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

Independent
Electricity
Market Operator

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.

Caution and Disclaimer

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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.

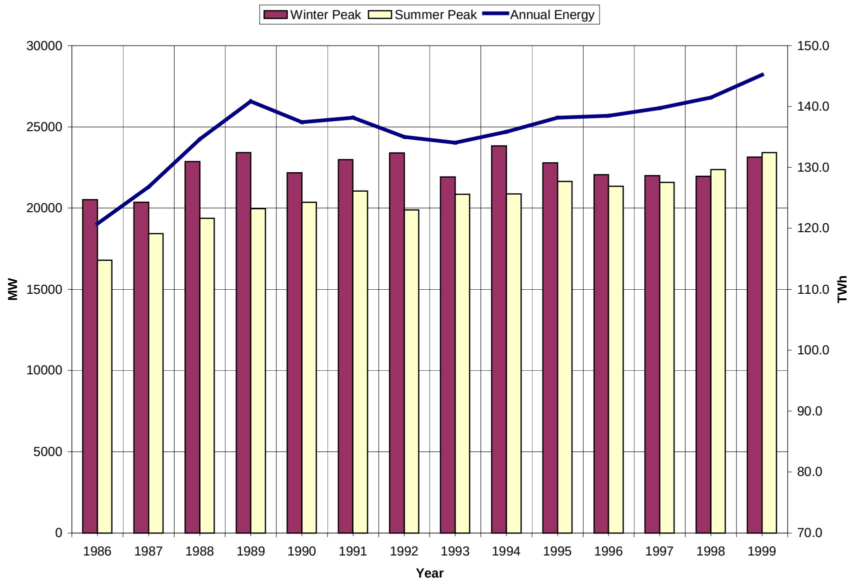
After market opening, a range of new forces will come into play that will change the dynamics of Ontario electricity demand. The IMO forecasting methodology will be revised substantially to reflect this.

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.

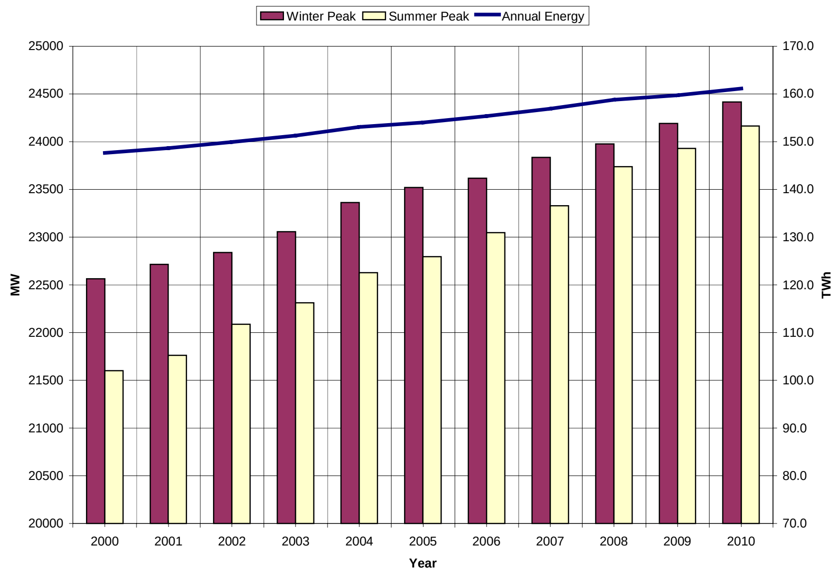
2.3 Median Demand Forecast

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

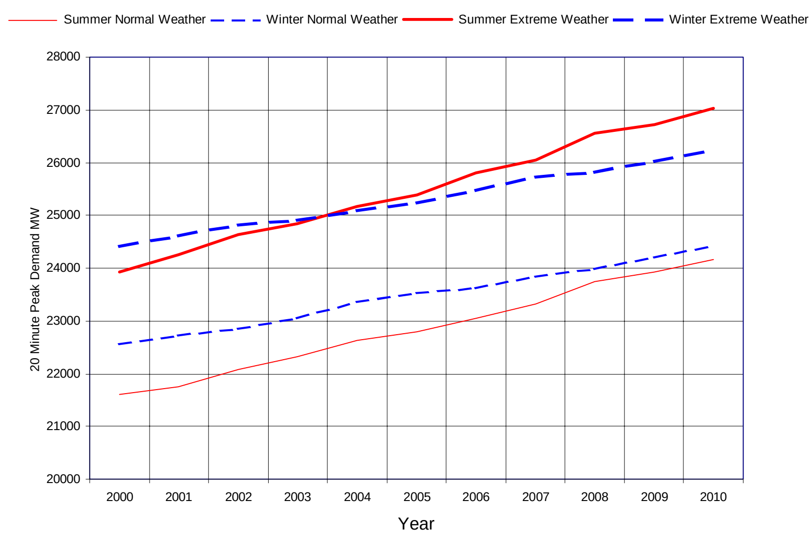


Table 2.1 20-Minute Peak Demand

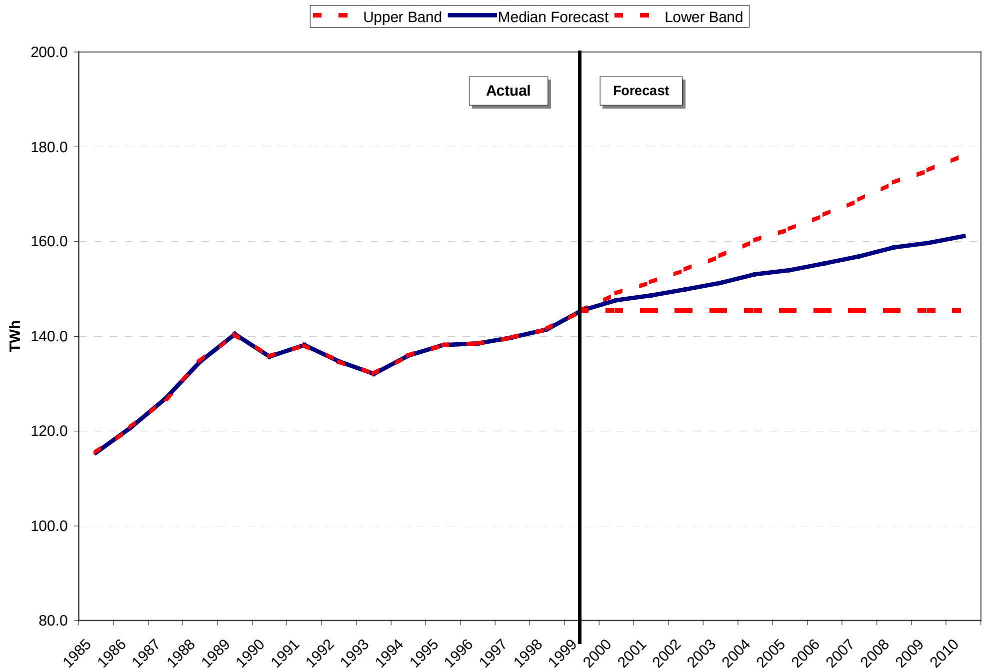
20 Minute System Peak	**Normal Weather**		**Extreme Weather[1]**	
	Summer (MW)	**Winter (MW)**	**Summer (MW)**	**Winter (MW)**
2000	21604	22563	23910	24413
2001	21761	22633	24255	24617
2002	22088	22841	24637	24815
2003	22314	23056	24699	24912
2004	22628	23205	25174	25070
2005	22796	23339	25396	25237
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.

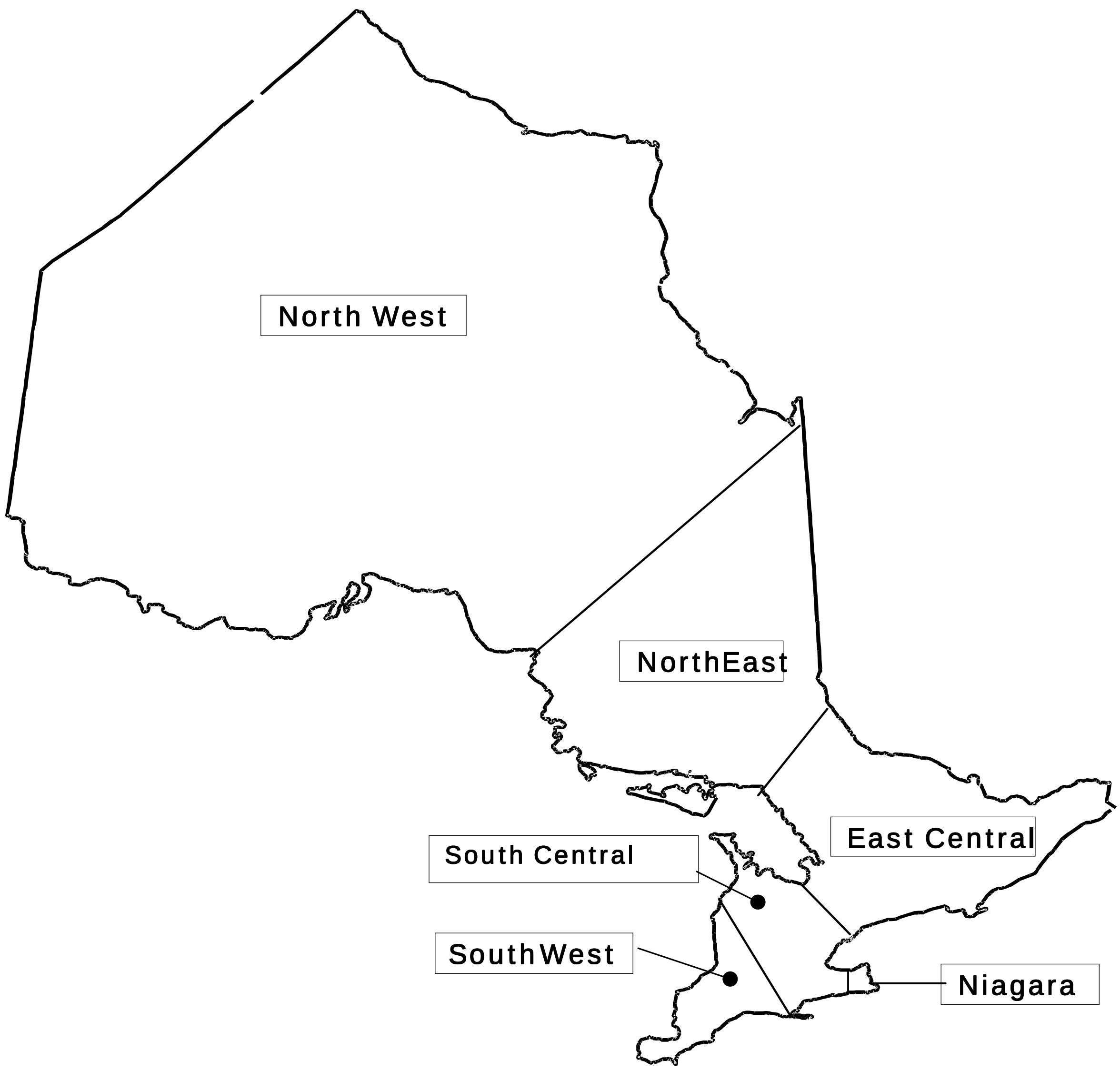
Projections of demand for the East-Central, South-Central, Niagara and SouthWest areas are based on forecasts of population growth in each of the areas. The median total system energy forecast is allocated to each area according to the population projections for these areas. The forecast for the NorthWest 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 report[1], 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.

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

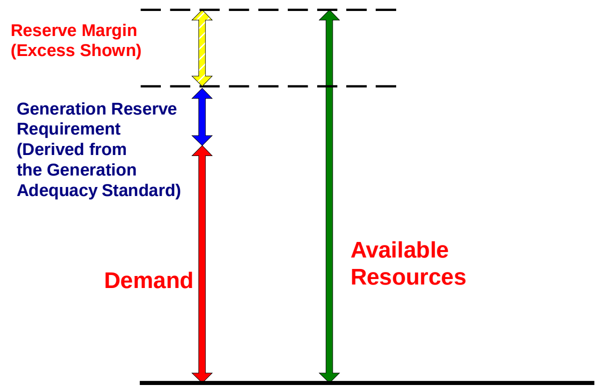
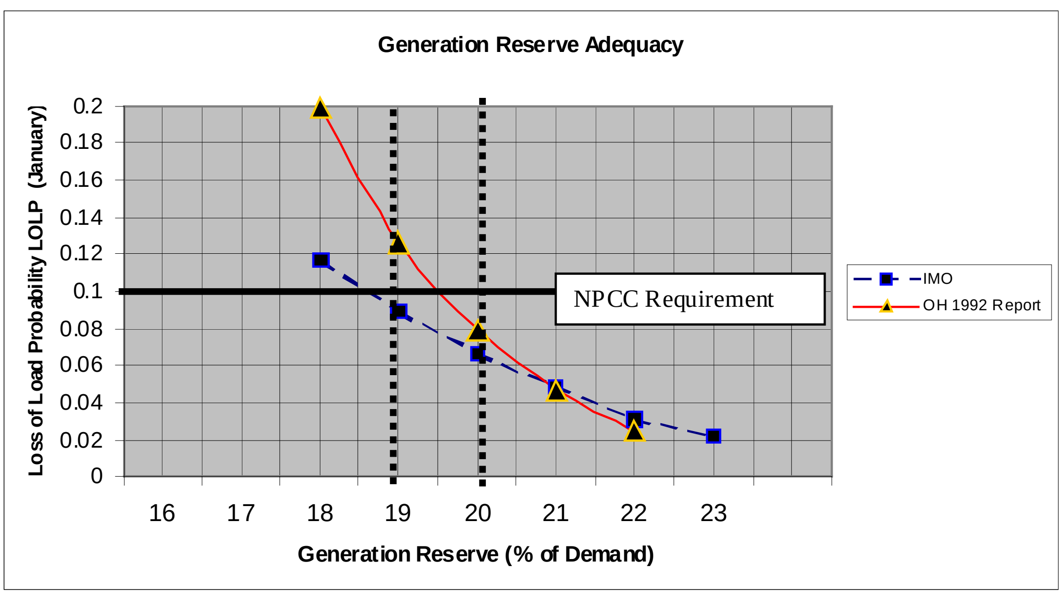


Figure 4.2 LOLP as a Function of Generation Reserve Requirement



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.

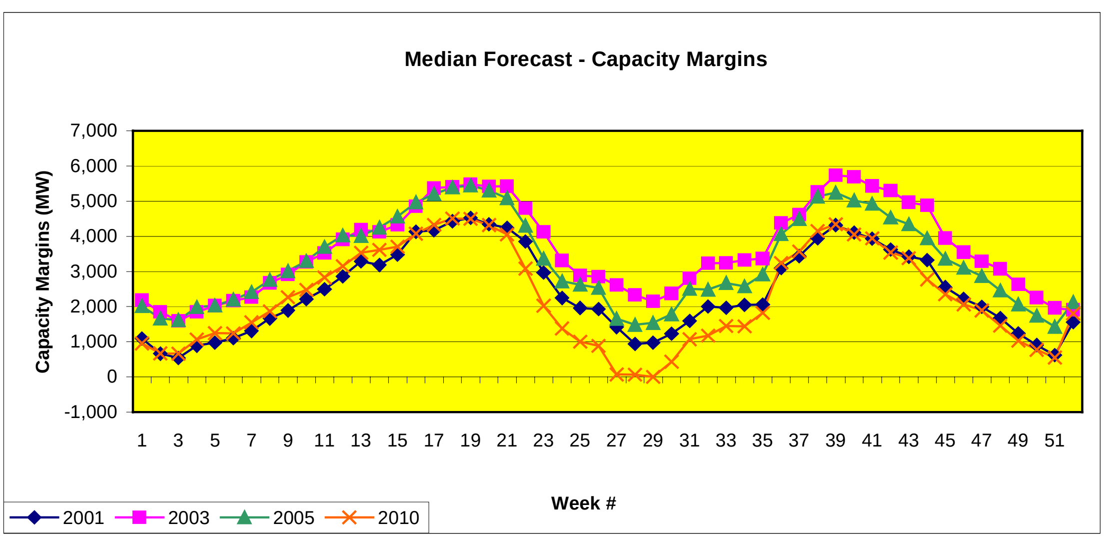
Table 4.1 Reserve Margins Under Median Forecast Winter Peak

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.

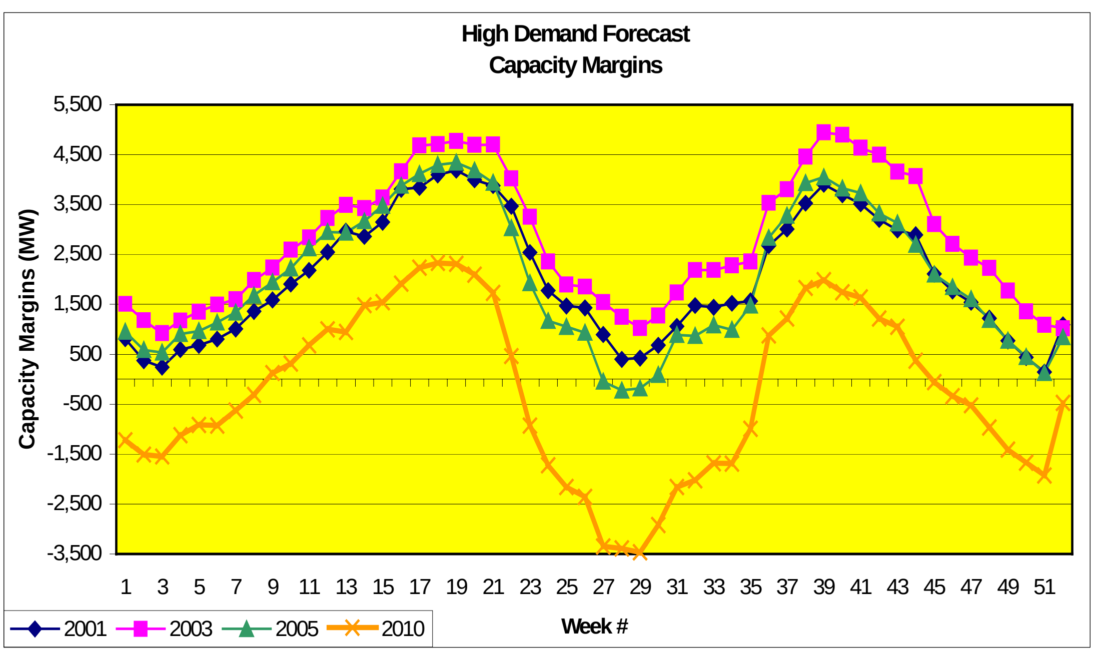
Table 4.3 High Demand Forecast Winter Peak Margins

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

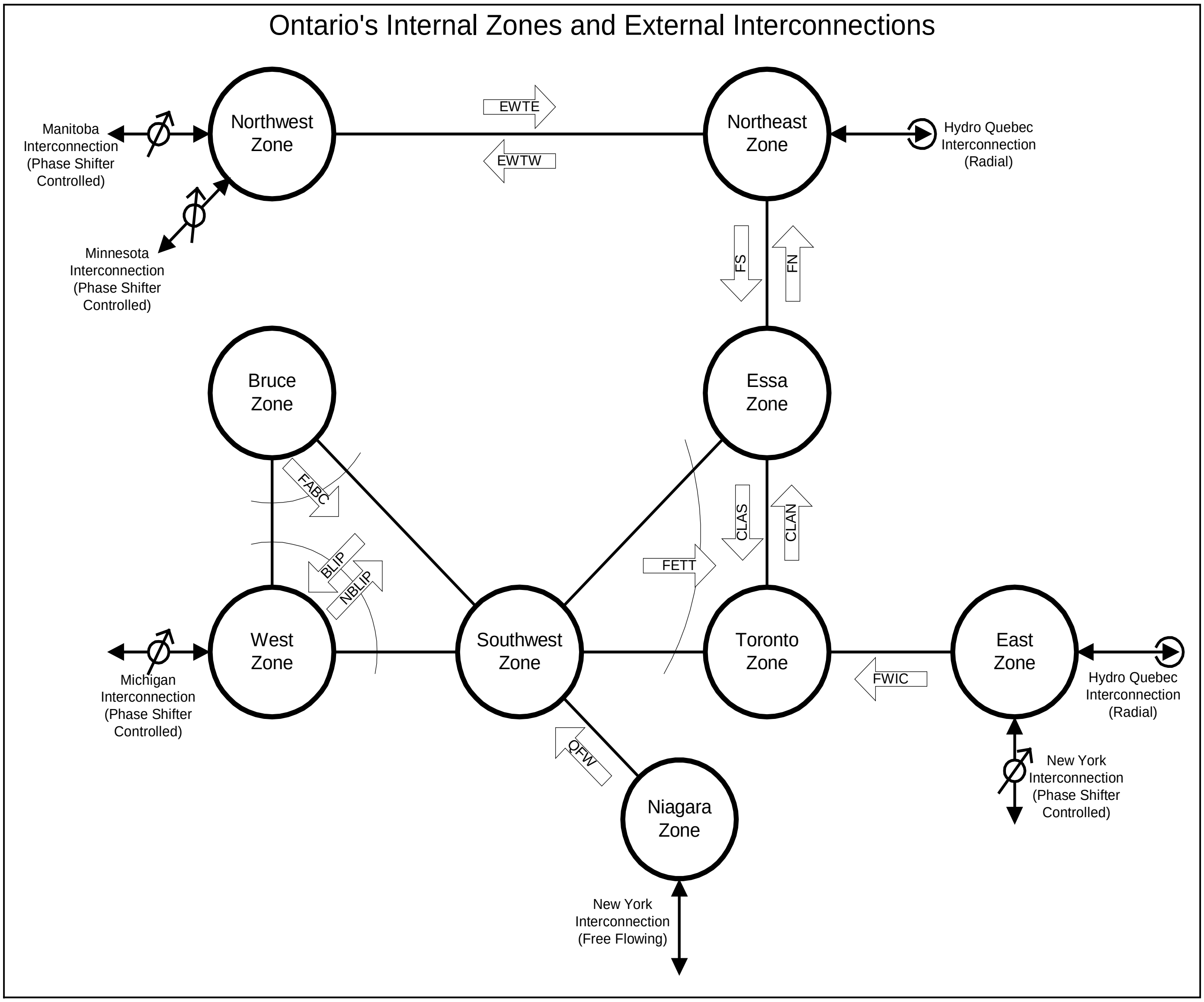


Table 5.1 Year 2000 Winter - Assumed Generation and Demand in Transmission Zones

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.

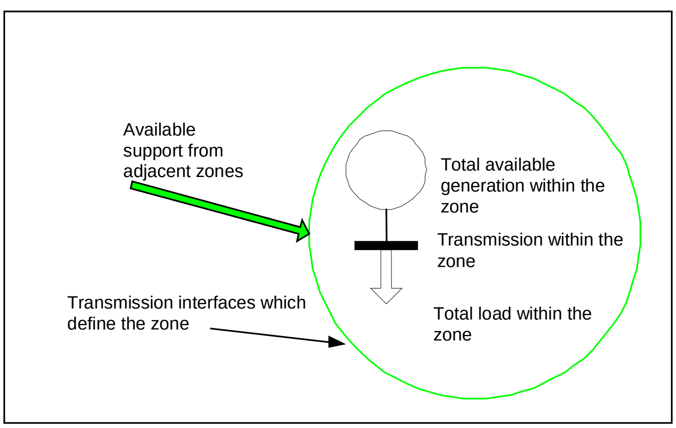
The impact of new generation and transmission projects is discussed in Section 6.4 and the overall conclusions of the transmission adequacy assessment are summarized in Section 6.5.

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



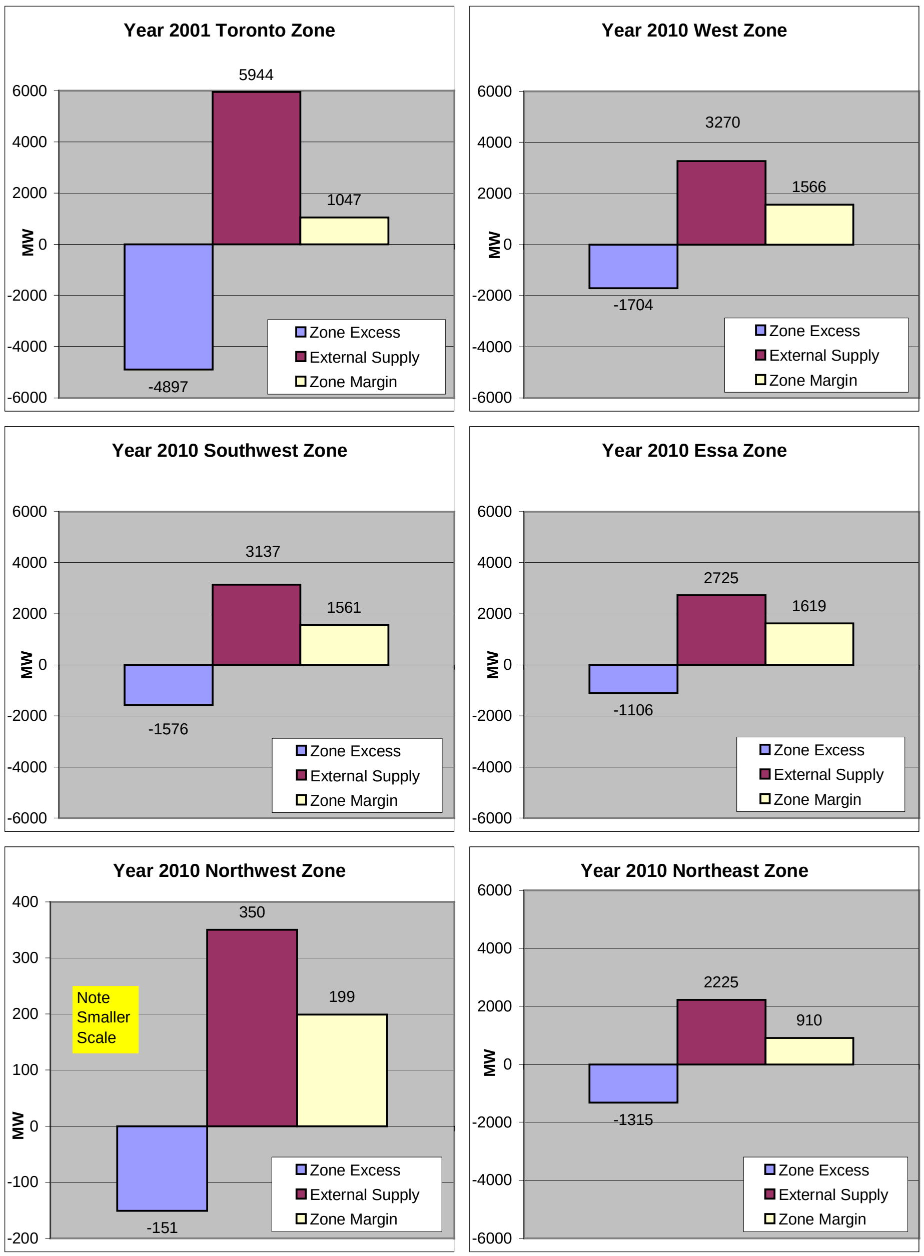
The following assumptions were made, in using the above model, to assess the reliability of supply to the various transmission zones. These assumptions represent conditions that were used, in the past, in the design of the Ontario Hydro transmission system and in the design of supply to local load areas. 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 capability 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.

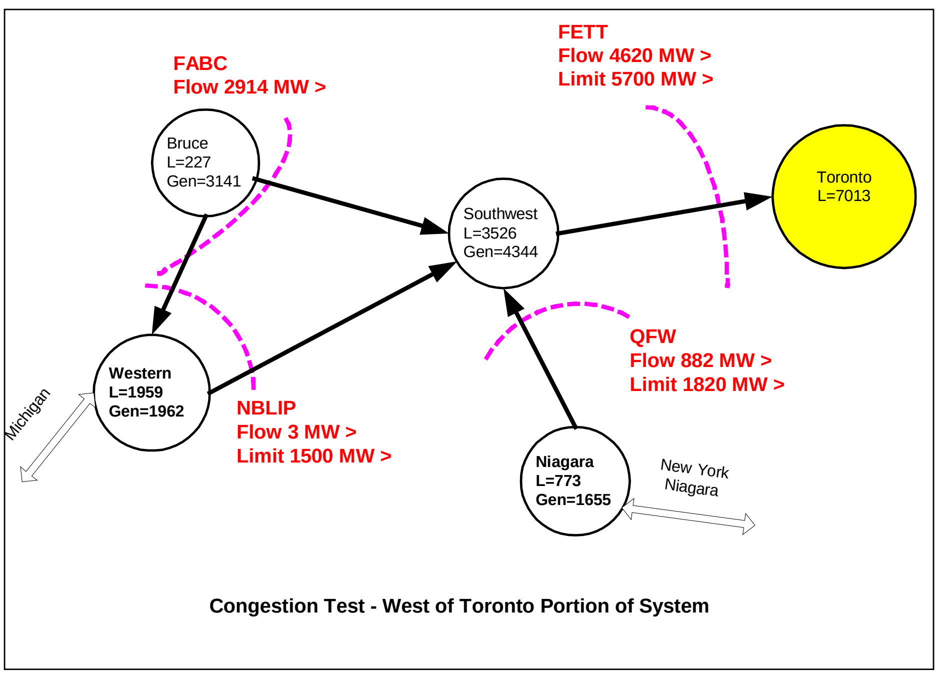
1. System stressed from Southwest of Toronto

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 (FETT[1]) 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

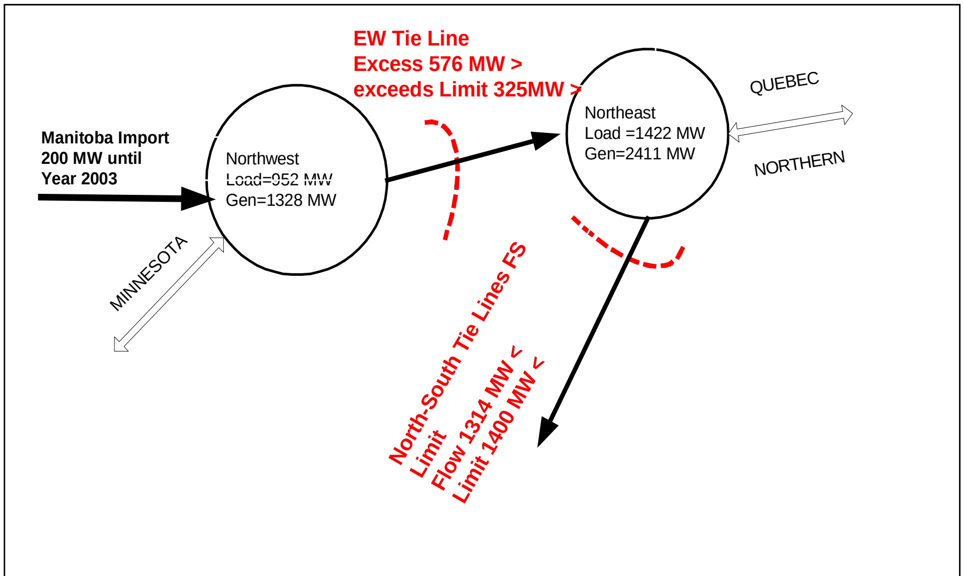


[1] Interfaces are displayed in Figures 6.3 to 6.5 and in Appendix D.

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

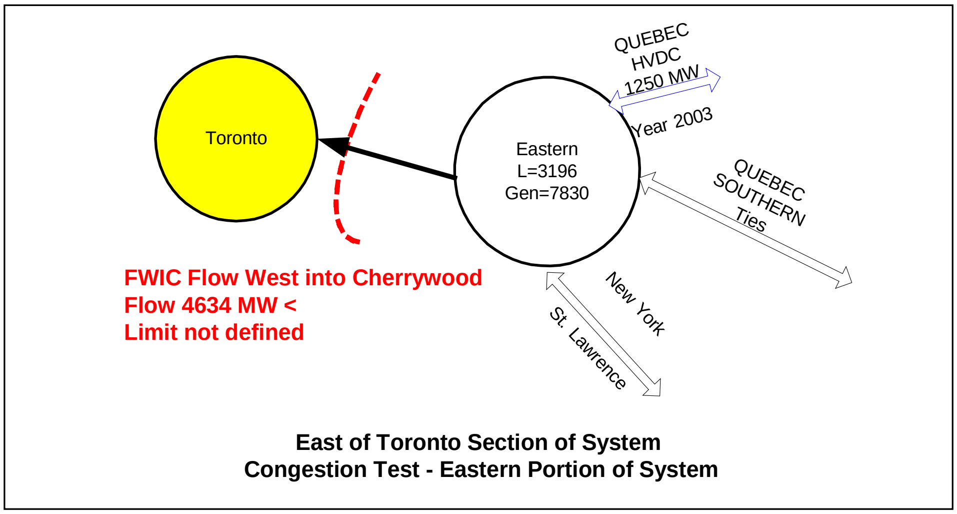


Congestion Test - North of Toronto Portion of system

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.