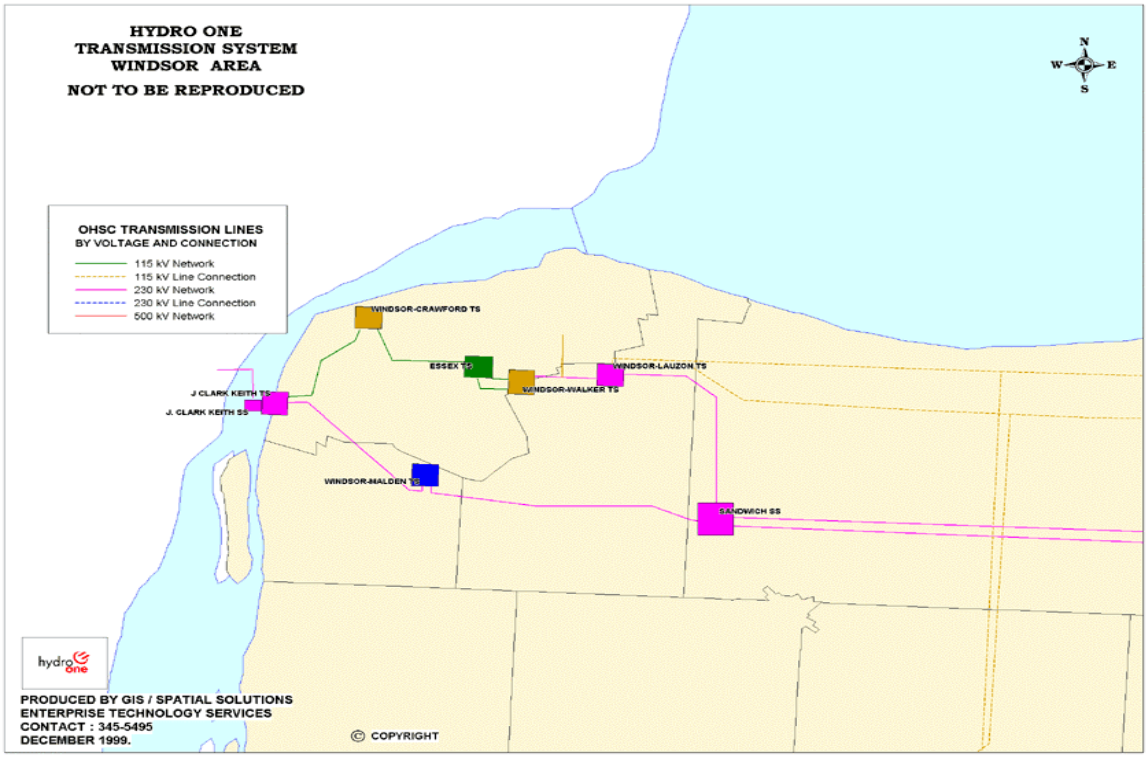


Figure B2.6 – Thunder Bay

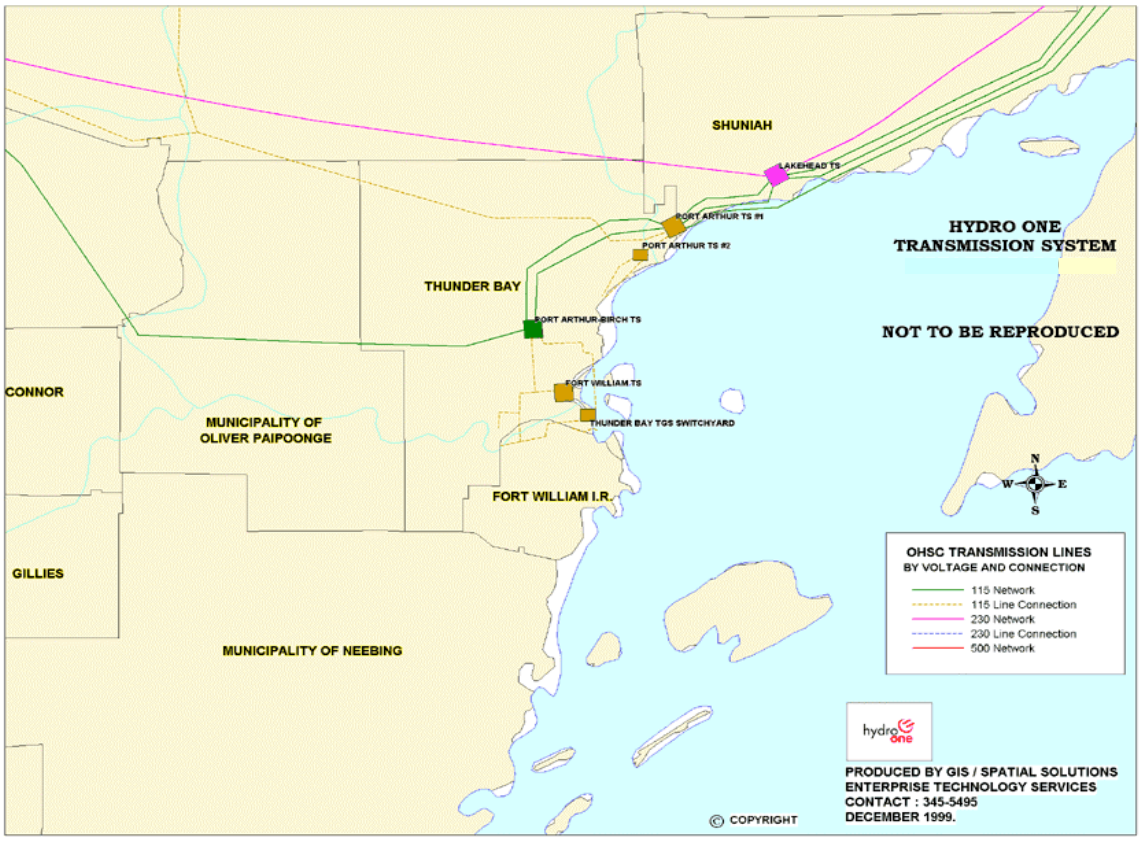


Figure B2.7 – Ottawa

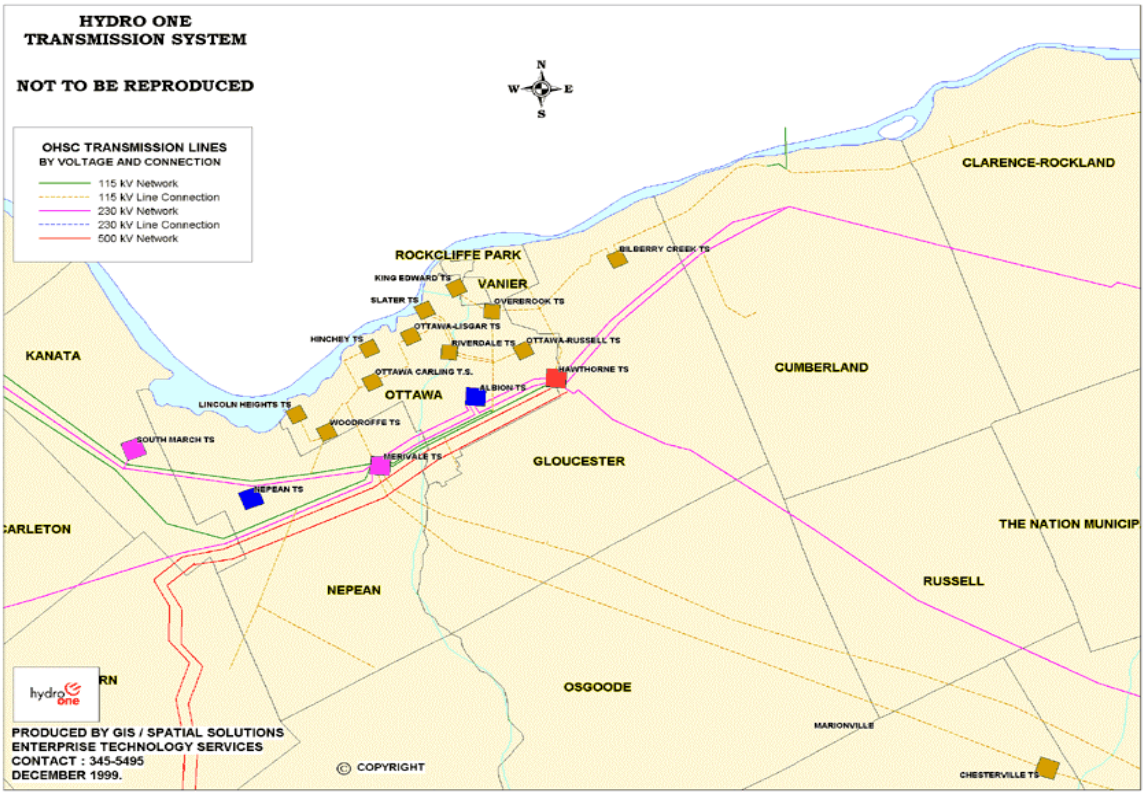


Figure B2.8 – London

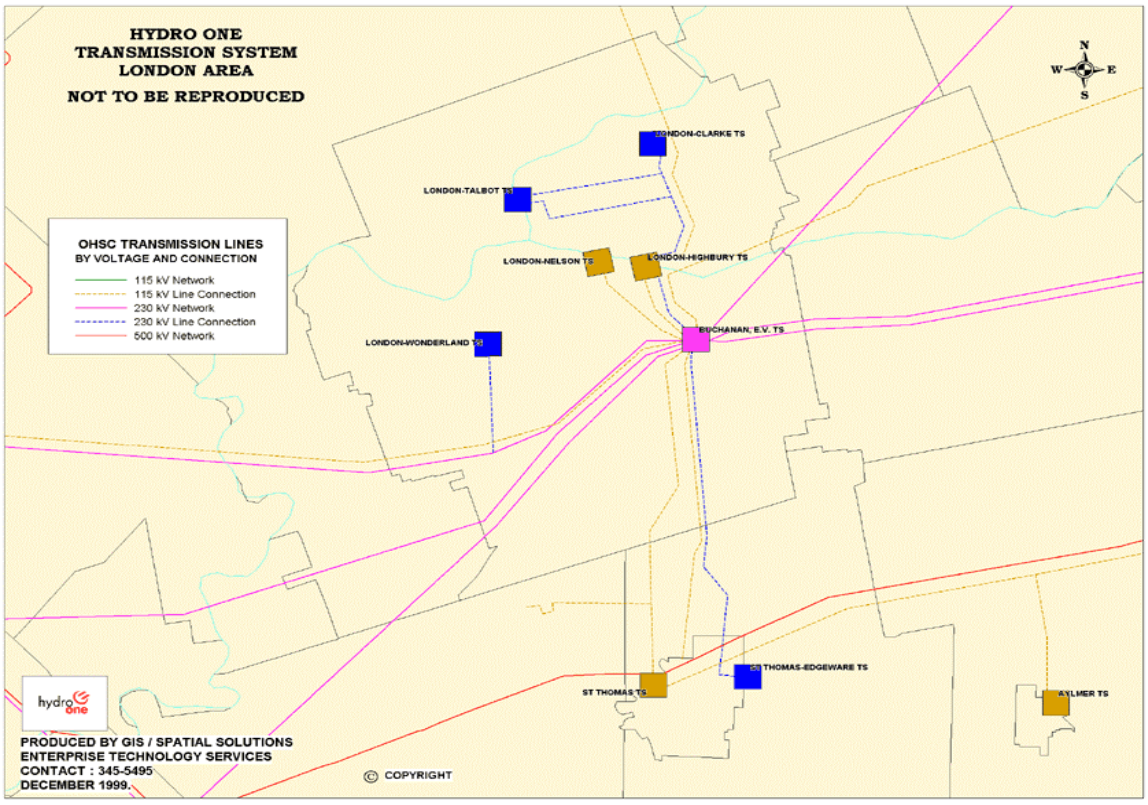


Figure B2.9 – Sudbury

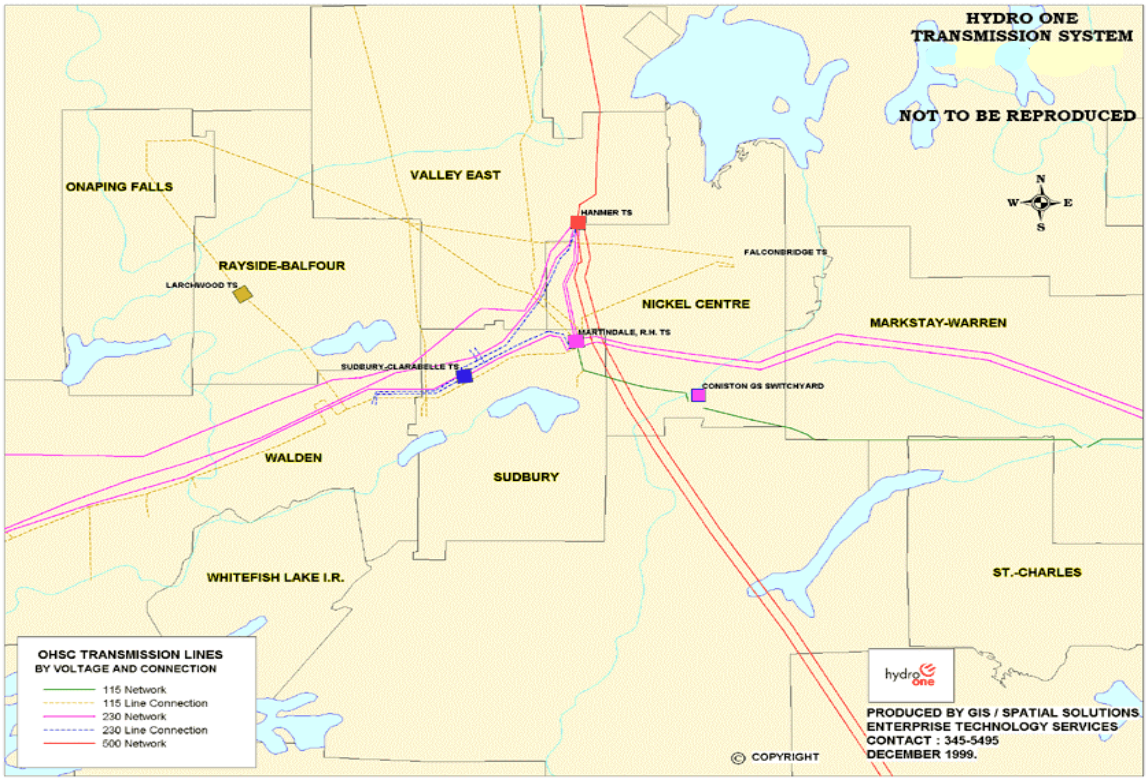
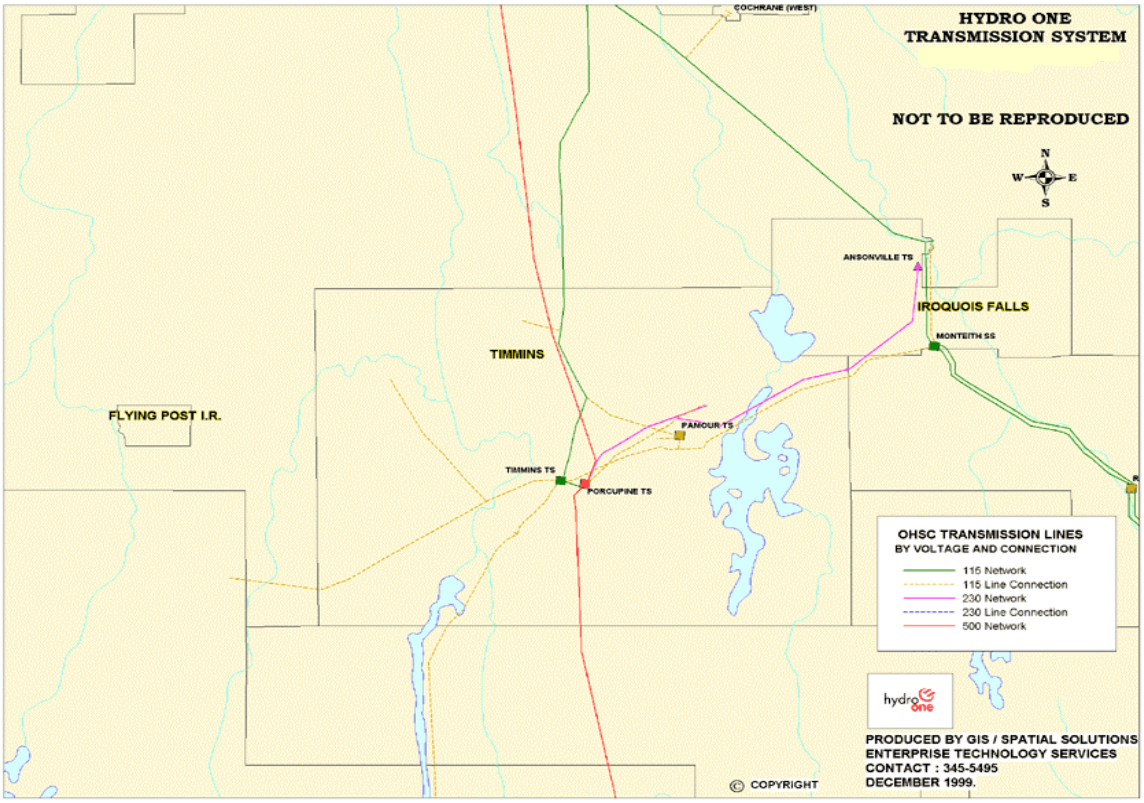


Figure B2.10 – Timmins



Appendix C – System Resources Details

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1.0 Resources Data Tables

Table C1.1 Ontario Power Generation Inc. Power Stations in Study

Name	Resource Type	Declared Net Capacity (MW)	Units
Bruce B	Nuclear	3,140	4
Darlington	Nuclear	3,524	4
Pickering A	Nuclear	2,060	4
Pickering B	Nuclear	2,064	4
Atikokan	Coal	215	1
Lakeview	Coal	1,140	4
Lambton	Coal	1,975	4
Lennox	Oil & Gas	2,140	4
Nanticoke	Coal	3,920	8
Thunder Bay	Coal	310	2
CTU's	Oil & Gas	22	5
Tacke Turbine	Wind	1	1
Abitibi Canyon	Hydro	314	5
Aguasabon	Hydro	46	2
Alexander	Hydro	67	5
Arnprior	Hydro	82	2
Aubrey Falls	Hydro	162	2
Barrett Chute	Hydro	176	4
Cameron Falls	Hydro	78	7
Caribou Falls	Hydro	87	3
Chats Falls[1]	Hydro	96	4
Chenaux	Hydro	139	8
Decew Falls 1	Hydro	23	4
Decew Falls 2	Hydro	144	2
Des Joachims	Hydro	429	8
Ear Falls	Hydro	17	4
G.W. Rayner	Hydro	46	2
Harmon	Hydro	141	2
Kakabeka Falls	Hydro	25	4
Kipling	Hydro	141	2
Little Long	Hydro	133	2
Lower Notch	Hydro	274	2
Manitou Falls	Hydro	66	5
Mountain Chute	Hydro	170	2
Otter Rapids	Hydro	182	4
Otto Holden	Hydro	243	8
Pine Portage	Hydro	131	4
R.H. Saunders	Hydro	1,005	16
Red Rock Falls	Hydro	41	2
Silver Falls	Hydro	48	1
Sir Adam Beck 1	Hydro	496	10
Sir Adam Beck 2	Hydro	1,360	16
Sir Adam Beck PGS	Hydro	174	6
Smoky Falls	Hydro	56	4
Stewartville	Hydro	182	5
Wells	Hydro	232	2
Whitedog Falls	Hydro	68	3
Other Hydro[2]	Hydro	206	86

[1] Capacity and units shown are for Ontario half of the station.

[2] They include plants with station capacity of less than 15 MW (156 MW) and 50 MW of hydro unit upgrades completed in year 2000.

Table C1.2 Ontario Power Generation Inc. Units Not In Study

Name	Capacity (MW)
Bruce A 1, 2, 3, 4 (Nuclear) (OS)	3,076
Lakeview Units 3, 4, 7, 8 (Coal) (RE)	1,138
Thunder Bay 1 (Coal) (RE)	94

Notes:
OS On long term scheduled maintenance or Forced Outage. Not available to operate (greater than 3 months)
RE Retired (no longer in service and not expected to be returned to service)

Table C1.3 Contract Generators Power Stations in Study

Resource Type	In-Service Capacity (MW)
Natural Gas	1,038
Natural Gas/ Black Liquor	103
Landfill Gas	57
Natural Gas/ Waste Heat	328
Hydro	75
Municipal Solid Waste	15
Steam	40
Subtotal (10 MW in size or greater shown above)	**1,656**
Subtotal (less than 10 MW in size) (See Table C1.4 for Details)	**110**
Total	**1,766**

Table C1.4 Contract Generators Small Power Stations in Study

Resource Type	In-Service Capacity (MW)
Natural Gas	10
Landfill Gas	5
Municipal Solid Waste	4
Wood Waste	17
Hydro	59
Waste/ Flare Gas	2
Subtotal (greater than or equal to 1 MW in size and less than 10 MW shown above)	97
Subtotal (less than 1 MW in size) – Mostly Hydro, with some Natural Gas	13
Total	**110 MW**

2.0 Generation Reserve Requirement

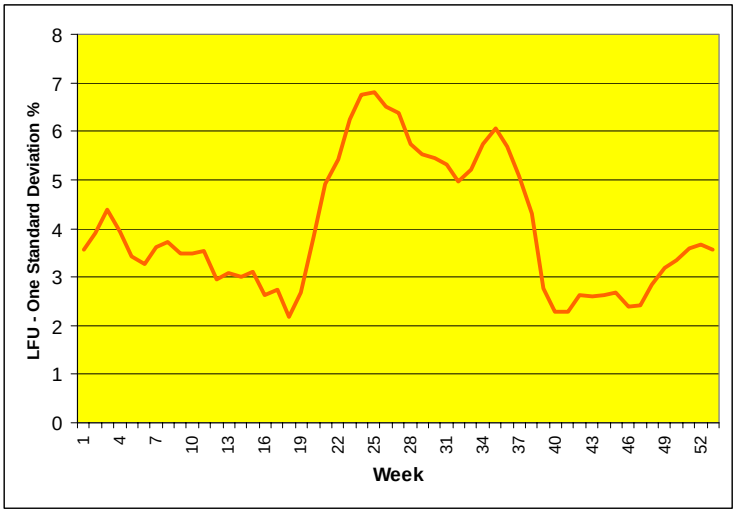
2.1 Method

The IMO uses a Load and Capacity (L&C) model to determine the Generation Reserve Requirements from week to week. The mix of generating plant, generating unit forced outage rates and the demand forecast and the associated uncertainties are inputs to the model. A Generation Adequacy Standard of 0.1 (day/year), is used to determine the Reserve Requirement for each week of the planning year. The adequacy of the available generation facilities to meet the demand over the 18-month study period can be assessed from the forecast weekly Margin, shown in Table C2.1.

2.2 Demand Forecast Uncertainty due to Weather

The total energy demand is split into weather and non-weather components. A normal distribution of weather swings, in any week, is provided by input of the associated standard deviation. This data is obtained from 30-year weather statistics and is updated annually. The standard deviation of weather-related demand (Load Forecast Uncertainty or LFU) varies between about 2% and 7 % through the year as shown in Figure C2.1. The peak demand probability distribution in any week is thus available to the L&C program.

Figure C2.1 Weekly Demand Forecast Uncertainty due to Weather



2.3 Resource Representation

Unit Ratings

Thermal generating units are assumed to be capable of operating at a level equal to their normal Maximum Continuous Rating (MCR). Hydroelectric system output is based on data provided by the Owners. The peak and energy output of all combustion turbines varies considerably with changes in ambient air temperature and, hence, both summer and winter values are included.

Forced Outage Rates of Generating Units

Derating-Adjusted Forced outage rates for each unit are used that reflect both forced outages and periods of derated output. Values are provided by Generation Plant Owners.

2.4 Representation of Interconnected Systems

There are effectively three systems that can provide assistance to Ontario, namely, USA, Quebec and Manitoba. For this study, interconnection assistance is not included, in the calculation of the Margin but is taken into account in the assessments, whenever a negative margin is indicated.

2.5 Transmission Systems

The Ontario IMO Controlled Grid consists of a robust southern grid and a sparse northern grid. The southern grid has few binding limits and these have been accounted for in this study. The northwestern part of the northern grid has limitations that potentially constrain generation capacity. Some 25-hz generation in the southern grid is bottled by frequency changer capability. Total generation limitations are modeled as a reduction in capability of up to 320 MW.

2.6 Study Procedures

For the 18-month assessment period, an LOLP value of 0.1 days per year was utilized to determine the Required Reserve in each week of the year. The uncertainty in the demand forecast varies from week to week, and the available generation mix may also vary, giving rise to a different Reserve Requirement for the Peak hour of each week. The risk is thus level throughout the year when calculating the Margin. Capacity available above the Reserve Requirement and Demand is considered to be surplus in any week and may be released for planned outages.

Table C2.1 Assessment of Gross Margin

Week Ending Day	Total Declared Net Capacity, MW	Primary Demand, MW	Generation Reserve Req. MW	Generation Reserve Req. %	Gross[1] Margin MW
08-Oct-00	30590	18980	2816	14.8	8794
15-Oct-00	30590	19037	2809	14.8	8744
22-Oct-00	30590	19434	2938	15.1	8218
29-Oct-00	30590	19605	2951	15.1	8034
05-Nov-00	30590	20297	3066	15.1	7227
12-Nov-00	30590	20901	3117	14.9	6572
19-Nov-00	30590	21237	3065	14.4	6288
26-Nov-00	30590	21427	3209	15.0	5954
03-Dec-00	30590	21736	3278	15.1	5576
10-Dec-00	30590	22069	3381	15.3	5140
17-Dec-00	30590	22327	3403	15.2	4860
24-Dec-00	30590	22556	3522	15.6	4512
31-Dec-00	30590	21790	3410	15.6	5390
07-Jan-01	29790	22235	3298	14.8	4257
14-Jan-01	29790	22596	3409	15.1	3785
21-Jan-01	29790	22632	3526	15.6	3632
28-Jan-01	29790	22367	3390	15.2	4033
04-Feb-01	29790	22333	3279	14.7	4178
11-Feb-01	29790	22227	3207	14.4	4356
18-Feb-01	29790	21979	3247	14.8	4564
25-Feb-01	29790	21618	3239	15.0	4933
04-Mar-01	29790	21415	3207	15.0	5168
11-Mar-01	29790	21100	3209	15.2	5481
18-Mar-01	29790	20818	3207	15.4	5765
25-Mar-01	29790	20545	3060	14.9	6185
01-Apr-01	29790	20183	2959	14.7	6648
08-Apr-01	29790	19884	2989	15.0	6917
15-Apr-01	29790	19584	2872	14.7	7334
22-Apr-01	29790	18985	2696	14.2	8109
29-Apr-01	29790	18936	2773	14.6	8081
06-May-01	29790	18798	2701	14.4	8291
13-May-01	29790	18659	2602	13.9	8529
20-May-01	29790	18711	2747	14.7	8332
27-May-01	29790	18669	3092	16.6	8029
03-Jun-01	29790	19042	3405	17.9	7343
10-Jun-01	29790	19735	3615	18.3	6440
17-Jun-01	29790	20319	3783	18.6	5688
24-Jun-01	29790	20576	3865	18.8	5349
01-Jul-01	29790	20675	3786	18.3	5329
08-Jul-01	29790	21174	3793	17.9	4823
15-Jul-01	29790	21756	3737	17.2	4297
22-Jul-01	29790	21760	3694	17.0	4336
29-Jul-01	29790	21548	3616	16.8	4626
05-Aug-01	29790	21211	3551	16.7	5028
12-Aug-01	29790	20877	3466	16.6	5447
19-Aug-01	29790	20870	3511	16.8	5409
26-Aug-01	29790	20696	3614	17.5	5480

Week Ending Day	Total Declared Net Capacity, MW	Primary Demand, MW	Generation Reserve Req. MW	Generation Reserve Req. %	Gross[1] Margin MW
02-Sep-01	29790	20588	3694	17.9	5508
09-Sep-01	29790	19682	3324	16.9	6784
16-Sep-01	29790	19462	3253	16.7	7075
23-Sep-01	29790	19088	3033	15.9	7669
30-Sep-01	29790	18904	2691	14.2	8195
07-Oct-01	29790	19095	2673	14.0	8022
14-Oct-01	29790	19273	2723	14.1	7794
21-Oct-01	29790	19541	2865	14.7	7384
28-Oct-01	29790	19744	2897	14.7	7149
04-Nov-01	29790	20193	2878	14.3	6719
11-Nov-01	29790	20946	3114	14.9	5730
18-Nov-01	29790	21308	3121	14.6	5361
25-Nov-01	29790	21527	3163	14.7	5100
02-Dec-01	29790	21791	3159	14.5	4840
09-Dec-01	29790	22173	3306	14.9	4311
16-Dec-01	29790	22475	3384	15.1	3931
23-Dec-01	29790	22715	3471	15.3	3604
30-Dec-01	29790	21788	3248	14.9	4754
06-Jan-02	29790	22555	3426	15.2	3809
13-Jan-02	29790	22778	3497	15.4	3515
20-Jan-02	29790	22840	3683	16.1	3267
27-Jan-02	29790	22611	3582	15.8	3597
03-Feb-02	29790	22555	3519	15.6	3716
10-Feb-02	29790	22354	3388	15.2	4048
17-Feb-02	29790	22189	3336	15.0	4265
24-Feb-02	29790	21801	3386	15.5	4603
03-Mar-02	29790	21634	3287	15.2	4869
10-Mar-02	29790	21302	3168	14.9	5320
17-Mar-02	29790	21048	3185	15.1	5557
24-Mar-02	29790	20713	3038	14.7	6039
31-Mar-02	29790	20365	3013	14.8	6412

[1] Gross Margin = Total Declared Net Capacity – Primary Demand – Generation Reserve Requirement. This quantity does not account for forced or planned outages for generation resources.

Appendix D – Transmission System Details

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List of Tables

List of Figures

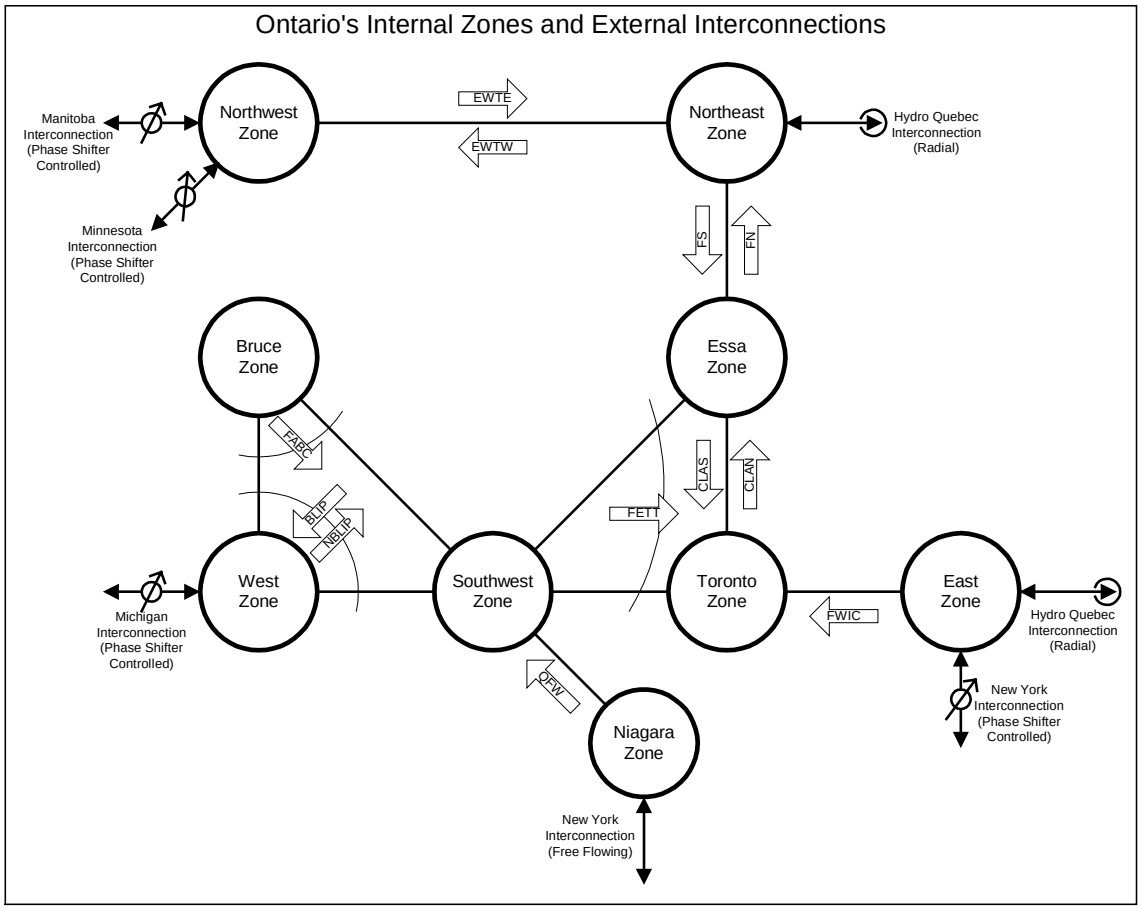
This appendix contains, in Section 1.0, a description of the Ontario Transmission System followed, in Sections 2.0 and 3.0, by Ontario's Interface and Interconnection Definitions and Limits. In Section 4.0 are shown Hydro One's committed transmission facilities addition plans and, in Section 5.0, the transmission outage plan for the studied period is presented along with comments regarding the impact of the outages, where necessary.

1.0 Transmission System Description

1.1 Transmission System Interfaces

There are eight major interfaces in the Ontario electricity system, which will be accounted for in this study, as illustrated in Figure D1.1.

Figure D1.1 Ontario's Internal Zones and External Interconnections



Interface Definitions

Interface definitions are formed by grouping one or more lines for the purpose of measuring their combined flow and enforcing a power flow limit or as it is more commonly called an interface limit. Interface limits are directional and interfaces may have limits imposed in one or both directions. Section 2.1 shows the major interface definitions used in Ontario. Notice that for each individual transmission element included in an interface definition both the positive direction of power flow and measurement point (e.g. which end of a transmission line the power flow is measured at) are specified.

Interface Capability Limits

Section 2.2 shows the base limits for the major interfaces that correspond to the definitions in Section 2.1; only normal system (all transmission elements in-service) limits are shown. Note that some limits are simply constants (e.g. BLIP) and others are more complicated and may depend on parameters such as specific generator unit statuses, other flows, primary demand, etc. (e.g. NBLIP, FETT, FABC). In cases where interface limits are based on thermal capability, separate ratings are shown for summer and winter conditions.

1.2 Interface Characteristics

The EWTE/EWTW Interface

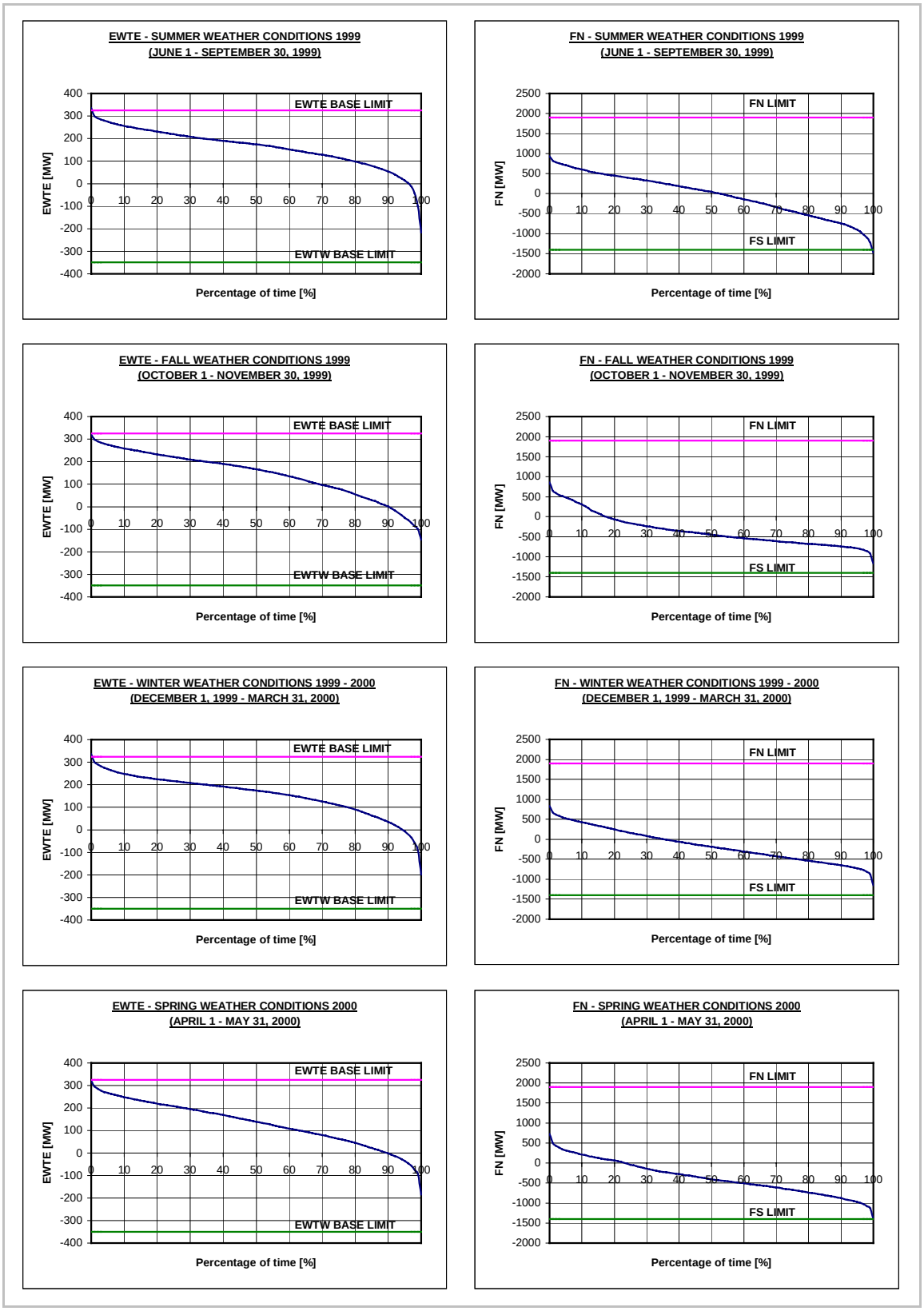
The East-West Transfer East (EWTE) and East-West Transfer West (EWTW) flows are functionally related to the power flows between Ontario and Manitoba (OMTE/OMTW etc.). In this relationship OMTE/OMTW flows can be generally thought of as the independent variables as they are under phase shifter control.

The maximum limits on the East-West tie are 325 MW to the east and 350 MW to the west. The EWTE and EWTW interfaces are constrained by stability limitations. A sample of historical flow distribution on the East West Ties is shown in the Figure D1.2.1.

The FN/FS Interface

The Flow South (FS) limit is 1,400 MW and the Flow North (FN) limit is 1,900 MW. The Flow North and Flow South interfaces are constrained by voltage and stability limits respectively. A sample of historical flow distribution on the Flow North / South interface is shown in the Figure D1.2.1.

Figure D1.2.1 – Historical Flow Distribution – EWTE/EWTW and FN/FS Interfaces



The CLAN/CLAS Interface

The Claireville North (CLAN) limit is 2,000 MW and the Claireville South (CLAS) limit is 1,000 MW.

The FABC Interface

The Flow Away From Bruce Complex (FABC) limit is a functional relationship with a number of other system parameters. With only a total of four Bruce units available (the other four are on indefinite outage) the FABC limit is high enough that it is never limiting. The FABC limit can also be improved through the use of generation rejection of Bruce units.

The FETT Interface

The FETT (Flow East Towards Toronto) interface limit is a function of a variety of parameters. Normally the limit is near its high end of about 5,700 MW. The interface is constrained by a combination of stability and thermal limits. There is no limit specified for flows to the west, as the level of flows expected in that direction will not cause system concerns. A sample of historical flow distribution on the FETT interface is shown in the Figure D1.2.2.

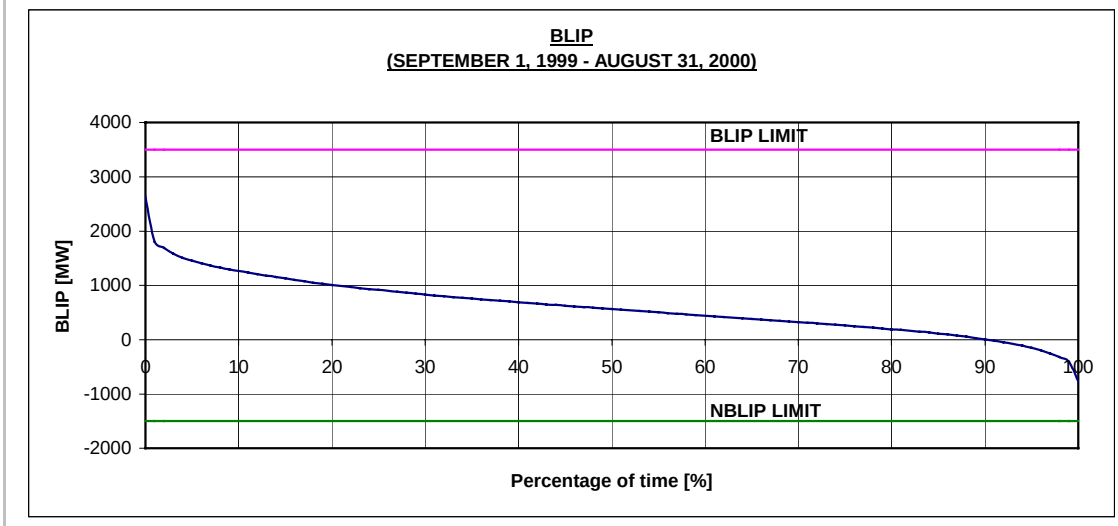
The QFW Interface

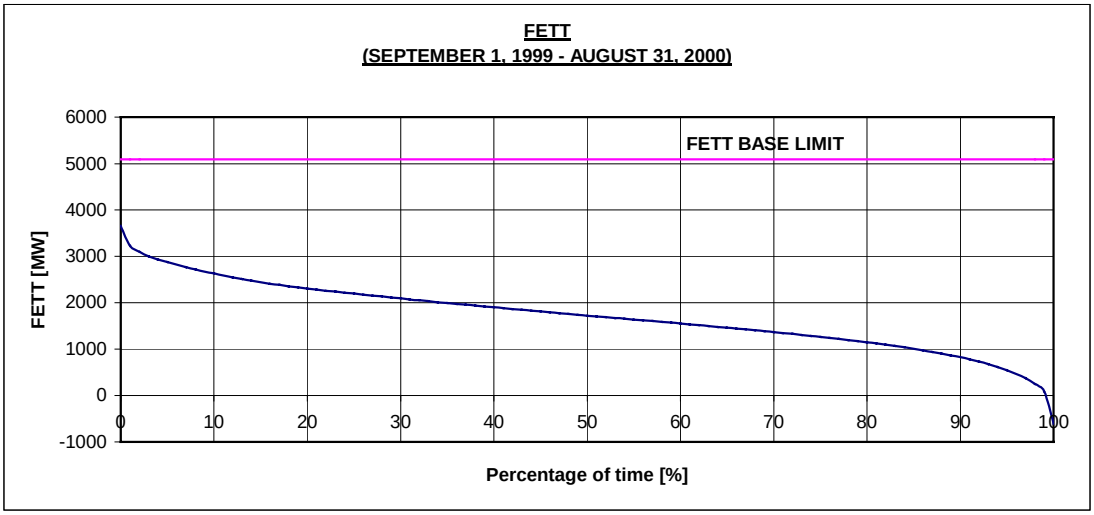
The QFW (Queenston Flow West) interface is limited to 2,000 MW for flows to the west in the winter. In the summer, the limit is 1,800 MW to the west. This interface is constrained by thermal limitations. There is no limit specified for flows to the east, as the level of flows expected in that direction will not cause system concerns. A sample of historical flow distribution on the QFW interface is shown in the Figure D1.2.2.

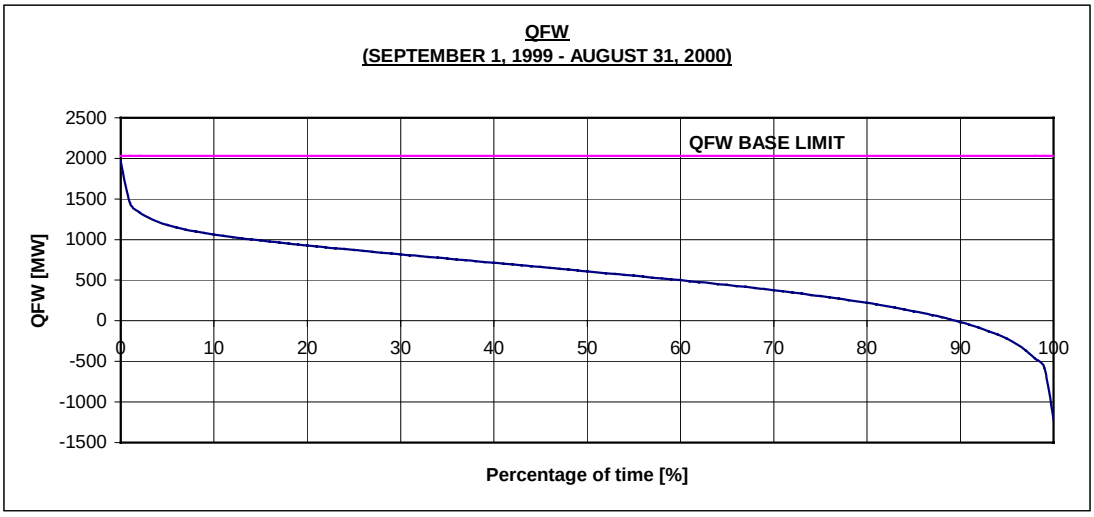
The BLIP/NBLIP Interface

The BLIP (Buchanan Longwood Input) interface is limited to 3,500 MW to the west due to stability limitations. The NBLIP interface limit is a function of a variety of parameters. Normally the limit is near its high end of about 1,500 MW; the interface is typically constrained by voltage limitations. A sample of historical flow distribution on the BLIP interface is shown in the Figure D1.2.2.

Figure D1.2.2 – Historical Flow Distribution – BLIP/NBLIP, FETT and QFW Interfaces







The FWIC Interface

This interface does not have a pre-defined limit. It is included in this study to provide a boundary for the creation of the East Zone to allow for specific forecasts for this region for such parameters as economic conditions for load growth, total resources, etc.

1.3 Transmission System Zones

The Ontario transmission system has been divided up into nine zones to facilitate the study. Zonal boundaries have been chosen to correspond with the interface definitions in Section 2.1.

Northwest Zone Characteristics

- The total resources generally exceed the peak primary demand.
- The generation is mainly hydroelectric with some coal
- The zone is externally connected to the Manitoba and Minnesota systems.
- Both interconnections are under phase shifter control.
- MAPP (Mid-Continent Area Power Pool) criteria (similar to NPCC) are observed in Manitoba and Minnesota and there is a plan to move toward MAPP criteria limits in the Northwest zone. For many years Manitoba has accepted Northwest zone limits based on criteria less stringent than MAPP, but recently Manitoba joined the MAPP reliability council and as a result Ontario is compelled accordingly.

Northeast Zone Characteristics

- The total resources generally exceed the peak primary demand.
- The generation is mainly hydroelectric with some cogeneration.
- The zone is externally connected to the Quebec grid.
- The interconnection with Quebec is radial.

Essa Zone Characteristics

- The total resources are much less than the peak primary demand.
- The generation is totally hydroelectric.
- There are no external interconnections.

East Zone Characteristics

- The total resources exceed the peak primary demand.
- The generation is a mix of hydroelectric, oil, and gas.
- The zone is externally connected to the Quebec grid.
- The interconnection with Quebec is radial.
- It is also externally connected to New York with phase shifter control.

Toronto Zone Characteristics

- The total resources are much less than the peak primary demand.
- The generation is mostly nuclear and coal.
- There are no external interconnections.

Bruce Zone Characteristics

- The total resources are much greater than the peak primary demand.
- The generation is mostly nuclear.
- There are no external interconnections.

Southwest Zone Characteristics

- The total resources are well balanced with the peak primary demand.
- The generation is mostly coal.
- There are no external interconnections.

West Zone Characteristics

- The total resources are slightly less than the peak primary demand.
- The generation is mostly coal.
- The interconnection with Michigan will be under phase shifter control, by June 2001.

Niagara Zone Characteristics

- The total resources are much higher than the peak primary demand.
- The generation is mostly hydroelectric.
- There is a free-flowing interconnection with New York.

1.4 Transmission System Interconnections' Capabilities and External Markets

The term interconnection is used to describe interfaces that join Ontario to other (external) control areas.

Ontario has interconnections with Manitoba, Minnesota, Quebec, Michigan, and New York.

Interconnection Definitions

Interconnection definitions are shown in Section 3.1.

Interconnection Limits

Interconnection limits are shown in Section 3.2.

Interconnection Characteristics

All of Ontario's non-radial interconnections are under phase-shifter control, except for Niagara New York.

New phase shifters will be installed on the Ontario – Michigan interconnection by June 2001. The purpose of the new phase shifters is to control a loop flow or parallel path flow called Lake Erie Circulation (LEC). LEC occurs naturally through a combination of transmission system impedance with interconnection-wide load/generation dispatch; it is measured as an unscheduled flow across the points of interconnection with New York, at Niagara Falls, and with Michigan. Much of the time, LEC enters Ontario at the New York Niagara interconnection and exits Ontario at the Michigan interconnection. Power flows associated with this condition are often greater than 500 MW; on occasion they exceed 1,000 MW. LEC flows also appear on and aggravate the BLIP and QFW interfaces as they are in a direct series path. With the incorporation of the new

phase shifters it is expected that the incidence of constrained operation of QFW will be greatly reduced.

The Ontario - Manitoba Interconnection

The OMTE and OMTW limits are both 288 MW in summertime, 300 MW in wintertime and are constrained by stability and thermal limitations.

The Ontario - Minnesota Interconnection

The MPFN and MPFS limits are 100 and 150 MW respectively and are constrained by stability and thermal limitations.

The Ontario - Michigan Interconnection

The Michigan interconnection is constrained by thermal limitations and will be under phase shifter control by June 2001.

Before June 2001:

During winter months, the limits are 1600 MW for flows into Ontario and 2,400 MW for flows out of Ontario. In the summer, the limits are 1,500 MW for flows into Ontario and 2,350 MW for flows out of Ontario.

After June 2001:

During winter months, the limits are 1800 MW for flows into Ontario and 2,450 MW for flows out of Ontario. In the summer, the limits are 1,765 MW for flows into Ontario and 2,450 MW for flows out of Ontario.

The Ontario - New York Niagara Interconnection

The New York Niagara interconnection, in the winter, is limited to 1,750 MW for flows into Ontario and 2,050 MW for flows out of Ontario. In the summer, the limit is 1,450 MW for flows into Ontario and 1,950 MW for flows out of Ontario. The interconnection is constrained by thermal limitations in the winter and summer.

The QFW interface is in series with the NY Niagara interconnection. All flows entering Ontario on the NY Niagara interconnection will also appear on the QFW interface; this includes purchases and parallel path flows. Based on past experience and studies, the QFW interface always hits its limit before the limit is reached on the NY Niagara interconnection for flows entering Ontario; as a result, the capability of the NY Niagara interconnection is never fully utilized.

Typically, when QFW hits its limit of 1,800 MW under summer conditions, the flow across the NY Niagara interconnection is 1,100 MW (its limit is 1,450 MW). Similarly, when QFW hits its limit of 2,000 MW under winter conditions, flow across the NY Niagara interconnection is 1,300 MW (its limit is 1,750 MW).

The Ontario - New York East Interconnection

The limit on this interconnection is 400 MW for flows into or out of Ontario. The interconnection is constrained by thermal limitations and is under the control of phase shifters.

The Ontario Northeast - Quebec Interconnection

The Quebec North interconnection is thermally limited to 78 MW under winter conditions and 64 MW under summer conditions, for flows into Ontario from radial generation in Quebec. For flows out of Ontario, the limit is 80 MW and this is simply based on the maximum amount of radial load available to be supplied in Quebec.

The Ontario East - Quebec Interconnection

The Quebec South interconnection is limited to 1,330 MW for flows into Ontario due to stability limitations and available radial generation. For flows out of Ontario the limit is 450 MW and is due to stability and thermal limitations.

2.0 Definitions and Limits of Ontario's Interfaces

2.1 Definitions of Ontario's Interfaces

(* signifies the measurement point)

Buchanan Longwood Input (BLIP) Interface consists of the following circuits:

B562L	Bruce A to Longwood* 500 kV
B563L	Bruce B to Longwood* 500 kV
N582L	Nanticoke to Longwood* 500 kV
D4W	Detweiler to Buchanan* 230 kV
D5W	Detweiler to Buchanan* 230 kV
M31W	Middleport to Buchanan* 230 kV
M32W	Middleport to Buchanan* 230 kV
M33W	Middleport to Buchanan* 230 kV

Negative Buchanan Longwood Input (NBLIP) Interface consists of the following circuits:

B562L	Longwood* to Bruce A 500 kV
B563L	Longwood* to Bruce B 500 kV
N582L	Longwood* to Nanticoke 500 kV
D4W	Buchanan* to Detweiler 230 kV
D5W	Buchanan* to Detweiler 230 kV
M31W	Buchanan* to Middleport 230 kV
M32W	Buchanan* to Middleport 230 kV
M33W	Buchanan* to Middleport 230 kV

Queenston Flow West (QFW) Interface consists of the following circuits:

Q23BM	Beck2* to Burlington and Middleport (Neale Junction) 230 kV
Q25BM	Beck2* to Burlington and Middleport (Neale Junction) 230 kV
Q24HM	Beck2* to Hamilton and Middleport (Hannon Junction) 230 kV
Q29HM	Beck2* to Hamilton and Middleport (Hannon Junction) 230 kV
Q30M	Beck 2 (Allanburg Junction*) to Middleport 230 kV

Flow East To Toronto (FETT) Interface consists of the following circuits:

B560V	Bruce A to Claireville* 500 kV
M570V	Milton to Claireville* 500 kV
M571V	Milton to Claireville* 500 kV
V586M	Middleport to Claireville* 500 kV
R14T	Trafalgar* to Richview 230 kV
R17T	Trafalgar* to Richview 230 kV
R19T	Trafalgar* to Richview 230 kV
R21T	Trafalgar* to Richview 230 kV
E8V	Orangeville to Essa* 230 kV
E9V	Orangeville to Essa* 230 kV

Flow North (FN) and Interface consists of the following circuits:

X503E Essa* to Hamner 500 kV
X504E Essa* to Hamner 500 kV
D5H Des Joachims* to Holden 230 kV

Flow South (FS) Interface consists of the following circuits:

X503E Hamner to Essa* 500 kV
X504E Hamner to Essa* 500 kV
D5H Holden to Des Joachims* 230 kV

East-West Transfer West (EWTW) Interface consists of the following circuits:

W21M Wawa* to Marathon 230 kV
W22M Wawa* to Marathon 230 kV

East-West Transfer East (EWTE) Interface consists of the following circuits:

W21M Marathon to Wawa* 230 kV
W22M Marathon to Wawa* 230 kV

Claireville North (CLAN) Interface consists of the following circuits:

E510V Claireville* to ESSA 500kV
E511V Claireville* to ESSA 500kV
B82V Claireville* to Brown Hill 230kV
B83V Claireville* to Brown Hill 230kV

Claireville South (CLAS) Interface consists of the following circuits:

E510V ESSA to Claireville* 500kV
E511V ESSA to Claireville* 500kV
B82V Brown Hill to Claireville* 230kV
B83V Brown Hill to Claireville* 230kV

Flow Away from Bruce Complex (FABC) Interface consists of the following circuits:

B560V Bruce* to Claireville 500kV
B561M Bruce* to Milton 500kV
B562L Bruce* to Longwood 500kV
B563L Bruce* to Longwood 500kV
B4V Bruce* to Orangeville 230kV
B5V Bruce* to Orangeville 230kV
B22D Bruce* to Detweiler 230kV
B23D Bruce* to Detweiler 230kV
B27S Bruce* to Owen Sound 230kV
B28S Bruce* to Owen Sound 230kV

Flow West Into Cherrywood (FWIC) Interface consists of the following circuits:

B540C Bowmanville to Cherrywood* 500kV
B541C Bowmanville to Cherrywood* 500kV
B542C Bowmanville to Cherrywood* 500kV
B543C Bowmanville to Cherrywood* 500kV
P15C Dobbin to Cherrywood* 230kV
C28C Chat Falls to Cherrywood* 230kV
H24C Havelock to Cherrywood* 230kV

H26C Havelock to Cherrywood* 230kV
M29C Merivale to Cherrywood* 230kV
B23C Belleville to Cherrywood* 230kV

2.2 Limits of Ontario's Interfaces

The Ontario major interfaces base limits, for all elements in service are shown in the Table D2.1.

Table D2.1 Ontario's Interface Base Limits

Interface	Operating Security Limits (MW)
BLIP	3500
NBLIP	1500
QFW	1800 Summer, 2000 Winter
FABC	5200, normally not limiting
FETT	5700
CLAN	2000
CLAS	1000
FN	1900
FS	1400
E-W	325 East, 350 West

3.0 Definitions and Limits of Ontario's Interconnections

3.1 Definitions of Ontario's Interconnections

The Ontario – Manitoba Interconnection

K21W Kenora 230 kV to Whiteshell 115 kV including combination voltage regulator and phase shifting transformer bank T7 at Whiteshell,

K22W Kenora 230 kV to Whiteshell 115 kV including combination voltage regulator and phase shifting transformer bank T8 at Whiteshell,

SK1 Rabbit Lake 115 kV to Seven Sisters 115 kV including an in-line voltage regulating transformer at Seven Sisters (radial operation only).

Ontario Manitoba Transfer West (OMTW) consists of the following circuits:

K21W Kenora* 230 kV to Whiteshell 230 kV
K22W Kenora* 230 kV to Whiteshell 230 kV

Ontario Manitoba Transfer East (OMTE) consists of the following circuits:

K21W Whiteshell 230 kV to Kenora* 230 kV
K22W Whiteshell 230 kV to Kenora* 230 kV

The Ontario – Minnesota interconnection

F3M Fort Frances 115 kV to International Falls 115 kV including two phase shifting transformers operated in series, T10 and T11, located at International Falls.

Minnesota Power Flow North (MPFN) consists of the following circuit:

F3M International Falls 115 kV to Fort Frances* 115 kV

Minnesota Power Flow South (MPFS) consists of the following circuit:

F3M Fort Frances* 115 kV to International Falls 115 kV

The Ontario – Quebec North interconnection consists of the following circuits:

D4Z Dymond* to Rapide Des Iles 115 kV,
H4Z Holden* to Kipawa 115 kV,

The Ontario – Quebec South interconnection consists of the following circuits:

X2Y Chenaux to Bryson 115 kV,
Q4C Chats Falls to Quoyon 230 kV,
P33C Chats Falls to Paugan 230 kV,
H9A Hawthorne to Maclaren 115 kV,
H2AR Hawthorne to Maclaren 115 kV,
B5D St. Isidore to Beauharnois 230 kV,
B31L St. Lawrence to Beauharnois 230 kV.

The Ontario – Michigan Interconnection consists of the following circuits:

Before June 2001:

B3N Scott* 230 kV to Bunce Creek 120 kV, including in-line autotransformer.
L4D Lambton* 230 kV to St. Clair 345 kV, including in-line autotransformer.

L51D Lambton* 230 kV to St. Clair 345 kV, including in-line autotransformer.
J5D Keith* 230 kV to Waterman 230 kV, including in-line combination voltage regulator and phase shifter SR5.

After June 2001:

B3N Scott* 230 kV to Bunce Creek 120 kV, including in-line autotransformer and phase shifter.
L4D Lambton* 230 kV to St. Clair 345 kV, including two autotransformers in parallel and phase shifter.
L51D Lambton* 230 kV to St. Clair 345 kV, including in-line autotransformer and phase shifter.
J5D Keith* 230 kV to Waterman 230 kV, including in-line combination voltage regulator and phase shifter SR5.

The Ontario – New York Interconnection at Niagara consists of the following 60 Hz circuits to the New York Power Authority (NYPA), and Niagara Mohawk (NiaMo):
BP76 Beck2 230 kV to Packard 230 kV (NiaMo), including in-line voltage regulating transformer R76,
PA27 Beck2 230 kV to Niagara Moses230 kV (NYPA), including in-line voltage regulating transformer R27,
PA301 Beck2 230 kV to Niagara Moses 345 kV (NYPA), including in-line 230 to 345 kV autotransformers T301,
PA302 Beck2 230 kV to Niagara Moses 345 kV (NYPA), including in-line 230 to 345 kV autotransformers T302,
BL104 Beck1 115 kV to Lockport 115 kV (NiaMo),

and the following two 25 Hz circuits

BSC105 Beck1 115 kV to Harper 69 kV (NiaMo), including an in-line 115 to 69 kV transformer at Parks TS,
BSH106 Beck G7 to Harper 69 kV (NiaMo).

The Ontario – New York Interconnection at St. Lawrence consists of the following 60 Hz circuits to the New York Power Authority (NYPA):
L33P St. Lawrence 230 kV to FDR Moses 230 kV (NYPA) including in-line voltage regulating transformer R33 and in-line phase shifting transformer PS33,
L34P St. Lawrence 230 kV to FDR Moses 230 kV (NYPA) including in-line combination voltage regulator and phase shifting transformer PSR34.

3.2 Limits of Ontario's Interconnections

The Ontario interconnection base limits, for all elements in service are shown in the Table D3.1.

Table D3.1 Ontario's Interconnection Limits

Interconnection	Limit (MW) Flows Out of Ontario MW	Limit (MW) Flows Into Ontario
Manitoba – Winter*	300	300
Manitoba – Summer*	288	288
Minnesota	150	100
Quebec North – Winter*	80	78
Quebec North – Summer*	80	64
Quebec South	450	1,330
New York East	400	400
New York Niagara – Winter*	2,050	1,750
New York Niagara – Summer*	1,950	1,450
Michigan – Winter*	2,400 / 2,450**	1,600 / 1,800**
Michigan – Summer*	2,350 / 2,450**	1,500 / 1,765**

*Seasonal Limits are based on thermal ratings and 75% of pre-load. Summer Limits apply from May 1 to October 31 and are based on 0-4 km/hr wind speed and 30 Deg.C ambient temperature (except on ties with Michigan, which are based on 35 Deg.C). Winter Limits apply from November 1 to April 30 and are based on 0-4 km/hr wind speed and 10 Deg.C ambient temperature.

** For the Ontario – Michigan Interconnection the displayed values are, respectively, before June 2001 and after June 2001 (the in service date of the phase shifters).

4.0 Plans – Hydro One

Table D4.1 Committed Plans - Hydro One

Committed Plans	Purpose	Description	Projected In-service
Establish connection to Maclaren Industries	Increase interconnection capacity to Hydro Quebec	Provide 230 kV interconnection via D5A	Sep. 2000
Install generation rejection scheme in the West System	Mitigate some of the impact of full compliance to NPCC, MAPP and NERC (this project deals with respecting loss of double circuit as single contingency).	Reject Atikokan GS for the loss of A21L/A22L or M23L/M24L. (Improve TEM and LE limits)	Nov. 2000
Install phase-shifters on the interconnection to Michigan	Control Lake Erie Circulation and increase import capability	845 MVA unit on L51D and L4D; Reconnect T7 auto to L4D for parallel operation with T8	Jun. 2001
Install shunt capacitor bank at Chatham SS	Increase load meeting capability for the Windsor area	230 kV Capacitor: 225 MVAR @ 249.4 kV	Jun. 2001
Refurbish Chatham SS	Replace end of life facilities	Replace 230 kV circuit breakers and associated equipment	Jul. 2001
Refurbish St Lawrence TS	Replace end of life facilities	Replace 230 kV circuit breakers and associated equipment	Jul. 2001
Refurbish L1S 115 kV line section	Transmission line refurbishment	Refurbish Crystal Falls GS x Warren DS	Dec. 2000

5.0 Planned Transmission Outages

Table D5.1 Transmission Outages Northwest Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
12	K3D Rabbit Lake x Vermilion Bay DS 115kV	18-Sep-00	30-Nov-00	Continuous	8		
13	ST5 Seven Sisters x Transcona 115kV	19-Sep-00	13-Oct-00	Continuous	8		
31	ST6 Seven Sisters x Transcona 115kV	02-Oct-00	13-Oct-00	Continuous	8		
74	D26A Dryden x Mackenzie 230kV	23-Oct-00	02-Nov-00	Continuous	1	250 MW OMTW; 225 MW TEM (Transfer East of Mackenzie)	Not Limiting for expected flow direction
95	WT34 Whiteshell x Transcona 115kV	06-Nov-00	01-Dec-00	Continuous	8		
96	907 Littlefork TS x SHAN 230kV	06-Nov-00	22-Nov-00	Continuous	None		
149	Whiteshell T8 failed	04-Jun-00	31-Dec-01	Continuous	None		

Table D5.2 Transmission Outages Northeast Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
11	L1S Verner DS x Warren DS 115kV	18-Sep-00	30-Nov-00	Continuous	None	5 MW D4Z or H4Z in Mode 2; 15 MW D4Z in Mode 3	
28	W2C Wawa x Chapleau MS 115kV	01-Oct-00	10-Oct-00	Continuous	1		
44	L22L25 Martindale 230kV	02-Oct-00	11-Oct-00	Continuous	8		
57	A24P Algoma x Mississagi 230kV	16-Oct-00	26-Oct-00	Continuous	None		
75	T28P Wells x Mississagi 230kV	23-Oct-00	27-Oct-00	Continuous	12		
97	X27A Hanmer x Algoma 230kV	06-Nov-00	24-Nov-00	Daily - PM only	0.5		
100	T27P Wells x Mississagi 230kV	13-Nov-00	24-Nov-00	Continuous	12		
110	P26W Mississagi x Wawa 230kV	27-Nov-00	08-Dec-00	Continuous	12	105 MW EWTE	May limit NW Zone Generation Dispatch

Table D5.3 Transmission Outages Essa Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
3	T5 Waubaushene 230kV	05-Sep-00	20-Oct-00	Continuous	48		
16	T2 Muskoka 230kV	25-Sep-00	06-Oct-00	Continuous	8		
32	S2S Meaford x Stayner 115kV	02-Oct-00	24-Nov-00	Continuous – No Weekends	4		
63	D4M Des Joachims GS x Minden 230kV	16-Oct-00	20-Oct-00	Continuous	3		
64	D4M Des Joachims GS x Minden 230kV	16-Oct-00	20-Oct-00	Continuous	8		

Table D5.4 Transmission Outages Bruce Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
33	T27 Bruce A 230kV	02-Oct-00	13-Oct-00	Continuous	8		
34	E BUS Bruce A 500kV	02-Oct-00	06-Oct-00	Continuous	8		
35	R27 Bruce A 28kV	02-Oct-00	13-Oct-00	Continuous	8		
58	T4L560 Bruce A 500kV	16-Oct-00	20-Oct-00	Continuous	4		
76	L560 BUS Bruce A 500kV	23-Oct-00	27-Oct-00	Continuous	8		
77	HT4 BUS Bruce A 500kV	23-Oct-00	27-Oct-00	Continuous	8		
90	T25 Bruce A 230kV	06-Nov-00	10-Nov-00	Continuous	8		
91	R25 Bruce A 28kV	06-Nov-00	10-Nov-00	Continuous	8		
92	L24T25 Bruce A 230kV	06-Nov-00	10-Nov-00	Continuous	8		

Table D5.5 Transmission Outages West Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
5	HL45 Buchanan 230kV	11-Sep-00	27-Oct-00	Continuous	None		
17	KL1 Scott 115kV	25-Sep-00	03-Oct-00	Continuous	None		
18	HL27 Scott 230kV	25-Sep-00	06-Oct-00	Continuous	None		
20	KT1L7 Seaforth 115kV	25-Sep-00	06-Oct-00	Continuous	None		
29	DL42 Longwood 230kV	01-Oct-00	07-Oct-00	Continuous	1		
30	L23L29 Chatham 230kV	01-Oct-00	13-Oct-00	Continuous	None		
36	L29 BUS Chatham 230kV	02-Oct-00	09-Oct-00	Daily - No Weekends	4		
37	PL6 Scott 115kV	02-Oct-00	12-Oct-00	Continuous	None		
45	L5L37 Buchanan 230kV	06-Oct-00	19-Oct-00	Continuous	None		
46	1K2 Buchanan 115kV	06-Oct-00	13-Oct-00	Continuous	None		
47	T4L5 Buchanan 115kV	09-Oct-00	20-Oct-00	Continuous	None		
52	T3 Crawford 115kV	13-Oct-00	29-Oct-00	Continuous	None		
53	J4C Keith TS x Crawford 115kV	14-Oct-00	18-Oct-00	Continuous	8		
54	1P2 Buchanan 115kV	14-Oct-00	20-Oct-00	Continuous	None		
55	T4 Crawford 115kV	14-Oct-00	29-Oct-00	Continuous	None		
56	KL29 Chatham 230kV	15-Oct-00	20-Oct-00	Continuous	None		
71	HL37 Buchanan 230kV	21-Oct-00	03-Nov-00	Continuous	None		
72	L5K Buchanan 115kV	21-Oct-00	27-Oct-00	Continuous	None		
73	DL21 Chatham 230kV	22-Oct-00	27-Oct-00	Continuous	None		
81	L9P Buchanan 115kV	28-Oct-00	03-Nov-00	Continuous	None		
83	L21L45 Chatham 230kV	29-Oct-00	03-Nov-00	Continuous	None		
89	KL45 Chatham 230kV	05-Nov-00	10-Nov-00	Continuous	None		
98	KL24 Chatham 230kV	12-Nov-00	17-Nov-00	Continuous	None		
103	DL28 Chatham 230kV	19-Nov-00	24-Nov-00	Continuous	None		
104	J5D Keith TS x Waterman 230kV	20-Nov-00	24-Nov-00	Continuous	1	100 MW FABC; 500 MW Positive BLIP & Negative BLIP; 400 MW OH-MICH & MICH-OH	Reduced Interconnection Capacity
109	L24L28 Chatham 230kV	24-Nov-00	01-Dec-00	Continuous	None		
111	B563L Bruce B x Longwood 500kV	27-Nov-00	15-Dec-00	Daily	2	700 MW FABC; 500 MW Negative BLIP; 500 MW FETT	Negative BLIP will reduce the interconnection import capability
112	K BUS Chatham 230kV	27-Nov-00	01-Dec-00	Continuous	4		
117	D BUS Chatham 230kV	04-Dec-00	08-Dec-00	Continuous	4		
140	W37 Buchanan x Talbot 230kV	02-Apr-01	13-Apr-01	Continuous	144		
147	W36 Buchanan x Talbot 230kV	16-Apr-01	27-Apr-01	Continuous	144		

Table D5.6 Transmission Outages Niagara Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
2	C2P Crowland x Port Colborne TS 115kV	13-Aug-00	17-Dec-00	Continuous	None		
6	B3 Burlington x Dundas 115kV	11-Sep-00	31-Oct-00	Continuous	1		
7	HL7 Allanburg 115kV	11-Sep-00	05-Oct-00	Continuous	None		
14	Q30M Beck 2 x Middleport 230kV	20-Sep-00	17-Nov-00	Continuous – No Weekends	2	100 MW FABC; 200 MW FETT 400 MW QFW	Not Limiting
19	D BUS Nanticoke 500kV	25-Sep-00	05-Oct-00	Continuous	1		
38	D1L29 Hamilton Beach 230kV	02-Oct-00	06-Oct-00	Continuous	24		
48	DL1 Allanburg 115kV	10-Oct-00	03-Nov-00	Continuous	None		
59	T8 Hamilton Beach 230kV	16-Oct-00	20-Oct-00	Continuous	8		
60	DL1 Allanburg 115kV	16-Oct-00	03-Nov-00	Continuous	None		
61	1D2 Beck 2 230kV	16-Oct-00	27-Oct-00	Continuous	None		
62	H8 BUS Hamilton Beach 115kV	16-Oct-00	20-Oct-00	Continuous	None		
78	B4 Burlington x Dundas 115kV	23-Oct-00	27-Oct-00	Continuous	4		
84	DK Newton 115kV	30-Oct-00	03-Nov-00	Continuous	12		
93	A36N Allanburg x Niagara Murray 115kV	06-Nov-00	16-Nov-00	Continuous	None		
102	D6V Detweiler x Orangeville 230kV	16-Nov-00	23-Nov-00	Daily	1		
105	T1 Hamilton Beach 230kV	20-Nov-00	24-Nov-00	Continuous	12		
106	A37N Allanburg x Niagara Murray 115kV	20-Nov-00	30-Nov-00	Continuous	None		
113	T7 Hamilton Beach 230kV	27-Nov-00	01-Dec-00	Continuous	12		
118	T6 Hamilton Beach 230kV	04-Dec-00	08-Dec-00	Continuous	12		
122	T5 Hamilton Beach 115kV	11-Dec-00	15-Dec-00	Continuous	12		
125	T8 Hamilton Beach 230kV	18-Dec-00	22-Dec-00	Continuous	12		
128	Q24HM Hamilton Beach x Dofasco Kenilworth CTS 230kV	15-Jan-01	19-Jan-01	Continuous	None		
130	Q29HM Hamilton Beach x Dofasco Kenilworth CTS 230kV	22-Jan-01	26-Jan-01	Continuous	None		

Table D5.7 Transmission Outages South Western Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
65	T11 Nanticoke 500kV	16-Oct-00	27-Oct-00	Continuous	96		

Table D5.8 Transmission Outages Toronto Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
4	DL511 Claireville 500kV	05-Sep-00	27-Oct-00	Continuous	96		
8	E511V Essa x Claireville 500kV	11-Sep-00	03-Nov-00	Daily	4	700 MW CLAN; 1200 MW FN (Normal); 100 MW FS with G/R	Flow North may become limiting at off peak hours requiring Northern generation to be operated
9	T4 Malvern 230kV	11-Sep-00	20-Oct-00	Continuous	48		
15	R21T Richview x HANJ 230kV	23-Sep-00	06-Oct-00	Continuous	12		
21	T3 Ellesmere 230kV	25-Sep-00	06-Oct-00	Continuous	4		
27	R19T HANJ x Richview 230kV	25-Sep-00	06-Oct-00	Continuous	12		
39	H BUS Cecil 115kV	02-Oct-00	06-Oct-00	Continuous	8		
40	E511V Essa x Claireville 500kV	02-Oct-00	06-Oct-00	Continuous	12		
41	L7L8 Cecil 115kV	02-Oct-00	27-Oct-00	Continuous	48		
49	KL561 Milton 500kV	10-Oct-00	17-Nov-00	Continuous	6	400 MW FETT	Not Limiting
66	T23 Scarboro 230kV	16-Oct-00	20-Oct-00	Continuous	4		
79	L24CR Lakeview GS x Cooksville x Richview 230kV	23-Oct-00	10-Nov-00	Continuous - No Weekends	2		
80	B560V Bruce A x Claireville 500kV	23-Oct-00	27-Oct-00	Continuous	8	850 MW FABC; 500 MW Negative BLIP; 500 MW FETT	Negative BLIP will reduce the interconnection import capability
82	T1 Markham MTS 1 230kV	28-Oct-00	05-Nov-00	Continuous	None		
85	L5D Leaside x Duplex 115kV	30-Oct-00	03-Nov-00	Continuous	8		Some Toronto area outages may be impactive due to coincident Toronto Zone Generator Outages scheduled in Oct and early Nov
86	T16 Claireville 500kV	30-Oct-00	03-Nov-00	Continuous	8	150 MW FETT	See above
101	T8P Pickering B 230kV	13-Nov-00	17-Nov-00	Continuous	4		
107	C4R Cherrywood x Malvern 230kV	20-Nov-00	08-Dec-00	Continuous	12	150 MW FETT	Not Limiting
108	C5R Cherrywood x Malvern 230kV	20-Nov-00	08-Dec-00	Continuous	12	150 MW FETT	Not Limiting
114	L540 BUS Cherrywood 500kV	27-Nov-00	01-Dec-00	Continuous	4		
115	B540C Bowmanville x Cherrywood 500kV	27-Nov-00	01-Dec-00	Continuous	4		
116	T2 Carlton 115kV	27-Nov-00	01-Dec-00	Continuous	None		
119	B541C Bowmanville x Cherrywood 500kV	04-Dec-00	08-Dec-00	Continuous	4		

(Table D5.8 continued)

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
120	L541 BUS Cherrywood 500kV	04-Dec-00	08-Dec-00	Continuous	4		
121	T3 Carlton 115kV	04-Dec-00	08-Dec-00	Continuous	None		
123	C4R Malvern x LEAJ 230	11-Dec-00	22-Dec-00	Continuous	12	150 MW FETT	Not Limiting
124	C5R Malvern x LEAJ 230	11-Dec-00	22-Dec-00	Continuous	12	150 MW FETT	Not Limiting
126	H35D Hamilton Beach x Dofasco Bay Front CTS 230kV	01-Jan-01	31-Jan-01	Continuous	None		

Table D5.9 Transmission Outages East Zone

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
1	T52 Lennox 500kV	07-Mar-99	15-Mar-01	FO	None		
22	D6 PTAW x Chalk River CTS 115kV	25-Sep-00	06-Oct-00	Continuous	4		
23	W6MC Stewartville x Marchwood MS 115kV	25-Sep-00	03-Nov-00	Continuous - No Weekends	4	140 MW Lower Madawaska Total	May bottle generation at local hydro plants unless coincident generator outages are scheduled
24	X522A Lennox x Hawthorne 500kV	25-Sep-00	06-Oct-00	Continuous - No Weekends	4	400 MW Flow Into Ottawa (FIO)	Not Limiting for Demand Levels in the Fall of Year 2000
25	L22 BUS St Lawrence 230kV	25-Sep-00	05-Oct-00	Continuous	6		
26	AL22 St Lawrence 230kV	25-Sep-00	15-Oct-00	Continuous	144		
42	L2L21 Hinchinbrooke 230kV	02-Oct-00	06-Oct-00	Continuous	1		
43	HL34 St Lawrence 230kV	02-Oct-00	06-Oct-00	Continuous	8		
50	X6 Chenaux x Cobden TS 115kV	10-Oct-00	27-Oct-00	Continuous	1		
51	X523A Lennox x Hawthorne 500kV	10-Oct-00	27-Oct-00	Continuous - No Weekends	4	400 MW Flow Into Ottawa (FIO)	Not Limiting for Demand Levels in the Fall of Year 2000
67	L22L27 Hinchinbrooke 230kV	16-Oct-00	20-Oct-00	Continuous	1		
68	HT5L31 Hawthorne 230kV	16-Oct-00	20-Oct-00	Continuous	4		
69	M5G Merivale x Lisgar TS 115kV	16-Oct-00	26-Oct-00	Continuous	24		
70	HL26 St Lawrence 230kV	16-Oct-00	12-Nov-00	Continuous	144		
87	L24A St Lawrence x Hawthorne 230kV	30-Oct-00	10-Nov-00	Continuous - No Weekends	4	100 MW FIO	Not Limiting for Demand Levels in the Fall of Year 2000
88	C27P Dobbin TS x BANN 230kV	30-Oct-00	03-Nov-00	Continuous	12	240 MW Flow Into Dobbin (FID); 30 MW FIO	Requires local generation support and/or Generator cross-tripping armed
138	G4 Darlington A 0kV	30-Mar-01	15-Apr-01	FO	0.1		
94	P4S Sidney TS x Port Hope 115kV	06-Nov-00	28-Dec-00	Continuous - No Weekends	4	75 MW FLOW Into Dobbin	Requires local generation support and/or Generator cross-tripping armed
99	L21L26 St Lawrence 230kV	12-Nov-00	08-Dec-00	Continuous	144		
127	L31L33 St Lawrence 230kV	02-Jan-01	26-Jan-01	Continuous	144		
129	B31L Beauharnois x St Lawrence 230kV	15-Jan-01	01-Feb-01	Continuous – No Weekends	None	400 MW Beauharnois Delivery Limit; 100 MW FIO	Reduced import Capability from Hydro Quebec from 800 MW to 400 MW at Beauharnois
131	L31 BUS St Lawrence 230kV	29-Jan-01	09-Feb-01	Continuous	6		
132	AL31 St Lawrence 230kV	29-Jan-01	23-Feb-01	Continuous	144		

(Table D5.9 continued)

Seq Id#	Element Description	Start	Finish	Outage Type	Recall Hours	Reduction in Limit	Impact
135	L24 BUS St Lawrence 230kV	26-Feb-01	09-Mar-01	Continuous	6		
136	L22L24 St Lawrence 230kV	26-Mar-01	19-Apr-01	Continuous	6		
141	KL520 Lennox 500kV	02-Apr-01	06-Apr-01	Continuous	4		
142	K BUS Lennox 500kV	02-Apr-01	06-Apr-01	Continuous	4		
143	T51 Lennox 500kV	02-Apr-01	06-Apr-01	Continuous	4		
148	H32L33 St Lawrence 230kV	23-Apr-01	17-May-01	Continuous	6		