

Independent Electricity Market Operator

10 Year Outlook:

***An Assessment of the Adequacy of Generation and
Transmission Facilities to Meet Future Electricity Needs in
Ontario***

From January 2001 to December 2010

Executive Summary

This report presents an assessment of the adequacy of existing and committed generation and transmission facilities to meet the needs of Ontario in the ten-year period from 2001 to 2010.

Assuming median demand growth, the energy demand is forecast to grow at an average rate of 0.9% per year - from 149 TWh in Year 2001 to 161 TWh at the end of the study period. The forecast Peak Demand, measured over a 20-minute interval, rises from a range of 22,000 - 24,600 MW in 2001 to a range of 24,000 - 27,000 MW at the end of the period. The ranges represent forecast demands from normal to extreme weather conditions.

The required level of reliability corresponds to a generation reserve requirement of between 18% and 20% of the peak demand. The available generation capacity in the study period is adequate, under the median demand forecast scenario, to supply loads with the required level of reliability. Lower generation margins are forecast in the first two study years and the last three study years. There is a trend towards lower margins in the summer than in the winter in the last three years of the study period, brought about by the increasing air conditioning load.

Under the high demand forecast scenario, which represents energy growth at an average rate of 2% per year, available generation capacity in the study is not adequate to meet generation margin requirements beginning in 2005. Potential new generation projects, which are known but have not been included in this assessment, should be capable of alleviating potential capacity shortfalls.

The transmission system capability is adequate to supply the various transmission zones in the system under extreme weather conditions and both median and high forecast demand levels. Congestion is unlikely to occur (with all transmission elements in service) during the study period, except for the transmission system emanating from the NorthWest and NorthEast Transmission Zones.

Conclusions

1. Under the median load growth scenario, lower generation margins which are forecast in the first two study years and the last three study years indicate a potential requirement for additional generation capacity to be made available during those periods. Market Participants should take this into account in their planning.
2. Under a high load growth scenario, additional resources could be required as early as 2005 in order to maintain an adequate level of supply reliability. Currently identified potential generating projects would provide sufficient capacity to meet this potential need.
3. An increase in transmission capacity from the NorthWest and the NorthEast Transmission Zones would reduce congestion and improve market efficiency in those areas.

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1.0 Introduction

The Ontario Electricity Market Rules (Chapter 5) 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. 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 and to report its findings to the Minister of Energy, Science and Technology and to the Ontario Energy Board (OEB).

In March 2000, the IMO published an 18-month assessment as part of this latter requirement. The purpose of the 18-month report was to advise the Minister and the OEB of potentially adverse conditions that might be avoided through revision of maintenance outage plans for generation and transmission equipment. This report presents a 10-year forecast and assessment of generation and transmission, the purposes of which are to:

- provide input to relevant standards authorities with respect to their responsibilities for reviewing the status of reliability within each control area,
- provide input to market participants for long-term planning and investment decisions,
- provide input to reports to the Board of Directors of the IMO, the OEB and the Ontario Government regarding projected transmission and generation adequacy,
- provide input to any decisions by the Board of Directors of the IMO regarding the activation and changing requirements of the capacity reserve market.

This report covers the ten-year period from January 1, 2001 to December 31, 2010. The lead-time to install new generation is expected to be less than five years but the lead-time to install major transmission lines may be much longer.

The focus of this assessment is to provide insight into potential investment opportunities including the potential need for new or modified IMO-controlled grid facilities to maintain the reliability of the system and to assist the IMO-administered markets to operate efficiently. The assessment of adequacy of generation capacity is based upon ensuring that sufficient resources are available to meet the forecast demand after satisfying a reserve requirement. The assessment of the adequacy of transmission capability is based upon ensuring that sufficient transmission capability is available to transmit power to loads in a secure manner with an acceptable degree of reliability.

Section 2 of this report provides a 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 is presented in Section 4. The transmission system that is expected to be available is described in Section 5 and its capability to carry future power transfers is assessed in Section 6. The findings and conclusions of this assessment are contained in Section 7.

2.0 Forecast of Ontario Electricity Demand

2.1 Demand Forecasting Methodology

The forecasts of energy and peak demand on the Ontario system that are used in this report have been based on information from the January 2000 long-term forecast produced by Ontario Power Generation Inc. (OPGI). 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. The energy forecast is based on forecast growth in baseload demand and in seasonal weather-sensitive demand. For Ontario's East system, which is driven to a much larger extent than the West system by residential and commercial load, space conditioning load is a prime factor in winter and summer peak demand. The forecast is based on Normal Weather conditions, as measured by an average over the last 30 years.

The following forecasts were developed for the current forecast and assessment study:

- 20-minute coincident system peak demands (under Normal Weather conditions) and associated demand variations due to swings in weather;
- hourly energy and peak demands (under Normal Weather conditions).

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.

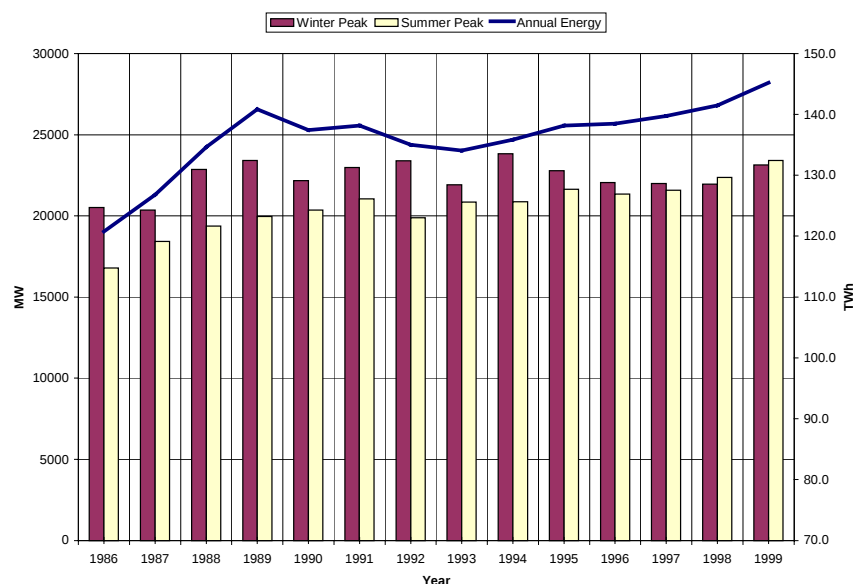
After market opening, a range of new forces will come into play that will change the dynamics of Ontario electricity demand. The IMO forecasting methodology will be revised substantially to reflect this.

2.2 Historical Demand

Historical Primary energy demand (GWh) and the summer and winter hourly peak demands (MW) for the Ontario system for the period 1986-1999 are shown in the Figure 2.1. Actual (not weather normalized) growth in total energy has averaged 1.4% annually over the period, while annual growth in system peak demand has averaged 0.9% for the winter and 2.6% for the summer.

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 occurred during the afternoon of early to mid-July. The occurrence of this summer vs. winter peak 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. Actual 20-minute peak demands that occurred in the summer and winter of year 1999 were 23,435 MW and 23,308 MW respectively. The actual 20-minute peak demand in year 2000 winter (Monday, January 17) was 23,428 MW.

Figure 2.1 Historical Primary Demand - Actual Weather



The peak demand, on any day, is very sensitive to ambient weather conditions. Over the past 10 years winter and summer peak demands have varied by 2,000 to 3,500 MW in response to different weather conditions. For any given summer day, the impact of air conditioning loads can be quite high; for example, during a particularly hot two-week period in the summer of 1999, air conditioning demand was estimated to be about 6,500 MW.

On a daily basis, electricity demand can vary by 6,000 to 9,000 MW from off-peak hours (11 p.m. to 6 a.m.) to the peak hours. A typical day during the winter will see both a morning peak and an afternoon peak. Residential appliances and lighting loads are the primary factors driving the system peak demands.

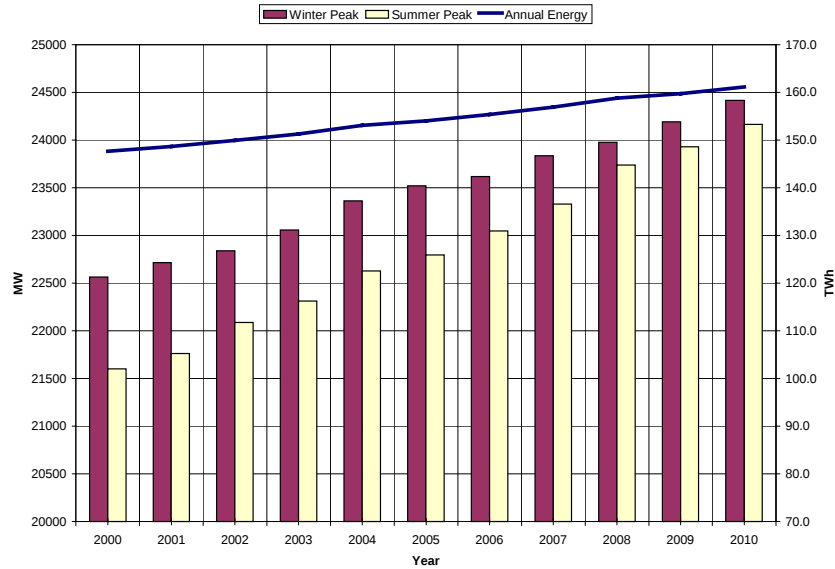
2.3 Median Demand Forecast

The demand forecast produced for this analysis is based on the assumption of Normal Weather Conditions. For the latest 30-year period, normal daily mean temperatures measured at Pearson International Airport range from -6.9°C in mid-January to 21.6°C in late July.

Over the forecast period, Ontario electrical energy use is expected to increase, on average, by about 0.9% annually. This increase is from 149 TWh in Year 2001 to 161 TWh in Year 2010, as shown in Table 2.2, roughly in line with growth experienced over the latter part of the 1990's and expected growth in provincial population growth. Peak demand is forecast to grow at an annual rate of 0.8% for the winter peak and 1.1% for the summer peak. Notwithstanding the experience of the past two years, the Ontario system is currently a winter peaking system and, under normal weather conditions, is expected to remain winter peaking over the forecast period. By the end of the forecast period, however, it is expected that summer peaks will be similar to winter peaks as summer space conditioning load grows and winter conditioning load remains flat.

The median forecast for energy and summer and winter peaks, under Normal Weather Conditions, is shown graphically in Figure 2.2. The increase in summer peak relative to winter peak is noticeable in the figure.

Figure 2.2 Median Primary Demand Forecast - Normal Weather



The median summer and winter 20-minute peak demand (under Normal Weather Conditions and Severe Weather Conditions) for the next 10 years is shown in Table 2.1 and also in Figure 2.3. Under Normal Weather conditions, the Winter Peak, measured on a 20-minute peak basis, is forecast to reach 24,306 MW by 2010, while the Summer Peak is forecast to reach 24,164 MW. Under severe weather conditions, the 20-minute Winter Peak is forecast to reach 26,073 MW, while the Summer Peak is forecast to reach 26,952 MW.

Table A.1 in Appendix A provides details of monthly peak demands and their standard deviation based on historical variations.

Figure 2.3 Range of Forecast 20-Minute Peak Demands

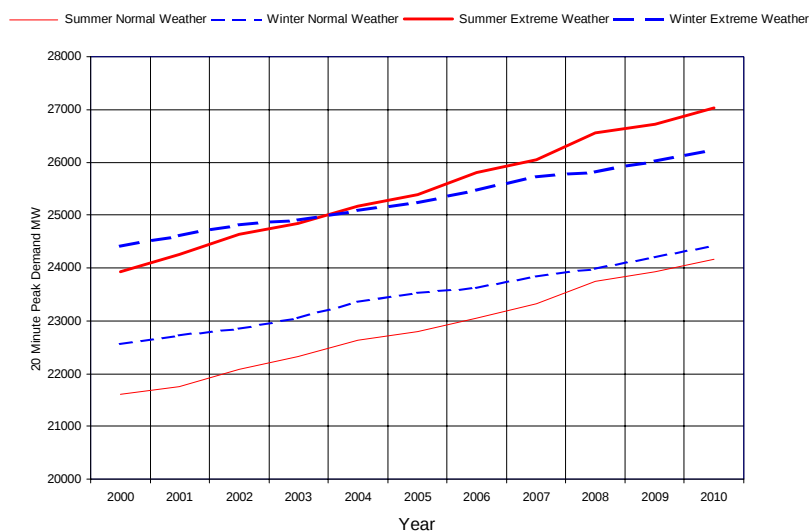


Table 2.1 20-Minute Peak Demand

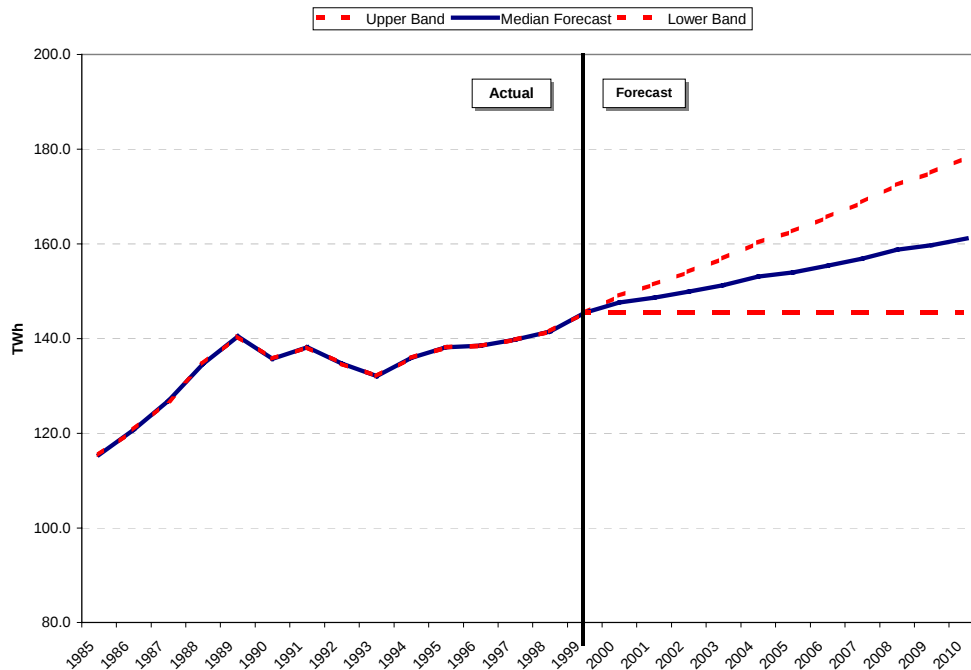
20 Minute System Peak	Normal Weather		Extreme Weather ⁽¹⁾	
	Summer	Winter	Summer	Winter
	(MW)	(MW)	(MW)	(MW)
2000	21604	22563	23910	24413
2001	21761	22633	24255	24617
2002	22088	22841	24637	24815
2003	22314	23056	24699	24912
2004	22628	23205	25174	25070
2005	22796	23339	25396	25237
2006	23049	23532	25813	25482
2007	23328	23739	26042	25728
2008	23738	23903	26554	25830
2009	23929	24175	26725	26023
2010	24164	24306	26952	26073
Average	1.1%	0.8%	-	-

⁽¹⁾Extreme Weather conditions cover 97.7% of time conditions (normal plus two standard deviations of a normal distribution)

2.4 Forecast Ranges

The upper and lower bands for the Ontario energy demand are shown in Figure 2.4. These bands represent scenarios of higher and lower energy demand growth. The upper band reflects an annual growth rate of about 2%, while the lower band reflects a status quo scenario. Bands based on statistical forecast uncertainty will be available in future reports.

Figure 2.4 Annual Energy Demand - Upper and Lower Forecast Bands - Normal Weather



2.5 Forecast by Load Forecast Areas

Demand for electricity differs across different areas of the province. For the purposes of this forecast, the province is divided into six load forecast areas, as illustrated in Figure 2.5. Table 2.2 shows the distribution of demand by these six load forecast areas. The East-Central area, which includes the Toronto and Ottawa areas, constitutes the largest proportion of electricity demand in the province.

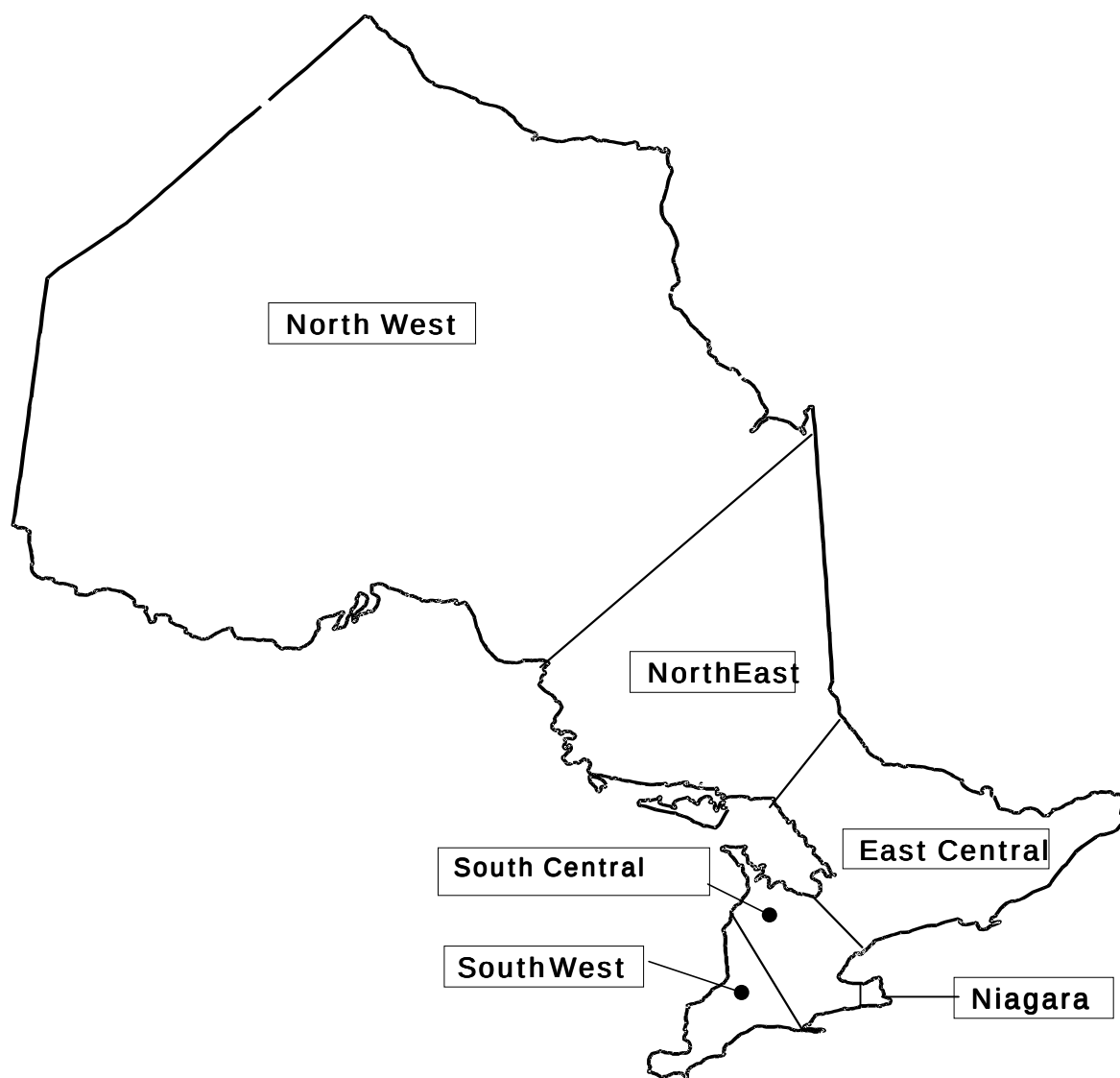
Projections of demand for the East-Central, South-Central, Niagara and SouthWest areas are based on forecasts of population growth in each of the areas. The median total system energy forecast is allocated to each area according to the population projections for these areas. The forecast for the NorthWest area is OPGI's forecast for the West System. The forecast for the NorthEast area tracks the NorthWest area forecast. Appendix A shows the annual forecast of peak demand by each area until 2010. The forecast shows that the demand in the Central-East area grows the fastest, followed by the South-Central area. The NorthWest and NorthEast areas show the slowest rates of demand growth.

Future projections of demand will be developed by Transmission Zone and based on relative economic activity within each of the zones. Transmission Zones are defined in Section 5 and Appendix D.

Table 2.2 Annual Energy Demand by Load Forecast Area - Normal Weather

	NorthWest	NorthEast	East-Central	South-Central	Niagara	South West	Ontario Total
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)
2001	8,087	11,145	76,981	30,225	6,299	15,884	148,621
2002	8,100	11,146	77,846	30,476	6,348	15,996	149,913
2003	8,114	11,155	78,771	30,732	6,401	16,110	151,284
2004	8,151	11,196	79,923	31,074	6,472	16,273	153,089
2005	8,138	11,167	80,599	31,238	6,505	16,340	153,987
2006	8,150	11,175	81,549	31,495	6,557	16,460	155,385
2007	8,162	11,185	82,558	31,784	6,616	16,589	156,894
2008	8,199	11,228	83,772	32,141	6,689	16,753	158,783
2009	8,186	11,194	84,477	32,314	6,723	16,825	159,719
2010	8,198	11,202	85,450	32,581	6,777	16,948	161,157
avg annual growth	0.11%	0.03%	1.15%	0.82%	0.79%	0.70%	0.88%
1999 distribution	5%	8%	53%	19%	4%	11%	100%

Figure 2.5 Load Forecast Areas



3.0 Resources

3.1 Introduction

This section describes the generating resources that are forecast to be available in the ten-year study period. Dispatchable loads are not included as resources, as was the case in the IMO's previous 18-month report¹, as this type of price-sensitive load may or may not be made available for dispatching by market participants, in response to price signals in the Ontario electricity market. Dispatchable loads are accounted for in the assessment of generation adequacy in Section 4.

Section 3.2 describes the declared net capacity of the generation resources that were included in the study. Section 3.3 describes the long-term bilateral external transactions (imports and exports) that were included in the study. Section 3.4 provides an overall summary of the available resources that were included in the study after taking into account various reductions and external transactions. Section 3.5 summarizes potential new generation projects in Ontario.

3.2 Generating Capacity Included in the Study

Generation from Ontario Power Generation Inc. (OPGI)

The OPGI generation included in the study is shown in Table 3.1; it includes nuclear, coal, oil and gas-fuelled generation, as well as hydroelectric and wind-powered stations. All the listed stations are available for use in Year 2001, except for Pickering A, as these units are on long term scheduled maintenance and are forecast by OPGI to return to service in the Years 2002 and 2003. Table 3.2 shows OPGI generators that are not included as resources in this study.

Committed Additional OPGI Resources in the Study

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 in the Study

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 Tables 3.3 and 3.4. The installations range in size from about 1 MW to 165 MW resulting in a total capacity of 1,690 MW at winter peak. Contracts on behalf of the Contract Generators are being managed, and their outputs forecast, by Hydro One Inc.

¹ An Assessment of the Adequacy and Capability of the Ontario Electricity System, March 2000 to August 2001 report dated March 17, 2000 published on the IMO website www.theimo.com

Table 3.1 Ontario Power Generation Inc. Power Stations in Study

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

⁽¹⁾ "OS" On long term scheduled maintenance or Forced Outage. Not available to operate (greater than 3 months).

⁽²⁾ Capacity and units shown are for Ontario half of the station.

⁽³⁾ 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 3.2 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 3.3 Contract Generators Power Stations in Study

Resource Type	In-Service Capacity (MW)
Natural Gas	1002
Landfill Gas/ Natural Gas	27
Landfill Gas	30
Natural Gas/ Waste Heat	431
Hydro	72
Subtotal (10 MW in size or greater shown above)	1,562
Subtotal (less than 10 MW in size) (See Table 3.4 for Details)	128
Total	1,690

Table 3.4 Contract Generators Small Power Stations in Study

Resource Type	In-Service Capacity (MW)
Natural Gas	19
Landfill Gas	5
Municipal Solid Waste	12
Wood Waste	17
Hydro	61
Subtotal (greater than or equal to 1 MW in size and less than 10 MW shown above)	114
Total (less than 1 MW in size) – Mostly Hydro, with some Natural Gas	14
Total	128 MW

Table 3.5 Summary of Generation Assumed Available in the Study Period (at Winter Peak)

Notes	Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Net Capacity											
1	OPGI Declared Net Capacity	27,794	27,794	27,794	27,794	27,794	27,794	27,794	27,794	27,794	27,794
2	Committed OPGI Generation	30	30	30	30	30	30	30	30	30	30
3	Contract Generators	1690	1690	1690	1690	1690	1690	1690	1690	1690	1690
4	Firm Import	200	200	200	0	0	0	0	0	0	0
5	Total Declared Net Capacity	29,714	29,714	29,714	29,514	29,514	29,514	29,514	29,514	29,514	29,514
Reductions to Net Capacity											
6	Known Deratings	124	124	0	0	0	0	0	0	0	0
7	Pickering A Units (Unavailable)	2,060	1,545	515	0	0	0	0	0	0	0
8	Hydro Plant Reductions	850	850	850	850	850	850	850	850	850	850
9	Available Generation Capacity	26,680	27,195	28,349	28,664	28,664	28,664	28,664	28,664	28,664	28,664

Notes to Table 3.5:

1. OPGI Declared Net Capacity
This is the total capacity available from OPGI owned generation units, as declared by OPGI in Table 3.1. This capacity includes Pickering A.
2. Committed OPGI Generation
OPGI has committed projects to upgrade some of their hydro 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 OEFC. 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 from Manitoba. 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. Known Deratings
The reported value is the currently known temporary deratings to the Declared Net Capacity (line 5). The deratings are based on information provided by the resource owner.
7. Pickering A Units
Pickering A units are forecast to return to service as shown based on forecast information provided by OPGI. The forecast calls for one Pickering A unit to return to service every six months, starting in January 2002.
8. Hydro Plant Reductions
Reductions to Hydro plants, which account for 98% dependable water availability, 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 98% dependable monthly water conditions. Niagara zone 25 Hz locked in generation capacity has also been accounted for as a further reduction.
9. Available Generation Capacity
This is the generation Capacity available to supply the forecasted demand, after all known reductions have been accounted for. It is the net declared capacity less the known deratings and Hydro 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. Maintenance outages are forecast for the period up to 18-months ahead and are included in the IMO's 18-month forecast.

3.3 Long Term External Transactions Outside the Province

OPGI has an existing contract for the purchase of 200 MW of firm capacity and energy from Manitoba Hydro, which expires on October 31, 2003. No other firm contracts have been identified for the study period.

3.4 Summary of Available Resources

Table 3.5 shows the total available generation capacity at the time of winter peak demand. The available generation (in line 9) ranges from 26,680 MW in Year 2001 to 28,664 MW in Year 2010.

3.5 Potential New Generation Sources

Table 3.6 shows potential new generation projects listed by their locations in the load forecast areas. This grouping is based on projects that have been identified to the IMO. These projects were not considered as part of the committed resources in this study.

Table 3.6 Location of Potential Generation Projects in Ontario

Load Forecast Area	Generation Capacity MW
South West Area	866
Niagara Area	250
East-Central Area	2,414
NorthEast Area	35
TOTAL	3,565

4.0 Resource Assessment

4.1 Introduction

This section provides an assessment of the adequacy of the available generating resources (as described in Section 3) to meet the forecast demand (as described in Section 2). The methodology used to carry out this assessment is outlined in Section 4.2 and in Appendix C and the assessment is outlined in Section 4.3. The conclusions from the adequacy assessment are outlined in Section 4.4.

4.2 Methodology to Assess Resource Adequacy

4.2.1 Generation Reserve Requirement

Generation Reserves are required to ensure that the forecast demand can be supplied with a sufficiently high level of reliability. This Generation Reserve Requirement is calculated from a specified Generation Adequacy Standard. The Required Generation Capacity, therefore, is that amount of generation capacity required to supply the peak demand and meet the Generation Reserve Requirement (see Figure 4.1).

The IMO is a member of the Northeast Power Coordinating Council (NPCC). Members are expected to demonstrate that they can achieve the following Generation Adequacy Standard:

"Sufficient generation reserve must be available such that, after allowing for interconnection assistance and emergency operating actions, the expected annual loss of load probability (LOLP), caused by a deficiency of generation, is less than 0.1 day per year".

The Loss of Load Probability (LOLP) level of 0.1 (day per year) can be equated to a Generation Reserve Requirement of between about 18% and 20% of peak demand for the Ontario System, as shown below.

As shown in Figure 4.2, the Loss of Load Probability (LOLP) decreases as the available Generation Reserve Margin increases. The IMO's Load and Capacity model (described in Appendix C) was used to produce this curve. The values presented are a function of the mix of generating units (size and forced outage rates) and weather forecast uncertainties and the curve was derived by studying several future years between 2001 and 2005. The IMO uses a Generation Adequacy Standard level of 18% in assessing generator outage requests in any week, over the next 18-months. For this study, a standard of 18% was used in Year 2001, 19% in 2002 and, thereafter, a Reserve Requirement which is equivalent to an LOLP of 0.1 day per year. The LOLP level of 0.1, as used in this study, is a more stringent application of the NPCC requirement since interconnection assistance and other emergency operating actions are not included in the LOLP calculation.

Ontario Hydro's Generation Reserve Requirement was studied in some detail in the System Planning Division of Ontario Hydro in 1992 and, for comparison purposes, a case from that study is also shown in Figure 4.2. This case excluded the uncertainty related to economic growth. The model, size of system and other variables were also different from the IMO Model. In the past, Ontario Hydro's Generation Reserve Requirement varied from 18% (short term) to

about 24% for longer term decisions; given the lead times for new generation, combined with a higher economic growth expectation, the higher values reflected higher levels of uncertainty.

The lead time for installing new generation has been reduced to under two years which, along with a relatively low growth rate, reduces uncertainties and the associated higher reserve requirements.

Figure 4.1 Reserve Margin

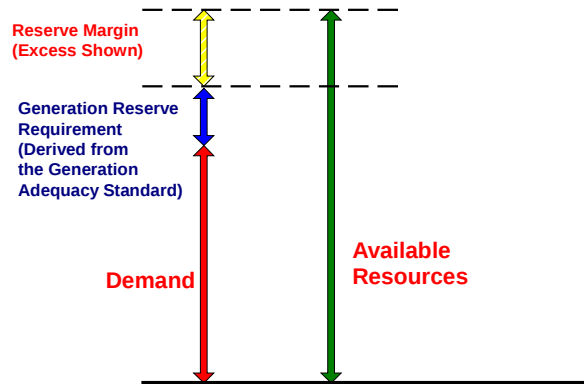
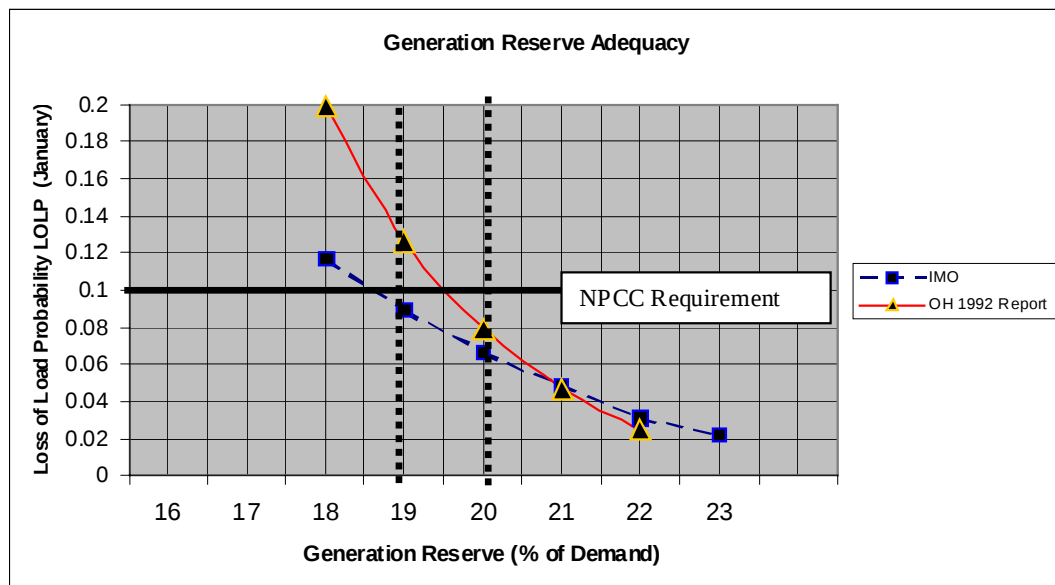


Figure 4.2 LOLP as a Function of Generation Reserve Requirement



4.3 Assessment of Resource Adequacy

4.3.1 Forecast Versus Required Reserve for the Median Demand Forecast

Over the forecast period, the Ontario electrical energy use is expected to increase, on average, by about 0.9% annually in the Median Demand Forecast. The Available Capacity above or below the Required Reserves (and demand) is shown as Margin (Excess/Shortfall) in Table 4.1 (for Winter peak hours) and Table 4.2 (for Summer peak hours) for the forecast period. The analysis shows that the Ontario System has sufficient reserves to meet the Required Reserve level for each year during the forecast period, with the exception of 2010 when the Margin is slightly negative at the peak hour in Summer. The forecast Margin is lower at winter peak as compared to the summer peak at the start of the forecast period but the situation is reversed towards the end of the forecast period. The Required Generation Reserves are higher in the summer mainly because of the air conditioning demand during hot and humid weather.

The situation at the peak of each week is shown for sample years in Figure 4.3. There are no planned outages in the study, although outages are usually taken through the year, except during the summer and winter peak demand periods. The Margin displayed is after taking into account the demand and the Required Reserve in each week. A positive Margin represents capacity that is available for planned outages. The situation at the start and end of the study period shows lower reserve margins, with the intervening years showing higher margins.

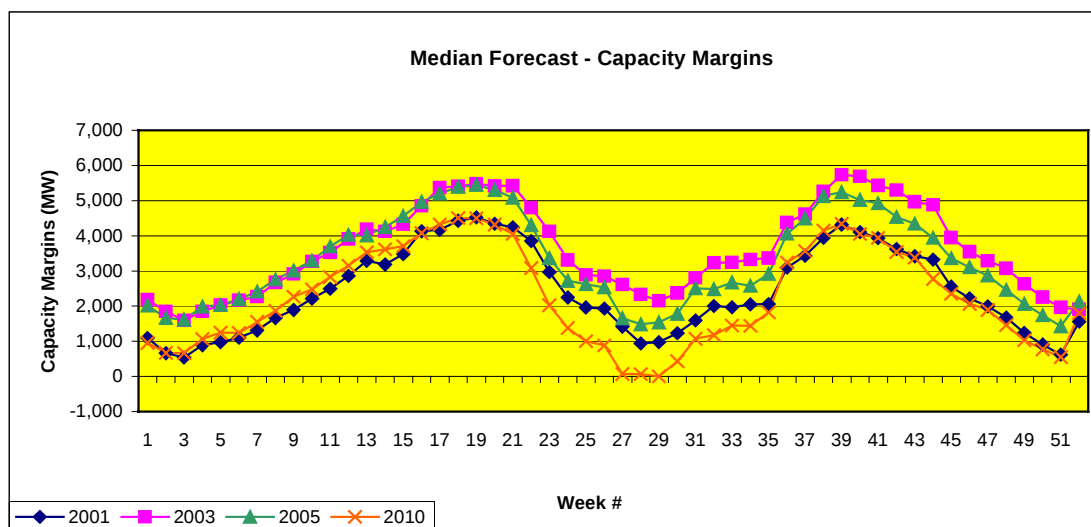
Table 4.1 Reserve Margins Under Median Forecast Winter Peak

Year	Winter Peak Demand Normal Weather	Week Ending	Available Capacity	Available Reserves	Required LOLP	% Reserve Required	Reserve Required	Margins Excess/ Shortfall [-]
2001	22,633	21-Jan-01	26,680	4,048	Calculated	18%	3,510	538
2002	22,840	20-Jan-02	27,195	4,355	Calculated	19%	3,432	923
2003	23,055	19-Jan-03	28,349	5,294	0.10000	LOLP	3,704	1,590
2004	23,205	18-Jan-04	28,664	5,459	0.10000	LOLP	3,734	1,725
2005	23,338	16-Jan-05	28,664	5,325	0.10000	LOLP	3,662	1,664
2006	23,532	15-Jan-06	28,664	5,132	0.10000	LOLP	3,655	1,477
2007	23,739	21-Jan-07	28,664	4,925	0.10000	LOLP	3,782	1,143
2008	23,903	20-Jan-08	28,664	4,761	0.10000	LOLP	3,754	1,007
2009	24,174	18-Jan-09	28,664	4,490	0.10000	LOLP	3,725	765
2010	24,306	17-Jan-10	28,664	4,359	0.10000	LOLP	3,685	674

Table 4.2 Reserve Margins Under Median Forecast Summer Peak

Year	Summer Peak Demand Normal Weather	Week Ending	Available Capacity	Available Reserves	Required LOLP	% Reserve Required	Reserve Required	Margins Excess/ Shortfall [-]
2001	21,760	22-Jul-01	26,370	4,610	Calculated	18%	3,629	981
2002	22,087	21-Jul-02	27,400	5,313	Calculated	19%	3,985	1,328
2003	22,312	20-Jul-03	28,554	6,242	0.10000	LOLP	4,091	2,151
2004	22,627	18-Jul-04	28,354	5,727	0.10000	LOLP	4,068	1,659
2005	22,796	24-Jul-05	28,354	5,559	0.10000	LOLP	4,020	1,539
2006	23,048	23-Jul-06	28,354	5,306	0.10000	LOLP	4,137	1,169
2007	23,327	21-Jul-07	28,354	5,027	0.10000	LOLP	4,158	869
2008	23,737	20-Jul-08	28,354	4,617	0.10000	LOLP	4,208	409
2009	23,927	19-Jul-09	28,354	4,427	0.10000	LOLP	4,195	232
2010	24,163	25-Jul-10	28,354	4,191	0.10000	LOLP	4,193	-2

Figure 4.3 Median Demand Forecast Capacity - Weekly Margins



4.3.2 Forecast Versus Required Reserve for the High Demand Forecast Scenario

In the High Demand Forecast scenario, the Ontario electrical energy use is expected to increase, on average, by about 2.0% annually. Generation Reserve Margins for the forecast period are shown in Table 4.3 (for Winter peak hours) and Table 4.4 (for Summer peak hours). The Margin is negative at the peak hour in Summer, beginning in 2005, and in both Summer and Winter beginning in 2007. The forecast Margin is higher at summer peak as compared to the winter peak until 2003, when the situation is reversed.

The situation at the peak of each week is shown in Figure 4.4. The Margin displayed is after taking into account the demand and the Required Reserve in each week. Positive margins indicate capacity available for maintenance outages.

In the High Demand scenario, small negative margins can be accommodated since dispatchable loads will likely respond to the resulting spot price increases and will be dispatched off. An allowance of 600 MW had been assumed in the past for similar actions. Similarly, additional imports would likely be attracted in such a situation as a result of increasing market prices. An allowance of 700 MW had been assumed in the past for such imports.

Based on the above results, additional resources could be required as early as 2005 for the Higher Demand Forecast scenario.

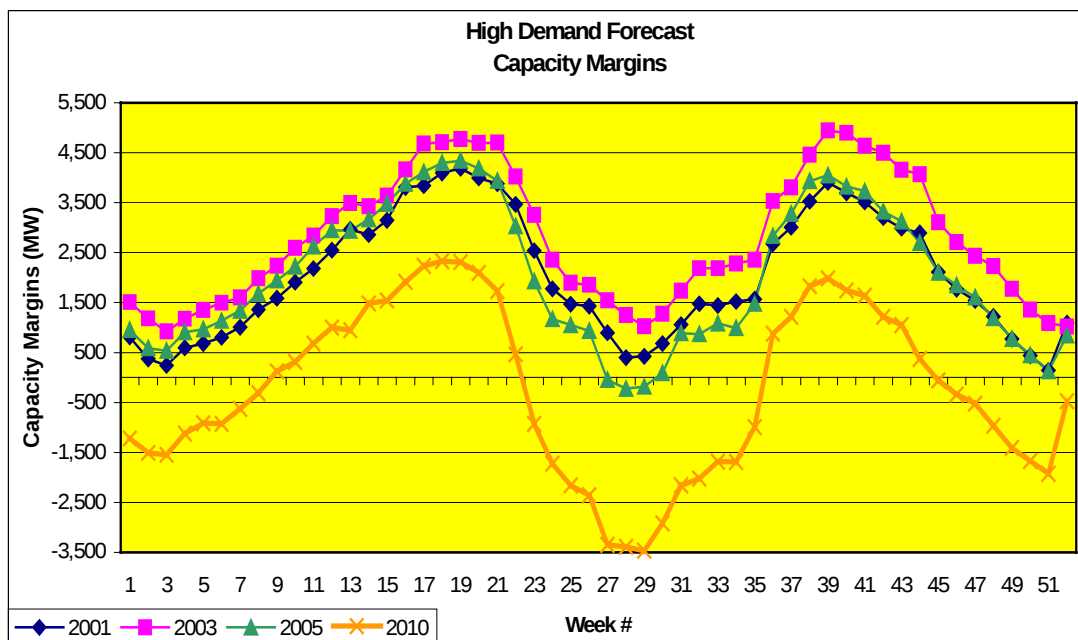
Table 4.3 High Demand Forecast Winter Peak Margins

Year	Winter Peak Demand Normal Weather	Week Ending	Available Capacity	Available Reserves	Required LOLP	Required % Reserve	Reserve Required	Margins Excess/ Shortfall [-]
2001	22,918	21-Jan-01	26,680	3,762	Calculated	18%	3,521	241
2002	23,306	20-Jan-02	27,195	3,889	Calculated	19%	3,451	438
2003	23,706	19-Jan-03	28,349	4,643	0.10000	LOLP	3,724	919
2004	24,047	18-Jan-04	28,664	4,617	0.10000	LOLP	3,757	860
2005	24,377	16-Jan-05	28,664	4,287	0.10000	LOLP	3,700	587
2006	24,772	15-Jan-06	28,664	3,892	0.10000	LOLP	3,696	196
2007	25,193	21-Jan-07	28,664	3,471	0.10000	LOLP	3,833	-362
2008	25,572	20-Jan-08	28,664	3,092	0.10000	LOLP	3,810	-718
2009	26,064	18-Jan-09	28,664	2,600	0.10000	LOLP	3,781	-1,181
2010	26,422	17-Jan-10	28,664	2,242	0.10000	LOLP	3,750	-1,508

Table 4.4 High Demand Forecast Summer Peak Margins

Year	Summer Peak Demand Normal Weather	Week Ending	Available Capacity	Available Reserves	Required LOLP	Required % Reserve	Reserve Required	Margins Excess/ Shortfall [-]
2001	22,282	22-Jul-01	26,370	4,088	Calculated	18%	3,661	427
2002	22,871	21-Jul-02	27,400	4,529	Calculated	19%	4,028	501
2003	23,363	20-Jul-03	28,554	5,191	0.10000	LOLP	4,163	1,028
2004	23,964	18-Jul-04	28,354	4,390	0.10000	LOLP	4,148	242
2005	24,413	24-Jul-05	28,354	3,941	0.10000	LOLP	4,120	-179
2006	24,965	23-Jul-06	28,354	3,389	0.10000	LOLP	4,243	-854
2007	25,559	21-Jul-07	28,354	2,795	0.10000	LOLP	4,289	-1,494
2008	26,320	20-Jul-08	28,354	2,034	0.10000	LOLP	4,392	-2,358
2009	26,833	19-Jul-09	28,354	1,521	0.10000	LOLP	4,394	-2873
2010	27,410	25-Jul-10	28,354	944	0.10000	LOLP	4,414	-3470

Figure 4.4 High Demand Forecast - Weekly Margins



4.3.3 Other Scenarios

There are several other situations that could cause the assumptions of the available resources to change from the assumptions used in the analysis in Sections 4.3.1 and 4.3.2. Typical changes to the assumed available generation could change the values by as much as 1500 MW. Tables 4.5 to 4.8 show the resulting Margins if the base assumptions are higher (new resources added) or lower (higher forced outages) than the forecast amount.

Table 4.5 Change in Resources from Base Assumptions Under Median Forecast Margins - Winter Peak Demand (MW)

Year	-1500 MW	-1000 MW	-500 MW	Base Excess/ Shortfall [-]	+500 MW	+1000 MW	+1500 MW
2001	-962	-462	38	538	1,038	1,538	2,038
2002	-577	-77	423	923	1,423	1,923	2,423
2003	90	590	1090	1,590	2,090	2,590	3,090
2004	225	725	1225	1,725	2,225	2,725	3,225
2005	164	664	1164	1,664	2,164	2,664	3,164
2006	-23	477	977	1,477	1,977	2,477	2,977
2007	-357	143	643	1,143	1,643	2,143	2,643
2008	-493	7	507	1,007	1,507	2,007	2,507
2009	-735	-235	265	765	1,265	1,765	2,265
2010	-826	-326	174	674	1,174	1,674	2,174

Table 4.6 Change in Resources from Base Assumptions Under Median Forecast Margins - Summer Peak Demand (MW)

Year	-1500 MW	-1000 MW	-500 MW	Base Excess/ Shortfall [-]	+500 MW	+1000 MW	+1500 MW
2001	-519	-19	481	981	1,481	1,981	2,481
2002	-172	328	828	1,328	1,828	2,328	2,828
2003	651	1,151	1,651	2,151	2,651	3,151	3,651
2004	159	659	1,159	1,659	2,159	2,659	3,159
2005	39	539	1,039	1,539	2,039	2,539	3,039
2006	-331	169	669	1,169	1,669	2,169	2,669
2007	-631	-131	369	869	1,369	1,869	2,369
2008	-1,091	-591	-91	409	909	1,409	1,909
2009	-1,268	-768	-268	232	732	1,232	1,732
2010	-1,502	-1,002	-502	-2	498	998	1,498

Table 4.7 Change in Resources from Base Assumptions Under High Demand Forecast Margins - Winter Peak Demand (MW)

Year	-1500 MW	-1000 MW	-500 MW	Base Excess/ Shortfall [-]	+500 MW	+1000 MW	+1500 MW
2001	-1,259	-759	-259	241	741	1,241	1,741
2002	-1,062	-562	-62	438	938	1,438	1,938
2003	-581	-81	419	919	1419	1,919	2,419
2004	-640	-140	360	860	1360	1,860	2,360
2005	-913	-413	87	587	1087	1,587	2,087
2006	-1,304	-804	-304	196	696	1,196	1,696
2007	-1,862	-1362	-862	-362	138	638	1,138
2008	-2,218	-1718	-1218	-718	-218	282	782
2009	-2,681	-2181	-1681	-1181	-681	-181	319
2010	-3,008	-2508	-2008	-1508	-1008	-508	-8

Table 4.8 Change in Resources from Base Assumptions Under High Demand Forecast Margins - Summer Peak Demand (MW)

Year	-1500 MW	-1000 MW	-500 MW	Base Excess/ Shortfall [-]	+500 MW	+1000 MW	+1500 MW
2001	-1,073	-573	-73	427	927	1,427	1,927
2002	-999	-499	1	501	1,001	1,501	2,001
2003	-472	28	528	1,028	1,528	2,028	2,528
2004	-1,258	-758	-258	242	742	1,242	1,742
2005	-1,679	-1,179	-679	-179	321	821	1,321
2006	-2,354	-1,854	-1,354	-854	-354	146	646
2007	-2,994	-2,494	-1,994	-1,494	-994	-494	6
2008	-3,858	-3,358	-2,858	-2,358	-1,858	-1,358	-858
2009	-4,373	-3,873	-3,373	-2,873	-2,373	-1,873	-1,373
2010	-4,970	-4,470	-3,970	-3,470	-2,970	-2,470	-1,970

4.4 Conclusions

Under the median demand forecast scenario, the available generation capacity in the study is adequate to meet forecast demands with an acceptable level of reliability. Lower generation margins, which are forecast in the first two study years and the last three study years, indicate a potential requirement for additional generating capacity to be made available. There is a trend towards lower margins in the summer than in the winter in the last three years of the study period.

Under the high demand forecast scenario, available generation is insufficient to meet required reserves beginning in 2005.

5.0 The Ontario Electricity System

5.1 Current Configuration of the Transmission System

5.1.1 Overview

The Ontario transmission system has been developed over the years to transfer power in bulk from point to point in Ontario and across the tie lines to neighbouring jurisdictions. These are the transmission paths that will facilitate competition between suppliers. Generally, the transmission system is robust but there are limits on the amount of power that can be transferred across critical circuits (or “interfaces”). These limits are based on both physical limitations and the need to respect system security criteria, where applicable, established by the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC).

The existing 500, 230 and 115 kV network is shown in Appendix B and the committed transmission plans are described in Section 5.3. The capability of the Ontario transmission system is described briefly in the following sections and in more detail in Appendix D.

5.2 Power Transmission Capability across Major Interfaces and Interconnections

5.2.1 Range of Power Flows

Transmission interfaces and zones are shown in Figure 5.1 and are defined in Appendix D, including the values of the power transfer limits. Table 5.1 shows the total assumed generation capacity in each zone by resource type and the Year 2000 Winter Peak Demand. Generation dispatch gives rise to power flow patterns across the system that vary from low load to high load periods and according to generation availability. The distribution of power flows across the transmission interfaces over the past year is shown in Appendix D.

Figure 5.1 Ontario's Internal Zones and Interconnections

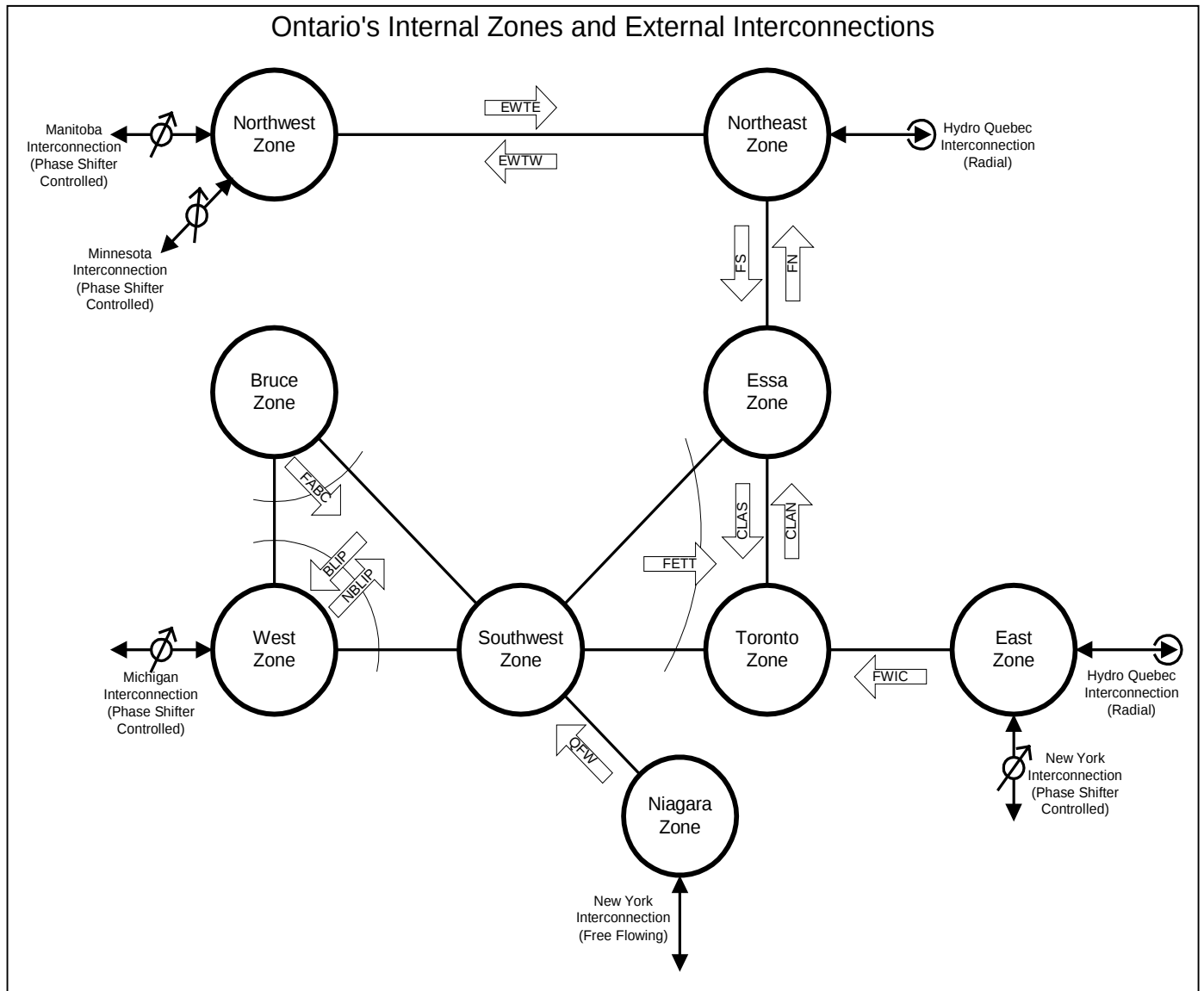


Table 5.1 Year 2000 Winter - Assumed Generation and Demand in Transmission Zones

Zone Name	Resource Type & Output of Units MW					Total Generation	Forecast 20-min Winter Peak Demand
	Hydro	Nuclear	Oil & Gas	Coal	Other	MW	MW
NorthWest	614	0	143	525	46	1,328	1,047
NorthEast	1,889	0	514	0	7	2,410	1,613
East	1,900	3,524	2,530	0	0	7,954	4,063
Essa	377	0	0	0	0	377	1,173
Toronto	0	2,064	110	1,148	70	3,392	6,823
Niagara	1,655	0	0	0	0	1,655	956
Bruce	0	3,140	0	0	1	3,141	130
SouthWest	152	0	292	3,895	4	4,344	4,389
Western	0	0	12	1,950	0	1,962	2,368
Small NUGs	7	0	1	0	0	8	
Totals MW	6,594	8,728	3,602	7,518	128	26,571	22,562

5.2.2 Transmission System Potential Concerns

The system is generally quite robust, except in Northern Ontario, and there are a number of potential concerns that can affect the reliability of the system and the efficiency of the market. The location of potential new generation sources can be limited by the weak local transmission in some areas of Northern Ontario. Various Special Protection Schemes (such as Generation and Load Rejection) are used to compensate for the lack of sufficient transmission and less restrictive security criteria have been allowed in these areas. Complex operating security limits are used to ensure system security in the NorthWest and NorthEast Zones. Some specific reliability concerns are outlined below:

1. Reliability Concerns:

- **NorthWest Zone** – The Thunder Bay area currently requires operation of one Thunder Bay GS generating unit to control local voltages within customer equipment ranges.
- **NorthEast Zone** – There are potential system security problems for the sudden outage of two radial 500-kV lines from Sudbury to Pinard, exposing the area loads to potential interruptions.
- **Toronto & Southern Ontario** – Transmission system voltages must be controlled within specified ranges and, therefore, certain generating units are required on-line during critical periods. In the Toronto area, control of transmission voltages above the minimum levels currently requires operation of Lakeview TGS and Pickering NGS units during high summer loads. A minimum number of units is also required at Lambton, Nanticoke and Lennox Generating Stations during some power transfer conditions, to control local transmission voltages. The Windsor area power transfer is at the limiting values under high load conditions.
- Short circuit levels at some points, particularly on the 115 kV system, are approaching local equipment ratings and may require equipment uprating in future.

2. Market Efficiency Concerns:

- **NorthWest Zone** - Generation may be bottled in the NorthWest Zone under most operating conditions, due to insufficient transmission capacity out of the zone. Congestion can occur in the NorthEast Zone during periods of high flows to the south.
- **QFW Interface** - High power flows between Eastern USA sending points and Michigan and points west have resulted in uncontrolled high power flows through the Ontario system resulting in congestion on the QFW interface and other impacts in the Ontario system. The completion of the installation of phase shifters on the Michigan tie lines should reduce the impact of the uncontrolled power flows.

5.2.3 Interconnections Between Control Areas

As shown in Figure 5.1, and further defined in Appendix D, Ontario is interconnected with Minnesota, Manitoba, Quebec, Michigan and New York. The IMO coordinates with the adjacent control areas to dispatch power sales and purchases in and out of Ontario over the tie lines. The interconnections can carry exports of up to 5930 MW of power (if available) and imports up to 5525 MW, depending on internal limits and the destination of the power in Ontario. High levels of power transfer from and to the USA have occurred in some unusual instances where the various systems provided support in system emergency conditions; otherwise the transfers are usually below about 2000 MW. The tie lines with Quebec, Manitoba and Minnesota are often operated up to their capability limits.

5.3 Committed Transmission Plans in the next 10 Years

The detailed committed plans for new transmission facilities are shown in Appendix D6. Major committed projects include an increased interconnection capability with Quebec (Maclaren), new transformer and phase shifting transformers on the Michigan ties, a new capacitor bank at Chatham and refurbishment of some switchyards, lines and system protection schemes.

Uncommitted plans include a new interconnection with Quebec, near Ottawa. This is a 1250 MW HVDC interconnection and is expected to be in service for operation in the winter of Year 2003. Other uncommitted transmission plans cover the connection of potential new generating plants.

6.0 Transmission Adequacy Assessment

6.1 Introduction

The assessment of the adequacy of transmission capability is based on ensuring that sufficient transmission capability is available to deliver power to loads in conformance with NPCC system security criteria and assuming continued reliance on Special Protection Schemes such as generation rejection and load rejection.

The principal purpose of the transmission adequacy assessment is to identify any transmission zones and load pockets within which load supply may potentially become unreliable. This could be due to a combination of factors such as load growth or reduction of generation capability within a zone or the inability of generation which is located within adjacent transmission zones to provide the required level of support to the zone due to transmission system limitations. This assessment is described in Section 6.2.

Another purpose of the transmission capability assessment is to identify transmission interfaces that have the potential to become congested and thus reduce market efficiency. This assessment is described in Section 6.3.

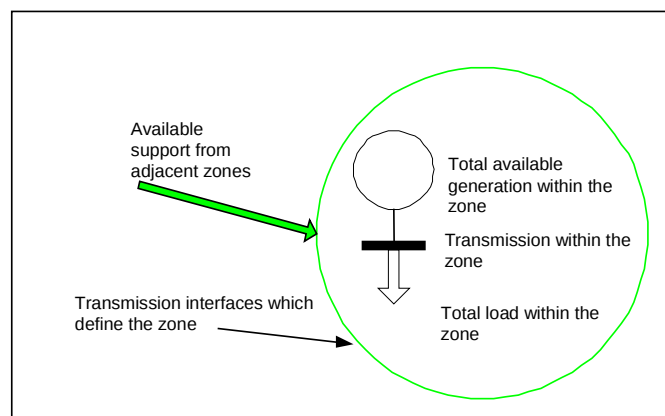
The impact of new generation and transmission projects is discussed in Section 6.4 and the overall conclusions of the transmission adequacy assessment are summarized in Section 6.5.

6.2 Reliability Assessment of Transmission Zones

6.2.1 Methodology and Assumptions

The assessment of reliability within each transmission zone is based on the conceptual model shown below in Figure 6.1.

Figure 6.1 Conceptual Reliability Model of a Transmission Zone



The following assumptions were made, in using the above model, to assess the reliability of supply to the various transmission zones. These assumptions represent conditions that were used, in the past, in the design of the Ontario Hydro transmission system and in the design of supply to local load areas. As such, they have a low probability of occurrence and do not represent typical conditions, as outlined below:

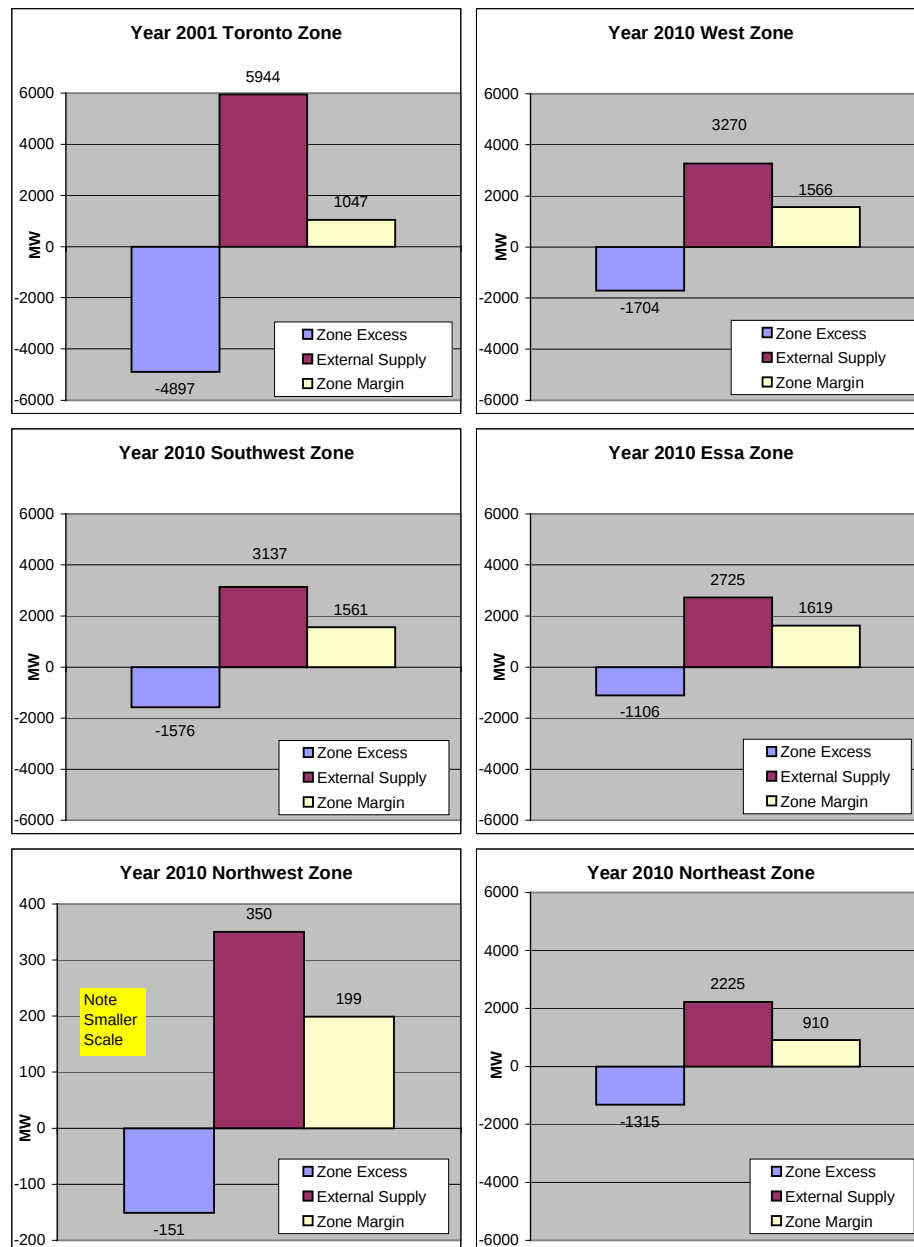
- Generation within the zone: Total available generation within the zone was assumed to be that amount of generation expected to be available if the two largest generating units within the zone were out of service. All available generation was assumed to be operating at maximum continuous output. In the NorthEastern Zone, Winter nighttime conditions were represented, as current practice is to operate the hydraulic generation output at a minimum and the need for support from outside the zones is the highest.
- Transmission within the zone: The transmission system within the zone was assumed to be adequate to supply all loads within the zone.
- Total loads within the zone: Total loads within the zone were assumed to be at high levels, such as those which may occur under extreme weather conditions, under both median and high demand forecast scenarios. There is only a 3% probability of loads being greater than those assumed due to weather effects.
- Available support from adjacent zones: Available support from adjacent zones was determined in the following manner:
 1. For the zone being studied, available generation and load within the zone were set at the levels described above and the amount of generation surplus or deficiency for each zone was calculated.
 2. Surplus generation within zones was then “transported” to deficient zones, to the extent possible, while respecting the operating security limits associated with the interfaces that define zonal boundaries, as described in Appendix D2. Interface Limit values were as described in Appendix D3. The interface limits are the same under summer and winter conditions, except for the Queenston Flow West (QFW) interface. For this interface the more restrictive summer limits were used.

6.2.2 Results of Reliability Assessment - Power Supply to Zones

The West, Southwest, Toronto, Essa, NorthEast (at night) and NorthWest (in Year 2010) zones show a local generation deficit requiring transfers in from the adjacent zones under the postulated local conditions described in Section 6.2.1. Each zone was studied separately for both the median and high demand forecast cases. The local deficit situation in the Toronto Zone is the largest in the Year 2001 (prior to the return of Pickering A units to service) and in Year 2010 for the other zones. The interface transmission capacity is sufficient to carry the required transfers into the various zones under both Winter and Summer peak conditions. In the case of the NorthEast zone, off-peak conditions under which the hydro output is at a very low level yields the most demanding but not limiting conditions. Winter Peak extreme weather conditions yield the worst case in all other zones. The capacity balance in each of the above deficit zones is summarized in Figure 6.2 for the median demand forecast case. The Zone Excess is the local

zone generation and load balance, with two of the largest units in each zone out of service (except for the NorthEast Zone as noted above). The External Supply is the lower of the interface transmission capacity limit and the excess generation capacity at that time. The Zone Margin is the difference between the External Supply and the Zone Deficiency.

Figure 6.2 Reliability Study – Median Demand Forecast Under Extreme Weather Conditions



Based on the results of the reliability assessment, it is concluded that the capability of the transmission system is adequate to supply the loads within each of the nine transmission zones, with an acceptable level of reliability, for the period 2001 to 2010. It should be noted, however, that the connection of new generation or load to the system may require transmission system modifications or additions in order to maintain current levels of reliability.

6.2.3 Reliable Supply to Load Pockets Within Transmission Zones

There are some potential concerns on the transmission system in load pockets within the transmission zones. In the NorthWest Zone must-run status may be required for Thunder Bay GS units (control of customer voltage levels), Ear Falls units and Caribou Falls units (local power inflows) under some load conditions. Other larger centres may also require must-run local generation under some load conditions. At times of off-peak generation, there are ongoing security problems in the NorthEast in balancing load and generation after an outage of any of the two single high capacity lines that serve the northern areas.

Assessment of Summer Voltage Problems in the Toronto Zone

During extreme hot and humid weather in the Toronto area, the load level increases by over 10%, compared to normal weather conditions, due to air conditioning load. The high reactive power consumption associated with this load can give rise to low transmission system voltages. This phenomenon was experienced under hot weather conditions in the summer of 1999, when the transmission voltage at the Milton 500-kV transformer station reached the minimum permissible level and load management, potentially including load shedding, would have been called upon had the weather not changed.

Load Flow studies were carried out to study the low transmission voltage problem in the Toronto Zone under summertime load conditions in the study period, as outlined in Appendix D. The results show that the critical condition, due to low voltages, is expected to continue through the summer of Years 2000 and 2001. After the return of Pickering A units (expected in Years 2002 and 2003), the voltage situation should be less critical but remains a concern over the longer term due to the growing summertime load demands in the area. In the longer term, there is a need for additional transmission voltage support sources in the Toronto Zone. Restrictions on the use of Lakeview generation for potential environmental concerns, or other reasons, may increase the stated needs

6.3 Congestion Assessment

Transmission flows are determined by the pattern of loads and generation, and the characteristics of the transmission system at any given time. Each of these factors is inherently somewhat unpredictable due to the effect of random forced outages on generation and transmission facilities and the effect of weather on load levels. With the opening of the Ontario Electricity Market, an additional level of complexity is added because bid and offer prices, rather than traditional economic dispatch principles, will determine the dispatch of generation. Without any history of market operation, congestion on the Ontario transmission system is impossible to forecast with any degree of certainty. Hence, rather than attempting to forecast congestion, an approach has been developed to identify the conditions under which congestion is likely to occur on the major transmission system interfaces during 2001. As additional generation is added to

appropriate points on the system in future years, the level of system flows would generally be expected to reduce and congestion would tend to be relieved.

Methodology

The following approach was used to identify conditions under which congestion is likely to occur. It tests the flexibility available to market participants located in North, West and East of Toronto to maximize their generation output in response to market prices.

- The system was “stressed” separately from the North, East and West relative to the load center in the Toronto Zone (which is generally deficient in generation at high load levels).
- In each scenario, load levels were set at 80% of peak and generation was maximized to the extent possible, noting any violation of operating security limits.

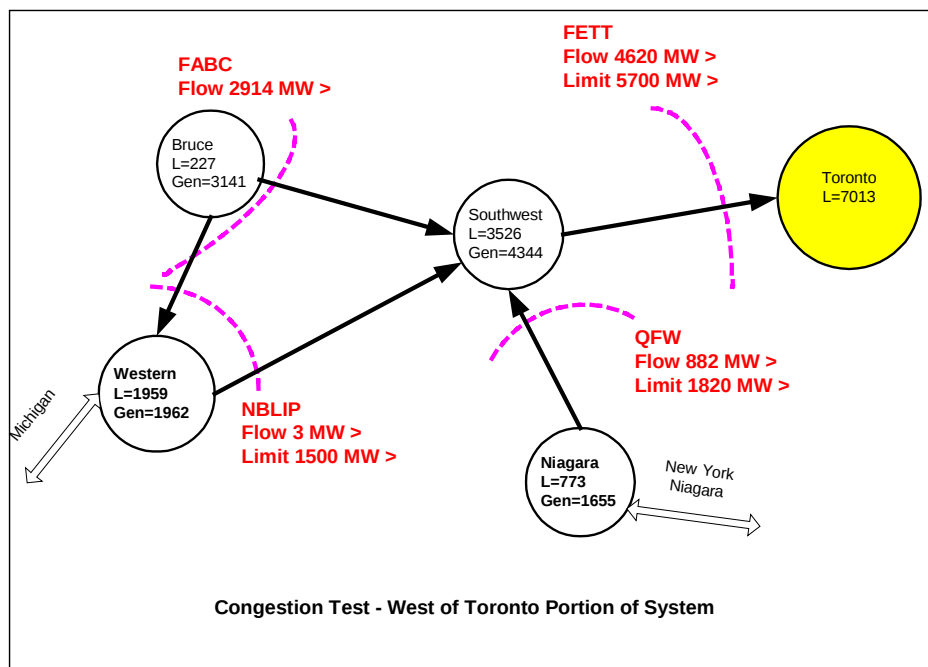
1. System stressed from Southwest of Toronto

The conditions in this scenario are displayed in Figure 6.3. Power is supplied from the Bruce complex and from Niagara towards Toronto stressing the Flow East into Toronto (FETT¹) interface. This interface reaches 80% of the transmission limit without any congestion in the intervening paths.

About 1000 MW power imported, from the USA at Niagara and/or from Michigan, would result in the FETT interface becoming congested, under the study scenario. A power import, which results in 1500 MW of power flow on the Michigan interconnection, will result in congestion on the NBLIP (Negative Buchanan Longwood Input) interface out of the Western zone. Power also circulates through Ontario, normally in at Niagara and out at Michigan, but can be controlled within the required limits. This circulating flow (not shown) would add to any congestion on the QFW interface but would reduce the flow on the Western Zone (NBLIP) interface.

In summary, congestion is unlikely in the Southwestern part of Ontario and, if it occurred, would most likely be caused by high imports combined with high generation. Exports of power would not result in congestion in Ontario due to the high capacity of the interconnections to the USA.

Figure 6.3 Maximum SW Generation and 80% Year 2001 Peak Demand

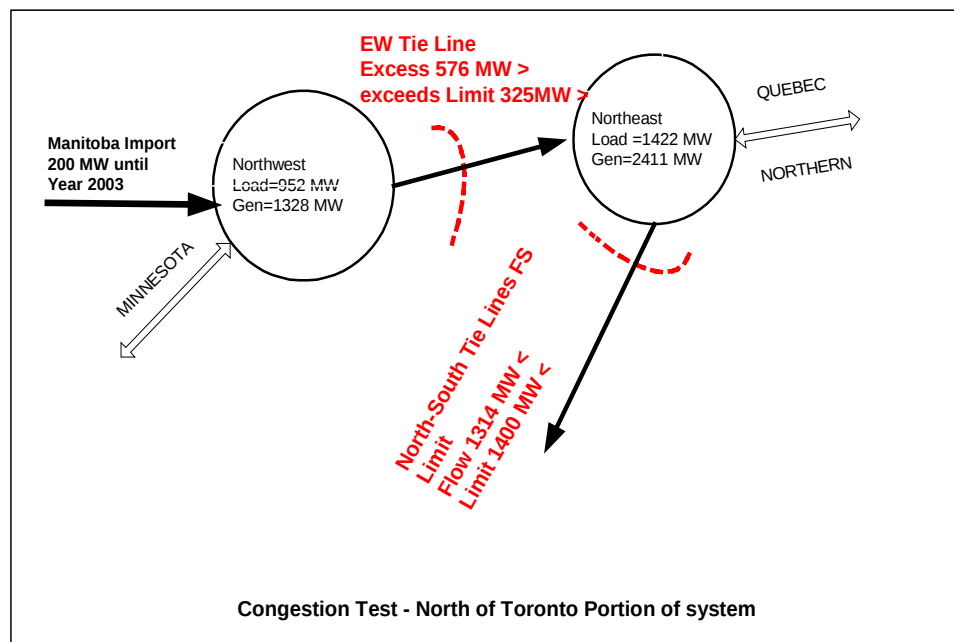


¹ Interfaces are displayed in Figures 6.3 to 6.5 and in Appendix D.

2. System Stressed from the North of Toronto

The conditions in this scenario are shown in Figure 6.4. With a Manitoba import of 200 MW, there is about 576 MW excess generation in the Northwest, of which only 325 MW can flow to the east system, leaving 251 MW of excess power in Northwestern Ontario. Further, the line losses on the long East–West tie line are quite high at the 325 MW flow level and up to 200 MW flow may be the economic limit. This situation gives rise to a high possibility of congestion on the East–West tie. Under these conditions, power may be directed towards Minnesota, depending upon the prevailing prices. Congestion may be relieved by an expanded transmission capacity or higher Northwestern load growth than that assumed. The flow from the NorthWest Zone adds to the excess from the NorthEastern zone and gives rise to a flow south, which is also close to the limits. High hydraulic generation output at spring freshet, combined with lower Northern load levels and imports from Quebec, can result in congestion on the Flow South interface, shown at 94% of the limit.

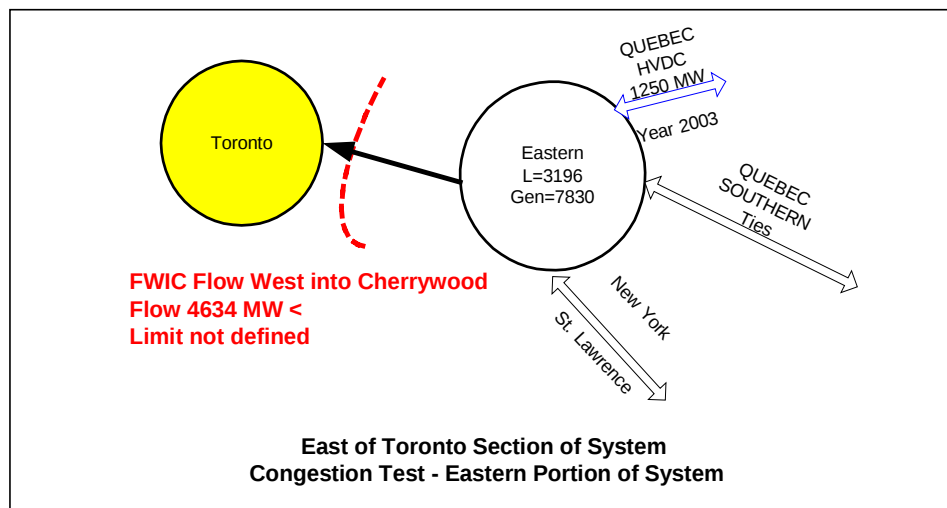
Figure 6.4 Maximum Northern Generation and 80% Year 2001 Peak Demand



3. System Stressed from the East of Toronto

The Eastern Zone excess, expressed as the FWIC flow (Flow West Into Cherrywood, a substation near Pickering) is about 4634 MW under maximum generation conditions in the Eastern Zone and 80% Winter Year 2001 Load Level. This flow includes the output of Darlington generating station. Imports of 800 MW from Quebec near Cornwall and another 1250 MW from the proposed HVDC interconnection near Ottawa will increase the Eastern excess amount to a maximum of about 6684 MW. No limit has been defined at the interface (FWIC) between the Eastern Zone and the Toronto Zone as this level of flow is not expected to cause congestion.

Figure 6.5 Maximum Eastern Generation and 80% Year 2001 Peak Demand



6.4 Impact of Potential New Generation and Transmission Projects

The proposed 1250 MW HVDC interconnection with Quebec is the only major transmission project under consideration in this study. The impact of the 1250 MW connection to Quebec is currently being assessed by the IMO. Results of this assessment will be posted on the IMO Website when they are available. The potential new generation projects (see Table 3.6) are located in the following Transmission Zones:

Western Zone: 866 MW

Niagara Zone: 250 MW

Toronto Zone: 2414 MW

NorthEast Zone: 35 MW

The power from these projects could be destined for delivery points inside or outside Ontario. The projects in the Toronto Zone will reduce the deficit in this zone and aid in the voltage control problem. The power projects in the Western zone will add to the excess from that zone

when the existing generation is at the maximum and imports are scheduled (and when zero exports are scheduled). The projects in the Niagara zone will increase the surplus in that zone.

6.5 Conclusions

Reliable Supply to Zones

The transmission capability is adequate to supply the various zones in the system at high load levels. The Toronto Zone voltage control, under high summertime loads in the Toronto Zone, will be a critical problem in the next year or so and will continue to be a concern in the longer term until additional voltage support sources can be added.

Market Efficiency

The system was (by generation dispatch) stressed from the west, east and north (of Toronto), in order to determine conditions where there may be congestion and thus a reduction in market efficiency:

- Conditions of maximum generation in Southwestern Ontario alone are not expected to result in congestion, unless combined with imports of over 1000 MW from New York at Niagara and from Michigan.
- Conditions of maximum generation and imports in Northern Ontario are expected to result in congestion on the East-West ties eastbound and on the North-South ties southbound. An increase in transmission capacity from the NorthWest and the NorthEast Zones would reduce the congestion.
- Conditions of maximum generation from east of Toronto are unlikely to result in congestion.

7.0 Findings and Conclusions

The purpose of this ten-year assessment was to assess the adequacy of existing and committed generation and transmission facilities and to identify any system security concerns. In doing so, it provides insight into potential opportunities for IMO-controlled grid investments or other actions by market participants to maintain the reliability of the system and to assist the IMO-administered markets to operate efficiently.

The assessment of adequacy of generation capacity was based upon ensuring that sufficient resources are available to meet the forecast demand with an acceptable degree of reliability. The assessment of the adequacy of transmission capability was based upon ensuring that sufficient transmission capability is available to transmit power to loads while maintaining an acceptable level of system security. The findings and conclusions of the study are outlined below.

7.1 Findings

7.1.1 Assessment of Adequacy of Resources

Median Demand Forecast

The available generation capacity in the study period is adequate to meet demands under the median demand forecast scenario with the specified level of reliability. Lower generation margins are forecast in the first two study years and the last three study years. There is a trend towards lower margins in the summer than in the winter in the last three years of the study period, brought about by the increasing air conditioning load.

Higher Demand Forecast

Under the high demand forecast scenario, generation capacity in the study is not adequate beginning in 2005. Generation margins are negative at the time of the summer peak, beginning in 2005, and for both winter and summer peaks beginning in 2007. The forecast generation margins are higher at summer peak as compared to the winter peak until 2003, when the situation is reversed.

7.1.2 Assessment of Adequacy of Transmission Capability

Reliable Supply to Zones

The transmission system is adequate to supply the various transmission zones in the system under extreme weather conditions. Load Flow studies were carried out to study the low transmission voltage problem in the Toronto Zone under summertime load conditions in the study period, as outlined in Appendix D. These studies indicate that this will be a critical problem in the next few years and will continue to be a concern in the longer term until additional voltage support sources can be added. Other transmission problems in load pockets have also been noted.

Market Efficiency Assessments

The transmission system was stressed from the west, east and north (of Toronto) and it was determined that congestion was unlikely to occur (with all transmission circuits in service) in the study period, except for the Northern Zones. Conditions of maximum generation and imports in Northern Ontario are expected to result in congestion on the East-West ties eastbound and on the North South ties southbound.

7.2 Conclusions

1. Under the median load growth scenario, lower generation margins which are forecast in the first two study years and the last three study years indicate a potential requirement for additional generation capacity to be made available during those periods. Market Participants should take this into account in their planning.
2. Under a high load growth scenario, additional resources could be required as early as 2005 in order to maintain an adequate level of supply reliability. Currently identified potential generating projects would provide sufficient capacity to meet this potential need.
3. An increase in transmission capacity from the NorthWest and the NorthEast Transmission Zones would reduce congestion and improve market efficiency in those areas.

Appendix A - Electricity Demand Forecast

Table A.1 - Monthly Energy Forecast (by Load Forecast Area) and System Peak Demand (Normal Weather)

	Northwest	Northeast	Central-East	South-Central	Niagara	Southwest	Total	System Peak Demand ¹	One Standard Deviation ¹
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)
Jan-00	752	1,074	7,155	2,686	573	1,402	13,641	22563	898
Feb-00	694	998	6,649	2,496	532	1,303	12,672	22095	762
Mar-00	704	1,019	6,787	2,548	543	1,330	12,931	21173	768
Apr-00	659	974	5,742	2,426	487	1,286	11,574	19913	645
May-00	638	973	5,736	2,424	486	1,284	11,540	18567	427
Jun-00	625	741	6,128	2,376	502	1,252	11,624	20301	1353
Jul-00	645	801	6,620	2,567	543	1,352	12,527	21604	1153
Aug-00	655	785	6,490	2,517	532	1,326	12,305	20965	1122
Sep-00	631	718	5,932	2,300	486	1,212	11,279	20328	1264
Oct-00	672	1,005	5,926	2,504	502	1,327	11,935	19606	519
Nov-00	699	1,042	6,148	2,598	521	1,377	12,385	21429	557
Dec-00	738	1,039	6,926	2,600	554	1,357	13,215	22557	838
Jan-01	750	1,078	7,276	2,720	580	1,418	13,822	22633	992
Feb-01	670	962	6,489	2,426	517	1,265	12,329	22334	767
Mar-01	703	1,017	6,860	2,564	547	1,337	13,029	21416	745
Apr-01	659	979	5,843	2,460	493	1,302	11,736	20184	619
May-01	638	974	5,809	2,445	491	1,294	11,651	18800	409
Jun-01	625	739	6,174	2,386	504	1,255	11,684	20577	1402
Jul-01	646	804	6,723	2,598	549	1,367	12,688	21761	1205
Aug-01	656	787	6,580	2,543	538	1,338	12,441	21212	1129
Sep-01	631	716	5,988	2,314	489	1,217	11,357	20588	1250
Oct-01	672	1,012	6,037	2,541	510	1,345	12,115	19745	515
Nov-01	699	1,040	6,205	2,612	524	1,382	12,462	21528	524
Dec-01	739	1,037	6,996	2,615	557	1,364	13,308	22717	818
Jan-02	750	1,078	7,350	2,740	584	1,427	13,930	22841	987
Feb-02	670	962	6,557	2,444	521	1,273	12,427	22556	809
Mar-02	703	1,009	6,882	2,565	547	1,336	13,043	21635	745
Apr-02	660	988	5,961	2,502	502	1,323	11,935	19850	629
May-02	639	974	5,879	2,467	495	1,304	11,758	19007	458
Jun-02	627	737	6,230	2,400	507	1,261	11,763	20888	1373
Jul-02	649	809	6,837	2,634	556	1,383	12,868	22088	1208
Aug-02	658	786	6,645	2,560	541	1,344	12,533	21627	1206
Sep-02	633	719	6,078	2,342	495	1,230	11,497	20864	1241
Oct-02	673	1,008	6,082	2,553	512	1,349	12,176	19882	524
Nov-02	700	1,037	6,257	2,626	527	1,388	12,534	21660	525
Dec-02	739	1,040	7,088	2,642	563	1,376	13,449	22835	825
Jan-03	751	1,077	7,427	2,759	588	1,435	14,036	23056	928
Feb-03	670	961	6,627	2,462	525	1,280	12,526	22703	780
Mar-03	703	1,014	6,989	2,596	553	1,350	13,205	21839	737
Apr-03	661	985	6,005	2,511	504	1,326	11,991	20298	610
May-03	640	973	5,934	2,482	498	1,310	11,837	19154	482
Jun-03	629	741	6,328	2,431	513	1,276	11,918	21001	1397
Jul-03	651	811	6,926	2,660	562	1,396	13,007	22314	1267
Aug-03	659	785	6,710	2,577	544	1,353	12,629	21780	1139
Sep-03	635	723	6,175	2,372	501	1,245	11,649	20138	1165
Oct-03	674	1,009	6,153	2,573	516	1,358	12,284	20023	516
Nov-03	701	1,034	6,306	2,637	529	1,392	12,600	22049	562
Dec-03	740	1,043	7,190	2,671	569	1,389	13,603	23007	790
Jan-04	751	1,074	7,485	2,771	590	1,440	14,112	23206	932

	Northwest	Northeast	Central-East	South-Central	Niagara	Southwest	Total	System Peak Demand ¹	One Standard Deviation ¹
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)
Feb-04	695	992	6,913	2,560	545	1,330	13,035	22862	780
Mar-04	703	1,018	7,096	2,627	560	1,366	13,370	21686	749
Apr-04	661	983	6,059	2,527	506	1,333	12,071	20552	636
May-04	641	971	5,980	2,494	500	1,315	11,901	19307	558
Jun-04	631	746	6,450	2,468	521	1,294	12,109	21248	1429
Jul-04	654	810	7,003	2,679	566	1,405	13,117	22628	1273
Aug-04	661	788	6,809	2,605	550	1,366	12,779	22135	1169
Sep-04	636	722	6,241	2,388	504	1,252	11,743	20903	1284
Oct-04	675	1,005	6,193	2,583	518	1,362	12,336	20322	522
Nov-04	702	1,044	6,433	2,683	538	1,415	12,814	22186	576
Dec-04	741	1,042	7,260	2,688	573	1,397	13,701	23362	863
Jan-05	751	1,070	7,540	2,782	593	1,445	14,181	23340	859
Feb-05	670	961	6,768	2,498	532	1,297	12,726	22991	776
Mar-05	703	1,015	7,151	2,639	562	1,371	13,440	22024	747
Apr-05	662	988	6,163	2,561	513	1,348	12,235	20685	629
May-05	642	974	6,075	2,524	506	1,329	12,052	19569	514
Jun-05	633	747	6,517	2,486	525	1,301	12,208	21486	1438
Jul-05	656	809	7,065	2,695	569	1,411	13,205	22796	1234
Aug-05	662	794	6,929	2,643	558	1,383	12,970	21941	1136
Sep-05	638	724	6,321	2,411	509	1,262	11,864	21266	1323
Oct-05	676	1,004	6,260	2,601	521	1,370	12,433	20478	533
Nov-05	703	1,041	6,494	2,698	541	1,421	12,898	22302	545
Dec-05	742	1,039	7,316	2,700	575	1,402	13,774	23522	862
Jan-06	751	1,073	7,641	2,808	598	1,457	14,328	23532	849
Feb-06	670	960	6,843	2,515	536	1,305	12,828	23217	782
Mar-06	703	1,020	7,268	2,671	569	1,386	13,616	22230	746
Apr-06	663	980	6,175	2,559	512	1,346	12,235	21005	652
May-06	643	980	6,173	2,558	512	1,345	12,212	19652	444
Jun-06	635	747	6,598	2,508	530	1,312	12,330	21726	1523
Jul-06	659	811	7,162	2,722	575	1,424	13,352	23049	1335
Aug-06	664	795	7,017	2,667	563	1,395	13,100	22404	1252
Sep-06	639	722	6,376	2,423	512	1,268	11,940	21486	1331
Oct-06	678	1,008	6,352	2,632	527	1,384	12,582	20630	530
Nov-06	703	1,042	6,566	2,721	545	1,431	13,009	22460	545
Dec-06	743	1,036	7,378	2,712	578	1,407	13,852	23617	814
Jan-07	751	1,076	7,747	2,838	605	1,471	14,487	23740	994
Feb-07	670	960	6,915	2,533	540	1,313	12,931	23401	806
Mar-07	703	1,017	7,328	2,684	572	1,391	13,695	22496	763
Apr-07	664	983	6,269	2,588	518	1,359	12,381	21236	667
May-07	645	980	6,251	2,581	517	1,355	12,329	19897	496
Jun-07	637	746	6,661	2,525	533	1,319	12,421	21992	1561
Jul-07	661	815	7,276	2,758	582	1,440	13,532	23328	1357
Aug-07	666	795	7,102	2,692	568	1,406	13,228	22722	1314
Sep-07	641	720	6,426	2,436	514	1,272	12,008	21875	1394
Oct-07	679	1,017	6,482	2,676	536	1,406	12,795	20785	518
Nov-07	704	1,042	6,641	2,742	549	1,440	13,118	22634	530
Dec-07	744	1,036	7,459	2,732	582	1,416	13,969	23836	831
Jan-08	751	1,075	7,830	2,858	609	1,479	14,601	23904	963
Feb-08	695	994	7,240	2,643	563	1,368	13,502	23618	775
Mar-08	703	1,007	7,333	2,677	570	1,385	13,675	22755	737
Apr-08	664	992	6,389	2,631	526	1,380	12,582	21157	623
May-08	646	979	6,305	2,596	520	1,362	12,407	20001	404
Jun-08	638	749	6,758	2,552	539	1,331	12,568	22331	1510
Jul-08	664	821	7,404	2,796	590	1,459	13,733	23738	1408
Aug-08	667	793	7,151	2,700	570	1,409	13,290	23044	1288
Sep-08	642	725	6,542	2,470	522	1,289	12,190	21042	1190
Oct-08	680	1,015	6,538	2,692	539	1,412	12,876	20958	508

	Northwest	Northeast	Central-East	South-Central	Niagara	Southwest	Total	System Peak Demand ¹	One Standard Deviation ¹
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)
Nov-08	705	1,038	6,686	2,753	551	1,444	13,176	23019	590
Dec-08	744	1,043	7,597	2,773	591	1,435	14,183	23978	804
Jan-09	751	1,071	7,889	2,872	611	1,485	14,678	24175	924
Feb-09	670	959	7,063	2,571	547	1,329	13,140	23807	770
Mar-09	703	1,016	7,486	2,725	580	1,409	13,919	22914	773
Apr-09	665	989	6,442	2,643	529	1,384	12,652	21398	650
May-09	647	975	6,354	2,607	522	1,366	12,470	20264	511
Jun-09	640	751	6,855	2,581	545	1,345	12,717	22506	1640
Jul-09	666	821	7,495	2,822	596	1,471	13,871	23929	1395
Aug-09	669	795	7,252	2,730	576	1,423	13,445	23438	1340
Sep-09	643	726	6,626	2,495	527	1,300	12,317	21899	1342
Oct-09	681	1,011	6,587	2,703	541	1,416	12,938	21159	494
Nov-09	706	1,039	6,769	2,777	556	1,455	13,302	23133	573
Dec-09	745	1,040	7,660	2,789	594	1,442	14,269	24192	857
Jan-10	751	1,066	7,944	2,882	614	1,489	14,747	24307	883
Feb-10	670	958	7,138	2,590	551	1,338	13,246	23793	778
Mar-10	703	1,020	7,595	2,756	587	1,424	14,084	22780	730
Apr-10	666	990	6,514	2,665	533	1,395	12,763	21576	651
May-10	648	977	6,433	2,632	526	1,377	12,594	20427	544
Jun-10	642	753	6,942	2,604	550	1,356	12,847	22713	1748
Jul-10	669	822	7,574	2,841	600	1,479	13,986	24164	1394
Aug-10	670	799	7,364	2,762	583	1,438	13,617	23726	1391
Sep-10	645	727	6,705	2,515	531	1,310	12,433	22232	1452
Oct-10	682	1,008	6,638	2,716	543	1,421	13,008	21442	523
Nov-10	707	1,044	6,870	2,811	562	1,471	13,465	23265	567
Dec-10	746	1,038	7,732	2,806	597	1,449	14,369	24415	840

Note 1: 20-Minute system peak and associated standard deviation is of weekly peak demand for each month

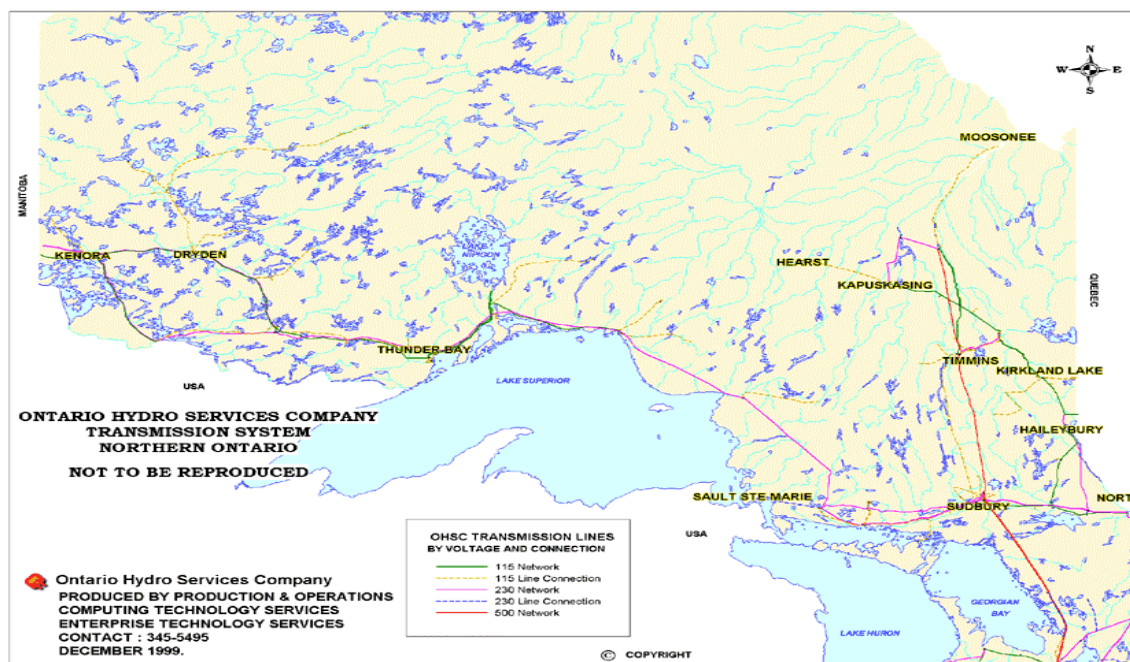
Appendix B - Ontario Electricity System - Maps

1. The Ontario Electricity System 230 & 500 kV Geographical Layout Map

Figure B1.1 – Southern Ontario



Figure B1.2 – Northern Ontario



2. Load Centres

Figure B2.1 – GTA

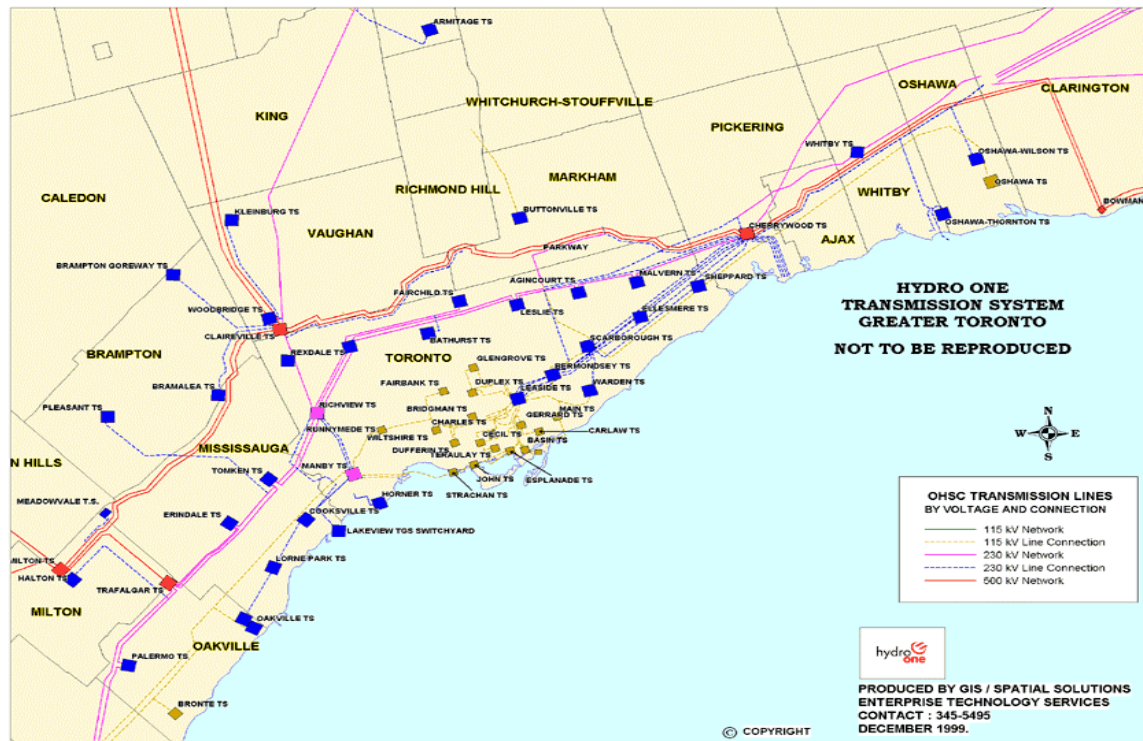


Figure B2.2 – Hamilton

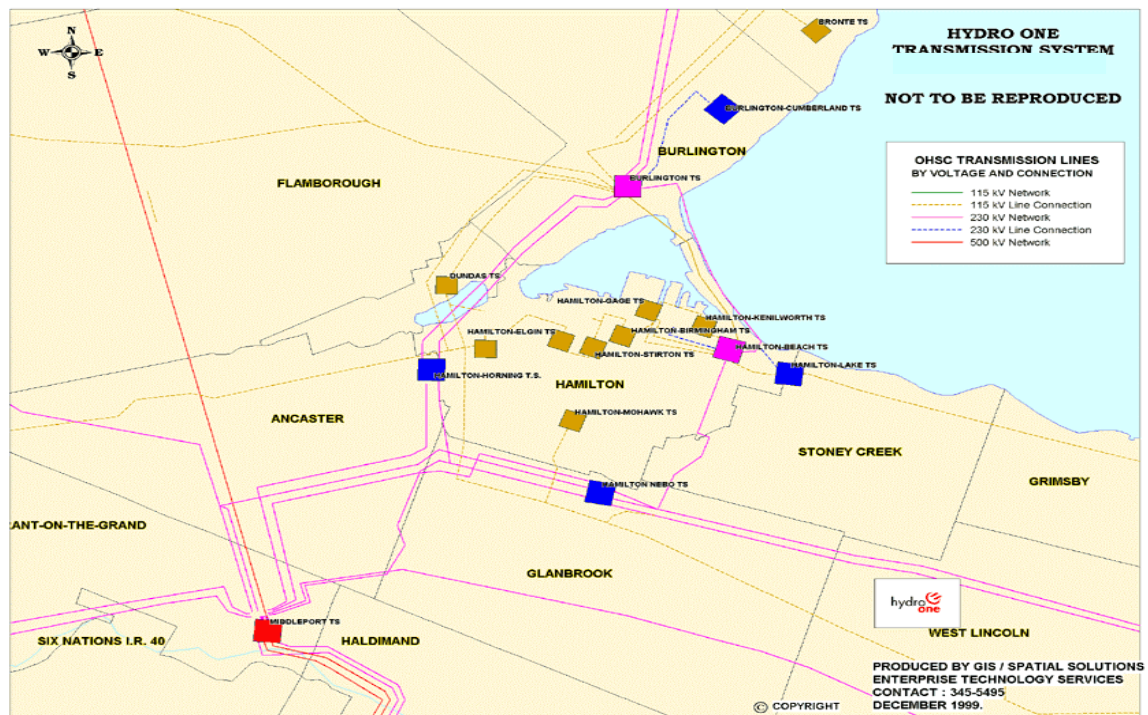


Figure B2.3 – Niagara

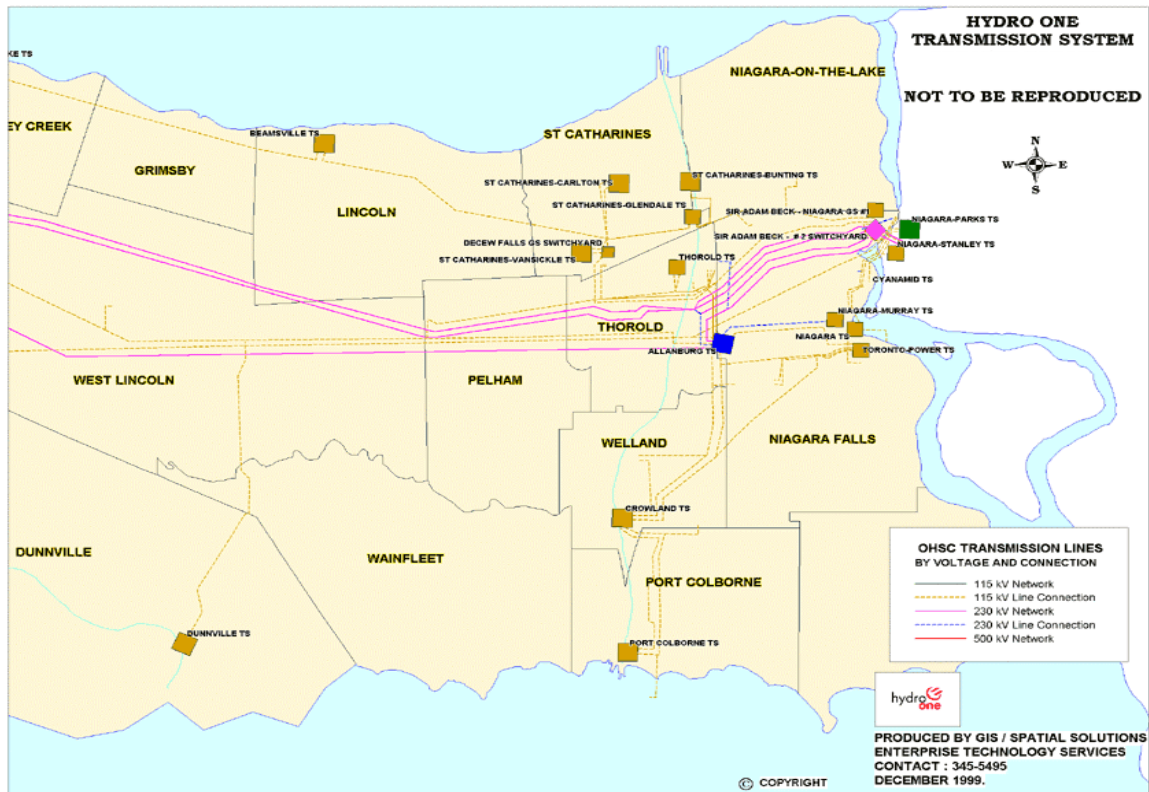


Figure B2.4 – Sarnia

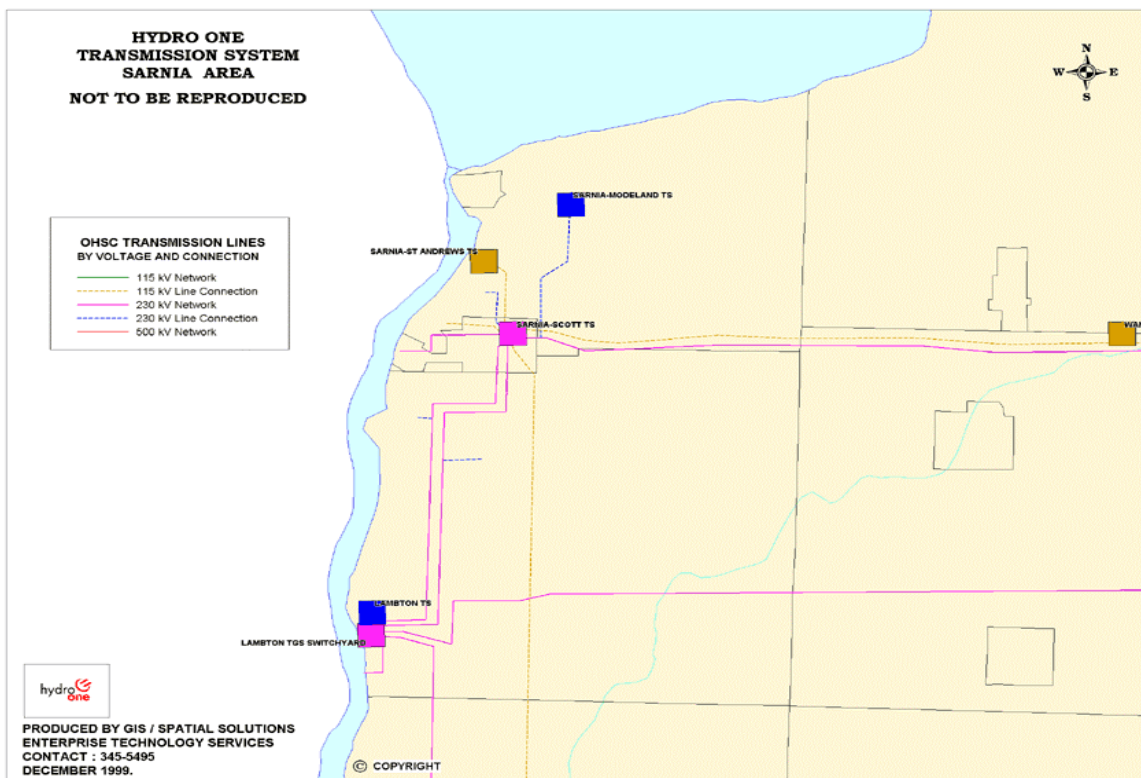


Figure B2.5 – Windsor

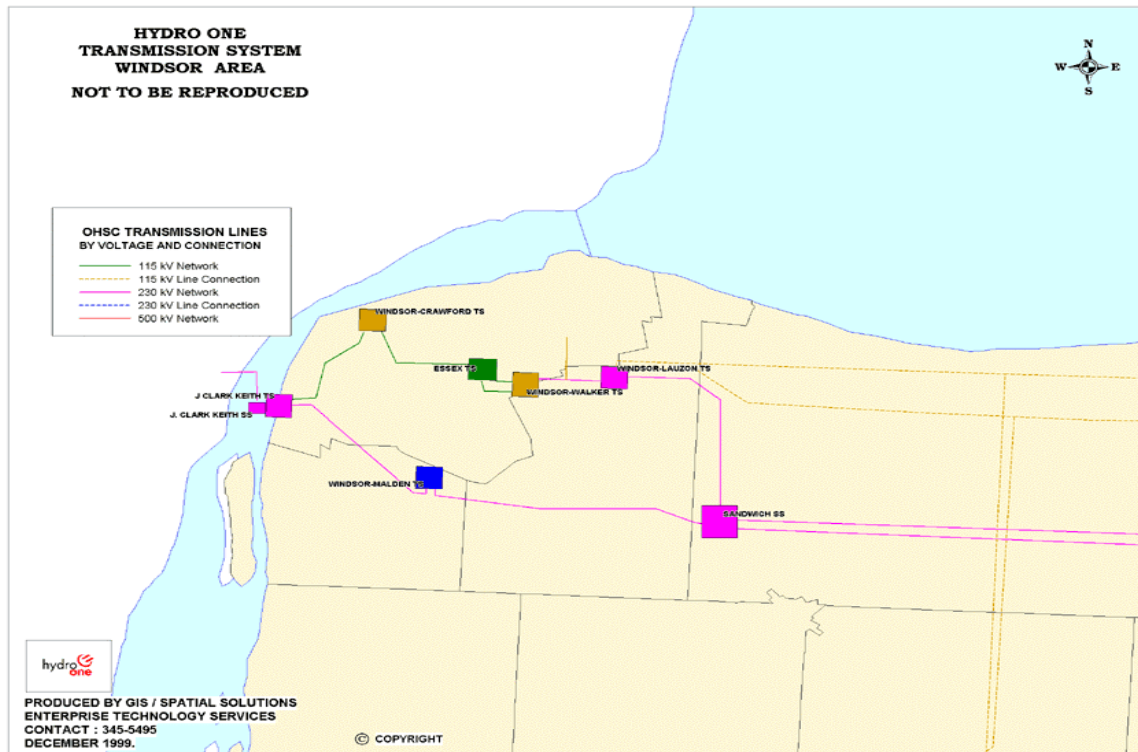


Figure B2.6 – Thunder Bay

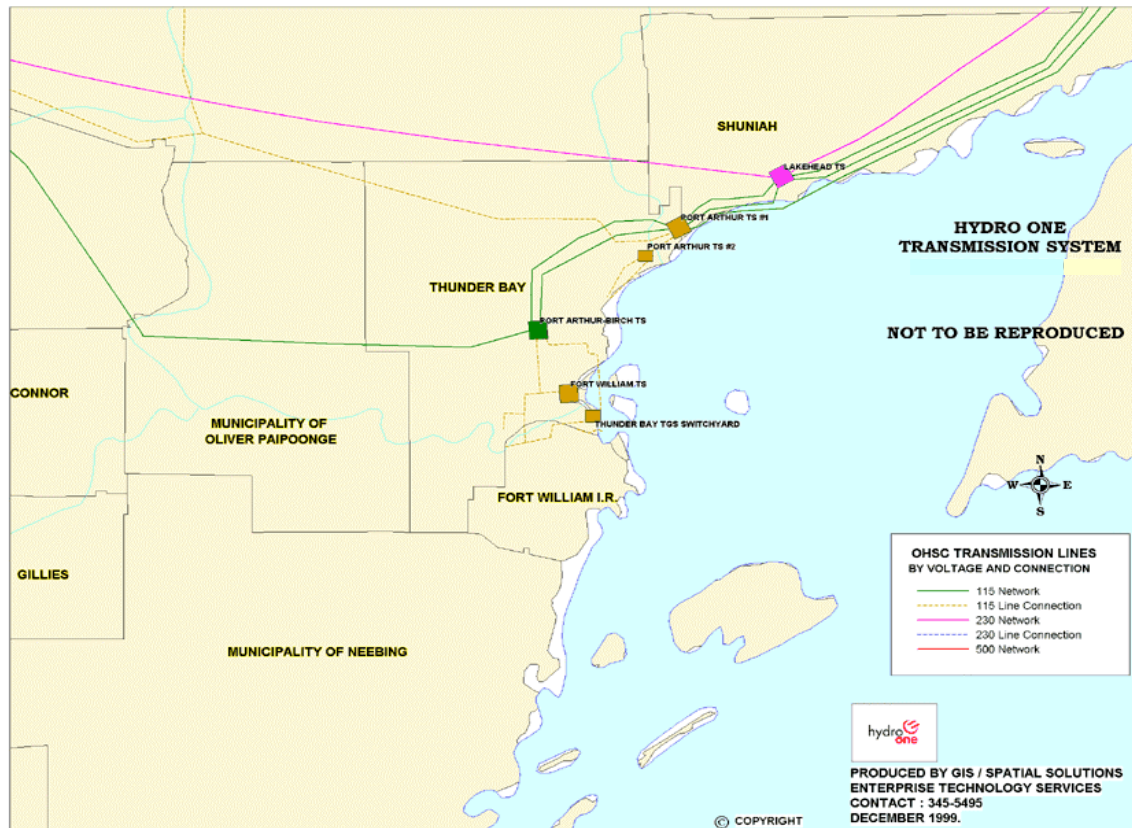


Figure B2.7 – Ottawa

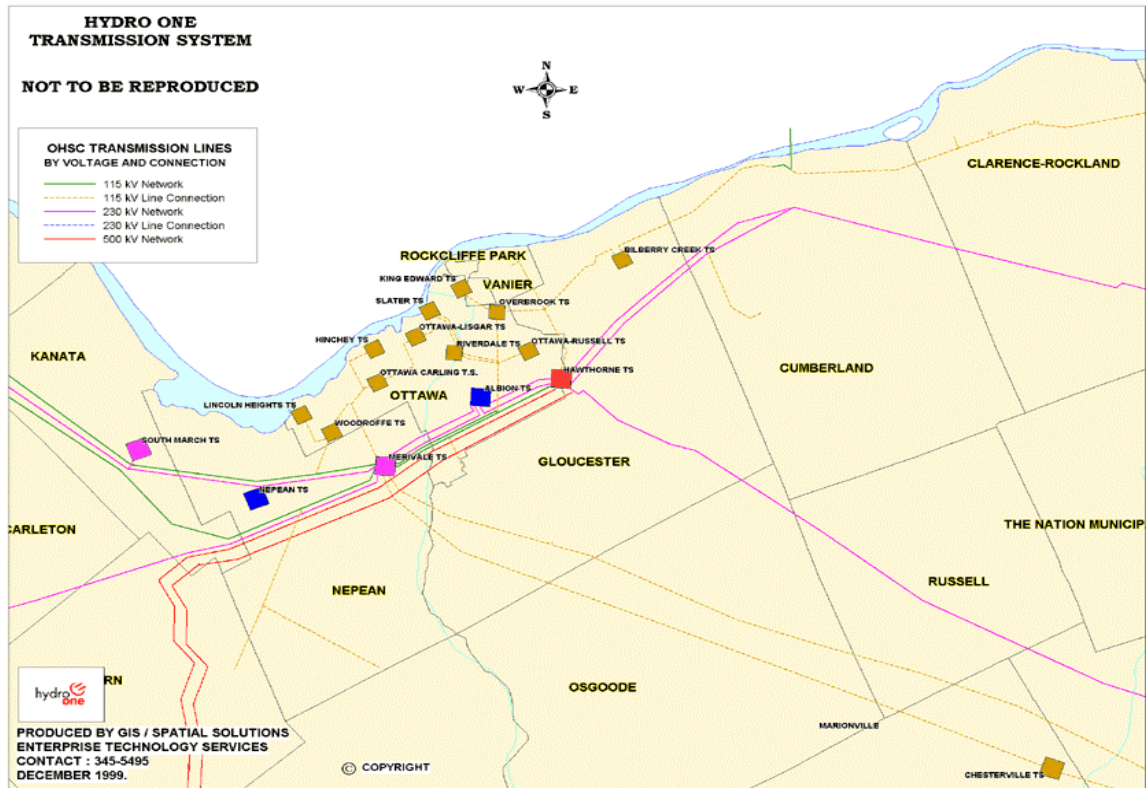


Figure B2.8 – London

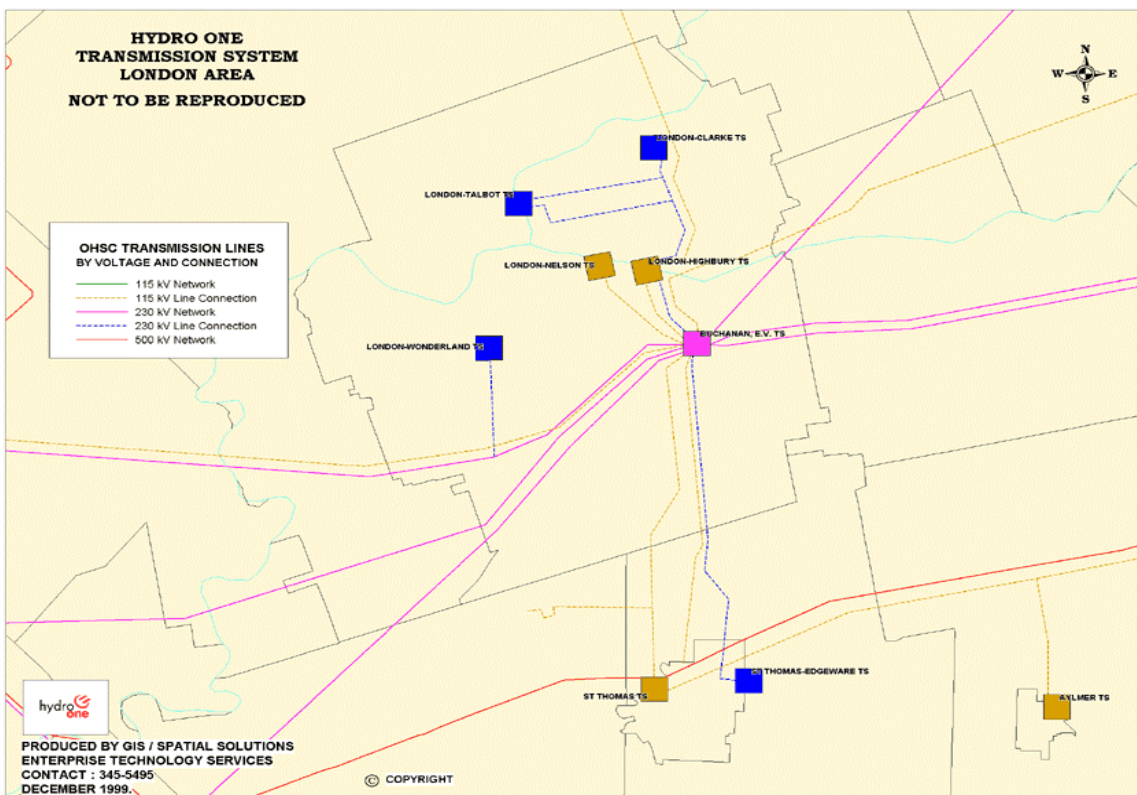


Figure B2.9 – Sudbury

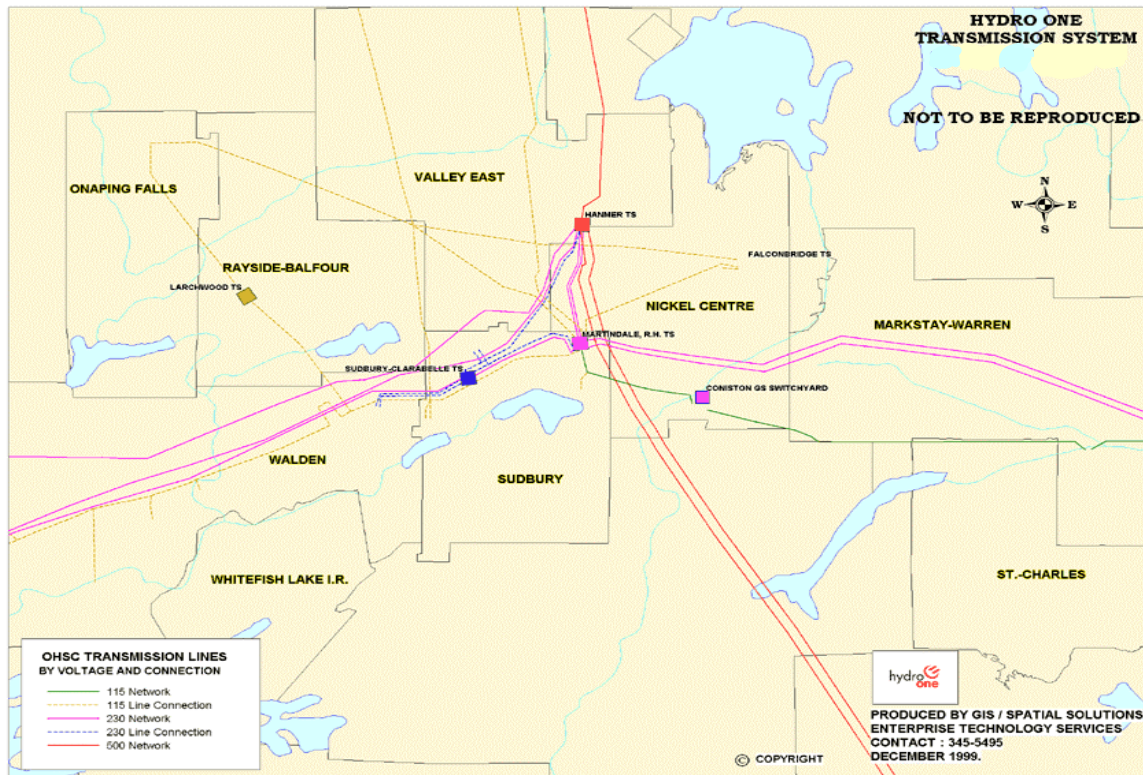


Figure B2.10 – Timmins

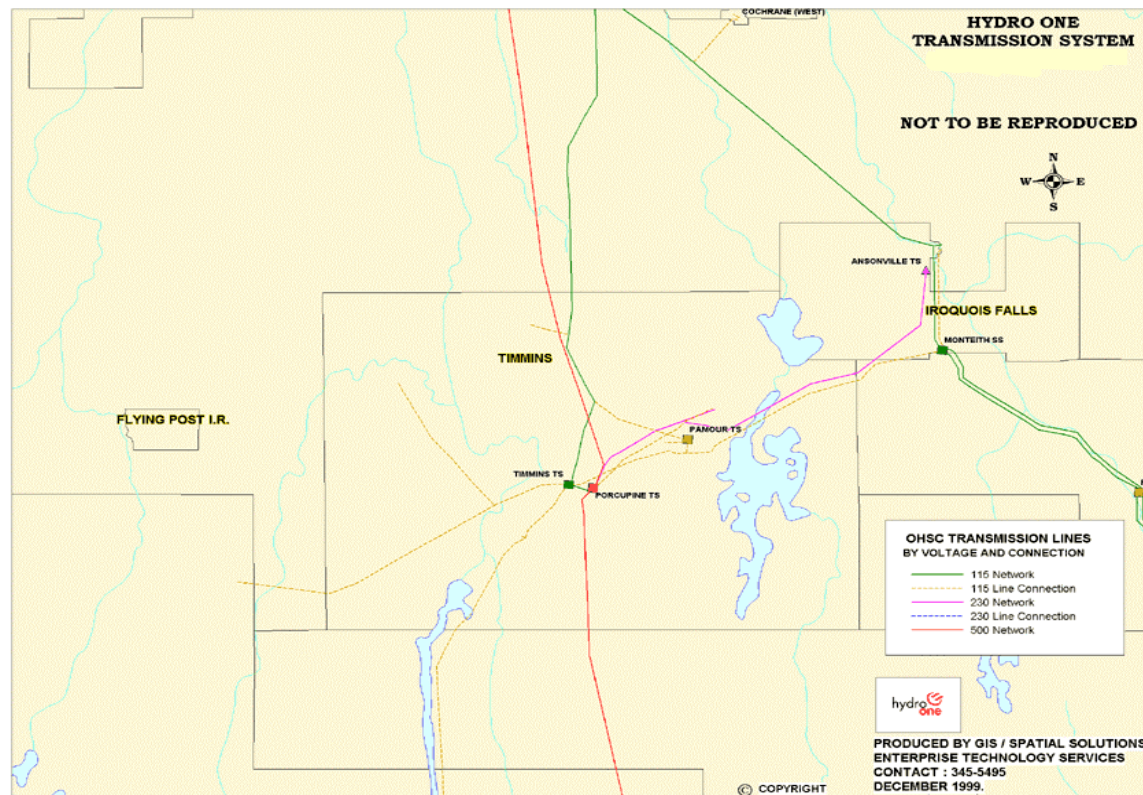


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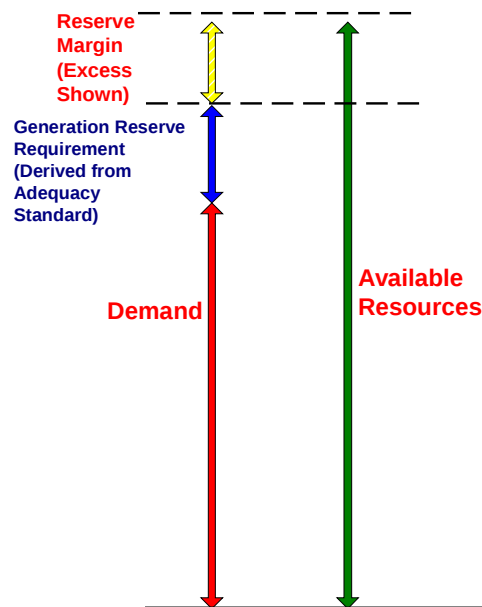
APPENDIX C

Determination of Generation Reserve Requirement

1.0 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 are inputs to the model. A Generation Adequacy Standard of 0.1 days/year, or the equivalent corresponding percent Reserve Margin, 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 ten-year study period, can be assessed from the forecast weekly Reserve Margin as shown in Figure C 1.

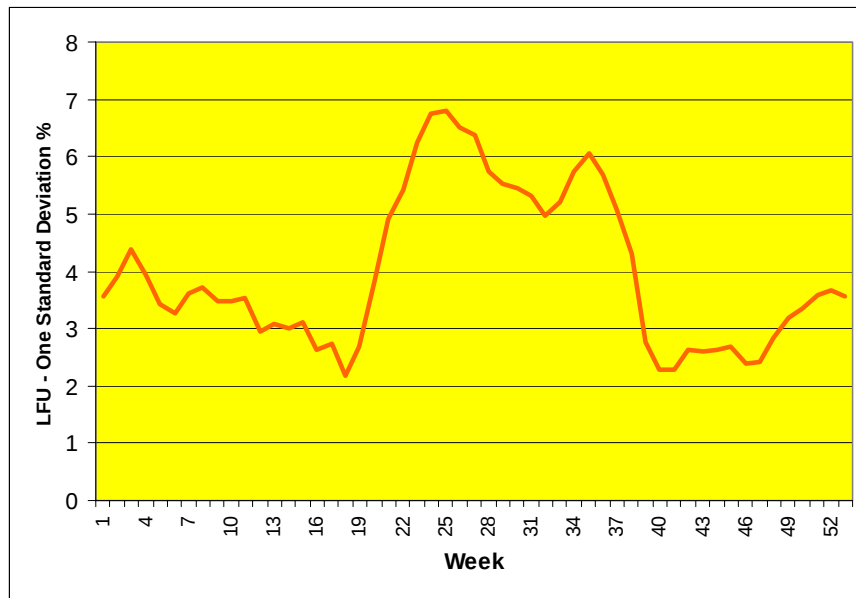
Figure C 1 Reserve Margin



2.0 Description and Basis of Demand Data

The demand model comprises weekly energy and peak demand data plus data related to the variability of the demand in any week due to swings in the weather. Hourly and 20-minute peak data is also derived. The description of the Demand-Weather relationship is based upon a four year record updated annually. 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.

Figure C2 Load Forecast Uncertainty due to Weather



The standard deviation of weather-related demand ranges from 2% to 7% over the year, as shown in Figure C 2. The peak demand probability distribution in any week is thus available to the L&C program.

The demand includes loads that can be interrupted in case of a shortfall in reserves. For this study, the interruptible loads are included in the demand forecast. They are used as a contingency measure at the assessment stage, if a reserve shortfall is indicated. In such cases, an assistance amount of 600 MW is considered to be available.

3.0 Generating Unit Representation

3.1 Unit Ratings

Thermal generating unit are assumed to be capable of operating at a level equal to their normal Maximum Continuous Rating (MCR). Hydraulic station peak outputs are based on dependable (exceeded 98 % of the time) river flows determined from about 60 years of record. The peak and energy output of all combustion turbines vary considerably with changes in ambient air temperature and, hence, both summer and winter values are included.

3.2 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. These rates are based upon experience in Ontario, and values published by NERC for the industry. Sensitivity studies are also considered with lower and/or higher forced outage rates. Short Maintenance outages are not included at the peak hours under study.

4.0 Study Procedures

For the years 2001 and 2002, the LOLP values corresponding to generation reserve levels of 18% and 19% respectively at the time of the January peak were calculated. These LOLP values were used to determine the Required Reserve in the remaining weeks of each year. For the years 2003 through 2010, 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. Capacity available above the Reserve Requirement and Demand is considered to be surplus in any week and may be released for planned outages.

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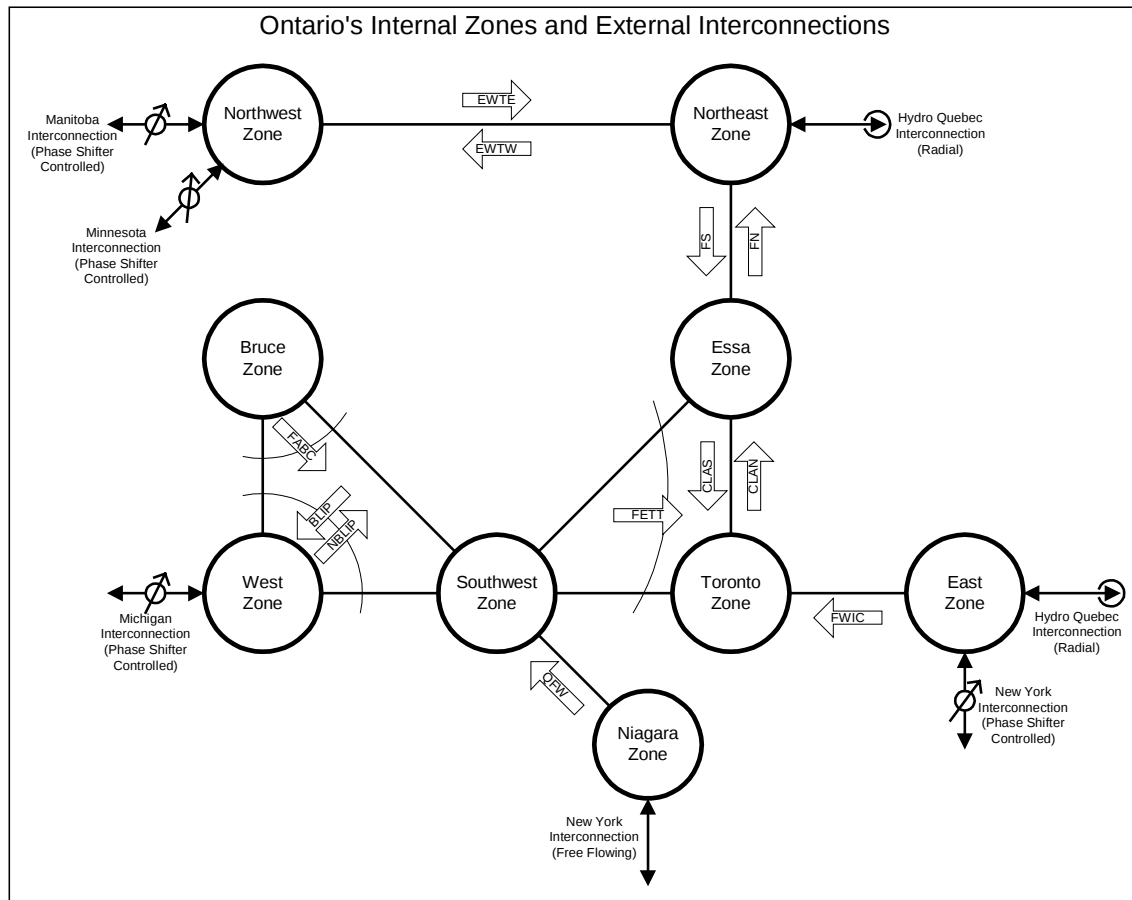
Appendix D - Transmission System Details

Appendix D1 - Transmission System Interfaces

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. Appendix D2 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

Appendix D3 shows the major interface limits that correspond to the definitions in Appendix D2; only normal system (all transmission elements in-service) limits are shown. Notice 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). Incases 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

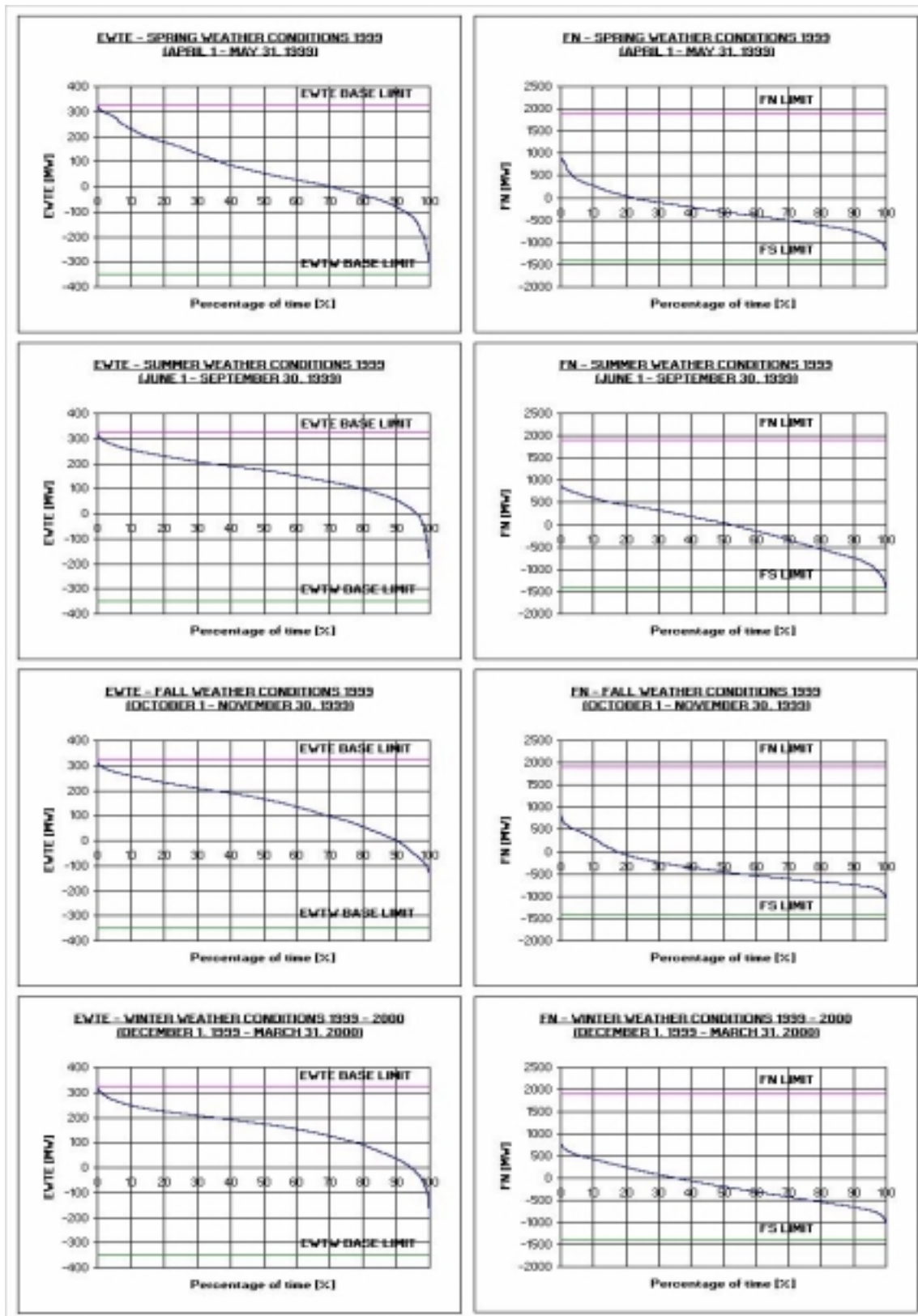
The East-West Transfer East (EWTE) and East-West Transfer West (EWTW) flows are functionally related to the power flows between Ontario and Manitoba (OMTE/OMTW etc.). In this relationship OMTE/OMTW flows can be generally thought of as the independent variables as they are under phase shifter control.

The maximum limits on the East-West tie are 325 MW to the east and 350 MW to the west. During freshet, the EWTE limit causes locked-in generation capacity in the Northwest zone. 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. During freshet, the Flow South interface is generally limiting the maximum use of lower-cost generating resources in the north. 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 Clairville North (CLAN) limit is 2,000 MW and the Clairville 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 as shown in Appendix D3. 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 as shown in Appendix D3. 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.

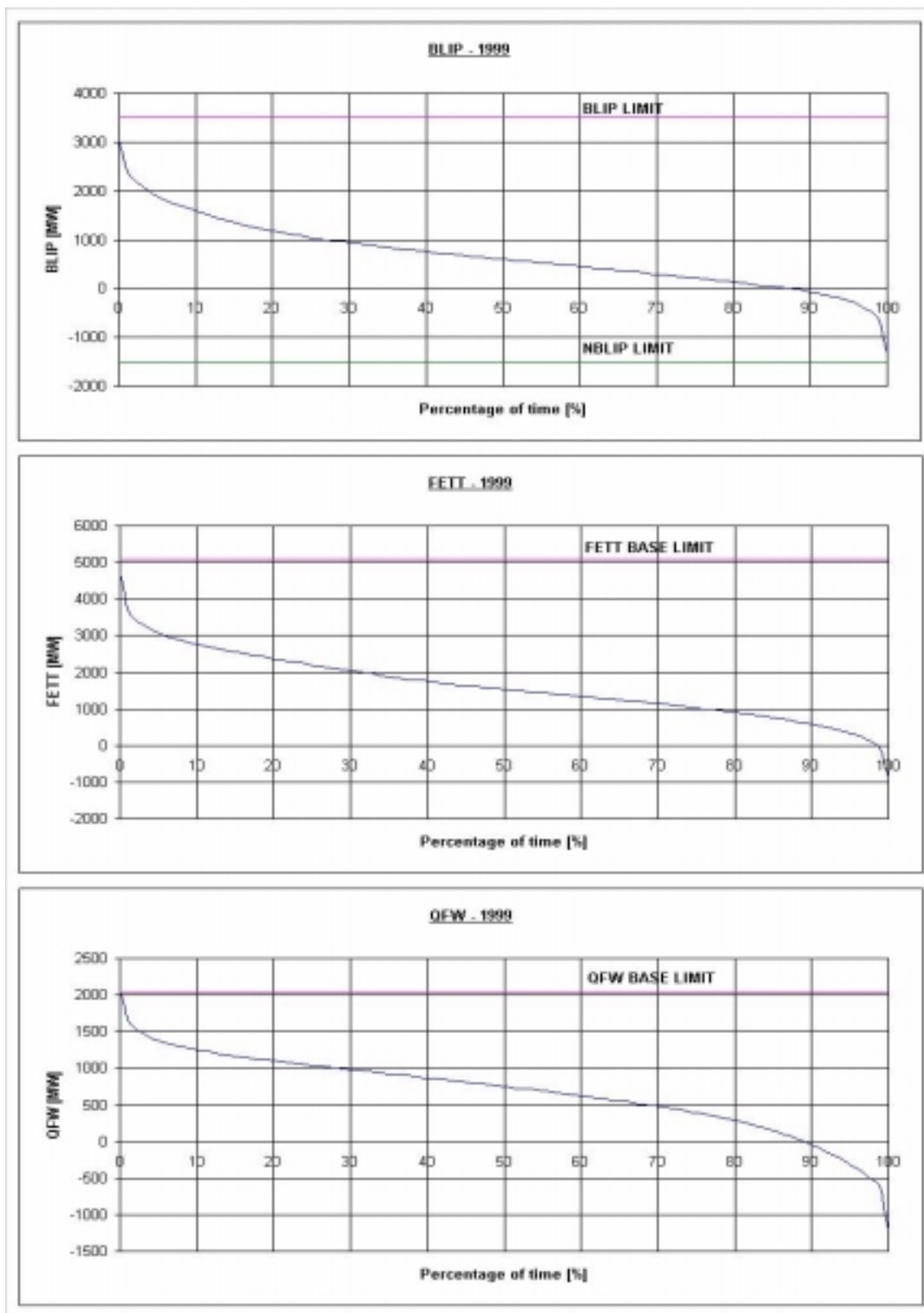
The QFW Interface

The QFW (Queenston Flow West) interface is limited to 2,030 MW for flows to the west in the winter. In the summer, the limit is 1,820 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 as shown in Appendix D3. 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 Flow North / South 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 Appendix D2.

Northwest Zone Characteristics

- The total resources generally exceed the peak primary demand.
- The generation is mainly hydroelectric with some coal
- Is externally connected to the Manitoba and Minnesota systems.
- The both interconnections are under phase shifter control.
- MAPP 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.
- 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 nuclear, hydroelectric, oil, and gas.
- 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 is under phase shifter control.

Niagara Zone Characteristics

- The total resources are much higher than the peak primary demand.
- The generation is mostly hydroelectric.

There is a synchronous interconnection with New York.

1.4 Transmission System Interconnections' Capabilities and External Markets

The term interconnection shall be use 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 Appendix D4.

Interconnection Capabilities

Interconnection capabilities are shown in Appendix D5.

Interconnection Characteristics

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

New phase shifters will be installed on the Ontario – Michigan interconnection by the end of summer 2000. The purpose of the new phase shifters is to control a loop flow or parallel path flow called Lake Erie Circulation (LEC) that enters Ontario at the New York Niagara interconnection and exits Ontario at the Michigan interconnection. Most of the time, power flows associated with this condition are 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.

For the period of this assessment, the interconnection capability of the transmission system is:

Out of Ontario 5,930 / 5,880 MW (Winter/Summer)

Into Ontario 5,525 / 5,180 MW (Winter/Summer)

There is a non-committed plan to install a new back-to-back HVDC tie with HQ on December 1, 2002 which would increase Ontario's interconnection capability by 1,250 MW in both directions.

The Ontario - Manitoba Interconnection

OPGI currently has a firm contract to purchase 200 MW from Manitoba; this expires on October 31, 2003. The OMTE and OMTW limits are both 240 MW 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 it is under phase shifter control. 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 1,790 MW for flows into Ontario and 2,100 MW for flows out of Ontario. In the summer, the limit is 1,480 MW for flows into Ontario and 2,070 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 1,820 MW under summer conditions, the flow across the NY Niagara interconnection is 1,100 MW (its limit is 1,480 MW). Similarly, when QFW hits its limit of 2,030 MW under winter conditions, flow across the NY Niagara interconnection is 1,300 MW (its limit is 1,790 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 65 MW 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 1,130 MW for flows into Ontario due to stability limitations and available radial generation. For flows out of Ontario the limits are 490 and 510 for summer and winter respectively and are due to stability and thermal limitations.

Appendix D2 - 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

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

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

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

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

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

B560V	Bruce* to Clairville 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

Appendix D3 - Ontario's Interface Limits For All Transmission Elements In-Service

FABC Interface Limit

Is the minimum of the following 13 equations:

Modules 3 & 4

$$F_{FABC} - 0.08 F_{BLIP} \leq 4325 - 75 \max\{0, 6 - N_{Nant}\} - 50 \max\{0, 2 - N_{Lamb}\} - 100 \max\{0, 2 - N_{Darl}\}$$

$$F_{FABC} \leq 4540 - 75 \max\{0, 6 - N_{Nant}\} - 50 \max\{0, 2 - N_{Lamb}\} - 100 \max\{0, 2 - N_{Darl}\}$$

Module 5

$$F_{FABC} + 0.11 F_{BLIP} \leq 4540 - (D_{PD} - D_{ref})/12 - 100(8 - N_{Nant}) - 50 \max\{0, 2 - N_{Lamb}\} + 50 (2N_{Pick} + N_{Lx} + N_{Lkv} + 4N_{Darl})]$$

$$F_{FABC} \leq 4240 - (D_{PD} - D_{ref})/12 - 100(8 - N_{Nant}) - 50 \max\{0, 2 - N_{Lamb}\} + 50 (2N_{Pick} + N_{Lx} + N_{Lkv} + 4N_{Darl})]$$

$$F_{FABC} \leq 4600 - 100 \max\{0, 6 - N_{Nant}\} - 50 \max\{0, 2 - N_{Lamb}\} - 100 \max\{0, 2 - N_{Darl}\}$$

Modules 7 & 8

$$F_{FABC} - 0.1 F_{BLIP} \leq 4743 - (D_{PD} - D_{ref})/12 - 100(8 - N_{Nant}) - 50 \max\{0, 2 - N_{Lamb}\} + 50 (2N_{Pick} + N_{Lx} + N_{Lkv} + 4N_{Darl})]$$

$$F_{FABC} \leq 5000 - (D_{PD} - D_{ref})/12 - 100(8 - N_{Nant}) - 50 \max\{0, 2 - N_{Lamb}\} + 50 (2N_{Pick} + N_{Lx} + N_{Lkv} + 4N_{Darl})]$$

$$F_{FABC} - 0.08 F_{BLIP} \leq 4525 - 75 \max\{0, 6 - N_{Nant}\} - 50 \max\{0, 2 - N_{Lamb}\} - 100 \max\{0, 2 - N_{Darl}\}$$

$$F_{FABC} \leq 4740 - 75 \max\{0, 6 - N_{Nant}\} - 50 \max\{0, 2 - N_{Lamb}\} - 100 \max\{0, 2 - N_{Darl}\}$$

Module 10

$$F_{FABC} - 0.19 F_{BLIP} \leq 4586 - 75(8 - N_{Nant}) - 50 \max\{0, 2 - N_{Lamb}\}$$

$$F_{FABC} \leq 5100 - 75(8 - N_{Nant}) - 50 \max\{0, 2 - N_{Lamb}\}$$

$$F_{FABC} - 0.1 F_{BLIP} \leq 4193 - 70 \max\{0, 6 - N_{Nant}\} - 50 \max\{0, 2 - N_{Lamb}\} - 50 \max\{0, 2 - N_{Darl}\}$$

$$F_{FABC} \leq 4450 - 70 \max\{0, 6 - N_{Nant}\} - 50 \max\{0, 2 - N_{Lamb}\} - 50 \max\{0, 2 - N_{Darl}\}$$

Where:

F_{FABC} = MW Flow on the FABC Interface
 F_{BLIP} = MW Flow on the BLIP Interface
 N_{Nant} = number of on-line units at Nanticoke
 N_{Lamb} = number of on-line units at Lambton
 N_{Pick} = number of on-line units at Pickering
 N_{Lx} = number of on-line units at Lennox
 N_{Lkv} = number of on-line units at Lakeview
 N_{Darl} = number of on-line units at Darlington
 D_{PD} = Primary Demand
 D_{ref} = 22000 for summer and 25000 for winter

FETT Interface Limit

Is the minimum of the following two equations:

$$F_{FETT} \leq 3300 + (D_{ref} - D_{PD})/6 - P_{SLC} - \max\{200(7 - N_{Nant}), 150(8 - N_{Nant})\} - 100 \max\{0, (3 - N_{Pick})\} + 100 (2N_{Pick} + N_{Lx} + N_{Lkv} + 4N_{Darl})$$

$$F_{FETT} + 1.5 F_{FS} \leq 4500 + (D_{ref} - D_{PD})/6 - P_{SLC} - \max\{200(7 - N_{Nant}), 150(8 - N_{Nant})\} - 100 \max\{0, (3 - N_{Pick})\} + 100 (2N_{Pick} + N_{Lx} + N_{Lkv} + 4N_{Darl})$$

$$F_{FETT} \leq 5700$$

Where:

F_{FETT} = MW Flow on the FETT Interface
 F_{FS} = MW Flow on the Flow South Interface
 N_{Nant} = number of on-line units at Nanticoke
 N_{Pick} = number of on-line units at Pickering
 N_{Lx} = number of on-line units at Lennox
 N_{Lkv} = number of on-line units at Lakeview
 N_{Darl} = number of on-line units at Darlington
 D_{PD} = primary demand
 D_{ref} = 22000 for summer and 25000 for winter
 P_{SLC} = penalty due to summer load criteria
 $= 0$ if $D_{PD} \leq 22000$ or when the summer load criteria are not applicable
or $= 200$ if $22000 < D_{PD} \leq 22600$ and when the summer load criteria are applicable
or $= 400$ if $22600 < D_{PD} \leq 23200$ and when the summer load criteria are applicable
or $= 800$ if $23200 < D_{PD}$ and when the summer load criteria are applicable

BLIP Interface Limit

$$F_{BLIP} \leq 3500 \text{ where } F_{BLIP} = \text{MW Flow on the BLIP Interface}$$

NBLIP Interface Limit

Is the minimum of the following five equations:

$$\begin{aligned}
 F_{\text{NBLIP}} &\leq 1500 \\
 F_{\text{NBLIP}} &\leq 500 N_{\text{Lamb}} + 250 I_{\text{Lamb-I/S}=0} I_{\text{Bru-I/S} \geq 2} \\
 F_{\text{NBLIP}} &\leq 250 N_{\text{Nant}} + 250 I_{\text{Nant-I/S} \geq 4} + 250 \\
 F_{\text{NBLIP}} &\leq 250 N_{\text{Nant}} + 1500 I_{\text{Bru-I/S} \geq 2} \\
 F_{\text{NBLIP}} &\leq \max\{0, 250 (N_{\text{Nant}} - 1)\} + 1500 I_{\text{Lamb-I/S} \geq 2} + 1500 I_{\text{Bru-I/S} \geq 2}
 \end{aligned}$$

Where:

F_{NBLIP} = MW Flow on the NBLIP Interface
 N_{Nant} = number of on-line units at Nanticoke
 N_{Lamb} = number of on-line units at Lambton
 $I_{\text{Lamb-I/S}=0}$ = 1 or 0 (“1” if no Lambton units on-line, otherwise “0”)
 $I_{\text{Lamb-I/S} \geq 2}$ = 1 or 0 (“1” if two or more on-line units at Lambton, otherwise “0”)
 $I_{\text{Bru-I/S} \geq 2}$ = 1 or 0 (“1” if two or more on-line units at Bruce, otherwise “0”)
 $I_{\text{Nant-I/S} \geq 4}$ = 1 or 0 (“1” if four or more on-line units at Nanticoke, otherwise “0”)

(Note that since Bruce A is out of service, F_{NBLIP} is only valid for up to 4 units at Bruce in-service.)

CLAN Interface Limit

$F_{\text{CLAN}} \leq 2000$ where F_{CLAN} = MW Flow on the CLAN Interface

CLAS Interface Limit

$F_{\text{CLAS}} \leq 1000$ where F_{CLAS} = MW Flow on the CLAS Interface

FN Interface Limit

$FN \leq 1900$ where FN = MW Flow on the FN Interface

FS Interface Limit

$FS \leq 1400$ where FS = MW Flow on the FS Interface

QFW Interface Limit

$QFW \leq 1820$ for Summer Conditions
 $QFW \leq 2030$ for Winter Conditions
 where QFW = MW Flow on the QFW Interface

FWIC Interface Limit

There is no pre-defined limit on this interface. The interface definitions exist to provide a boundary point for the East Zone.

EWTE Interface Limit

Is the minimum of the following six equations:

$$\begin{aligned}
 EWTE &\leq 325 \\
 EWTE &\leq 875 - 2.5 * OMTW - 2.5 * MPFS \\
 EWTE &\leq 875 - 2.5 * OMTW \\
 EWTE &\leq 425 - 0.55 * OMTW - MPFS \\
 EWTE &\leq 325 - 0.55 * OMTW \\
 EWTE &\leq 425 - MPFS
 \end{aligned}$$

Where:

EWTE = MW Flow on the EWTE Interface

OMTW = MW Flow on the OMTW Interface

MPFS = MW Flow on the MPFS Interface

EWTW Interface Limit

Is the minimum of the following four equations:

$$\text{EWTW} \leq 350$$

$$\text{EWTW} \leq 902.5 - 2.5 \cdot \text{OMTE} - 2.5 \cdot \text{MPFN}$$

$$\text{EWTW} \leq 840 - 2.5 \cdot \text{OMTE}$$

$$\text{EWTW} \leq 400 - \text{MPFN}$$

Where:

EWTE = MW Flow on the EWTE Interface

OMTE = MW Flow on the OMTE Interface

MPFN = MW Flow on the MPFN Interface

In the equations for EWTE and EWTW the parameters OMTE,OMTW,MPFS, and MPFN are generally thought of as the independent variables as they are under phase shifter control.

Appendix D4 - 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.
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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	Chenau to Bryson 115 kV,
Q4C	Chats Falls to Quoyon 230 kV,
P33C	Chats Falls to Pagan 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:

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 in-line autotransformer 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 Moses 230 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 T310 and T302,
PA302 Beck2 230 kV to Niagara Moses 345 kV (NYPA), including in-line 230 to 345 kV autotransformers T310 and 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.

Appendix D5 - Ontario's Interconnection Limits For All Transmission Elements In-Service

The following interconnection limits are not constant numbers, they are functionally related with each other and also with EWTE and EWTW as shown in Appendix D4

OMTW Interconnection Limit – Ontario to Manitoba

Is the minimum of the following two equations:

$$\text{OMTW} \leq 240$$

$$\text{OMTW} \leq 375 - \text{MPFS}$$

Where:

MPFS = MW Flow on the MPFS Interface

OMTE Interconnection Limit – Manitoba to Ontario

Is the minimum of the following two equations:

$$\text{OMTE} \leq 240$$

$$\text{OMTE} \leq 325 - \text{MPFN}$$

Where:

MPFN = MW Flow on the MPFN Interface

MPFS Interconnection Limit – Ontario to Minnesota

Is the minimum of the following two equations:

$$\text{MPFS} \leq 150$$

$$\text{MPFS} \leq 375 - \text{OMTW}$$

Where:

OMTW = MW Flow on the OMTW Interface

MPFN Interconnection Limit – Minnesota to Ontario

Is the minimum of the following two equations:

$$\text{MPFN} \leq 100$$

$$\text{MPFN} \leq 325 - \text{OMTE}$$

Where:

OMTE = MW Flow on the OMTE Interface

Table D5.1 – Ontario's Interconnection Limits

Interconnection	Limit (MW) Flows Out of Ontario MW	Limit (MW) Flows Into Ontario
Quebec North	80	65
Quebec South – Winter*	510	1,130
Quebec South – Summer*	490	1,130
New York East	400	400
New York Niagara – Winter*	2,100	1,790
New York Niagara – Summer*	2,070	1,480
Michigan - Winter*	2,450	1,800
Michigan - Summer*	2,450	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.

Appendix D6 – Plans – Hydro One

Table 6.1 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	June 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)	July 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	July 2000
Install shunt capacitor bank at Chatham SS	Increase load meeting capability for the Windsor area	230 kV Capacitor: 225 MVAR @ 249.4 kV	June 2001
Refurbish Chatham SS	Replace end of life facilities	Replace 230 kV circuit breakers and associated equipment	July 2001
Refurbish St Lawrence TS	Replace end of life facilities	Replace 230 kV circuit breakers and associated equipment	July 2001
Refurbish L1S 115 kV line section	Transmission line refurbishment	Refurbish Crystal Falls GS x Warren DS	Dec. 2000

Appendix D7 - Load Flow Study

1. Purpose

The purpose of the load flow study was to assess the Transmission Power System behavior during extreme load demand conditions (extreme cold weather in the wintertime and extreme hot weather in the summertime).

2. Assumptions

Nine cases were studied, as outlined in the Tables D7.1 and D7.2. In seven of the cases there were no sales or purchases for the Ontario Power System. In one of the cases, Ontario was selling 2000 MW (1000 MW to Michigan and 1000 MW to New York) and, in the last case, Ontario was purchasing 2000 MW (1000 MW from Michigan and 1000 MW from New York).

The following major assumptions were implemented in the studied cases:

- The load level was set according to the primary demand forecasted values as winter/summer “weekly 20 minutes peaks” (mean values) plus two times their “standard deviation” (see Table 2.1 in Section 2).
- The only case where one “standard deviation” was used is the one with 2000MW sales. This assumption is reasonable, because under such extreme weather conditions high sales are unlikely.
- The generation level was set accordingly, considering the available resources (see Table 3.1 to 3.5 in Section 3)
- The Operating Security Limits for the Ontario Transmission Power System were assumed to be the same for all the studied years, since there are no significant changes in the System configuration which will impact on the Operating Security Limits.

3. Results - Comments

After solving the load flows, all the Operating Security Limits were checked. The study results are summarized in tables D7.1 (Ontario net interchange = 0) and D7.2 (Ontario net interchange = +/-2000).

- In all cases there is sufficient generation available inside Ontario to supply the demand.
- In all winter cases there are no violations of the Operating Security Limits.
- In the summer case where the net interchange = +2000 (Ontario is selling 2000MW), given the moderate Mx demand (the primary demand is the “weekly 20 minutes peak” (mean value) plus only one “standard deviation”), there are no violations of the Operating Security Limits.
- In all summer cases where the net interchange is zero, the steady state voltage at Milton 500kV bus drops below 520kV. All the Operating Security Limits in Southern Ontario area are valid for a voltage at Milton TS greater or equal than 520kV. Therefore pre-contingency voltages lower than this value at Milton TS are considered unacceptable.
- All other parameters for the summer cases are within the Operating Security Limits.
- However, even in the cases where the Milton 500kV bus voltage is above the lower limit, yet the voltages at Milton and Middleport 500kV buses are quite low. This reveals the need of the Milton 500kV area enforcement from the voltage control point of view.
- In order to find the best solution to the “Milton 500kV bus voltage problem”, in depth studies are proposed by the IMO. Joint studies, involving Hydro One and Ontario Power Generation Inc., will be also proposed.

Table D7.1 – Net interchange = 0 MW

Load Flow Case	Net Interchange	Primary Demand as Per the Forecast (Winter/ Summer 20min Peak Plus 2SD)	Milton 500kV Minimum Voltage	Observations
	MW	MW	kV	
Winter 2001	0	24617	520.16	Even without Var support from Pickering A the voltage at Milton TS is above the lower limit
Summer 2001	0	24255	513.8	The high Mx demand and the lack of Var support from Pickering A results in voltage problems at Milton TS
Winter 2003	0	24912	525.2	Because of the relatively low Mx demand the Milton voltage is above the lower limit
Summer 2003	0	24848	517.02	The high Mx demand, even with Var support from Pickering A, results in voltage drop below the lower limit at Milton
Winter 2005	0	25246	524.24	Because of the relatively low Mx demand the Milton voltage is above the lower limit
Summer 2005	0	25396	516.15	The high Mx demand results in voltage drop below the lower limit at Milton
Summer 2010	0	27037	510.08	The high Mx demand results in voltage drop below the lower limit at Milton

Table D7.2 – Net interchange = +/-2000 MW

Load Flow Case	Net Interchange	Primary Demand as Per the Forecast (Summer/Winter 20min Peak Plus 1SD/2SD)	Milton 500kV Minimum Voltage	Observations
	MW	MW	kV	
Summer 2003	+2000	23581	521.29	Even though the voltage at Milton TS is quite low, it is yet above the 520 kV limit
Winter 2005	-2000	25246	520.44	Even though the voltage at Milton TS is quite low, it is yet above the 520 kV limit