

Independent Electricity Market Operator

18-Month Outlook:

An Assessment of the Adequacy of the Ontario Electricity System

From October 2001 to March 2003

September 28, 2001



Executive Summary

The IMO has a responsibility to forecast the demand for electricity in the province and to assess whether the existing and proposed generation and transmission facilities are adequate to meet Ontario's needs. This report presents an assessment of the adequacy of resources and transmission for the Ontario electricity system for the 18-month period from October 2001 through March 2003. This assessment is based on forecasts of electricity demand and available supply combined with current information on the configuration and capability of the transmission system. Outage plans of generators and transmitters are based on information available as of August 3, 2001.

The overall conclusion of this assessment is that there are expected to be sufficient resources and transmission available to Ontario to supply the forecast Ontario demands and to meet the specified reserve margins under the forecast conditions studied in this report. The adequacy of supply is assessed based upon the resource adequacy criteria established by the Northeast Power Coordinating Council (NPCC). In addition, an assessment is made of how the weekly peak Ontario demand plus a weekly reserve requirement can be met for each week of the Outlook timeframe. The adequacy of transmission capability is assessed by determining whether sufficient transmission capability exists to serve demand in conformance with NPCC criteria related to system security.

Figure 1 illustrates the weekly resource adequacy situation for the Ontario Electricity System for two possible resource availability scenarios for the period: a base scenario and a severe scenario. The forecast Loss of Load Expectation associated with these scenarios during the study period is within the NPCC requirement, although this requirement is just met for the more severe resource availability scenario, where proposed new generation sources and generating units on long-term outage come into service one year later than their identified date. The resource projections in Figure 1 includes only available generation in Ontario and low levels of external supply which are pre-committed to Ontario. For periods of time when the available reserve is less than the reserve requirements, additional allowance for assistance over interconnections, combined with other available operating procedures, is expected to result in sufficient reserve margins.

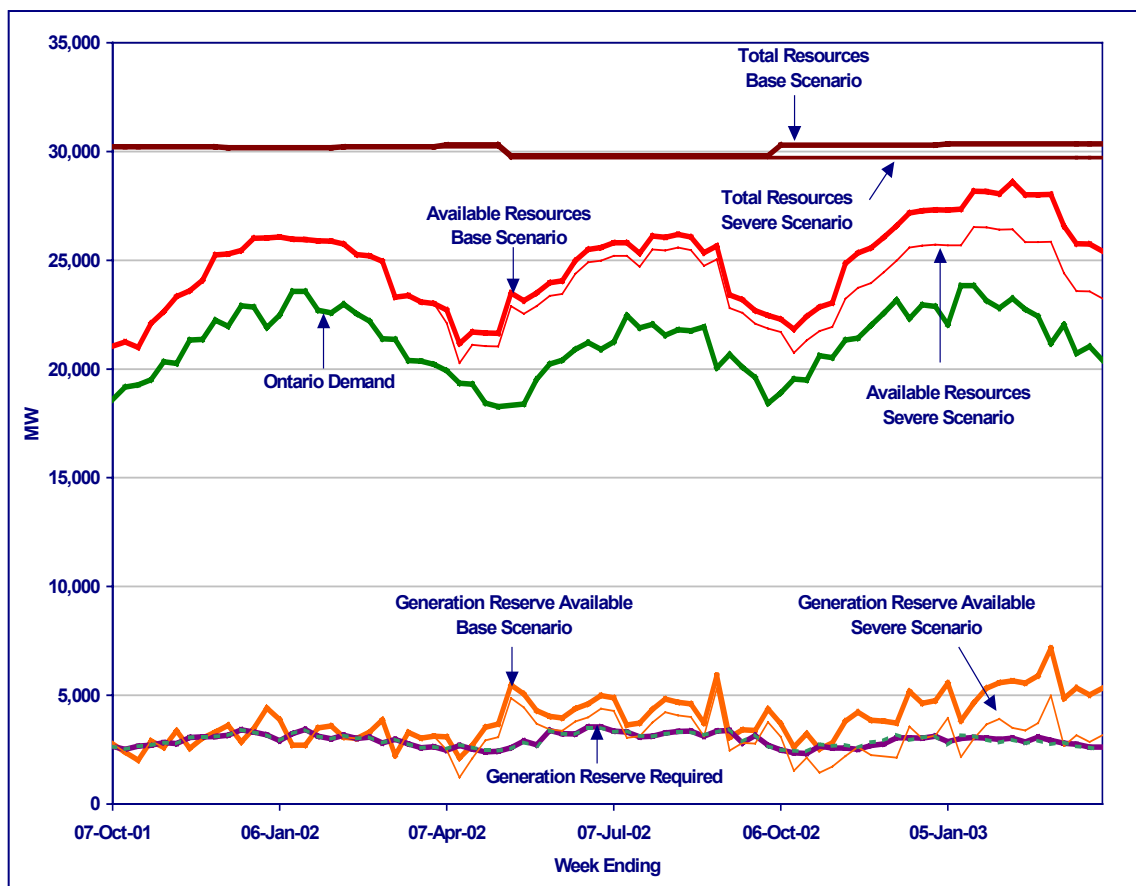
The resource adequacy assessments described in this Outlook take into consideration the full range of expected weather conditions on a probabilistic basis. As is always the case with forecasts such as these, it should be recognized that certain combinations of extreme weather and/or lower than forecast resources, could result in lower than desired levels of reliability. Results are presented assuming Normal weather as a base. This resource adequacy assessment and its conclusion assume that after market opening, market mechanisms will result in resources being available to Ontario at a comparable level to those which are currently available.

The electricity demand forecast is generally slightly lower than the previous demand forecast that was prepared for the 18-Month Outlook published in May 2001. This change is due to the inclusion of actual data up to the end of June 2001, and updated economic drivers. The electricity demand shown in Figure 1 is based on a normal weather forecast. For 2002, the normal weather winter peak is forecast to be 23,567 MW and the summer peak is forecast to be 22,474 MW. Expected variations from normal weather are considered in establishing the required weekly reserve margins rather than in the demand levels shown. In comparing the recent events of the

summer of 2001 with historical data since 1995, it is readily apparent that the days of August 7th through the 9th were hotter than any days experienced in the previous six years. As expected, in conjunction with the higher temperatures were higher peak demand values. After adjusting for the underlying weather, the weather corrected peak values are not out of line with the historical weather corrected peak values. The actual conditions experienced in July and August of this year will be included in the historical record of the next 18-Month Outlook.

The transmission system is adequate to supply loads under forecast conditions studied in this Outlook, with some limits on the flexibility for planned outages in the Toronto and Windsor areas. Reactive capability of Lakeview, Pickering and Darlington units is required to maintain adequate voltage levels during summer peak demand periods.

Figure 1 18-Month Forecast of Resource Adequacy



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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 resources 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).

This is the third 18-Month Outlook issued by the IMO. It supercedes the report titled “An Assessment of the Adequacy of the Ontario Electricity System from April 2001 to September 2002”, dated April 20, 2001.

This Outlook covers the 18-Month period from October 1, 2001 to March 31, 2003. Its purpose is to advise the Minister of Energy Science and Technology, the Ontario Energy Board and Market Participants of the resource and transmission adequacy of the Ontario electricity system, and to assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment.

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

This Outlook presents an assessment of adequacy based on the stated assumptions, and using the described methodology. Readers may envision other possible scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgement in considering possible future scenarios. This Outlook provides a base upon which changes in assumptions can be considered.

Readers are invited to provide comments on this report or to give suggestions as to the content of future reports. To do so, please call the IMO Help Centre at 905-403-6900 or 1-888-448-7777, or send an email to forecasts.assessments@theIMO.com.

2.0 Forecast of Ontario Electricity Demand

2.1 Introduction

The Ontario electricity demand is the sum of coincident loads plus the losses on the IMO-controlled grid. Ontario demand does not include loads that are supplied by embedded generation nor those not served by the IMO-controlled grid (e.g. Cornwall Electric).

Section 2.2 describes the process used to forecast electricity demand. Section 2.3 looks at the categories of variables that are used to derive the forecast and briefly discusses their relative impacts. Section 2.4 looks at both historical and forecasted energy demand, while Section 2.5 presents information on historical and forecasted peak demand. Section 2.6 compares this 18-Month forecast to the previous 18-Month forecast. Appendix A contains additional demand forecast details and analysis.

This forecast was based on actual demand, weather and economic data ending June 30, 2001. The forecast horizon of this report is October 2001 through to March 2003.

2.2 Forecasting Process

The forecast of Ontario electricity demand used in this assessment was developed by the IMO utilizing a forecasting system developed in conjunction with Regional Economic Research.

The system utilizes multivariate econometric equations to estimate the relationships between energy and peak demand and a number of analytical factors or drivers. The drivers that the system includes are weather effects, economic data and calendar variables. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. Several calibration routines within the system ensure the integrity of the forecast with respect to energy and peak demand, and regional and system wide projections.

The forecasting system produces the following output:

- a forecast of the 20-minute east and west peak demand, as well as the coincident system peak demand (under Normal/Extreme/Mild weather conditions);
- hourly energy demand by region (under Normal/Extreme/Mild weather conditions);
- load forecast uncertainty representing one standard deviation in demand as a function of variations in weather.

For the purpose of analysis several weather scenarios were generated. The Base Case demand forecast is generated using the Median economic forecast in conjunction with Normal weather. An explanation of Normal weather and the other weather scenarios is contained in Appendix A, Section 1.0.

Since the last forecast, the model has been re-estimated based on data through the end of June 2001. The structure of the forecasting system has not been altered but the coefficients have been recalculated to reflect the additional information of recent data. In addition, an analysis of the peak demand and unusually hot weather conditions during August 2001 have been considered in

this Outlook, but actual data for August was not explicitly included in the demand forecast calibration.

2.3 Forecast Drivers

Consumption of energy is modeled on three sets of forecast drivers; calendar variables, weather effects and economic conditions. Each of these drivers is embedded in the forecasting system and each plays a role in shaping the results.

Calendar variables include the day of the week and holidays, both of which impact energy consumption. Generally, electricity consumption is higher during the week than on weekends and there is a pattern determined by the specific day of the workweek. Holidays act much like weekends, in that energy consumption is lower on holidays. The reason for this relationship is that industrial load is lower on holidays and weekends as fewer facilities are operating.

Hours of daylight are key in shaping peak demand. For example, after the sun has set, electricity demand is higher due to the need for electric lighting. This is particularly important in winter when sunset coincides with increases in load associated with cooking load and return to home activities. Hours of daylight are included with calendar variables since forecasting both is very straightforward.

Weather effects include measures of temperature, cloud cover, wind speed and dew point. Both energy and peak demand are weather sensitive. The length and severity of a season's weather contributes to the level of energy consumed and acute weather conditions usually underpin the seasonal peaks.

For purposes of the demand forecast, weather is not forecasted but "Normal" weather is utilized. Normal weather is generated from historical weather data. Two additional weather scenarios were produced including an Extreme scenario composed of cold winters and hot summers and a Mild scenario built on warm winters and cool summers. The "Extreme" scenario is generated according to the methodology set out in Appendix A, Section 1.0. Any methodology assumes a certain probability of observing those values, or conversely, a certain probability that those values will be exceeded. The IMO will be updating and reviewing its weather scenarios to ensure that they reflect the appropriate level of risk.

It should be recognized that for resource adequacy assessments, the "Normal" weather forecast is used in conjunction with a measure of "load forecast uncertainty" to consider a full range of peak demands, that can occur with various weather conditions with varying probability of occurrence.

Economic conditions contribute to the growth in both energy and peak demand. To produce a demand forecast an economic forecast of various drivers is required. A consensus of five major, publicly available provincial forecasts was utilized to generate the economic drivers used in the model.

Overall, the growth of the Canadian economy is expected to slow, as the U.S. expansion remains weak. Although expectations are for a return to more robust growth, the timing of that return has continued to be pushed further into the future. Weak corporate profits have meant lower investment despite relatively low interest rates. Consumer spending remains positive despite the negative performance of the stock market. This relatively "upbeat" mood is the foundation for a stronger 2002 after a mixed 2001. In Ontario, domestic consumption has kept growth strong.

However, recent employment data indicates that the U.S. slowdown has started to impact Ontario's economy through industrial activity. This has contributed to the projected "weakness" for the remainder of 2001. Ontario's economy is expected to pick up along with the U.S. economy in 2002, as the fundamentals for sustained growth remain intact. It should be noted that the economic impacts of the recent tragic events in the US have not been factored into this Outlook.

For the forecast period, Ontario is expected to see housing starts of 67,250 in 2001, before rising to nearly 69,000 in 2002. Employment is projected to grow by 1.7% in 2001, strengthening to 2.1% in 2002. Table 2.1 presents these key Ontario economic drivers.

Table 2.1 Ontario Economic Drivers

Year	Ontario Employment		Ontario Housing Starts	
	Thousands	Annual Growth (%)	Thousands	Annual Growth (%)
1995	5,128	2.02	31.9	-23.26
1996	5,175	0.92	39.5	23.89
1997	5,298	2.37	50.0	26.47
1998	5,476	3.35	50.1	0.23
1999	5,672	3.59	62.9	25.63
2000	5,856	3.23	67.4	7.15
2001 (f)	5,953	1.65	67.3	-0.21
2002 (f)	6,079	2.12	69.0	2.48

Notes to Table 2.1:

(f) indicates a forecasted value.

2.4 Energy Demand

Energy demand represents the total consumption of electricity during a specified period of time, be it an hour, day, week, month, season or year. This section looks at historical energy demand and the factors affecting it. As well, this section presents the forecast for energy demand over the October 2001 to March 2003 time frame.

2.4.1 Historical Energy Demand

Actual primary energy demand has averaged annual growth of 1.6% over the historic period of 1986 to 2000. Energy demand is affected by the three classes of drivers but to varying degrees. On an annual basis, all years would be equal in terms of calendar effects except for leap years, which would have an additional day. Weather will impact annual energy consumption, however not to the degree that peak values are weather sensitive. As well, throughout the course of the year, the variability of weather will mean that highs and lows have a tendency to offset each other. The growth in energy demand is highly influenced by the economic class of drivers, which includes both economic activity and demographic factors.

Table 2.2 shows actual annual energy demand and annual energy demand adjusted for leap years for the period 1990-2000. As can be seen by the numbers, calendar impacts have a negligible impact on annual energy demand. Calendar variables would have a much larger impact when comparing seasons, months and weeks.

Table 2.3 displays the actual energy demand by season over the past five years. The first part of the table shows the demand by season; the second part the share of the seasonal year and the third part the average daily energy demand. Not surprisingly, winter accounts for nearly half of the total energy demand since winter accounts for nearly 42% of the seasonal year. However, the Average Daily Energy Demand does indicate that the winter season still has largest impact on energy demand.

Table 2.2 Ontario Annual Energy Demand, Leap Year Impacts

Calendar Year	Annual Energy Demand			
	Actual Energy (TWh)	Annual Growth (%)	Energy Adjusted for Leap Years (TWh)	Annual Growth (%)
1990	136.74	-2.86%	136.74	-2.86%
1991	136.97	0.16%	136.97	0.16%
1992	134.38	-1.89%	134.01	-2.16%
1993	133.48	-0.67%	133.48	-0.40%
1994	134.87	1.05%	134.87	1.05%
1995	137.04	1.60%	137.04	1.60%
1996	137.42	0.28%	137.04	0.00%
1997	138.37	0.69%	138.37	0.97%
1998	139.93	1.13%	139.93	1.13%
1999	144.09	2.97%	144.09	2.97%
2000	146.95	1.98%	146.54	1.70%

Table 2.3 Ontario Seasonal Energy Demand

Seasonal Year	Seasonal Energy Demand				
	Actual Winter Energy (TWh)	Actual Spring Energy (TWh)	Actual Summer Energy (TWh)	Actual Fall Energy (TWh)	Total Energy (TWh)
1996	62.61	21.74	33.23	21.75	137.42
1997	61.52	21.90	34.00	22.17	138.37
1998	61.25	22.15	36.19	22.46	139.93
1999	61.97	22.08	37.45	23.19	144.09
2000	63.45	23.10	36.85	23.59	146.95
Seasonal Share	Winter Share (%)	Spring Share (%)	Summer Share (%)	Fall Share (%)	Total (%)
1996	45%	16%	24%	16%	100%
1997	44%	16%	24%	16%	100%
1998	43%	16%	25%	16%	100%
1999	43%	15%	26%	16%	100%
2000	43%	16%	25%	16%	100%
Seasonal Year	Average Daily Energy Demand (GWh)				
	Winter	Spring	Summer	Fall	Total
1996	412	356	361	357	381
1997	407	359	370	363	382
1998	406	363	393	368	389
1999	410	362	407	380	396
2000	417	379	401	387	402

Notes to Table 2.3:

The winter season is from November 1st through to March 31st. Therefore, in the case of 1996, the winter spans November 1995 through to March 1996.

Table 2.4 shows the hottest summers and coldest winters of the last thirty years (1971-2000). This ranking is based on the cumulative temperature and humidity index. This helps put the Average Daily Energy Demand values from Table 2.3 into perspective. The increases in the Average Daily Energy Demand for the winter of 1996 and 2000 can be attributed to the cold weather. The same applies for the summer values of 1998 and 1999. One of the key impacts of the hot summers experienced in recent years is to increase the penetration of space cooling or air conditioning. Mitigating some of the increase in cooling-sensitive loads is the on-going replacement of older, inefficient air conditioning units with newer more efficient units. The overall impact of these hotter summers and increased penetration of air conditioning has been to make demand more sensitive to hot weather.

Table 2.4 Ontario's Hottest Summers and Coldest Winters

Rank	Hottest Summers	Coldest Winters
1	1995	1996
2	1999	1984
3	1973	1976
4	1983	1980
5	1991	1992
6	1988	1988
7	1998	2000
8	1987	1977
9	1975	1994
10	1993	1978

Table 2.5 shows the weather corrected annual energy demand. The actual energy demand is adjusted to reflect the normal weather construct that underpins the forecast. The correction for each of the years is less than 1%, showing that variations in weather throughout the year tend to mitigate each other. It is also interesting to note that weather corrections have lowered the value in 5 of the 6 years shown. However, this recent trend has not influenced this Outlook's forecast any more than the previous 20 years of historical data, since the forecasting methodology employed does not attempt to include cyclical affects of weather, which occur with various frequencies.

Table 2.5 Ontario Annual Energy Demand, Actual and Weather Corrected

Calendar Year	Annual Energy Demand			
	Actual Energy (TWh)	Annual Growth (%)	Weather Corrected Energy (TWh)	Annual Growth (%)
1995	137.04	1.60%	135.76	0.66%
1996	137.42	0.28%	136.43	0.49%
1997	138.37	0.69%	138.04	1.18%
1998	139.93	1.13%	140.46	1.75%
1999	144.09	2.97%	143.49	2.16%
2000	146.95	1.98%	146.70	2.24%

Table 2.6 shows the growth in annual energy demand and the economic drivers. The table illustrates the relationship, particularly with respect to employment, between the drivers and annual energy demand.

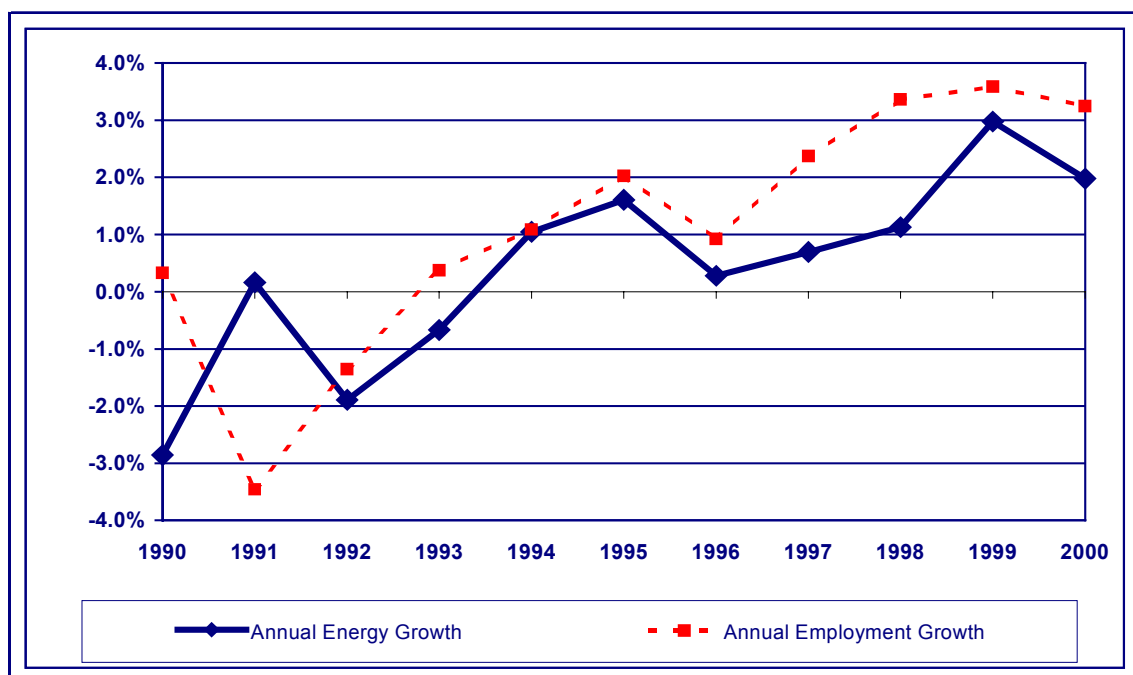
Appendix A, Section 4 contains analytical factors showing the impacts of changes to the drivers on energy demand.

Table 2.6 Ontario Annual Energy Demand and Economic Factors

Calendar Year	Annual Energy Demand and Economic Factors		
	Actual Energy Demand Growth (%)	Employment Growth (%)	Housing Stock Growth (%)
1990	-2.86%	0.33%	1.46%
1991	0.16%	-3.46%	1.24%
1992	-1.89%	-1.36%	1.30%
1993	-0.67%	0.37%	1.02%
1994	1.05%	1.09%	1.08%
1995	1.60%	2.02%	0.82%
1996	0.28%	0.92%	1.01%
1997	0.69%	2.37%	1.26%
1998	1.13%	3.36%	1.25%
1999	2.97%	3.58%	1.55%
2000	1.98%	3.24%	1.64%

Figure 2.1 graphically shows employment growth and the growth in annual energy demand. It is easy to see that over the course of a year the level of economic activity will heavily influence energy demand.

Figure 2.1 Annual Energy Demand and Employment Growth



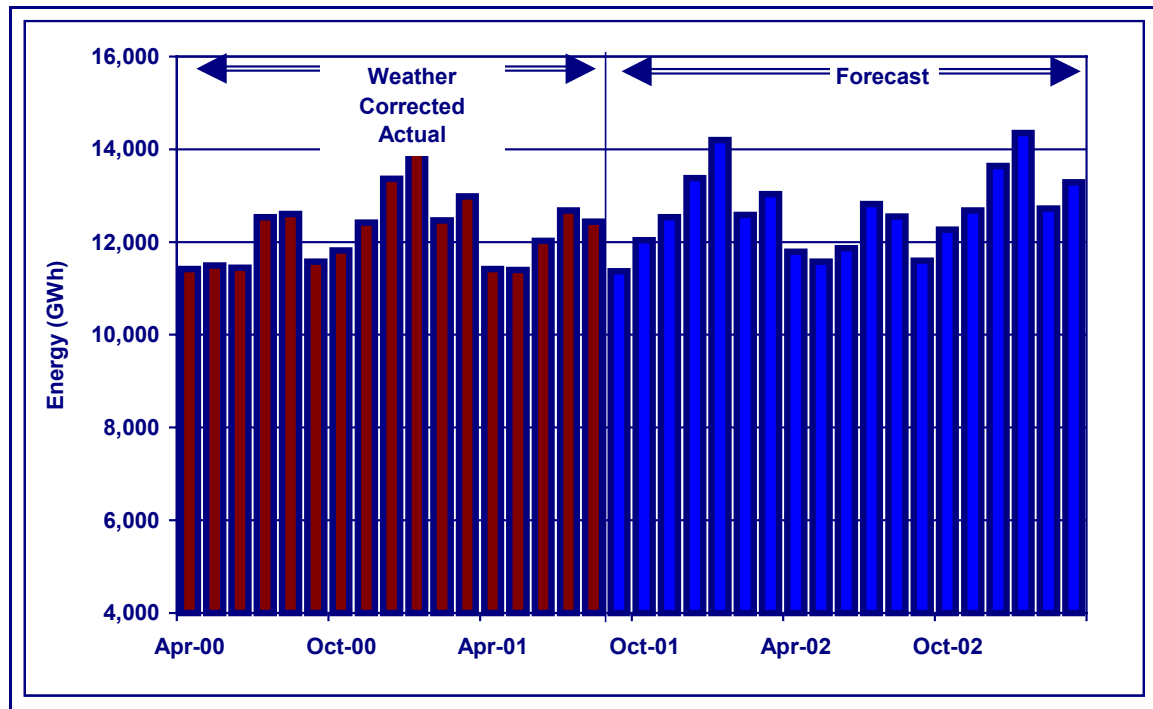
2.4.2 Energy Demand Forecast

The predicted monthly energy demand for the system for the time frame October 2001 through to March 2003 is contained in Table 2.7. The forecast is based on Normal weather. For a more detailed discussion on Normal weather see Appendix A, Section 1. Figure 2.2 shows the monthly energy demand. Energy demand is expected to exhibit average annual growth of 0.4% over 2001 and 1.3% over 2002. Growth in demand is driven by changes in economic activity, the number of end-users and the penetration of electric powered devices.

Although this section of the report deals with summary details at the system level, the demand forecast is produced on an hourly basis for all nine zones within the system. A forecast of zonal energy demand by week is provided in Appendix A, Section 2 and a map of the zones is depicted in Figure A1. Energy demand growth varies across the zones as they are subject to different economic forces.

Table 2.7 Ontario Monthly Energy Demand, Normal Weather

Month	Energy Demand
	(GWh)
Oct-01	12,040
Nov-01	12,533
Dec-01	13,377
Jan-02	14,199
Feb-02	12,582
Mar-02	13,035
Apr-02	11,791
May-02	11,576
Jun-02	11,862
Jul-02	12,820
Aug-02	12,555
Sep-02	11,602
Oct-02	12,266
Nov-02	12,682
Dec-02	13,640
Jan-03	14,355
Feb-03	12,725
Mar-03	13,288

Figure 2.2 Monthly System Energy Demand – Normal Weather

2.5 Peak Demand

Peak demand represents the maximum requirement for electricity at a specific point in time. Ontario measures peak demand as a 20-minute average. One can look at the daily, weekly, monthly, seasonal or annual peak. This section looks at historical peak demand and the factors affecting it. As well, this section presents the forecast for peak demand over the October 2001 to March 2003 time frame.

2.5.1 Historical Peak Demand

Historically, Ontario's electricity peak demand has occurred during the winter, usually in the months of December through February and between the hours of 5 p.m. to 7 p.m. Exceptions to this were in 1998, 1999, and 2001, when the annual peak demand occurred during the afternoon of July and August. Peak demand is affected by the three classes of drivers but to varying degrees.

Calendar variables, in conjunction with weather, have a large impact on peak demand. Weekly or monthly peak demands rarely occur on a weekend or holiday. Table 2.8 shows the actual summer and winter peaks dates for the time frame 1990 to 2001.

Table 2.8 Historical Peak Dates

Seasonal Year	Peak Demand			
	Winter Peak Date	Day of Week	Summer Peak Date	Day of Week
1990	13-Dec-89	Wed	04-Jul-90	Wed
1991	21-Jan-91	Mon	29-Aug-91	Thu
1992	16-Jan-92	Thu	26-Aug-92	Wed
1993	01-Feb-93	Mon	27-Aug-93	Fri
1994	19-Jan-94	Wed	17-Jun-94	Fri
1995	06-Feb-95	Mon	15-Aug-95	Tue
1996	11-Dec-95	Mon	07-Aug-96	Wed
1997	17-Jan-97	Fri	14-Jul-97	Mon
1998	14-Jan-98	Wed	15-Jul-98	Wed
1999	13-Jan-99	Wed	05-Jul-99	Mon
2000	17-Jan-00	Mon	31-Aug-00	Thu
2001	12-Dec-00	Tue	08-Aug-01	Wed

In conjunction with calendar impacts, weather plays the biggest role in determining peak values. Acute weather conditions underpin peak demand, particularly so if those weather conditions persist over several days. Table 2.9 ranks the weather for each of the peak dates in Table 2.8. A value of one would indicate that the weather for that day was either the coldest or hottest of that year, based on the Temperature Humidity Index (THI). Since peak values are determined by both weather and calendar variables, a second column for both the summer and winter peaks dates shows the ranking again after eliminating holiday and weekend observations.

Table 2.9 Peak Dates' Weather Rankings

Seasonal Year	Peak Demand			
	Winter Peak Date Seasonal Rank	Winter Peak Date Seasonal Rank (Excl. Weekends & Holidays)	Summer Peak Date Seasonal Rank	Summer Peak Date Seasonal Rank (Excl. Weekends & Holidays)
1990	9	7	1	1
1991	1	1	10	8
1992	1	1	2	2
1993	2	1	2	2
1994	2	1	2	1
1995	2	1	3	3
1996	18	13	2	1
1997	2	1	1	1
1998	2	1	2	2
1999	2	2	1	1
2000	1	1	1	1
2001	20	11	3	3

From Table 2.9 we can see the importance of calendar and weather variables as they impact the peak demand. Over the course of a season, weather can exhibit great variability. For example, a

winter that is generally mild will have a lower than normal energy demand, but can still give rise to a higher than normal peak demand due to a short cold spell. The Normal weather construct that underpins the forecast attempts to capture this variability in the weather. Therefore, the winter of the Normal weather will contain average days, cold days and mild days, mimicking real weather variability. Despite the variability in the Normal weather, it is quite possible to experience weather conditions well in excess of these values. Table 2.10 shows the ten coldest and hottest days, based on the THI, experienced over the time frame 1970-2001.

Table 2.10 Hottest and Coldest Days from 1970-2001

Rank	Hottest Days	Coldest Days
1	14-Jul-95	15-Jan-94
2	05-Jul-99	17-Jan-82
3	09-Aug-01	19-Jan-94
4	07-Aug-01	03-Jan-81
5	04-Jul-99	17-Feb-79
6	08-Jul-88	11-Jan-81
7	18-Jun-94	16-Jan-94
8	20-Jul-77	04-Jan-81
9	08-Aug-01	23-Jan-76
10	12-Jul-87	18-Jan-97

Peak demand values for these days would be in excess of those predicted using the Normal weather since these weather conditions represent such a deviation from the expected range of values. The probability of observing these values can be calculated based on historical data with the likelihood of experiencing being low. For example, based on historical data, the probability of observing the average daily temperature for August 8th, 2001 is less than 0.3% or once in every 5 years. It is interesting to note that similarly high temperatures were experienced on August 7th. These two consecutive days of unusually hot weather combined to produce an August 8th peak demand value which is higher than the peak that would otherwise been experienced if there was only one day of unusually hot weather. The probability of experiencing two consecutive days when the temperature exceeds 31 degrees is even less likely than 0.3%. The peak value for August 8th of 25,269 MW can also be given a probability based on the peak forecast and the associated load forecast uncertainty. According to the April 2001 18-Month Outlook the probability of observing this peak demand value was less than 0.1%.

Table 2.11 shows the actual summer and winter peaks from 1990 through to 2001 (to date). Unlike energy demand which shows a generally smooth upward trend, peak demand shows the variability more closely associated with the weather underpinning that day's peak.

Table 2.11 Actual Historical Peak Demand

Seasonal Year	Winter Peak (MW)	Summer Peak (MW)
1990	23,630	20,453
1991	23,212	21,150
1992	23,540	19,976
1993	22,087	20,937
1994	24,007	20,923
1995	22,855	21,770
1996	22,823	21,428
1997	22,197	21,667
1998	21,575	22,443
1999	23,308	23,435
2000	23,428	23,222
2001	23,291	25,269

Notes to Table 2.11:

The winter season is from November through till March. Therefore, in the case of 1996, the winter spans November 1995 through to March 1996. The summer peak value for 2001 is for data up to August 12th, 2001.

As with energy demand, peak demand can be adjusted to reflect the Normal weather construct rather than the actual weather underpinning it. The results of this correction are shown in Table 2.12. By comparing this table with the previous one it is possible to discern those seasons where the peak weather conditions were above or below the Normal weather. For example, the weather-corrected peak for the week ending August 12th, 2001 is 22,168 MW, 368 MW higher than the April 2001, 18-Month Forecast for that week (21,804 MW).

Table 2.12 Weather Corrected Historical Peak Demand

Seasonal Year	Winter Peak (MW)	Summer Peak (MW)	Winter Peak Correction Factor (MW)	Summer Peak Correction Factor (MW)
1995	21,499	20,813	-1,356	-957
1996	21,718	20,565	-1,105	-863
1997	22,380	20,816	183	-851
1998	22,352	21,806	777	-637
1999	22,632	21,908	-676	-1,527
2000	22,804	22,065	-624	-1,157
2001	23,114	22,168	-177	-3,101

2.5.2 Peak Demand Forecast

The forecast of monthly peak demand is contained in Table 2.13. A forecast of zonal weekly peak demand (both coincident and non-coincident) is contained in Appendix A, Section 3.0. The Normal weather winter peak for 2002 is expected to be 23,567 MW, increasing to 23,827 MW for winter 2003. The Normal weather summer peak for 2002 is projected to be 22,474 MW. These values represent the combination of the forecast of economic activity and the Normal weather construct. Figure 2.3 displays the forecast of the Normal weather system weekly peaks

As described in Appendix A, Section 1, Normal weather represents “an average” of historical weekly peak weather values. As such, there is a likelihood that actual weather may be less severe

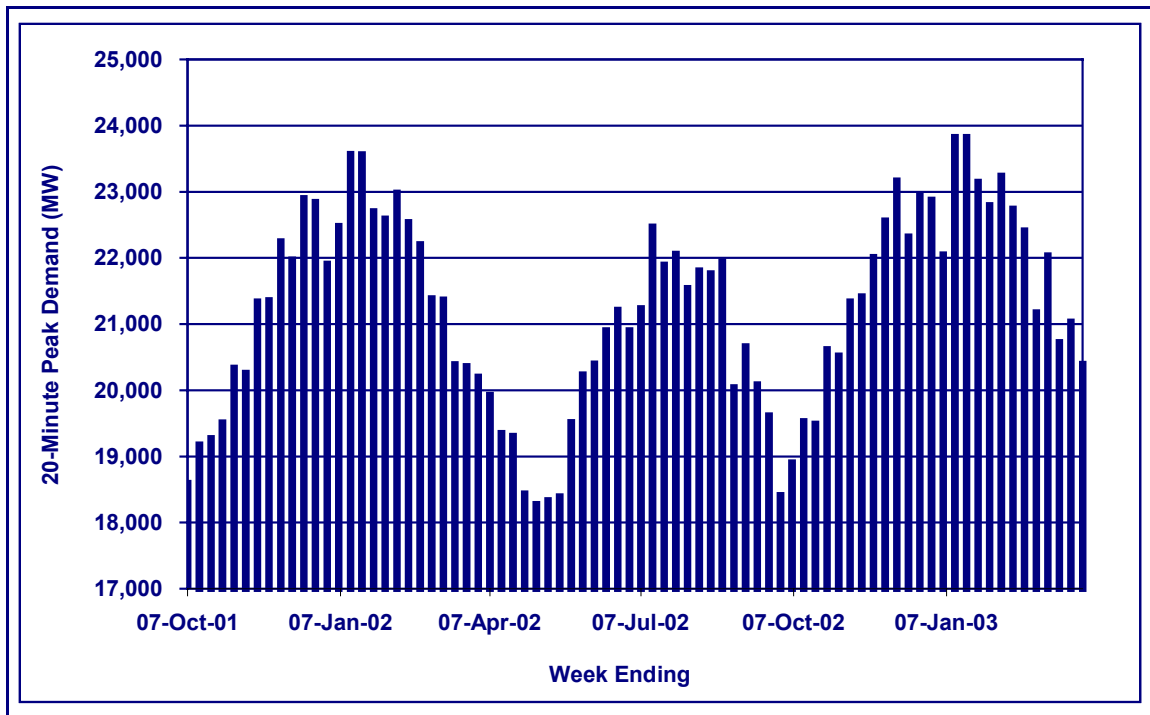
or may be more severe than Normal weather, and hence actual demands may be higher or lower than the Normal weather peak demand forecast. This occurred during the past summer when unusually high and prolonged temperatures resulted in an all-time Ontario peak demand of 25,269 MW. Based on past experience, every one-degree Celsius increase above the Normal summer mean daily temperature increases peak demand by an estimated 375 MW.

Table 2.13 also includes the forecast of monthly peak demands using Extreme weather conditions. An explanation of how the Extreme weather scenario is generated is contained in Appendix A Section 1.0. In short, for any given week of the year, the Extreme peak causing weather will be more extreme than all but 2 observations over the 30-year history for that week. This translates into probability of the weekly peak Extreme weather conditions being exceeded less than 1% of the time. However, even these Extreme weather conditions would be not as hot as the weather experienced in early August 2001.

The resource adequacy assessments described in Section 4 of this Outlook take into consideration the full range of possible weather conditions on a probabilistic basis. Results are presented assuming Normal weather as a base. Allowance for the probability of demand being higher than those assumed in the base case is made in the calculation of the required reserve level. This is explained more fully in Appendix C, Section 1.

Table 2.13 Forecast of Monthly Peak Demand

Month	Normal Weather Peak Demand	Extreme Weather Peak Demand
	(MW)	(MW)
Oct-01	19,781	20,256
Nov-01	22,248	22,667
Dec-01	22,905	23,651
Jan-02	23,567	24,341
Feb-02	22,980	23,493
Mar-02	21,387	22,314
Apr-02	19,924	19,924
May-02	19,516	20,614
Jun-02	21,215	22,834
Jul-02	22,474	23,618
Aug-02	21,943	23,420
Sep-02	20,662	20,662
Oct-02	20,618	20,618
Nov-02	22,563	22,912
Dec-02	23,166	23,912
Jan-03	23,827	24,601
Feb-03	23,240	23,824
Mar-03	22,033	22,411

Figure 2.3 Forecast of Weekly 20-Minute System Peak Demand - Normal Weather

2.6 Comparison of Current Forecast to Previous Forecasts

The most recent forecast with which this 18-Month forecast can be compared is the April 2001, 18-Month forecast. The fundamental changes are the inclusion of additional data, the re-estimation of the forecasting system and an updated economic forecast. Actual weather, load and economic data through till the end of June 2001 were incorporated into the forecasting system prior to re-estimation. Upon re-estimation, this additional data further refines the coefficients in helping explain the relationships between peak and energy demand and weather, calendar and economic variables. Structurally, the forecasting system remains the same.

The updated economic forecast expects a weaker Ontario economy for the remainder of 2001 before strengthening in 2002. This means this current forecast would see lower levels of economic activity throughout the forecast horizon in comparison to the April 2001, 18-Month. However the growth in 2002 is expected to be higher than was forecasted in the April 2001, 18-Month.

With respect to electricity demand, the lower level of economic activity is reflected in the forecast for the 2002 normal weather winter peak (23,567 MW for the September 2001 forecast vs. 23,731 MW from the April 2001 forecast) and a 2002 normal weather summer peak for 2002 (22,474 vs. 22,611 MW respectively). The projected energy demand for 2001 is lower than April's forecast due to the same economic conditions. This forecast predicts 148.7 TWh of annual energy demand for 2001, as opposed to the 149.9 TWh predicted in the April 2001 forecast.

3.0 Resources

This Section describes the generation resources that are considered in this Outlook based on information available to the IMO as of August 3, 2001.

Section 3.1 describes the capacity of the existing installed generation resources that are included in this Outlook. Section 3.2 describes the long-term bilateral external transactions (imports and exports) that are considered. Section 3.3 summarizes new generation projects in Ontario, which have been identified to the IMO through the Connection Assessment and Approval (CAA) process, as of August 2001. Section 3.4 provides an overall summary of the generation resource scenarios considered in the Outlook.

3.1 Existing Installed Generation Resources

The existing installed generation is summarized in Table 3.1. It includes nuclear, coal, oil, gas, hydroelectric, wind-powered, wood and waste-fuelled generation. The installations range in size from less than 1 MW to 881 MW net electrical output, and result in a total capacity of 29,523 MW. Excluded from the study are embedded generators that are not managed by Ontario Electricity Financial Corporation (OEFC) or generation not directly connected to the IMO-controlled grid.

Although announcements have been made about the intention of Bruce Power to return to service two of the Bruce A units, the capacity of installed generation resources used for this Outlook does not include Bruce A units, which are currently in laid-up state. These units will be included in future studies if their proposed restart has been submitted to the IMO for Connection Assessment and Approval.

All the listed generation is considered available for use in the 18-month period, except for some of the Pickering A nuclear units. They are forecast by Ontario Power Generation Inc. (OPGI) to return to service starting in 2002.

Table 3.1 Existing Installed Generation Resources

Resource Type	Total, MW	# of Stations	Size Range, MW
Nuclear	10,808	4	515 - 881
Coal	7,553	5	155 - 490
Oil / Gas	3,706	31	0.43 - 525
Hydroelectric	7,419	127	0.04 - 136
Miscellaneous (wind, waste, wood, etc.)	37	6	1 - 15
Total	29,523	173	<1 - 881

Changes from the previous 18-Month Outlook

The previous 18-Month Outlook reported installed generation resources totaling 29,492 MW. Differences are due to minor changes in the rating for some generating units.

Forecast failure rates (DAFOR/DAUFOP) for some generating units have been updated to reflect their latest forced outage behaviour.

3.2 Long Term External Transactions Outside the Province

Availability of 700 MW of firm capacity and energy from outside Ontario is included in the assessment for the months of October, November 2001 and February, March, April 2002. For the period of December 2001 and January 2002, an amount of 650 MW of firm external resources is included. For the remainder of the 18-month interval, 200 MW of firm capacity and energy from external sources has been identified. No other firm purchase contracts have been identified for the study period. There are no firm sales identified at any point in the study period.

3.3 Potential New Generation Resources

In accordance with the Market Rules, Chapter 4, Section 6, any participant planning a new or modified connection to the IMO-controlled grid must apply to the IMO for approval under the Connection Assessment and Approval (CAA) process.

Table 3.2 summarizes potential new generation projects that have been identified to the IMO through the CAA process, as of August 2001 and whose estimated in-service date falls in the 18-month interval studied. In Table 3.2, the information regarding resource type, capacity and estimated in-service date is provided by the proponents. The CAA Status column shows the status of each project; SIA means the System Impact Assessment has been completed or is in progress, while PA means the Preliminary Assessment has been completed or is in progress.

Table 3.2 Potential Generation Projects in Ontario

Project Name	System Zone	Resource Type	Capacity MW	Proponent's Estimated I/S Date	CAA Status
AGSTAR	West	Gas	88	2002 - Q1	PA
Transalta	West	Gas	490	2002 - Q3	SIA
Northland (Kirkland)	Northeast	Gas	48	2002 - Q4	SIA
Enron	West	Gas	505	2002 - Q4	SIA
Northland (Thorold)	Niagara	Gas	296	2003 - Q1	PA
Total			1427		

Details about the CAA process, the status of all current applicants, including copies of available Preliminary Assessment (PA) and System Impact Assessment (SIA) Reports can be found on the IMO's web site www.theIMO.com under the "Connection Assessments" link.

Due to uncertainties with respect to the timing of these projects, or in some cases even whether they will proceed, the IMO has reasonable doubt whether the commissioning of some of the above listed projects will occur within the 18-month time span. To reflect a conservative approach to this uncertainty, not all of the proposed generation is considered in this Outlook.

3.4 Summary of Generation Resource Scenarios

In assessing future resource adequacy, it is necessary to make a number of assumptions regarding the magnitude of supply resources that will be available. Two resource scenarios are considered

in the present Outlook: a Base Scenario and a Severe Scenario. Both resource scenarios are built based on the existing installed resources shown in Table 3.1.

Under the **Base Scenario**, about 45% of the capacity of the new generation projects is assumed to be placed in-service at the estimated dates, and therefore is added to the Installed Resources for the applicable timeframe. Generator outages and return to service dates of generators on long-term outages are based on information received from generator owners.

The **Severe Scenario** assumes a one-year delay for the in-service dates of new generation projects and generators on long-term outages. Consequently, this scenario assumes reduced available resources by up to about 1,600 MW.

Table 3.3 shows a snapshot of the available resources assumed in the study, under the two scenarios, at the time of the winter 2002, summer 2002 and winter 2003 peak demands. The resource pictures are developed starting from the existing installed generation resources shown in Table 3.1. External transactions, described in Section 3.2, are added to obtain Total Resources. Generation additions are included in the Base Scenario only, as mentioned above. Generator deratings, generator outages under each resource scenario, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity are subtracted from Total Resources to obtain Available Resources.

Table 3.3 Summary of Available Resources

Notes	Description \ Year	Winter Peak 2002		Summer Peak 2002		Winter Peak 2003	
		Base Scenario	Severe Scenario	Base Scenario	Severe Scenario	Base Scenario	Severe Scenario
1	Installed Resources	29,523	29,523	29,611	29,523	30,149	29,523
2	Firm Imports	650	650	200	200	200	200
3	Total Resources	30,173	30,173	29,811	29,723	30,349	29,723
4	Total Reductions in Resources	4,203	4,203	4,004	4,519	2,172	3,202
5	Available Resources	25,970	25,970	25,807	25,204	28,177	26,521

Notes to Table 3.3:

1. Installed Resources: This is the total capacity of the existing installed generation resources in Ontario assumed to be available over the summer and winter peaks in the 18-month time span, as described in section 3.1. This value includes all the generators in Ontario, except Bruce A, retired generators, embedded generators not managed by OEFC or generators not directly connected to the IMO-controlled grid. For the Base Scenario only, 45% of the total new generation capacity is progressively included, according to estimated in-service dates in Table 3.2.
2. Imports: Represents the amount of external capacity considered to be reliably committed to Ontario under existing contracts/agreements.
3. Total Resources: This is the sum of lines 1 and 2 above.
4. Total Reductions in Resources: These reductions represent, under each of the two scenarios, the sum of generator deratings, planned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity.
5. Available Resources: This is the difference between lines 3 and 4 above.

4.0 Resource Adequacy Assessment

This Section provides an assessment of the adequacy of the resources described in Section 3 to meet the forecast demand described in Section 2. The methodology used to carry out this assessment is described in detail in Appendix C. Results of the adequacy assessment are described in Section 4.1 and conclusions are provided in Section 7.

4.1 Assessment of Generation Resources Adequacy

4.1.1 Weekly Margins

It should be noted that the entire assessment of Ontario generation resource adequacy is based on the inherent assumption that after market opening, market mechanisms will result in resources being available to Ontario at a comparable level to those which are currently available.

Reserve Margins for each week, for both resource scenarios studied, under normal weather conditions, are shown in Figure 4.1. The total reductions to resources are shown in Figure 4.2. Further details and explicit values are provided in Appendix C. Analysis of forecast Reserve Margins indicates the following:

Under the **Base Scenario**, most of the forecast Reserve Margins are positive in the period covered by this Outlook. The estimated Loss of Load Expectation, (LOLE) indicates that the Ontario electricity system will be operated at a lower risk level than required by the NPCC resource adequacy standard.

Reserve margins above required levels indicate that opportunities for the scheduling of additional generator outages exist in May, June, November and December 2002, as well as in February and March 2003.

Based on past experience, and information available from external systems, external resources are likely to be available during the very few weeks which indicate negative Reserve Margins exceeding 500 MW. Neighbouring systems are outside their seasonal peak demand, and/or have sufficient spare generating capacity during such periods. The amounts of additional generation resources needed in these weeks, in order to restore margins to desired levels, would be no more than 750 MW.

Under the **Severe Scenario**, the lack of generation resource additions and one year delay in return to service of generating units on long-term outages would result in lower Reserve Margins, although most of remain them positive. The estimated LOLE indicates that the Ontario electricity system would still meet the NPCC resource adequacy standard under this severe scenario.

No opportunities for additional generator planned outages exist in the study period, as indicated by the sparse occurrence of large positive margins. This scenario would only leave some room for additional forced outages or some flexibility in rescheduling the existing planned outages.

Weeks with negative Reserve Margins exceeding 500 MW in the study period occur in periods when external resources are likely to be available, since neighbouring systems are outside their seasonal peak demand periods, and/or have sufficient spare generating capacity. The amounts of

additional generation resources needed in these weeks, in order to restore margins to desired levels, would not exceed 1,000 to 1,500 MW.

4.1.2 Uncertainties in Forecast Margins

Uncertainties in demands due to **weather effects** and uncertainties in generator forced outages have been taken into account in the calculation of Required Reserves, as described in Appendix C under the Load and Capacity model description. Therefore Reserve Margins reflect the effect of such uncertainties.

Although current **economic conditions** are reflected in the base demand forecast, uncertainties in the forecast demand due to unforeseen economic growth or decline are not reflected. Changes to economic conditions that may occur after the demand forecast was produced are generally captured by subsequent Outlook Report. Readers may wish to make their own assessments by considering that higher demand growth reduces Reserve Margins while lower demand growth increases Reserve Margins.

Generating unit **forced outage** uncertainties in excess of the allowance already included in the assessment can have negative impacts on Reserve Margins. These events can be caused by random unit failures or by unplanned extensions to planned maintenance. In the latter case, the IMO has considered that certain outage extension risks exist; these are included the Severe Scenario in the present Outlook.

In conjunction with all the above-mentioned uncertainties, sufficient control actions exist to restore Reserve Margins to adequate levels, should deficiencies persist into the near term operating horizon.

4.1.3 Outage Coordination and Dependence on External Resources

Management of the Ontario load and capacity situation is a continual process, which responds to numerous factors that can affect the adequacy of the Ontario supply situation. The availability of generating units (i.e. the requirement for unit outages) and resource imports from other control areas are major factors that significantly impact supply adequacy. Generator outage plans are developed to balance the need for adequate supply while providing the necessary outage time to ensure continued equipment and staff safety, meet regulatory requirements and to maintain long term equipment reliability. Most outages are scheduled during the fall and spring periods to take advantage of lower demands and the availability of surplus capacity from other control areas, if needed, to ensure Ontario's supply adequacy. If, during the course of time, new outages are identified or the duration of scheduled outages change, plans will be developed by the IMO with Market Participants to re-establish acceptable levels of adequacy. The above are considered normal planning activities and exclude any emergency control actions that are available to the IMO in day to day operations.

Generators, Transmitters and other market participants are expected to address the coordination of planned outages of their equipment, one with the other, in their bilateral operating agreements. However, the IMO assesses the individual plans of each market participant from an integrated perspective. The results of the IMO's integrated assessment are intended to provide information to participants to assist in identifying opportunities for further coordination or by suggesting changes in timing to mitigate reliability concerns. Positive Reserve Margins indicate periods

where generators could plan for additional outages or exports. Negative Reserve Margins indicate a potential dependence on additional external resources and suggest that generation impactful outages should be rescheduled to a more optimal time-period to restore the prescribed reserve levels.

External generation resources of up to 1,000 MW outside peak demand periods are reasonably expected to be available to offer into the Ontario market, in the case of resource shortfalls within Ontario, as a response to market prices. During Ontario summer peak demand periods of July and August, experience has shown that the remainder of the Northeastern systems of Canada and the United States are often also at their peak demand with both generation and transmission systems at their limits. Therefore no reliance is placed upon external generating capacity in July and August. This conservative approach is considered appropriate, and still provides opportunities for imports in the operating timeframe, as proven by recent summer 2001 experience. During winter peak periods, although Canadian systems face their highest demands, other Northeast systems often have spare capacity. External resources of up to 700 MW can usually be relied upon at winter peak periods. A recent load and capacity assessment study performed by the East Central Area Reliability Region (ECAR) forecasts, a Reserve Margin of about 2,600 MW at the time of the 2002 winter peak demand in Ontario.

Figure 4.1 18-Month Forecast of Resource Adequacy

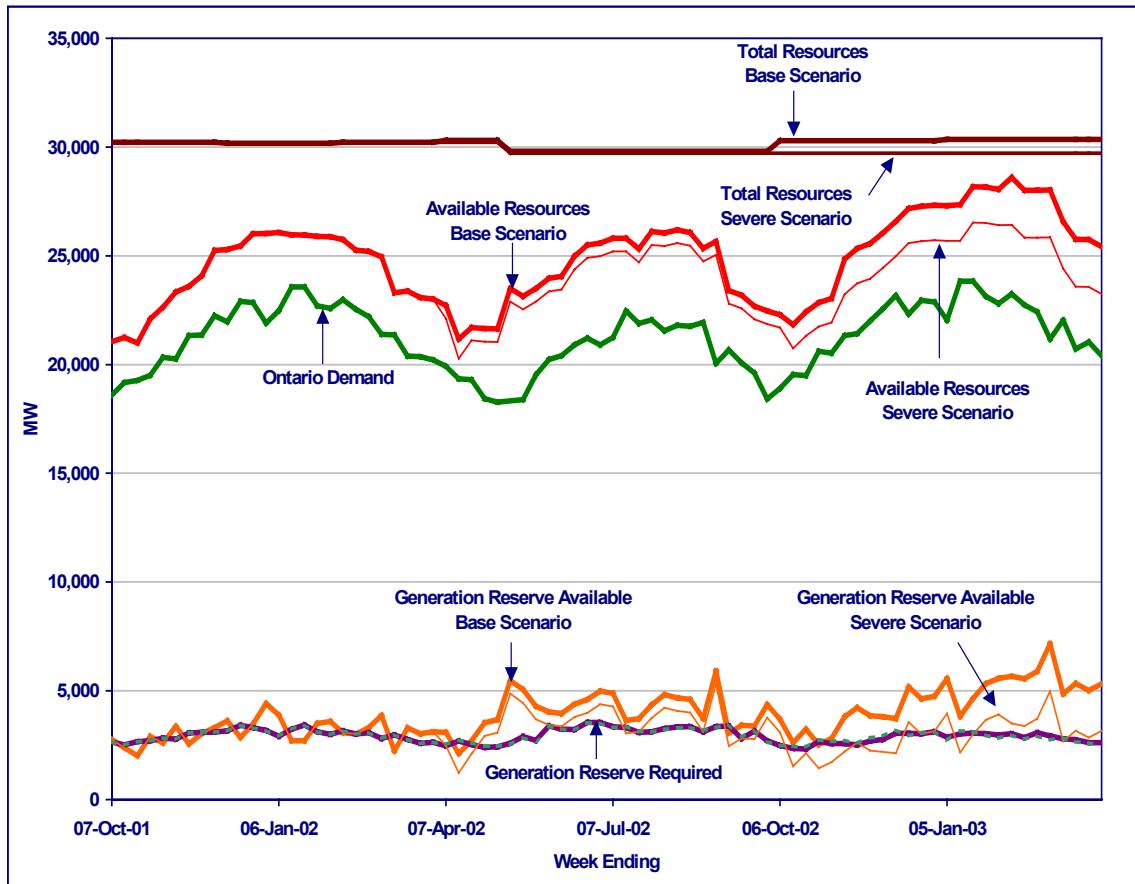
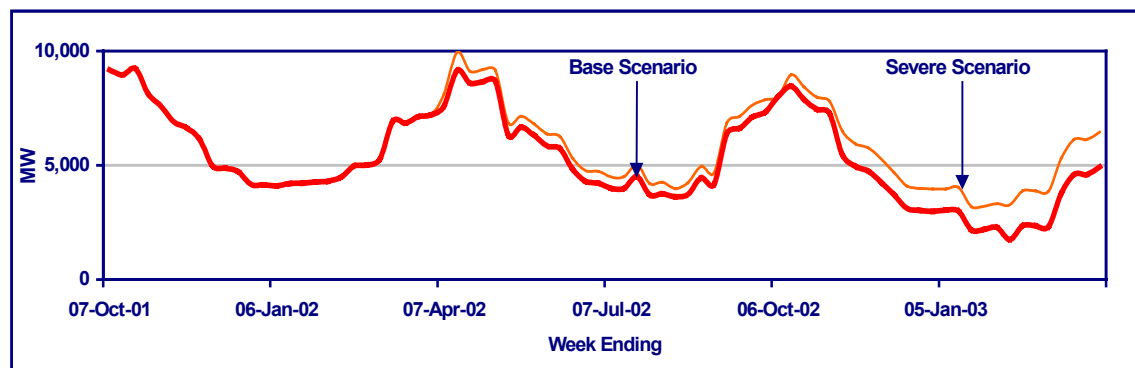


Figure 4.2 Total Reductions in Resources

**Note to Figure 4.2:**

Total Reductions in Resources represent, for each resource scenario, the sum of generator deratings, planned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity.

5.0 The Ontario Transmission System

5.1 Current Configuration of the Transmission System

The existing 500, 230 and 115 kV transmission network is shown in Appendix B.

Figures 5.1 and 5.2 provide a geographic depiction of Ontario's internal transmission zones, major transmission interfaces, and transmission interconnection points with other jurisdictions. Operating security limits for these interfaces and interconnections are also included in Figure 5.2. The interconnection and interface limits are used to ensure system stability, acceptable pre- and post-contingency voltage levels and/or thermal levels.

The total Ontario import/export capability is not the arithmetic sum of the individual interconnection flow limits. At best, the interconnections can carry coincident exports of up to 5,800 MW and coincident imports of up to 3,900 MW. The coincident export/import capabilities can be limited because of transfer limitations internal to Ontario and because of the combined transfer capability of the interconnections between Ontario, Michigan and New York.

The characteristics of the transmission zones, transfer interfaces and interconnections are described in Appendix D.

5.2 Changes/Updates to Transmission Projects from the Previous 18-Month Outlook

Committed transmission projects are summarized in Appendix D, Section D4 by transmission zone. The projects were taken from Hydro One's "24 Month Forecast of Milestone Dates for New BES Facilities" report, also simply referred to as the "milestone report", dated June 25, 2001. For the time period of this Outlook, Hydro One has committed transmission projects in all transmission zones except Bruce.

The milestone report contains several new committed projects with some of the committed projects identified in previous Outlooks no longer listed. Most of the changes are minor in nature and are not expected to significantly impact the operation of the IMO controlled – grid.

There is a committed transmission project associated with the incorporation of the TransAlta generating project in the West zone. The project involves the installation of two new 230 kV breakers, the replacement of four 115 kV breakers, and the retermination of radial 230 kV circuits N6S and L23N at Scott Transmission Station. In addition, a two kilometer section of 230 kV circuits N21W and N22W has to be upgraded. The expected in-service date of this project is October 2002.

Although not listed in the milestone report, the modification of the Ontario – Michigan interconnection is near completion. The remaining work associated with this project involves the incorporation of three phase shifters. For 230 kV circuit B3N, the Michigan 675 MVA phase shifter is available for service, but is currently bypassed from use. For 230 kV circuit L51D, the 845 MVA phase shifter at the Lambton Thermal Generating Station (TGS) has failed and is currently out of service. Prior to its failure, the operation of this phase shifter was restricted to neutral tap operation only. The expected return to service date is unknown at this time. For

230 kV circuit L4D, the 845 MVA phase shifter to be installed at Lambton TGS has expected in-service date of December 15, 2001. Phase shifting control of the Ontario – Michigan interconnection will only be utilized when all three phase shifters are in-service. At this time, there is uncertainty as to when this will happen because of the failed L51D phase shifter.

The last 18-month Outlook reported that the incorporation of the TransAlta and Michigan generating projects were going to increase fault levels at the Lambton 230 kV switchyard beyond the fault interrupting capabilities of the breakers. To alleviate this concern, the Outlook stated that the reconfiguration of some 230 kV circuits at the Lambton switchyard was required, to allow the Lambton 230 kV busbar to be operated “split”. Recent fault studies with revised equipment parameters have shown that the Lambton fault levels are not expected to be exceeded with these generating projects.

Figure 5.1 Ontario's Internal Transmission Zones

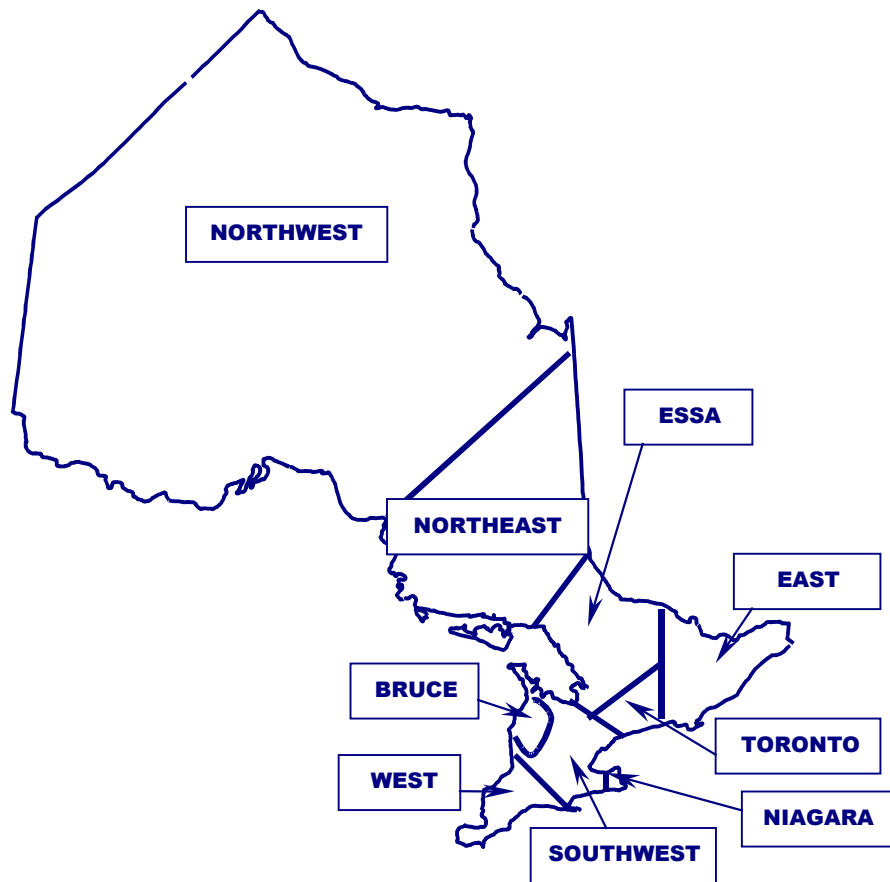
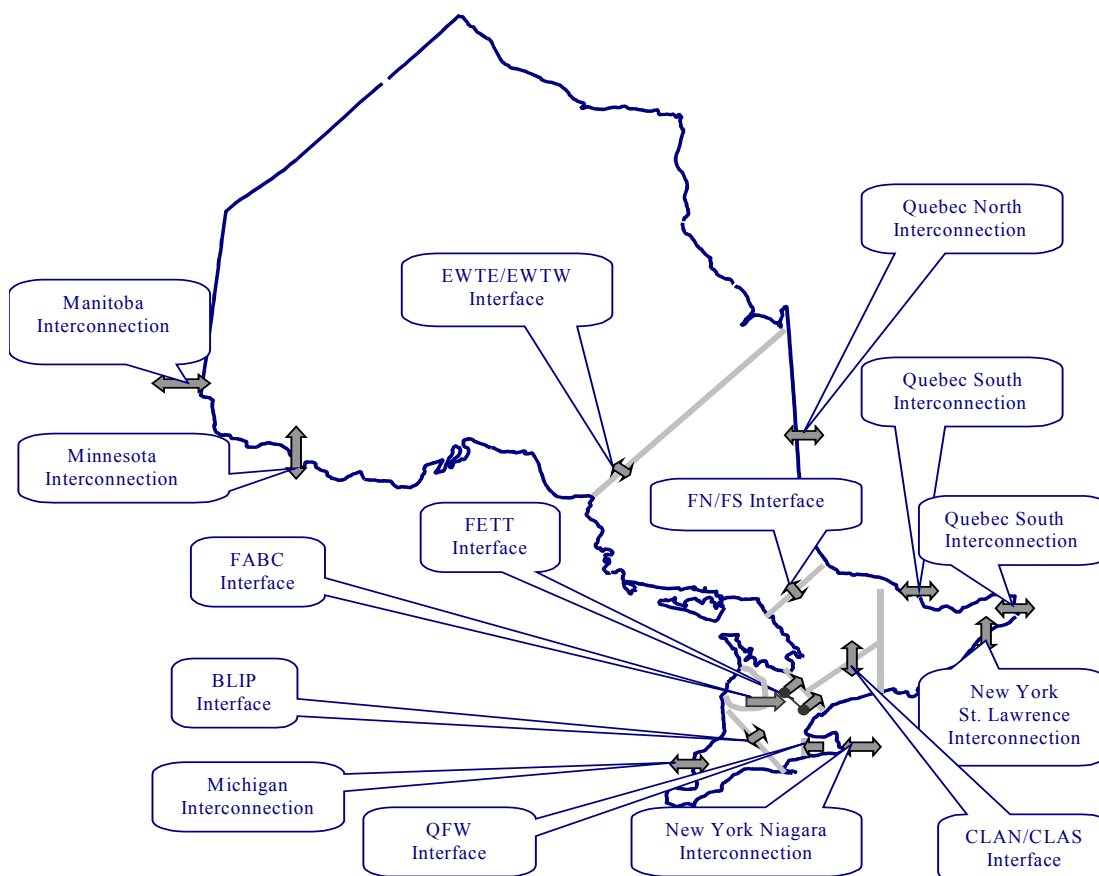


Figure 5.2 Ontario's Significant Internal Transfer Interfaces and Points of Interconnection With Neighbouring Areas**Interconnection****Manitoba****Minnesota****Quebec North****Quebec South****New York Niagara (60 Hz and 25 Hz)****New York St. Lawrence****Michigan****Flow Limit in MW**

Before January 30, 2002: 218 in, 163 out Summer / 259 in, 190 out Winter

After January 30, 2002: 343 in, 288 out Summer / 369 in, 300 out Winter

100 in, 150 out

64 in, 107 out Summer / 78 in, 115 out Winter

1,328 in, 432 out Summer / 1,328 in, 452 out Winter

1,400 in, 2,100 out Summer / 1,650 in, 2,100 out Winter

400 in, 400 out

Before PS I/S: 1,500 in, 2,350 out Summer / 1,600 in, 2,400 out Winter

After PS I/S: 1,650 in, 2,450 out Summer / 1,750 in, 2,700 out Winter

Transmission Transfer Interface**East-West Tie East (EWTE)****East-West Tie West (EWTW)****Flow North (FN)****Flow South (FS)****Claireville North (CLAN)****Claireville South (CLAS)****Flow Away From the Bruce Complex (FABC)****Buchanan Longwood Input (BLIP)****Negative BLIP (NBLIP)****Queenston Flow West (QFW)****Flow East to Toronto (FETT)****Base Limit in MW**

325

350

1,900

1,400

2,000

1,000

5,200, normally not limiting

3,500

1,500

1,800 Summer / 2000 Winter

5,700; 5,500 Summer if Ontario Demand (OD) between 22,001

and 22,600 MW; 5,300 Summer if OD between 22,600 and 25,000

MW; 5,100 Summer if OD between 25,001 MW and 26,000 MW

6.0 Transmission Adequacy Assessment

The principal purpose of this transmission adequacy assessment is to identify any transmission system reliability concerns within the 18-month period of this Outlook and to highlight transmission outages that should be rescheduled or coordinated with generation outages to mitigate those concerns.

At this time, Hydro One is the largest transmitter in Ontario and is the only transmitter considered in this Outlook. On a monthly basis, Hydro One submits to the IMO an 18-month rolling outage plan detailing planned transmission outages. For this Outlook, the Hydro One outage plan submitted on June 15, 2001 was used.

Transmitters and generators are expected to have a mutual interest in developing an ongoing arrangement to coordinate their outage planning activities. The IMO has an obligation under the market rules to review the integrated plans of generators and transmitters to identify situations that may adversely impact the operation of the system and to notify the affected participants of these impacts.

The scope of the transmission assessment for this report is outlined in Section 6.1. The primary assessment is contained in Section 6.2, while voltage and other concerns that may impact on system operation in the study period are outlined in Sections 6.3 and 6.4. A summary of the adequacy of the transmission system is provided in Section 7.

6.1 Scope of Transmission Assessment

Hydro One's transmission outage plan is shown in Appendix D, Tables D5.1 to D5.9 for each transmission zone. The outage plan includes outages for transmission facilities with voltage levels of 115 kV and higher and with a duration longer than 5 days. The following items are listed for each outage, with items one to four having been provided by Hydro One:

- 1) Start and finish dates,
- 2) Description of outaged transmission element or elements,
- 3) Outage type (DNW - Daily Not Weekends; DWW - Daily With Weekends; CNW - Continuous Not Weekends; CWW - Continuous With Weekends),
- 4) Recall time,
- 5) Description of outage impact to IMO-controlled grid, and
- 6) Reduction in the interconnection flow limits and/or major interface base limits (expressed in Megawatts).

Items 5 and 6 are only provided if the outage affects to an interconnection and/or interface which has been defined in Appendix D, Sections D2 and D3. For these outages, if the recall time is greater than 36 hours and if the limit is penalized greater than 10%, there is an additional assessment, as required, to indicate the potential for constrained generation, the impact on generation reserve requirements and any local minimum generation requirements.

6.2 Assessment of Transmission Outage Plan

The IMO's assessment of the impact of the transmission outage plan provided by Hydro One is shown in Appendix D, Tables D5.1 to D5.9. In these tables, each element in Hydro One's outage plan is assessed individually by indicating the possible impacts and the reduction in transmission interface and/or interconnection limits.

Outages that may affect interconnection support or generation access to the IMO-controlled grid should be coordinated with the generator owners involved, especially at times when generation reserve margins are below required levels.

In summary, only a few of the planned outages will potentially impact the dispatch of generation. A further analysis of overlapping outages did not result in the identification of any further impacts. The outages with the highest potential impact are listed below:

Northeast Transmission Zone

The 115 kV LIS circuit outage from July 10, 2001 to December 14, 2001 affects the Quebec North interconnection. However, the outage is not expected to be limiting.

Toronto Transmission Zone

There are several concurrent outages that affect the FETT interface starting in September 2001 to mid-November 2001. The expected Ontario demand during this time period is not expected to create high FETT energy flows on this interface. Therefore, the outages are not expected to be limiting. Any requirement for additional FETT impactive outages during this time period may be restricted.

It is recognized by the IMO that there will be additional outage requirements and/or changes identified by Hydro One as time approaches the Outlook study period. New requirements and/or changes to the outage plan will be assessed at that time for system impacts.

6.3 System Voltage and Thermal Concerns

Low system voltage concerns in certain sub-areas of the province will limit the generation and transmission outages that can be planned during summer peak demand periods. The various system voltage concerns are described below.

In the Windsor area, load growth will continue to stress the capability of the existing system under extreme-weather, summer peak conditions, such that voltages are expected to be near the low end of the acceptable range even with most static reactive sources in-service. In addition, maintaining acceptable voltage levels may require restrictions on the use of the J5D interconnection for exporting power to Michigan. For summer peak demands exceeding 25,000 MW, maintaining acceptable voltage levels may require the use of the J5D interconnection for importing power from Michigan. This requirement was experienced during the August 2001 peak demands that exceeded 25,000 MW. Planned outages to generating units or transmission circuits in the Windsor and Sarnia area should therefore be avoided during summer peak periods.

During the August 2001 peak demands exceeding 25,000 MW, pre-contingency voltage levels in the Toronto zone were acceptable but with little margin for contingencies. The reactive requirement to maintain voltage levels at or above the minimum required levels was very high.

Most static reactive resources and transmission elements were required in-service; in addition, the Lakeview, Pickering and Darlington units had to supply higher than normal amounts of reactive power. The high demand for reactive power left significantly lower than normal reactive margin for contingencies. The performance of these units in providing reactive power to maintain acceptable voltage levels in the Toronto zone during summer peak periods is extremely important. Restrictions on the use of the reactive capability of the Lakeview, Pickering and Darlington units during summer peak conditions would increase the need for additional reactive supply in the Greater Toronto Area. Planned outages to these units should be scheduled outside the summer peak periods.

High thermal loadings were also observed during the August 2001 hot weather conditions. With some local generating facilities operating at less than full output, the 500/230 kV autotransformers located at the Cherrywood Transmission Station in the Toronto zone were operated at power levels near, but below their continuous ratings.

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

6.4 Forced Outages

Due to a forced outage, the Whiteshell T8 transformer in Manitoba is currently unavailable until January 30, 2002. This has reduced the transfer capability between Manitoba and Ontario. The outage also reduces the East-West tie capability, in the order of 50 to 100 MW, further reducing dispatching flexibility in the Northwest zone and requiring more coordination in the planning of transmission and generation outages.

The T4 autotransformer at the Longwood Transmission Station in the West zone has been forced out of service until December 31, 2001. This outage penalizes the FABC interface limit by 50 MW, but is not considered restrictive.

7.0 Overall Findings and Conclusions

An assessment of the adequacy of transmission and generation resources in the Ontario electricity system has been carried out for the period from October 2001 through March 2003. The assessment is based on a forecast of electricity demand and available supply combined with current information on the configuration and capability of the transmission system. The most recent known outage plans of generators and transmitters, as well as information related to proposed transmission and generation facilities additions are incorporated in the assessment.

- Adequate generation resources exist for the study period. Loss of Load Expectation, (LOLE) is within the NPCC resource adequacy standard.
- Under the Base Scenario, opportunities for additional generator outages exist in May, June, November and December 2002, as well as in February and March 2003.
- External resources are likely to be available during the few weeks in the assessment period for which negative Reserve Margins exceeding 500 MW are forecast. Neighbouring systems are outside their seasonal peak demand, and/or have sufficient spare generating capacity during such periods.
- Sufficient control actions are available to manage uncertainties in demand or resource levels, which might exceed the allowances covered by the Required Reserve.
- The transmission outage plan has been reviewed for system impacts. The plan is not expected to significantly constrain generation dispatch. Outages to transmission circuits in the Toronto zone are not expected to be limiting for the forecasted demand conditions.
- The forced outage of the Whiteshell T8 transformer will adversely impact Ontario Manitoba transfer capability and may at times limit dispatch flexibility in the Northwest zone. The forced outage of the Longwood T4 autotransformer is not expected to be restrictive.
- System voltage concerns during times of summer peak demands are expected to limit the flexibility for planning outages in the Toronto zone and Windsor area. The reactive capability of the Lakeview, Pickering and Darlington units is required to maintain voltage levels above the minimum required levels in the Toronto zone during summer peak conditions.
- Voltage concerns in the Thunder Bay area will continue to require reactive support from the rotating reactive resources in the area.

Appendix A – Electricity Demand Forecast

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1.0 Weather Scenarios

Normal weather is constructed on a weekly basis, starting on Monday and ending on Sunday. For each year of historical weather data the observations are therefore divided up into weeks. Each of the daily observations will be sorted from highest to lowest within each week for the entire 30-year weather history. Use temperature as an example, the average of the coldest day in Week 1 for each year from 1971 through to 2000 will become the coldest day of Week 1 of the Normal weather construct. The average of the next coldest day for each year of Week 1 will become the second coldest day of Week 1 of the Normal weather. This is repeated for all days, for all weeks in order to construct the Normal weather year. For summer values, the hottest days would be averaged to determine the hottest days within the Normal weather construct.

Using Normal weather for the forecast impacts energy demand less so than peak demand. Since recent history has exhibited milder winters and hotter summers, there has been a shift in energy consumption from winter to summer. Using Normal weather re-allocates some energy demand from the summer to the winter, more in line with the traditional weather patterns the system is subject to.

For the purposes of analysis and since Normal weather may not be experienced, two other weather scenarios are also generated. The Extreme weather scenario is generated using the same methodology as the Normal weather, but rather than using the whole 30 year history for each day the sample is restricted to the 5 most extreme observations for each day. Likewise, the Mild weather scenario utilizes the same methodology but restricts the historical sample to the 5 mildest days. Therefore, the Extreme weather scenario would have a colder winter and hotter summer relative to the Normal weather scenario and the Mild weather scenario would have a warmer winter and cooler summer compared to the Normal.

Load Forecast Uncertainty (LFU) is another approach to account for the uncertainty associated with variability in weather. LFU represents one standard deviation in peak demand due to weather variations. Unlike the weather scenarios, which are derived to provide point forecasts under different weather conditions, LFU is used to develop distributions of possible outcomes around those point forecasts. This allows for probabilistic resource adequacy assessments.

2.0 Energy Demand Forecast Details

Table A1 Weekly Zonal Energy Forecast, Normal Weather

Week Ending	(GWh)									
	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total System
7-Oct-01	151	205	461	115	788	114	15	497	301	2,646
14-Oct-01	149	207	461	115	789	113	15	493	297	2,639
21-Oct-01	148	217	487	121	833	116	15	511	300	2,749
28-Oct-01	147	223	495	123	847	118	15	517	300	2,786
4-Nov-01	153	219	500	124	855	119	15	518	309	2,812
11-Nov-01	156	226	507	126	866	121	16	529	316	2,862
18-Nov-01	156	226	524	130	895	119	16	539	314	2,919
25-Nov-01	157	229	530	132	906	121	16	545	319	2,955
2-Dec-01	157	232	532	138	907	120	17	553	320	2,976
9-Dec-01	159	236	542	158	917	121	17	564	321	3,035
16-Dec-01	158	241	549	161	930	121	17	567	321	3,064
23-Dec-01	160	242	560	164	948	122	17	573	325	3,111
30-Dec-01	148	235	538	157	911	115	16	542	314	2,976
6-Jan-02	163	242	548	161	935	121	17	555	324	3,066
13-Jan-02	167	251	585	172	1,000	126	18	594	339	3,254
20-Jan-02	168	254	594	175	1,015	126	18	601	341	3,293
27-Jan-02	168	249	560	165	957	125	17	584	335	3,162
3-Feb-02	165	247	572	168	977	124	17	582	330	3,182
10-Feb-02	165	247	574	169	980	125	18	592	335	3,205
17-Feb-02	165	242	562	165	960	124	17	583	331	3,149
24-Feb-02	164	239	553	163	945	125	17	579	332	3,118
3-Mar-02	162	237	551	162	942	124	17	569	325	3,091
10-Mar-02	159	231	540	159	923	123	17	564	325	3,042
17-Mar-02	157	228	527	155	901	122	17	553	316	2,975
24-Mar-02	154	225	516	152	881	122	16	548	315	2,929
31-Mar-02	149	222	483	142	826	117	16	523	296	2,773
7-Apr-02	147	229	497	126	857	122	16	537	304	2,835
14-Apr-02	149	216	488	124	841	117	16	520	305	2,776
21-Apr-02	147	209	477	121	822	117	15	517	301	2,726
28-Apr-02	143	200	470	119	810	115	15	505	297	2,673
5-May-02	144	197	465	118	802	115	15	502	298	2,656
12-May-02	142	193	463	117	799	114	15	499	297	2,639
19-May-02	139	198	457	116	788	113	15	493	293	2,610
26-May-02	138	190	454	115	782	113	15	492	294	2,593
2-Jun-02	140	193	465	116	796	119	15	507	315	2,667
9-Jun-02	142	189	481	117	812	118	15	515	317	2,706
16-Jun-02	139	180	485	118	819	119	15	517	327	2,719
23-Jun-02	141	180	505	123	853	120	16	529	329	2,796
30-Jun-02	140	181	515	125	869	122	16	530	335	2,833

Notes to Table A1:

Figure may not add due to rounding.

Table A1 – continued

Week Ending	(GWh)									
	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total System
7-Jul-02	133	174	524	128	886	119	16	528	332	2,839
14-Jul-02	139	180	541	132	914	128	17	563	368	2,982
21-Jul-02	136	176	531	129	897	124	16	541	357	2,908
28-Jul-02	139	179	525	128	887	119	16	533	337	2,864
4-Aug-02	140	179	521	127	880	119	16	531	340	2,852
11-Aug-02	143	189	520	127	879	122	16	535	341	2,872
18-Aug-02	142	190	513	125	866	121	16	527	339	2,838
25-Aug-02	142	196	507	123	857	123	16	529	340	2,834
1-Sep-02	145	203	495	120	836	123	16	525	336	2,797
8-Sep-02	137	206	494	120	834	120	16	523	332	2,781
15-Sep-02	142	203	475	116	802	117	15	514	316	2,700
22-Sep-02	146	200	470	114	794	115	15	506	309	2,669
29-Sep-02	148	202	462	112	780	114	15	503	306	2,642
6-Oct-02	153	208	467	117	802	116	15	508	309	2,693
13-Oct-02	151	207	471	119	811	117	15	510	307	2,709
20-Oct-02	153	224	489	124	842	118	16	521	306	2,792
27-Oct-02	150	226	498	126	858	120	16	526	307	2,826
3-Nov-02	154	220	506	128	872	121	16	533	315	2,866
10-Nov-02	159	229	512	130	883	123	16	541	323	2,916
17-Nov-02	157	229	525	133	905	121	16	545	319	2,950
24-Nov-02	161	234	537	136	926	124	17	561	328	3,024
1-Dec-02	158	233	537	139	924	122	17	564	326	3,022
8-Dec-02	164	242	548	161	937	124	17	578	330	3,101
15-Dec-02	158	241	548	161	936	121	17	570	323	3,076
22-Dec-02	161	245	563	166	963	124	17	585	330	3,155
29-Dec-02	149	236	537	158	918	117	16	550	319	3,000
5-Jan-03	161	240	548	161	937	121	17	557	324	3,065
12-Jan-03	167	251	584	172	999	127	18	598	342	3,258
19-Jan-03	169	254	603	177	1,030	128	18	613	347	3,340
26-Jan-03	169	251	570	168	974	127	18	596	342	3,215
2-Feb-03	167	248	573	169	978	125	18	587	334	3,199
9-Feb-03	165	248	583	172	996	127	18	605	342	3,256
16-Feb-03	165	243	572	168	978	126	18	596	337	3,204
23-Feb-03	165	240	560	165	957	127	18	590	338	3,159
2-Mar-03	162	234	545	160	931	125	17	571	328	3,074
9-Mar-03	161	234	560	165	957	126	17	583	333	3,138
16-Mar-03	157	228	532	157	909	124	17	561	321	3,005
23-Mar-03	156	228	529	156	904	125	17	564	324	3,001
30-Mar-03	151	224	511	150	873	123	17	554	313	2,915

Notes to Table A1:

Figure may not add due to rounding.

3.0 Peak Demand Forecast Details

Table A2 Weekly Zonal Coincident Peak Demand Forecast, Normal Weather

Week Ending	20-Minute Coincident Peak Demand (MW)										Load Forecast Uncertainty
	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total System	
7-Oct-01	917	1,227	3,380	840	5,781	758	103	3,450	2,138	18,595	668
14-Oct-01	915	1,344	3,526	876	6,030	772	107	3,581	2,023	19,174	363
21-Oct-01	900	1,361	3,568	887	6,101	764	107	3,595	1,991	19,274	387
28-Oct-01	900	1,384	3,598	894	6,154	789	108	3,627	2,057	19,512	491
4-Nov-01	957	1,382	3,786	941	6,475	823	111	3,709	2,156	20,339	395
11-Nov-01	946	1,364	3,780	939	6,464	816	111	3,706	2,138	20,262	457
18-Nov-01	963	1,418	4,007	996	6,852	843	116	3,896	2,247	21,336	437
25-Nov-01	959	1,449	4,020	999	6,874	833	116	3,892	2,217	21,357	569
2-Dec-01	971	1,500	4,167	1,035	7,125	857	124	4,152	2,318	22,248	464
9-Dec-01	983	1,481	4,101	1,200	6,942	849	121	4,044	2,252	21,972	653
16-Dec-01	1,005	1,544	4,296	1,257	7,270	863	126	4,234	2,310	22,905	747
23-Dec-01	989	1,526	4,297	1,257	7,272	869	125	4,180	2,326	22,842	713
30-Dec-01	985	1,511	4,088	1,196	6,919	846	119	3,990	2,255	21,909	774
6-Jan-02	1,023	1,547	4,184	1,231	7,149	860	121	4,068	2,298	22,480	657
13-Jan-02	1,012	1,557	4,465	1,314	7,629	866	127	4,244	2,353	23,567	748
20-Jan-02	1,030	1,541	4,446	1,308	7,596	874	128	4,280	2,361	23,564	953
27-Jan-02	1,039	1,539	4,209	1,239	7,192	868	124	4,151	2,342	22,701	804
3-Feb-02	1,019	1,543	4,204	1,237	7,183	836	124	4,152	2,292	22,590	689
10-Feb-02	992	1,495	4,299	1,265	7,346	848	128	4,276	2,331	22,980	721
17-Feb-02	997	1,518	4,217	1,241	7,206	832	124	4,156	2,248	22,540	599
24-Feb-02	1,003	1,503	4,085	1,202	6,979	849	124	4,156	2,308	22,208	770
3-Mar-02	1,130	1,741	3,795	1,117	6,484	881	116	3,869	2,256	21,387	705
10-Mar-02	1,003	1,394	3,906	1,150	6,674	868	118	3,954	2,303	21,370	724
17-Mar-02	1,042	1,597	3,652	1,075	6,240	832	111	3,720	2,118	20,387	740
24-Mar-02	967	1,399	3,703	1,090	6,327	833	112	3,752	2,178	20,361	551
31-Mar-02	984	1,418	3,637	1,070	6,215	829	113	3,797	2,142	20,206	650
7-Apr-02	913	1,362	3,657	925	6,302	824	111	3,716	2,114	19,924	496
14-Apr-02	964	1,312	3,487	882	6,008	806	109	3,644	2,138	19,350	526
21-Apr-02	942	1,291	3,505	887	6,040	796	109	3,648	2,088	19,306	425
28-Apr-02	887	1,204	3,355	849	5,781	771	103	3,463	2,022	18,434	511
5-May-02	872	1,237	3,317	839	5,715	761	102	3,419	2,011	18,274	593
12-May-02	1,005	1,461	3,227	816	5,560	784	100	3,349	2,029	18,332	640
19-May-02	1,013	1,476	3,229	817	5,564	779	102	3,404	2,007	18,390	1,000
26-May-02	1,030	1,543	3,415	864	5,885	848	105	3,509	2,316	19,516	826
2-Jun-02	1,072	1,508	3,558	866	6,010	927	107	3,568	2,622	20,237	1,372
9-Jun-02	1,092	1,487	3,607	878	6,093	901	111	3,706	2,528	20,403	1,234
16-Jun-02	931	1,196	3,876	943	6,547	884	116	3,869	2,537	20,900	1,174
23-Jun-02	871	1,074	3,970	966	6,706	914	116	3,891	2,706	21,215	1,386
30-Jun-02	1,007	1,353	3,720	905	6,284	936	117	3,910	2,671	20,904	1,381

Notes to Table A2:

Load Forecast Uncertainty (LFU) is one standard deviation in system peak demand due to variations in weather.

Table A2 - continued

Week Ending	20-Minute Coincident Peak Demand (MW)										Load Forecast Uncertainty
	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total System	
7-Jul-02	886	1,257	4,033	982	6,812	844	115	3,842	2,466	21,237	1,165
14-Jul-02	955	1,331	4,043	984	6,829	1,010	123	4,111	3,088	22,474	1,093
21-Jul-02	831	1,056	4,091	996	6,911	951	120	4,032	2,909	21,896	961
28-Jul-02	863	1,102	4,246	1,033	7,172	870	120	4,018	2,635	22,060	977
4-Aug-02	1,018	1,385	3,990	971	6,740	870	117	3,906	2,545	21,542	1,110
11-Aug-02	979	1,352	3,992	972	6,743	953	119	3,971	2,727	21,807	1,166
18-Aug-02	892	1,180	4,145	1,009	7,001	878	117	3,917	2,626	21,764	1,177
25-Aug-02	972	1,270	4,136	1,007	6,987	901	117	3,933	2,620	21,943	1,022
1-Sep-02	948	1,282	3,678	895	6,212	843	110	3,680	2,398	20,046	1,242
8-Sep-02	922	1,296	3,795	924	6,410	864	116	3,892	2,445	20,662	1,360
15-Sep-02	972	1,344	3,672	894	6,202	838	112	3,761	2,291	20,085	890
22-Sep-02	960	1,288	3,589	874	6,063	812	109	3,663	2,259	19,617	1,229
29-Sep-02	1,048	1,476	3,248	791	5,487	787	101	3,382	2,093	18,413	858
6-Oct-02	958	1,305	3,431	835	5,795	812	105	3,507	2,157	18,905	714
13-Oct-02	1,093	1,584	3,444	871	5,936	825	107	3,583	2,088	19,531	328
20-Oct-02	1,049	1,633	3,452	873	5,949	819	106	3,559	2,047	19,490	372
27-Oct-02	1,126	1,814	3,601	911	6,205	887	110	3,683	2,281	20,618	486
3-Nov-02	1,097	1,726	3,660	926	6,307	843	111	3,708	2,141	20,519	427
10-Nov-02	1,162	1,824	3,779	956	6,512	894	113	3,800	2,299	21,339	479
17-Nov-02	1,004	1,469	3,941	997	6,792	863	118	3,962	2,269	21,415	356
24-Nov-02	1,186	1,839	3,915	991	6,747	901	119	3,972	2,338	22,008	493
1-Dec-02	1,077	1,531	4,149	1,050	7,150	890	125	4,193	2,397	22,563	491
8-Dec-02	1,228	2,000	4,121	1,213	7,041	912	124	4,155	2,373	23,166	757
15-Dec-02	1,028	1,537	4,120	1,212	7,039	842	123	4,104	2,317	22,321	745
22-Dec-02	1,092	1,588	4,167	1,226	7,120	907	127	4,257	2,470	22,955	732
29-Dec-02	1,190	1,926	4,101	1,207	7,007	897	122	4,091	2,339	22,880	844
5-Jan-03	1,117	1,501	4,064	1,196	6,944	854	117	3,934	2,322	22,050	633
12-Jan-03	1,008	1,548	4,519	1,330	7,722	885	129	4,305	2,382	23,827	706
19-Jan-03	1,030	1,537	4,502	1,325	7,692	885	130	4,337	2,390	23,827	813
26-Jan-03	1,018	1,548	4,336	1,276	7,408	873	125	4,197	2,370	23,151	770
2-Feb-03	1,001	1,518	4,274	1,258	7,303	854	124	4,143	2,322	22,796	703
9-Feb-03	990	1,498	4,347	1,279	7,428	864	130	4,343	2,360	23,240	737
16-Feb-03	982	1,524	4,266	1,255	7,289	835	125	4,192	2,275	22,745	606
23-Feb-03	988	1,508	4,133	1,216	7,063	852	125	4,191	2,335	22,413	853
2-Mar-03	955	1,457	3,910	1,151	6,681	815	117	3,906	2,179	21,171	701
9-Mar-03	970	1,468	4,150	1,221	7,091	811	121	4,044	2,156	22,033	716
16-Mar-03	951	1,420	3,793	1,116	6,480	810	116	3,885	2,154	20,724	710
23-Mar-03	936	1,424	3,868	1,138	6,610	818	118	3,946	2,175	21,034	555
30-Mar-03	911	1,399	3,760	1,107	6,425	803	113	3,792	2,088	20,396	640

Table A3 Weekly Zonal Non-Coincident Peak Demand Forecast, Normal Weather

Week Ending	20-Minute Non-Coincident Peak Demand (MW)									
	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
7-Oct-01	941	1,398	3,406	846	5,824	763	106	3,476	2,138	18,898
14-Oct-01	931	1,398	3,530	877	6,036	796	107	3,581	2,199	19,455
21-Oct-01	923	1,496	3,568	887	6,101	786	107	3,595	2,051	19,514
28-Oct-01	910	1,499	3,601	895	6,159	798	109	3,627	2,057	19,655
4-Nov-01	962	1,523	3,786	941	6,475	823	112	3,722	2,156	20,500
11-Nov-01	979	1,535	3,780	939	6,464	824	111	3,725	2,171	20,528
18-Nov-01	978	1,502	4,007	996	6,852	843	116	3,898	2,247	21,439
25-Nov-01	999	1,592	4,020	999	6,874	835	116	3,896	2,217	21,548
2-Dec-01	979	1,579	4,167	1,035	7,125	857	124	4,152	2,318	22,336
9-Dec-01	1,000	1,619	4,101	1,200	6,942	849	120	4,045	2,273	22,149
16-Dec-01	1,005	1,636	4,296	1,257	7,270	863	129	4,252	2,310	23,018
23-Dec-01	994	1,652	4,297	1,257	7,272	869	126	4,189	2,333	22,989
30-Dec-01	995	1,672	4,088	1,196	6,919	846	119	3,990	2,255	22,080
6-Jan-02	1,034	1,679	4,184	1,231	7,149	860	122	4,074	2,308	22,641
13-Jan-02	1,032	1,687	4,465	1,314	7,629	866	127	4,257	2,362	23,739
20-Jan-02	1,039	1,703	4,446	1,308	7,596	874	130	4,311	2,379	23,786
27-Jan-02	1,045	1,645	4,223	1,243	7,215	868	124	4,189	2,357	22,909
3-Feb-02	1,041	1,656	4,218	1,241	7,208	850	124	4,152	2,297	22,787
10-Feb-02	1,021	1,647	4,299	1,265	7,346	855	128	4,276	2,331	23,168
17-Feb-02	1,019	1,598	4,217	1,241	7,206	839	125	4,156	2,257	22,658
24-Feb-02	1,011	1,663	4,114	1,211	7,030	849	123	4,156	2,308	22,465
3-Mar-02	1,165	1,757	3,864	1,137	6,602	881	117	3,873	2,256	21,652
10-Mar-02	1,177	1,702	3,906	1,150	6,674	875	118	3,954	2,303	21,859
17-Mar-02	1,081	1,645	3,682	1,084	6,292	832	113	3,768	2,133	20,630
24-Mar-02	1,098	1,666	3,727	1,097	6,368	853	115	3,771	2,178	20,873
31-Mar-02	1,156	1,729	3,688	1,085	6,301	840	114	3,797	2,142	20,852
7-Apr-02	1,211	1,732	3,657	925	6,302	868	111	3,734	2,143	20,683
14-Apr-02	1,084	1,605	3,499	885	6,029	837	109	3,644	2,138	19,830
21-Apr-02	1,120	1,586	3,516	890	6,059	853	109	3,648	2,093	19,874
28-Apr-02	1,049	1,495	3,370	852	5,807	800	103	3,463	2,022	18,961
5-May-02	1,084	1,470	3,326	841	5,731	801	103	3,419	2,015	18,790
12-May-02	1,045	1,492	3,335	844	5,748	822	103	3,430	2,063	18,882
19-May-02	1,059	1,561	3,419	865	5,891	859	106	3,509	2,316	19,585
26-May-02	1,058	1,605	3,429	867	5,909	858	102	3,404	2,105	19,337
2-Jun-02	1,072	1,568	3,558	866	6,010	945	108	3,582	2,626	20,335
9-Jun-02	1,106	1,534	3,607	878	6,093	946	111	3,706	2,644	20,625
16-Jun-02	1,092	1,388	3,876	943	6,547	886	117	3,869	2,537	21,255
23-Jun-02	1,039	1,373	3,970	966	6,706	918	117	3,891	2,706	21,686
30-Jun-02	1,029	1,364	3,748	912	6,331	951	118	3,912	2,671	21,036

Table A3 - continued

Week Ending	20-Minute Non-Coincident Peak Demand (MW)									
	Northwest	Northeast	East	Essa	Toronto	Niagara	Bruce	Southwest	West	Total
7-Jul-02	922	1,284	4,035	982	6,816	858	115	3,847	2,466	21,325
14-Jul-02	1,019	1,408	4,100	998	6,926	1,029	125	4,182	3,088	22,875
21-Jul-02	1,121	1,491	4,107	1,000	6,937	956	120	4,032	2,916	22,680
28-Jul-02	1,144	1,527	4,247	1,034	7,174	885	121	4,018	2,635	22,785
4-Aug-02	1,069	1,407	3,992	972	6,742	889	117	3,906	2,566	21,660
11-Aug-02	1,165	1,648	4,017	978	6,785	967	119	3,971	2,727	22,377
18-Aug-02	1,113	1,576	4,147	1,009	7,005	938	117	3,924	2,626	22,455
25-Aug-02	1,060	1,522	4,139	1,007	6,991	913	119	3,971	2,684	22,406
1-Sep-02	1,012	1,528	3,682	896	6,220	852	110	3,696	2,398	20,394
8-Sep-02	1,129	1,677	3,795	924	6,410	879	117	3,892	2,468	21,291
15-Sep-02	1,059	1,585	3,674	894	6,206	843	112	3,761	2,325	20,459
22-Sep-02	1,129	1,518	3,589	874	6,063	823	109	3,663	2,259	20,027
29-Sep-02	1,112	1,544	3,340	813	5,642	801	105	3,483	2,158	18,998
6-Oct-02	1,154	1,593	3,448	852	5,824	812	106	3,516	2,235	19,540
13-Oct-02	1,212	1,637	3,466	877	5,972	846	108	3,612	2,173	19,903
20-Oct-02	1,115	1,693	3,464	876	5,970	819	109	3,559	2,106	19,711
27-Oct-02	1,126	1,814	3,601	911	6,205	888	110	3,683	2,281	20,619
3-Nov-02	1,153	1,726	3,660	926	6,307	843	112	3,732	2,188	20,647
10-Nov-02	1,182	1,824	3,779	956	6,512	894	114	3,829	2,299	21,389
17-Nov-02	1,141	1,780	3,941	997	6,792	876	118	3,962	2,331	21,938
24-Nov-02	1,188	1,839	3,942	997	6,793	901	120	4,037	2,345	22,162
1-Dec-02	1,257	1,893	4,149	1,141	7,150	908	126	4,193	2,397	23,214
8-Dec-02	1,228	2,000	4,121	1,213	7,041	912	124	4,155	2,385	23,179
15-Dec-02	1,148	1,853	4,120	1,212	7,039	864	124	4,157	2,343	22,860
22-Dec-02	1,141	1,893	4,202	1,237	7,179	907	128	4,257	2,470	23,414
29-Dec-02	1,190	1,926	4,126	1,214	7,051	897	122	4,091	2,366	22,983
5-Jan-03	1,117	1,675	4,109	1,209	7,022	854	120	4,012	2,322	22,440
12-Jan-03	1,029	1,678	4,519	1,330	7,722	885	128	4,320	2,390	24,001
19-Jan-03	1,042	1,684	4,502	1,325	7,692	885	131	4,372	2,407	24,040
26-Jan-03	1,052	1,700	4,336	1,276	7,408	873	126	4,232	2,370	23,373
2-Feb-03	1,050	1,644	4,274	1,258	7,303	859	124	4,182	2,322	23,016
9-Feb-03	1,018	1,682	4,347	1,279	7,428	871	131	4,343	2,360	23,459
16-Feb-03	1,034	1,642	4,268	1,256	7,293	851	127	4,192	2,287	22,950
23-Feb-03	1,013	1,650	4,162	1,225	7,112	853	127	4,191	2,337	22,670
2-Mar-03	1,019	1,561	3,910	1,151	6,681	832	119	3,949	2,217	21,439
9-Mar-03	989	1,613	4,150	1,221	7,091	827	122	4,044	2,232	22,289
16-Mar-03	969	1,547	3,812	1,122	6,514	820	115	3,885	2,170	20,954
23-Mar-03	966	1,524	3,868	1,138	6,610	826	119	3,951	2,187	21,189
30-Mar-03	935	1,542	3,774	1,111	6,449	817	115	3,880	2,119	20,742

4.0 Analytical Factors Affecting Demand

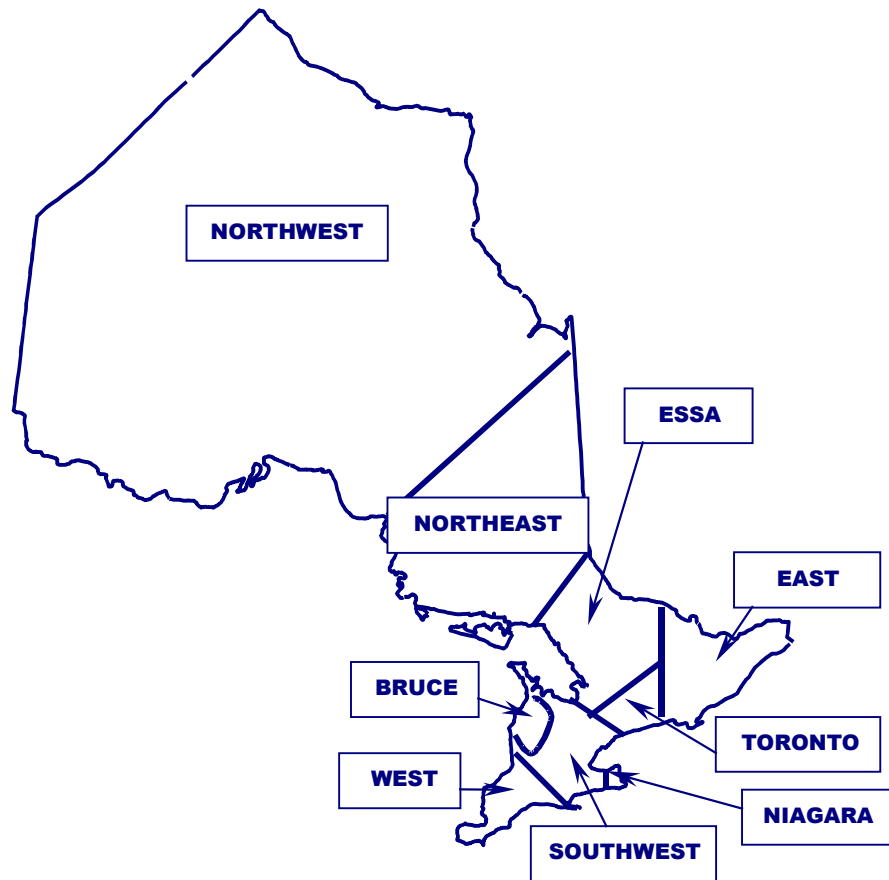
Table A4 Approximate Analytical Factors Affecting Demand

Factors Affecting Daily Energy Demand			
Variable Class	Variable	Change in Variable	Impact On Daily Energy Demand (MWh)
Weather	Daily Avg Temperature		
	> 16° C	1°C Increase	6,500 MWh Increase
	10°C > and < 16° C	1°C Increase	800 MWh Increase
	< 10°C	1°C Decrease	2,500 MWh Increase
	Daily Avg Humidity - Dewpoint		
	> 16° C	1°C Increase	2,400 MWh Increase
	10°C > and < 16° C	1°C Increase	300 MWh Increase
	< 10°C	1°C Decrease	900 MWh Increase
Economic	Employment	Increase of 1,000 jobs	20 MWh Increase
	Housing Stock	Increase of 1,000 Houses	30 MWh Increase
Calendar	Holidays	New Year's Day	58,000 MWh Decrease
		Good Friday	46,000 MWh Decrease
		Victoria Day	51,000 MWh Decrease
		Canada Day	2,200 MWh Decrease
		Simcoe Day	36,500 MWh Decrease
		Labour Day	54,000 MWh Decrease
		Thanksgiving Day	52,000 MWh Decrease
		Remembrance Day	700 MWh Increase
		Christmas	81,300 MWh Decrease
		Boxing Day	66,100 MWh Decrease
		New Year's Eve	31,500 MWh Decrease
	Day of Week	Monday vs Sunday	43,000 MWh Increase
		Tuesday vs Sunday	44,500 MWh Increase
		Wednesday vs Sunday	44,750 MWh Increase
		Thursday vs Sunday	44,500 MWh Increase
		Friday vs Sunday	41,750 MWh Increase
		Saturday vs Sunday	11,400 MWh Increase

Table A4 - continued

Factors Affecting Daily Peak Demand			
Variable Class	Variable	Change in Variable	Impact On Daily Peak Demand (MW)
Weather	Temperature		
	> 16° C	1°C Increase	375 MW Increase
	10°C > and < 16° C	1°C Increase	70 MW Increase
	< 10°C	1°C Decrease	110 MW Increase
	Humidity - Dewpoint		
	> 16° C	1°C Increase	140 MW Increase
	10°C > and < 16° C	1°C Increase	25 MW Increase
	< 10°C	1°C Decrease	40 MW Increase
Economic	Employment	Increase of 1,000 jobs	1 MW Increase
	Housing Stock	Increase of 1,000 Houses	2 MW Increase
Calendar	Holidays	New Year's Day	2,600 MW Decrease
		Good Friday	2,000 MW Decrease
		Victoria Day	2,300 MW Decrease
		Canada Day	250 MW Increase
		Simcoe Day	1,400 MW Decrease
		Labour Day	2,250 MW Decrease
		Thanksgiving Day	2,300 MW Decrease
		Remembrance Day	250 MW Decrease
		Christmas	4,500 MW Decrease
		Boxing Day	3,000 MW Decrease
		New Year's Eve	1,500 MW Decrease
	Day of Week	Monday vs Sunday	2,000 MW Increase
		Tuesday vs Sunday	1,900 MW Increase
		Wednesday vs Sunday	1,900 MW Increase
		Thursday vs Sunday	1,800 MW Increase
		Friday vs Sunday	1,600 MW Increase
		Saturday vs Sunday	250 MW Increase

Figure A1 Ontario's Internal Zones



Appendix B – Ontario Transmission System – Maps

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Figure B2 Northern Ontario Transmission System 50

Figure B3 Southern and Eastern Ontario Transmission System 51

Figure B1 Ontario Transmission System

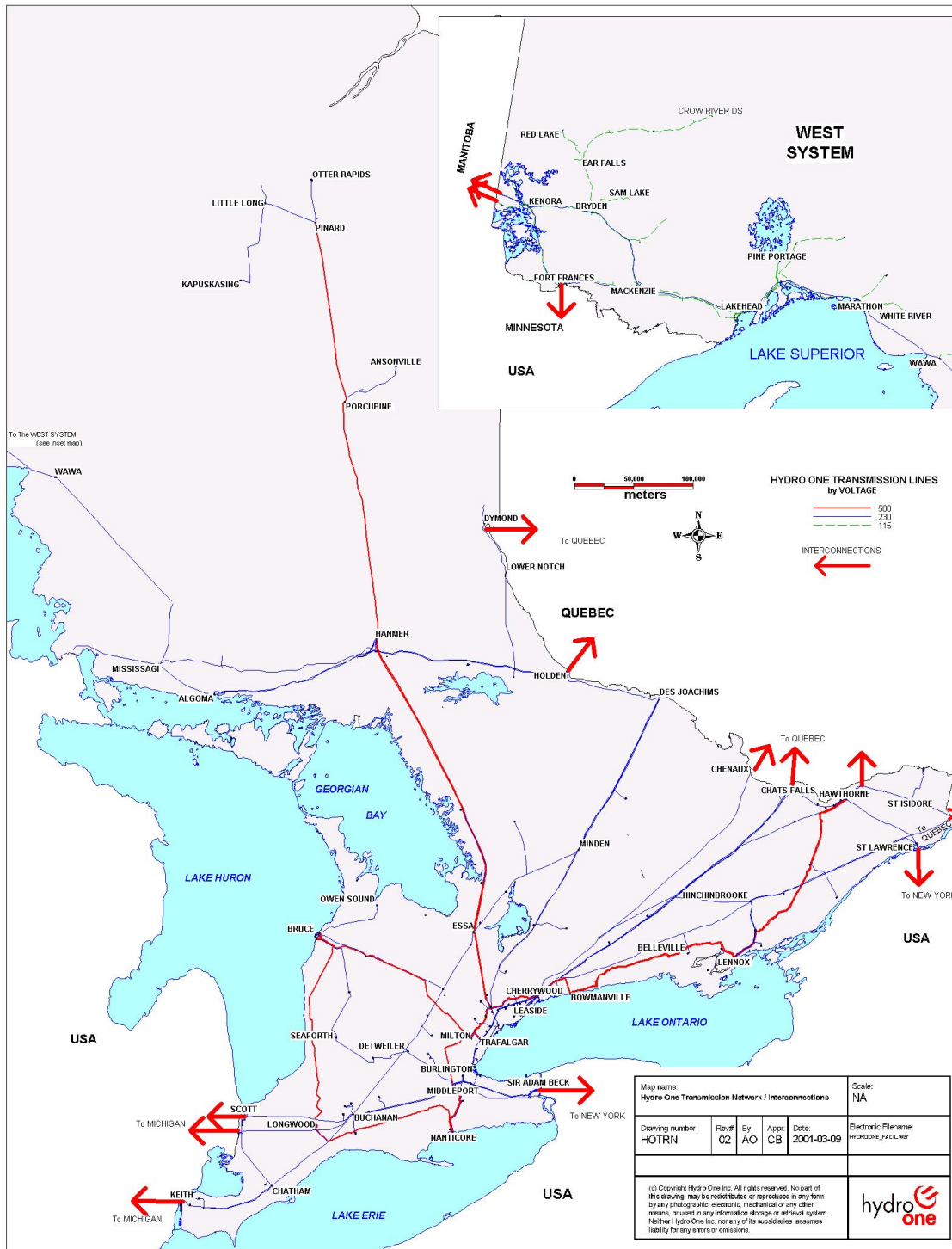


Figure B2 Northern Ontario Transmission System

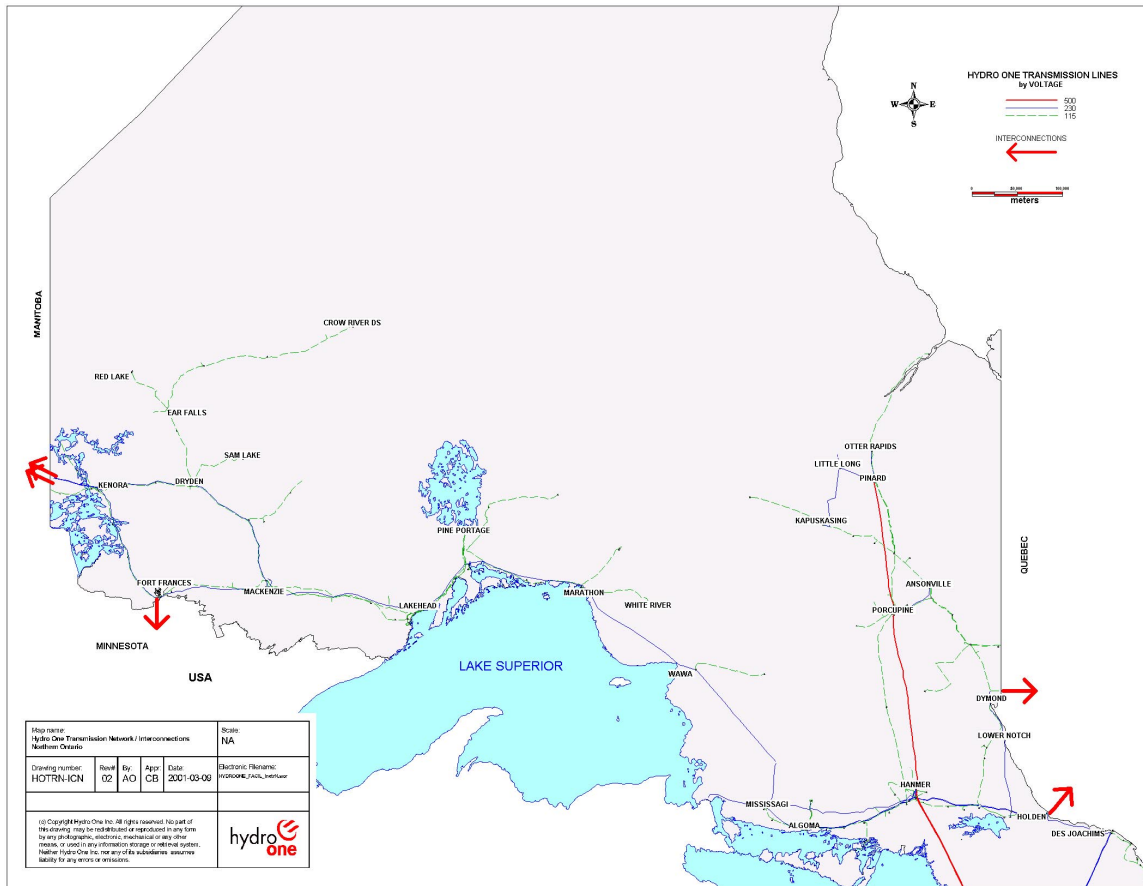
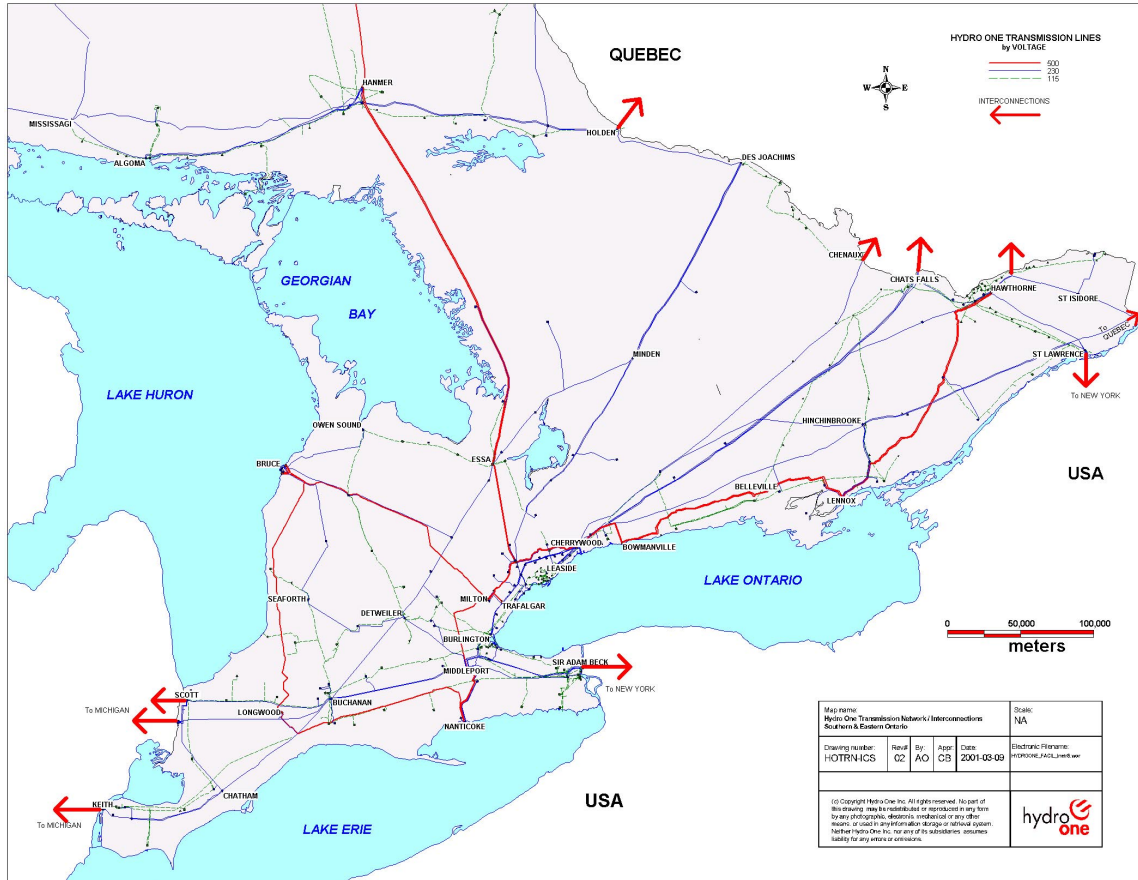


Figure B3 Southern and Eastern Ontario Transmission System



Appendix C – System Resources Details

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1.0 Resource Adequacy Assessment Methodology

1.1 Resource Adequacy Standard

The IMO, as a member of the NPCC, is expected to demonstrate that it can achieve the following resource adequacy standard:

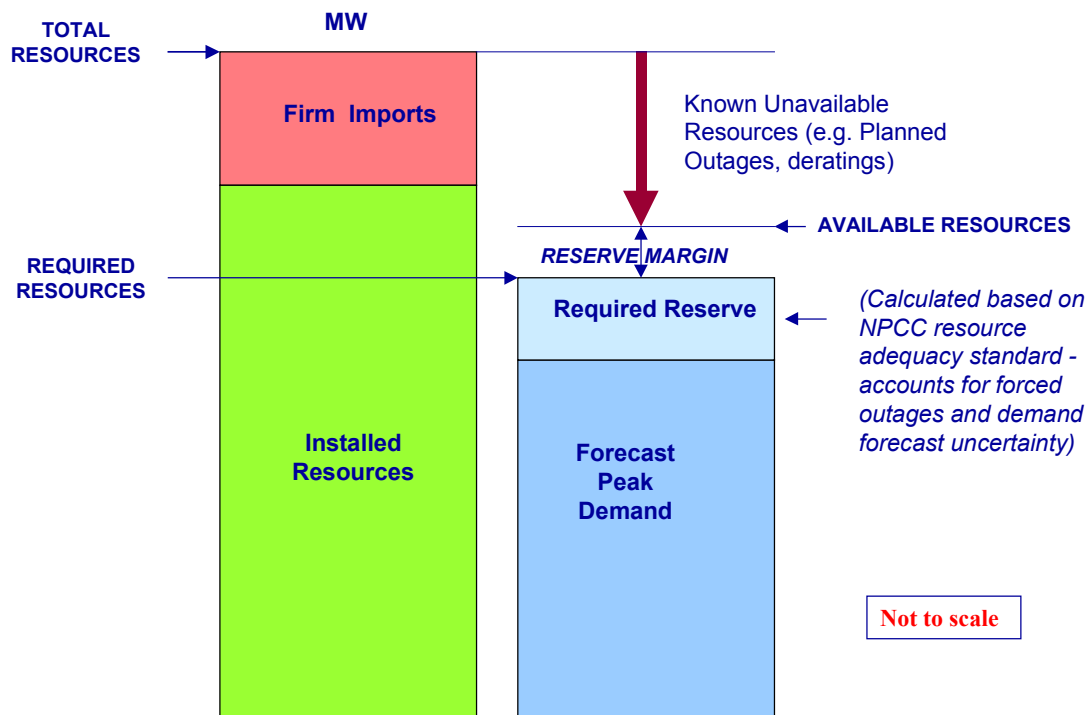
"...after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource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

The IMO employs an NPCC-accepted variation of this standard, which is a Loss of Load Expectation of not more than 0.1 days per year.

Reserve resources are required to ensure that the forecast demand can be supplied with a sufficiently high level of reliability. The amount of Required Reserve is calculated to meet the requirements of the NPCC resource adequacy standard. The Required Resources are the amount of resources required to supply the peak demand and meet the Required Reserve.

The Reserve Margin is the difference between Available Resources and Required Resources as illustrated in Figure C1.1.

Figure C1.1 Reserve Margin



It should be noted that the Required Reserve is a planning parameter. In day to day operation the available resources must cover the demand plus the Operating Reserve, which for Ontario is about 1,350 MW, depending on the size of the largest generating units in service.

1.2 Method Used to Assess Generation Resources Adequacy

1.2.1 Load and Capacity Model

The IMO uses a Load and Capacity (L&C) model to determine the Required Reserves from week to week. The mix of generating plant, generating unit forced outage rates, the demand forecast and its uncertainty are inputs to the model. A resource adequacy standard equivalent to an annual loss of load probability (LOLP) of 0.1 is used to determine the Reserve Requirement for each week of the planning year.

The probabilistic calculation of the Required Reserve for each planning week is performed as follows:

Based on the generating units' Maximum Continuous Ratings and Forced Outage Rates, a Capacity on Outage Probability Table is built, in which the probabilities of having various amounts of capacity on forced outage are determined and stored. A graphical example is provided in Figure C1.2.

In the Load and Capacity model, a normal distribution of demand values around the mean demand value is assumed. For each weekly 20-minute peak demand, as the mean value, and its Load Forecast Uncertainty (LFU), as the standard deviation, the model builds a multi-step approximation of the normal distribution. Figure C1.3 illustrates a seven-step example of such an approximation, using a weekly 20-minute peak value of 23,000 MW and an associated LFU value of 1,000 MW. Subsequently, in the calculation of the Required Reserve for each planning week, not only the mean value of the peak demand is included, but also a range of peak demand values, going from mild to extreme demand values. In Figure C1.3 for example, the peak values considered in the calculation of the Required Reserve would range from 20,000 MW to as high as 26,000 MW. Consequently, the calculated Required Reserve reflects not only the impact of the generation mix (generators size and failure rates) but also the impact of uncertainties in demand related to weather, by averaging the impact of the peak demand values around the forecast mean value, weighted by their associated probabilities of occurrence (shown in Figure C1.3 under the curve).

The Required Reserve calculation is executed in an iterative manner. In each iteration, an amount of Generation Reserve is assumed and an associated $LOLP_{CALC}$ is derived, convolving the LFU corresponding to the demand value modeled as described above, with the Capacity on Outage Probability Table. The iterative process is repeated with small changes to the assumed Generation Reserve until the $LOLP_{CALC}$ becomes equal or less than the target of 0.1. When this condition becomes true, the assumed level of Generation Reserve equals the Required Reserve necessary to meet the reliability target.

The adequacy of the available resources to meet the demand over the study period can then be assessed, in a deterministic calculation, as shown in Figure C1.1. For each planning week, the minimum level of Available Resources is determined, starting with the total resources then subtracting generator deratings, planned and long term unplanned generator outages, generation

constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity. The Reserve Margin is then obtained by subtraction of the Required Resources (equal to Demand plus the Required Reserve) from the minimum Available Resources.

Figure C1.2 Capacity on Outage Probability Table – Graphical Example

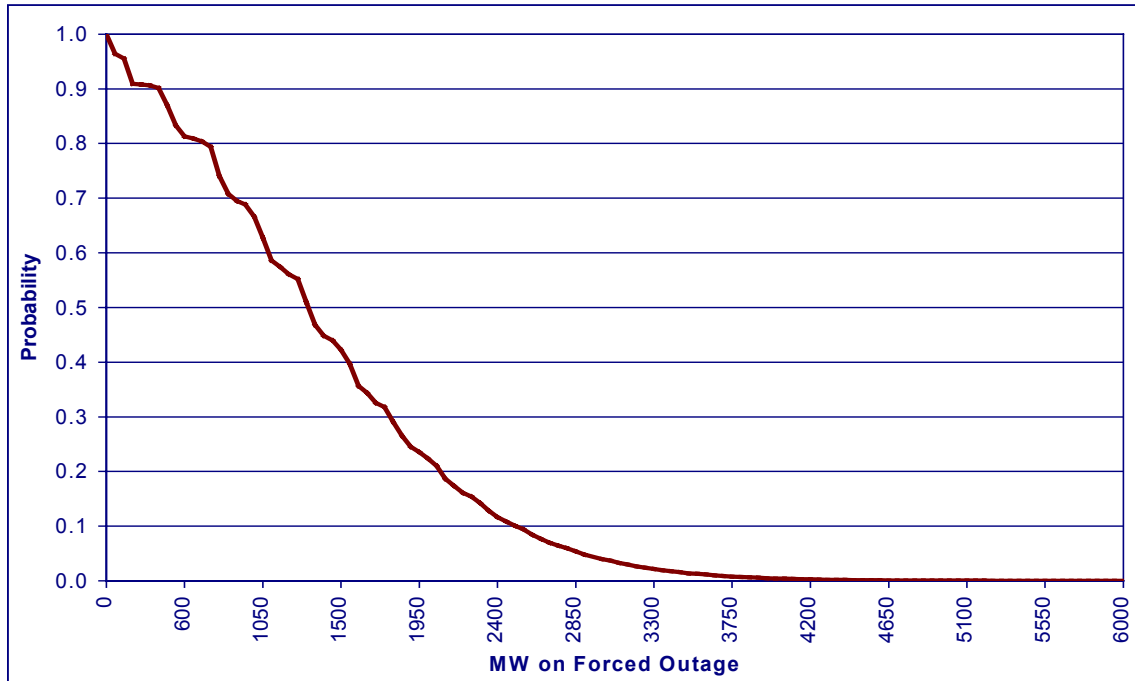
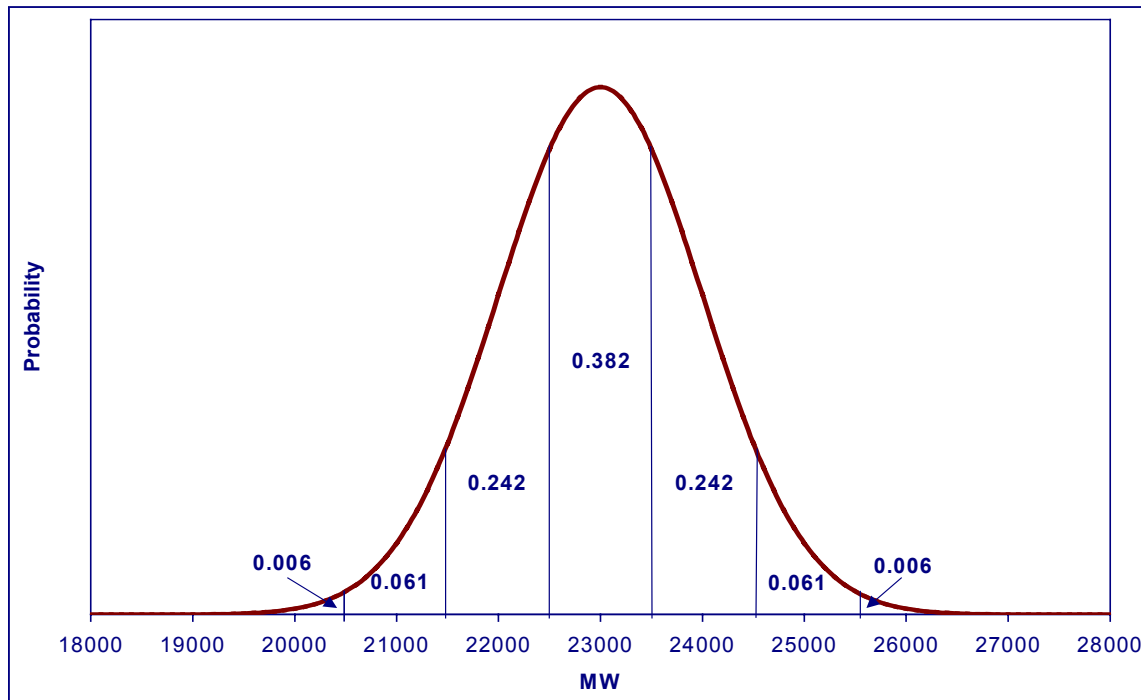


Figure C1.3 Seven-Step Approximation of Normal Distribution - Example

The actual LOLP for each planning week can then be calculated in a similar way as described above. This time the Available Generation Reserve is known, so the LOLP can be derived in one iteration, by convolving the LFU corresponding to the Demand value (normal distribution assumed) with the Capacity on Outage Probability Table. Finally the annual LOLE can be derived using the individual LOLPs from each of the component planning weeks. If the annual LOLE is less than or equal to 0.1, the NPCC resource adequacy standard is met, before even considering other actions available in day-to-day operation, such as interconnection assistance, emergency purchases, reductions of the operating reserve levels, voltage reductions, etc.

It should be noted that negative Reserve Margins in some weeks do not necessarily mean a violation of the NPCC resource adequacy standard. They only mean possible higher risk levels for the respective weeks. Whenever a negative Reserve Margin is identified, the available actions to restore the reserves to desired levels are assessed.

1.2.2 Representation of Demand and Its Uncertainty Due to Weather

Demand values include loads that can be dispatched off or otherwise interrupted in the case of a shortfall in reserves. For modeling purposes, the dispatchable demand was assumed to be supplied, and was included in the peak demand forecast when the Required Reserve was probabilistically calculated. At the deterministic assessment stage, dispatchable demands and interruptible loads were deducted from the peak demand. A value of 300 MW was assumed for interruptible or dispatchable demands based on past operational experience. The IMO expects to be in a better position to forecast dispatchable demand levels as Market Participant registration progresses and market experience is gained.

The total energy demand is split into weather and non-weather components. A normal distribution of weather swings, in any week, is provided by input of the associated standard

deviation. This data is obtained from 30-year weather statistics and is updated annually. The standard deviation of weather-related demand (Load Forecast Uncertainty or LFU) varies between about 2% and 7% through the year. The peak demand probability distribution (normal distribution assumed) in any week is available to the L&C program.

1.2.3 Representation of Generation Resources

Unit Ratings

Thermal generating units are assumed to be capable of operating at a level equal to their normal Maximum Continuous Rating (MCR) or as otherwise identified to the IMO. Hydroelectric station peak outputs are based on one hour sustainable capability determined from about 30 years of record; these values are provided by the generation plant owners. The peak and energy output of all combustion turbines varies considerably with changes in ambient air temperature and, hence, both summer and winter values are included.

Forced Outage Rates of Generating Units

Derating-Adjusted Forced outage rates that are used for each unit reflect both forced outages and periods of derated output. The values are provided by the generation plant owners, based on past experience modified to reflect forecast improvements from maintenance activities or declines due to age or need for repair.

1.2.4 Representation of Interconnected Systems

There are five interconnected systems that could provide additional resources to supply Ontario, namely, New York, Michigan, Quebec, Minnesota and Manitoba. Ontario total coincident import capability is approximately 3,900 MW.

Available Resource values include external resources backed by firm purchase contracts. The inclusion of only firm purchases in the assessment represents a conservative assumption. External generation of up to 1,000 MW outside peak demand periods is reasonably expected to be available to bid into the Ontario market, in the case of resource shortfalls, as a response to market prices. During winter peak periods, although Canadian systems face their highest demands, other Northeast systems often have spare capacity. External resources of up to 700 MW can usually be relied upon at winter peak periods. This assumption is supported by a recent load and capacity assessment study performed by the East Central Area Reliability Region (ECAR), which forecasts an ECAR Reserve Margin of about 2,600 MW at the time of the 2002 winter peak demand in Ontario. During Ontario summer peak demand periods of July and August, experience has shown that the summer peaking systems of NPCC are often also at their peak demand with both generation and transmission systems at their limits. Therefore no reliance is placed upon external generating capacity in July and August unless it is backed by firm purchase contracts.

1.2.5 Representation of Transmission System

The Ontario IMO-controlled grid consists of a robust southern grid and a sparse northern grid. The northwestern part of the northern grid has limitations, which potentially constrain-off generation capacity. Some 25-hz generation in Niagara zone is constrained-off by frequency changer capability. The total amount of the constrained-off generation varies between 0 and about 350 MW, depending on the load and resource levels, especially in the Northwest zone.

Constrained-off generation is subtracted from the Available Resources when calculating the Reserve Margins.

2.0 Resources Adequacy Assessment Tables

Table C2.1 Assessment of Resources Adequacy – Base Scenario

Week Ending Day	Primary Demand MW	Total Resources MW	Total Reductions in Resources MW	Available Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Margin MW
07-Oct-01	18,595	30,223	9,165	21,058	15.1	2,763	14.2	2,641	122
14-Oct-01	19,174	30,223	8,973	21,250	12.6	2,376	13.1	2,517	-141
21-Oct-01	19,274	30,223	9,232	20,991	10.6	2,017	13.8	2,657	-640
28-Oct-01	19,512	30,223	8,124	22,099	15.0	2,887	13.9	2,705	182
04-Nov-01	20,339	30,223	7,580	22,643	13.0	2,603	13.9	2,819	-216
11-Nov-01	20,262	30,223	6,896	23,327	16.9	3,365	13.7	2,770	595
18-Nov-01	21,336	30,223	6,629	23,594	12.2	2,558	14.3	3,056	-498
25-Nov-01	21,357	30,223	6,143	24,080	14.4	3,023	14.5	3,088	-65
02-Dec-01	22,248	30,223	4,968	25,255	15.1	3,307	13.9	3,101	206
09-Dec-01	21,972	30,173	4,883	25,290	16.7	3,618	14.3	3,152	466
16-Dec-01	22,905	30,173	4,718	25,455	12.6	2,850	14.9	3,404	-554
23-Dec-01	22,842	30,173	4,159	26,014	15.4	3,472	14.4	3,300	172
30-Dec-01	21,909	30,173	4,146	26,027	20.4	4,419	14.5	3,175	1,244
06-Jan-02	22,480	30,173	4,108	26,065	17.5	3,885	12.9	2,905	980
13-Jan-02	23,567	30,173	4,203	25,970	11.6	2,703	13.7	3,235	-532
20-Jan-02	23,564	30,173	4,211	25,962	11.6	2,698	14.5	3,418	-720
27-Jan-02	22,701	30,173	4,274	25,899	15.6	3,498	13.7	3,107	391
03-Feb-02	22,590	30,173	4,300	25,873	16.1	3,583	13.2	2,989	594
10-Feb-02	22,980	30,223	4,478	25,745	13.5	3,065	13.7	3,155	-90
17-Feb-02	22,540	30,223	4,967	25,256	13.6	3,017	13.4	3,010	7
24-Feb-02	22,208	30,223	5,020	25,203	15.0	3,295	13.8	3,065	230
03-Mar-02	21,387	30,223	5,275	24,948	18.3	3,861	13.1	2,808	1,053
10-Mar-02	21,370	30,223	6,928	23,295	10.6	2,225	13.9	2,974	-749
17-Mar-02	20,387	30,223	6,849	23,374	16.4	3,288	13.5	2,755	533
24-Mar-02	20,361	30,223	7,134	23,089	15.1	3,029	12.7	2,578	451
31-Mar-02	20,206	30,223	7,211	23,012	15.6	3,105	13.0	2,628	477
07-Apr-02	19,924	30,311	7,597	22,714	15.7	3,090	12.3	2,460	630
14-Apr-02	19,350	30,311	9,148	21,163	11.1	2,113	13.8	2,679	-566
21-Apr-02	19,306	30,311	8,599	21,712	14.2	2,705	13.1	2,525	180
28-Apr-02	18,434	30,311	8,660	21,651	19.4	3,517	13.0	2,393	1,124
05-May-02	18,274	30,311	8,666	21,645	20.4	3,671	13.2	2,419	1,252
12-May-02	18,332	29,811	6,308	23,503	30.3	5,471	14.1	2,576	2,895
19-May-02	18,390	29,811	6,672	23,139	27.9	5,049	15.7	2,888	2,161
26-May-02	19,516	29,811	6,314	23,497	22.3	4,281	13.9	2,715	1,566
02-Jun-02	20,237	29,811	5,846	23,965	20.2	4,027	16.7	3,381	646
09-Jun-02	20,403	29,811	5,746	24,065	19.7	3,961	15.8	3,220	741
16-Jun-02	20,900	29,811	4,825	24,986	21.3	4,386	15.4	3,219	1,167
23-Jun-02	21,215	29,811	4,301	25,510	22.0	4,595	16.7	3,542	1,053
30-Jun-02	20,904	29,811	4,220	25,591	24.2	4,988	16.9	3,539	1,449

(Table C2.1 continued)

Week Ending Day	Primary Demand MW	Total Resources MW	Total Reductions in Resources MW	Available Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Margin MW
07-Jul-02	21,237	29,811	3,997	25,814	23.3	4,877	15.7	3,343	1,534
14-Jul-02	22,474	29,811	4,004	25,807	16.4	3,633	14.7	3,303	330
21-Jul-02	21,896	29,811	4,499	25,312	17.2	3,715	14.1	3,087	628
28-Jul-02	22,060	29,811	3,703	26,108	20.0	4,348	14.1	3,119	1,229
04-Aug-02	21,542	29,811	3,751	26,060	22.7	4,817	15.1	3,261	1,556
11-Aug-02	21,807	29,811	3,630	26,181	21.7	4,674	15.3	3,328	1,346
18-Aug-02	21,764	29,811	3,741	26,070	21.5	4,606	15.3	3,340	1,266
25-Aug-02	21,943	29,811	4,452	25,359	17.2	3,716	14.2	3,124	592
01-Sep-02	20,046	29,811	4,160	25,651	29.9	5,905	16.7	3,347	2,558
08-Sep-02	20,662	29,811	6,396	23,415	15.0	3,053	16.4	3,387	-334
15-Sep-02	20,085	29,811	6,617	23,194	17.2	3,408	13.9	2,798	610
22-Sep-02	19,617	29,811	7,122	22,689	17.5	3,372	16.0	3,144	228
29-Sep-02	18,413	29,811	7,337	22,474	24.1	4,361	14.6	2,692	1,669
06-Oct-02	18,905	30,301	8,006	22,295	19.8	3,690	13.2	2,486	1,204
13-Oct-02	19,531	30,301	8,464	21,837	13.6	2,607	12.1	2,359	248
20-Oct-02	19,490	30,301	7,887	22,414	16.8	3,224	11.9	2,320	904
27-Oct-02	20,618	30,301	7,461	22,840	12.4	2,522	12.9	2,661	-139
03-Nov-02	20,519	30,301	7,271	23,030	13.9	2,811	12.5	2,563	248
10-Nov-02	21,339	30,301	5,458	24,843	18.1	3,803	12.0	2,565	1,238
17-Nov-02	21,415	30,301	4,961	25,340	20.0	4,225	11.7	2,507	1,718
24-Nov-02	22,008	30,301	4,737	25,564	17.8	3,856	12.2	2,687	1,169
01-Dec-02	22,563	30,301	4,242	26,059	17.1	3,796	12.2	2,762	1,034
08-Dec-02	23,166	30,301	3,711	26,590	16.3	3,725	13.1	3,044	681
15-Dec-02	22,321	30,301	3,118	27,183	23.4	5,162	13.6	3,031	2,131
22-Dec-02	22,955	30,301	3,022	27,279	20.4	4,624	13.2	3,021	1,603
29-Dec-02	22,880	30,301	2,977	27,324	21.0	4,744	13.6	3,120	1,624
05-Jan-03	22,050	30,349	3,044	27,305	25.5	5,555	13.0	2,864	2,691
12-Jan-03	23,827	30,349	2,999	27,350	16.2	3,822	12.6	3,009	813
19-Jan-03	23,827	30,349	2,172	28,177	19.8	4,650	12.8	3,058	1,592
26-Jan-03	23,151	30,349	2,184	28,165	23.3	5,314	13.1	3,023	2,291
02-Feb-03	22,796	30,349	2,288	28,061	24.7	5,565	13.0	2,963	2,602
09-Feb-03	23,240	30,349	1,750	28,599	24.7	5,659	13.0	3,027	2,632
16-Feb-03	22,745	30,349	2,344	28,005	24.8	5,560	12.6	2,856	2,704
23-Feb-03	22,413	30,349	2,344	28,005	26.6	5,892	13.7	3,067	2,825
02-Mar-03	21,171	30,349	2,322	28,027	34.3	7,156	13.8	2,932	4,224
09-Mar-03	22,033	30,349	3,769	26,580	22.3	4,847	12.6	2,787	2,060
16-Mar-03	20,724	30,349	4,593	25,756	26.1	5,332	13.3	2,747	2,585
23-Mar-03	21,034	30,349	4,601	25,748	24.2	5,014	12.5	2,623	2,391
30-Mar-03	20,396	30,349	4,930	25,419	26.5	5,322	12.8	2,617	2,705

Table C2.2 Assessment of Resources Adequacy – Severe Scenario

Week Ending Day	Primary Demand MW	Total Resources MW	Total Reductions in Resources MW	Available Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Margin MW
07-Oct-01	18,595	30,223	9,165	21,058	15.1	2,763	14.2	2,641	122
14-Oct-01	19,174	30,223	8,973	21,250	12.6	2,376	13.1	2,517	-141
21-Oct-01	19,274	30,223	9,232	20,991	10.6	2,017	13.8	2,657	-640
28-Oct-01	19,512	30,223	8,124	22,099	15.0	2,887	13.9	2,705	182
04-Nov-01	20,339	30,223	7,580	22,643	13.0	2,603	13.9	2,819	-216
11-Nov-01	20,262	30,223	6,896	23,327	16.9	3,365	13.7	2,770	595
18-Nov-01	21,336	30,223	6,629	23,594	12.2	2,558	14.3	3,056	-498
25-Nov-01	21,357	30,223	6,143	24,080	14.4	3,023	14.5	3,088	-65
02-Dec-01	22,248	30,223	4,968	25,255	15.1	3,307	13.9	3,101	206
09-Dec-01	21,972	30,173	4,883	25,290	16.7	3,618	14.3	3,152	466
16-Dec-01	22,905	30,173	4,718	25,455	12.6	2,850	14.9	3,404	-554
23-Dec-01	22,842	30,173	4,159	26,014	15.4	3,472	14.4	3,300	172
30-Dec-01	21,909	30,173	4,146	26,027	20.4	4,419	14.5	3,175	1,244
06-Jan-02	22,480	30,173	4,108	26,065	17.5	3,885	12.9	2,905	980
13-Jan-02	23,567	30,173	4,203	25,970	11.6	2,703	13.7	3,235	-532
20-Jan-02	23,564	30,173	4,211	25,962	11.6	2,698	14.5	3,418	-720
27-Jan-02	22,701	30,173	4,274	25,899	15.6	3,498	13.7	3,107	391
03-Feb-02	22,590	30,173	4,300	25,873	16.1	3,583	13.2	2,989	594
10-Feb-02	22,980	30,223	4,478	25,745	13.5	3,065	13.7	3,155	-90
17-Feb-02	22,540	30,223	4,967	25,256	13.6	3,017	13.4	3,010	7
24-Feb-02	22,208	30,223	5,020	25,203	15.0	3,295	13.8	3,065	230
03-Mar-02	21,387	30,223	5,275	24,948	18.3	3,861	13.1	2,808	1,053
10-Mar-02	21,370	30,223	6,928	23,295	10.6	2,225	13.9	2,974	-749
17-Mar-02	20,387	30,223	6,849	23,374	16.4	3,288	13.5	2,755	533
24-Mar-02	20,361	30,223	7,134	23,089	15.1	3,029	12.7	2,578	451
31-Mar-02	20,206	30,223	7,211	23,012	15.6	3,105	13.0	2,628	477
07-Apr-02	19,924	30,223	8,112	22,111	12.7	2,487	12.7	2,538	-51
14-Apr-02	19,350	30,223	9,953	20,270	6.4	1,220	14.1	2,728	-1,508
21-Apr-02	19,306	30,223	9,114	21,109	11.1	2,102	13.4	2,594	-492
28-Apr-02	18,434	30,223	9,175	21,048	16.1	2,914	13.4	2,461	453
05-May-02	18,274	30,223	9,181	21,042	17.1	3,068	13.4	2,452	616
12-May-02	18,332	29,723	6,823	22,900	27.0	4,868	13.8	2,523	2,345
19-May-02	18,390	29,723	7,187	22,536	24.6	4,446	15.4	2,834	1,612
26-May-02	19,516	29,723	6,829	22,894	19.1	3,678	13.7	2,670	1,008
02-Jun-02	20,237	29,723	6,361	23,362	17.2	3,424	16.6	3,362	62
09-Jun-02	20,403	29,723	6,261	23,462	16.7	3,358	15.8	3,228	130
16-Jun-02	20,900	29,723	5,340	24,383	18.4	3,783	15.3	3,198	585
23-Jun-02	21,215	29,723	4,816	24,907	19.1	3,992	16.6	3,516	476
30-Jun-02	20,904	29,723	4,735	24,988	21.3	4,385	16.8	3,502	883

(Table C2.2 continued)

Week Ending Day	Primary Demand MW	Total Resources MW	Total Reductions in Resources MW	Available Resources MW	Available Reserve %	Available Reserve MW	Required Reserve %	Required Reserve MW	Reserve Margin MW
07-Jul-02	21,237	29,723	4,512	25,211	20.4	4,274	15.6	3,306	968
14-Jul-02	22,474	29,723	4,519	25,204	13.7	3,030	15.0	3,360	-330
21-Jul-02	21,896	29,723	5,014	24,709	14.4	3,112	14.3	3,125	-13
28-Jul-02	22,060	29,723	4,218	25,505	17.2	3,745	14.0	3,095	650
04-Aug-02	21,542	29,723	4,266	25,457	19.8	4,214	14.9	3,210	1,004
11-Aug-02	21,807	29,723	4,145	25,578	18.9	4,071	15.1	3,286	785
18-Aug-02	21,764	29,723	4,256	25,467	18.6	4,003	15.2	3,298	705
25-Aug-02	21,943	29,723	4,967	24,756	14.4	3,113	14.5	3,174	-61
01-Sep-02	20,046	29,723	4,675	25,048	26.8	5,302	16.5	3,303	1,999
08-Sep-02	20,662	29,723	6,911	22,812	12.0	2,450	16.7	3,460	-1,010
15-Sep-02	20,085	29,723	7,132	22,591	14.2	2,805	14.3	2,868	-63
22-Sep-02	19,617	29,723	7,637	22,086	14.3	2,769	16.3	3,196	-427
29-Sep-02	18,413	29,723	7,852	21,871	20.7	3,758	14.4	2,651	1,107
06-Oct-02	18,905	29,723	8,031	21,692	16.6	3,087	13.2	2,486	601
13-Oct-02	19,531	29,723	8,979	20,744	7.9	1,514	12.6	2,455	-941
20-Oct-02	19,490	29,723	8,402	21,321	11.1	2,131	12.4	2,410	-279
27-Oct-02	20,618	29,723	7,976	21,747	7.0	1,429	13.4	2,753	-1,324
03-Nov-02	20,519	29,723	7,786	21,937	8.5	1,718	13.0	2,659	-941
10-Nov-02	21,339	29,723	6,488	23,235	10.4	2,195	12.7	2,711	-516
17-Nov-02	21,415	29,723	5,991	23,732	12.4	2,617	12.1	2,589	28
24-Nov-02	22,008	29,723	5,767	23,956	10.4	2,248	12.9	2,836	-588
01-Dec-02	22,563	29,723	5,272	24,451	9.8	2,188	12.9	2,914	-726
08-Dec-02	23,166	29,723	4,741	24,982	9.3	2,117	13.8	3,190	-1,073
15-Dec-02	22,321	29,723	4,148	25,575	16.1	3,554	13.2	2,943	611
22-Dec-02	22,955	29,723	4,052	25,671	13.3	3,016	13.3	3,054	-38
29-Dec-02	22,880	29,723	4,007	25,716	13.9	3,136	13.7	3,130	6
05-Jan-03	22,050	29,723	4,026	25,697	18.1	3,947	12.3	2,717	1,230
12-Jan-03	23,827	29,723	4,029	25,694	9.2	2,166	13.3	3,161	-995
19-Jan-03	23,827	29,723	3,202	26,521	12.7	2,994	13.2	3,134	-140
26-Jan-03	23,151	29,723	3,214	26,509	16.0	3,658	12.7	2,945	713
02-Feb-03	22,796	29,723	3,318	26,405	17.4	3,909	12.4	2,827	1,082
09-Feb-03	23,240	29,723	3,295	26,428	15.2	3,488	12.7	2,951	537
16-Feb-03	22,745	29,723	3,889	25,834	15.1	3,389	12.2	2,779	610
23-Feb-03	22,413	29,723	3,889	25,834	16.8	3,721	13.0	2,913	808
02-Mar-03	21,171	29,723	3,867	25,856	23.9	4,985	12.9	2,736	2,249
09-Mar-03	22,033	29,723	5,314	24,409	12.3	2,676	12.9	2,834	-158
16-Mar-03	20,724	29,723	6,138	23,585	15.5	3,161	12.8	2,653	508
23-Mar-03	21,034	29,723	6,146	23,577	13.7	2,843	12.3	2,596	247
30-Mar-03	20,396	29,723	6,475	23,248	15.7	3,151	12.3	2,500	651

Appendix D – Transmission System Details

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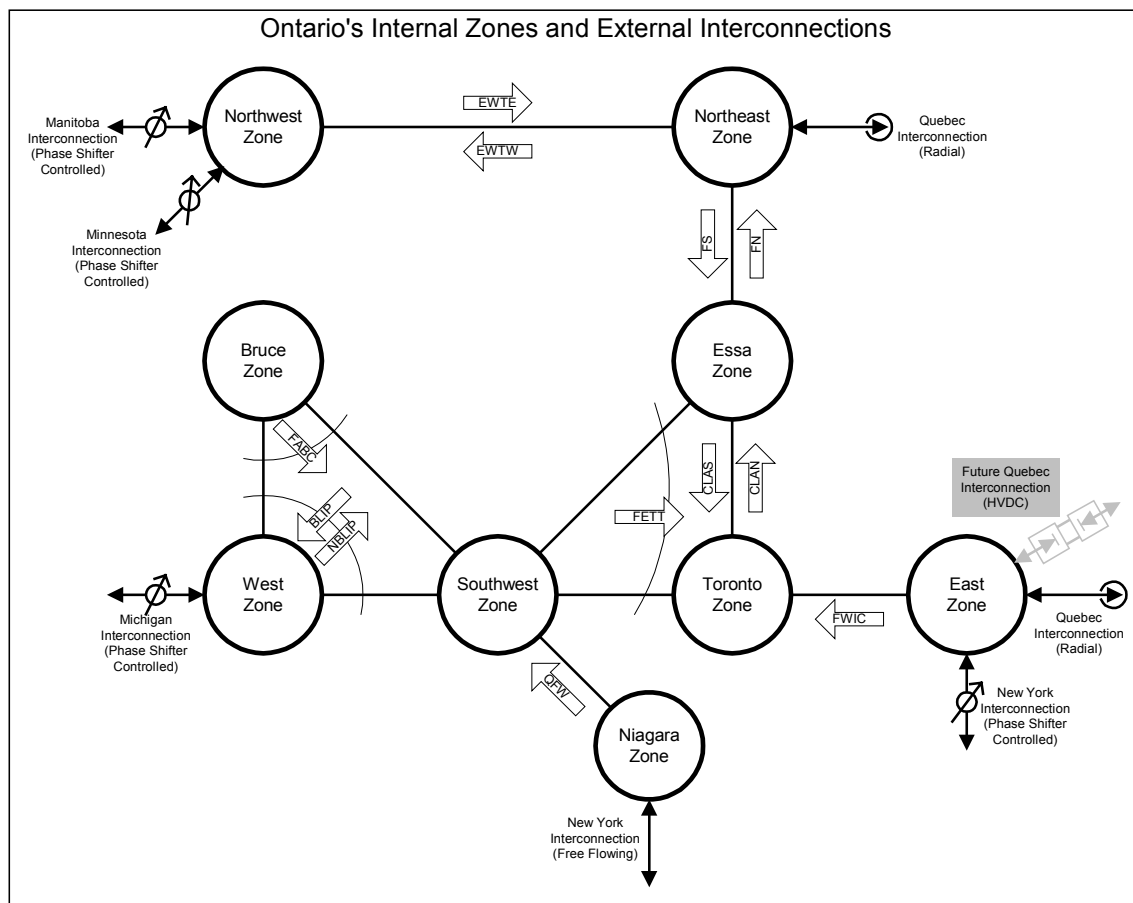
This appendix contains, in Appendix D1, a description of the Ontario Transmission System followed, in Appendix D2 and D3, by Ontario's Interface and Interconnection Definitions and Limits.

1.0 Transmission System Description

1.1 Transmission System Interfaces

There are eight major interfaces in the Ontario transmission 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 D2.1 shows the major interface definitions used in Ontario. Notice that for each individual transmission element included in an interface definition both the positive direction of power flow and measurement point (e.g. which end of a transmission line the power flow is measured at) are specified.

Interface Capability Limits

Appendix D2.2 shows the base limits for the major interfaces that correspond to the definitions in Appendix D2.1; only normal system (all transmission elements in-service) limits are shown. Note that some limits are simply constants (e.g. BLIP) and others are more complicated and may depend on parameters such as specific generator unit statuses, other flows, Ontario demand, etc. (e.g. NBLIP, FETT, FABC). In cases where interface limits are based on thermal capability, separate ratings are shown for summer and winter conditions.

1.2 Interface Characteristics

The EWTE/EWTW Interface

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

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

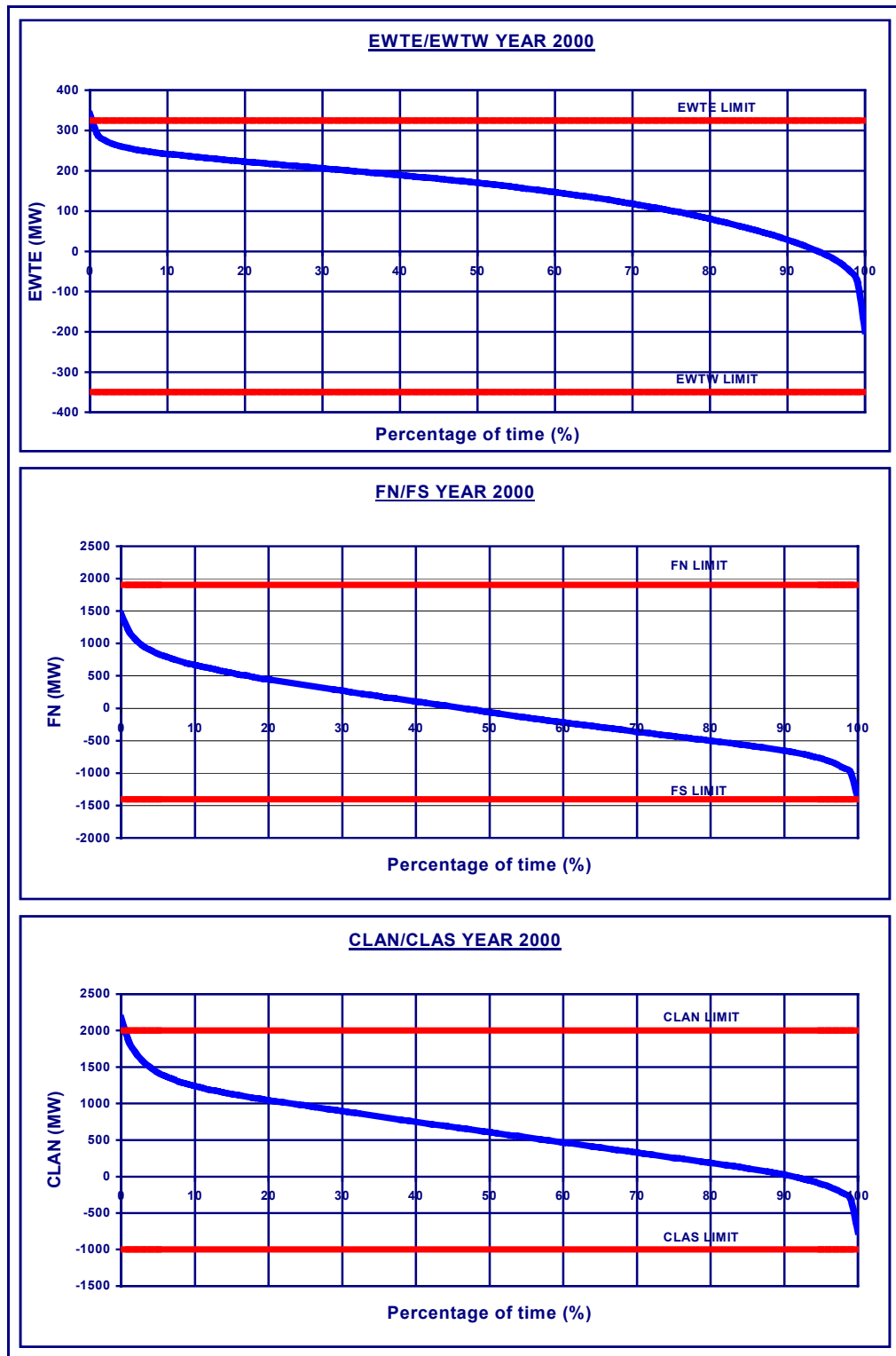
The FN/FS Interface

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

The CLAN/CLAS Interface

The Claireville North (CLAN) limit is 2,000 MW and the Claireville South (CLAS) limit is 1,000 MW. A sample of historical flow distribution on the CLAN/CLAS interface is shown in the Figure D1.2.1.

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



The FABC Interface

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

The BLIP/NBLIP Interface

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

The QFW Interface

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

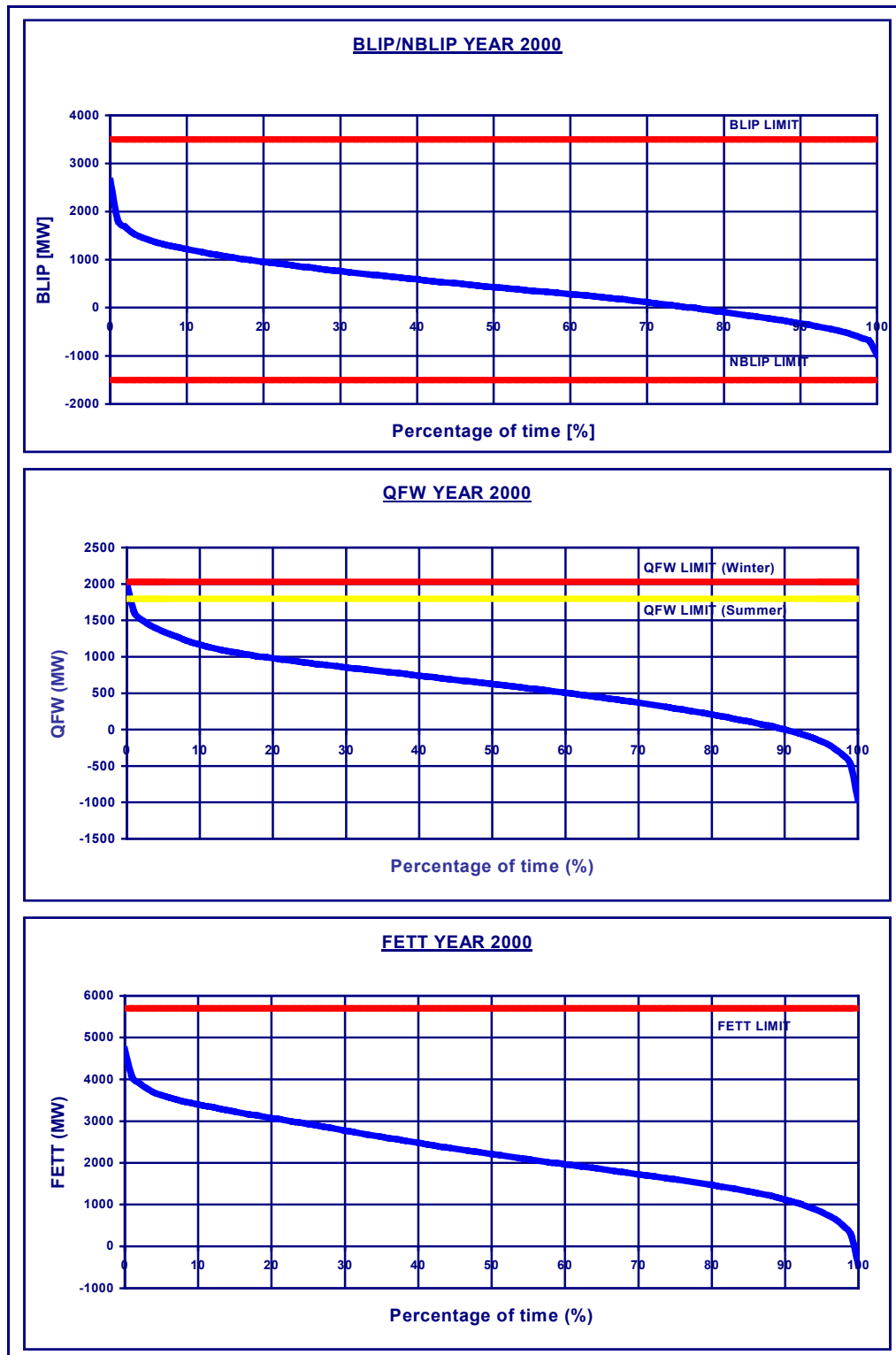
The FETT Interface

The Flow East Towards Toronto (FETT) interface limit is a function of a variety of parameters. Normally the limit is near its high end of about 5,700 MW. The interface is constrained by a combination of stability and thermal limits. There is no limit specified for flows to the west, as the current 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 FWIC Interface

The Flow West into Cherrywood (FWIC) 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.

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



1.3 Transmission System Zones

The Ontario transmission system has been divided into nine zones to facilitate the study. Zonal boundaries have been chosen to correspond with the interface definitions in Appendix D2.1.

Northwest Zone Characteristics

- The total resources generally exceed the zone peak demand.
- The generation is mainly hydroelectric with some coal
- The zone is externally connected to the Manitoba and Minnesota systems.
- The 230 kV Manitoba interconnections are under phase shifter control. The Manitoba 115 kV interconnection is radial. The Minnesota 115 kV interconnection is under phase shifter control.
- To comply with NPCC and MAPP (Mid Continent Area Power Pool) system security criteria, the IMO is committed to implementing enhanced security criteria for the operation of this zone. These criteria will respect double circuit contingencies during fair weather conditions. Currently, work is underway to develop mitigating measures for the implementation of these criteria. In order to ensure the reliability of the IMO-controlled grid in the Northwest, the enhanced security criteria will be implemented in stages when the mitigating measures are developed for the different recognized contingencies. It is expected that the enhanced security criteria will not be fully implemented until sometime in 2002 or 2003.

The application of these criteria for the operation of the Northwest zone is expected to impact the operation of the Northeast zone. Therefore, the security criteria for the Northeast will also be reviewed.

Northeast Zone Characteristics

- The total resources generally exceed the zone peak demand.
- The generation is mainly hydroelectric with some cogeneration.
- There is some 25 Hz generation radially connected to the 60 Hz electricity system via a frequency changer.
- The zone is externally connected to the Quebec grid.
- The interconnection with Quebec is radial.

Essa Zone Characteristics

- The total resources are much less than the zone peak demand.
- The generation is totally hydroelectric.
- For analytical purposes, Des Joachims generation and 115 kV load, which is physically located in the East zone, has been modeled to be part of the Essa zone. The Essa zone is the primary point of receipt of Des Joachims generation.
- There are no external interconnections.

East Zone Characteristics

- The total resources exceed the zone peak demand.
- The generation is a mix of nuclear, hydroelectric, oil, and gas.

- The zone is externally connected to the Quebec grid.
- The existing interconnection with Quebec is radial. The new interconnection with Quebec will be High Voltage Direct Current (HVDC) transmission. This new interconnection is expected to go in-service in May 2003.
- The zone is also externally connected to the St. Lawrence interface with New York via phase shifter control.

Toronto Zone Characteristics

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

Bruce Zone Characteristics

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

Southwest Zone Characteristics

- The total resources are well balanced with the zone peak demand.
- The load consists of 25 Hz and 60 Hz.
- The generation is mostly coal.
- There are no external interconnections.

West Zone Characteristics

- The total resources are slightly less than the zone peak demand.
- The generation is mostly coal.
- There is a free-flowing interconnection with Michigan. At some future date, the interconnection will be under phase shifter control.

Niagara Zone Characteristics

- The total resources are much higher than the zone peak demand.
- The load consists of 25 Hz and 60 Hz.
- The generation consists of 25 Hz and 60 Hz, and is mostly hydroelectric.
- There is a free-flowing interconnection with New York.

1.4 Transmission System Interconnection Capabilities and External Markets

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

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

Interconnection Definitions

Interconnection definitions are shown in Appendix D3.1.

Interconnection Flow Limits

Interconnection flow limits are shown in Appendix D3.2.

Interconnection Characteristics

All of Ontario's non-radial interconnections are under phase-shifter control, except for Niagara - New York. The new proposed 1,250 MW interconnection between Ottawa and Quebec will be High Voltage Direct Current (HVDC) transmission.

The total transfer capability from Ontario to Michigan and New York depends on the distribution of load and generation across the interconnection. At best, the total transfer is the sum of the two capabilities. At worst, the total transfer is the minimum of either the New York (St. Lawrence plus Niagara) or Michigan transfer capability.

The Ontario - Manitoba Interconnection

The Ontario-Manitoba Transfer East (OMTE) and Ontario-Manitoba Transfer West (OMTW) limits are both 288 MW in summertime, 300 MW in wintertime and are constrained by stability and thermal limitations. However, with the Whiteshell T8 transformer out of service in Manitoba, the OMTE and OMTW limits are 163 MW in the summertime and 190 MW in the wintertime. The Ontario-Manitoba 115 kV interconnection limits are 55 MW for flows into Ontario in the summertime and 69 MW for flows into Ontario in the wintertime.

The Ontario - Minnesota Interconnection

The Minnesota Power Flow North (MPFN) and Minnesota Power Flow South (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.

At this time, there is great uncertainty as to when phase shifting control of the Ontario – Michigan interconnection will occur. The purpose of the new phase shifters is to control a loop flow or a parallel path flow called Lake Erie Circulation (LEC). LEC occurs naturally through a combination of transmission system impedance with interconnection-wide load/generation dispatch; it is measured as an unscheduled flow across the points of interconnection with New York, at Niagara Falls, and with Michigan. Much of the time, LEC enters Ontario at the New York Niagara interconnection and exits Ontario at the Michigan interconnection. LEC flows also appear on and aggravate the BLIP and QFW interfaces as they are in a direct series path. The phase shifters, with an effective phase angle control range of ± 40 degrees under full load, are expected to control around 600 MW of LEC in either direction. Control of LEC to levels less than 600 MW should allow scheduled power flows to be maintained between Ontario, Michigan and New York, and should also greatly reduce the incidence of constrained operation of QFW interface. A sample of historical flow distribution for LEC is shown in the Figure D1.4.

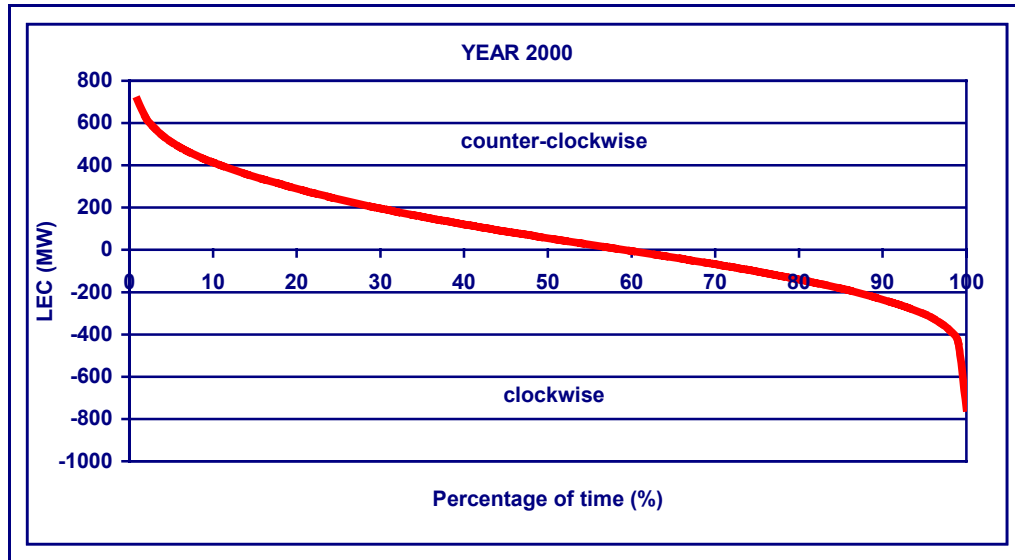
Before all phase shifters are in service:

During winter months, the limits are 1,600 MW for flows into Ontario and 2,400 MW for flows out of Ontario. In the summer, the limits are 1,500 MW for flows into Ontario and 2,350 MW for flows out of Ontario.

After all phase shifters are in service and operational:

During winter months, the limits are 1,750 MW for flows into Ontario and 2,700 MW for flows out of Ontario. In the summer, the limits are 1,650 MW for flows into Ontario and 2,450 MW for flows out of Ontario.

Figure D1.4 Historical Flow Distribution – Lake Erie Circulation



The Ontario - New York Niagara Interconnection (60 Hz and 25 Hz)

The New York Niagara interconnection, in the winter, is limited to 1,650 MW for flows into Ontario and 2,100 MW for flows out of Ontario. In the summer, the limit is 1,400 MW for flows into Ontario and 2,100 MW for flows out of Ontario. The interconnection is constrained by thermal limitations in the winter and summer.

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

Typically, when QFW hits its limit of 1,800 MW under summer conditions, the flow across the NY Niagara interconnection is 1,100 MW (its limit is 1,400 MW). Similarly, when QFW hits its limit of 2,000 MW under winter conditions, flow across the NY Niagara interconnection is 1,300 MW (its limit is 1,650 MW).

The Ontario - New York St. Lawrence 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 - Quebec North Interconnection

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

The Ontario - Quebec South Interconnection

The Quebec South interconnection is limited to 1,328 MW for flows into Ontario due to stability limitations and available radial generation. For flows out of Ontario the limits, due to stability and thermal limitations, are 432 MW for the summer and 452 MW for the winter.

At this time, limits for the HVDC interconnection have not been established.

2.0 Definitions and Limits of Ontario's Interfaces

2.1 Definitions of Ontario's Interfaces

(* signifies the measurement point)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2.2 Limits of Ontario's Interfaces

The Ontario major interfaces base limits, for all elements in service are shown in the Table D2.1. Detailed information on these limits can be found in the IMO System Control Orders (SCOs). These SCOs are available by request via the IMO Help Centre.

Table D2.1 Ontario's Interface Base Limits

Interface	Operating Security Limits (MW)
BLIP	3,500
NBLIP	1,500
QFW	1,800 Summer, 2,030 Winter
FABC	5,200, normally not limiting
FETT	5,700, 5,500 Summer ⁽¹⁾ , 5,300 Summer ⁽²⁾ , 5,100 Summer ⁽³⁾
CLAN	2,000
CLAS	1,000
FN	1,900
FS	1,400
E-W	325 East, 350 West

Summer Limits apply from May 1 to October 31. Winter Limits apply from November 1 to April 30.

(1) Limit is used if the summer Ontario demand is between 22,001 and 22,600 MW.

(2) Limit is used if the summer Ontario demand is between 22,601 and 25,000 MW.

(3) Limit is used if the summer Ontario demand is between 25,001 and 26,000 MW.

3.0 Definitions and Limits of Ontario's Interconnections

3.1 Definitions of Ontario's Interconnections

The Ontario – Manitoba Interconnection

K21W	Kenora 230 kV to Whiteshell 115 kV including combination voltage regulator and phase shifting transformer bank T7 at Whiteshell,
K22W	Kenora 230 kV to Whiteshell 115 kV including combination voltage regulator and phase shifting transformer bank T8 at Whiteshell,
SK1	Rabbit Lake 115 kV to Seven Sisters 115 kV including an in-line voltage regulating transformer at Seven Sisters (radial operation from Manitoba to Ontario 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
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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 Masson 115 kV,
D5A	Hawthorne to Masson 230 kV / Outaouais 325 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.
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- L4D Lambton* 230 kV to St. Clair 345 kV, including two autotransformers in parallel and phase shifter.
- L51D Lambton* 230 kV to St. Clair 345 kV, including in-line autotransformer and phase shifter.
- J5D Keith* 230 kV to Waterman 230 kV, including in-line combination voltage regulator and phase shifter SR5.

The Ontario – New York Interconnection at Niagara consists of the following 60 Hz circuits to the New York Power Authority (NYPA), and Niagara Mohawk (NiaMo):

- BP76 Beck2 230 kV to Packard 230 kV (NiaMo), including in-line voltage regulating transformer R76,
- PA27 Beck2 230 kV to Niagara 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 T301,
- PA302 Beck2 230 kV to Niagara Moses 345 kV (NYPA), including in-line 230 to 345 kV autotransformers T302,
- BL104 Beck1 115 kV to Lockport 115 kV (NiaMo),

The Ontario – New York Interconnection at Niagara consists of the following 25 Hz circuits to the Niagara Mohawk (NiaMo):

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

The Ontario – New York Interconnection at St. Lawrence consists of the following 60 Hz circuits to the New York Power Authority (NYPA):

- L33P St. Lawrence 230 kV to FDR Moses 230 kV (NYPA) including in-line voltage regulating transformer R33 and in-line phase shifting transformer PS33,
- L34P St. Lawrence 230 kV to FDR Moses 230 kV (NYPA) including in-line combination voltage regulator and phase shifting transformer PSR34.

3.2 Flow Limits of Ontario's Interconnections

The Ontario interconnection flow limits, for all elements in service are shown in the Table D3.1. The flow limit is the lesser value of either the operating limit or the transfer capability of an interconnection. In some cases, the operating limit and transfer capability of an interconnection may be the same value.

Table D3.1 Ontario's Interconnection Limits

Interconnection	Limit - Flows Out of Ontario MW	Limit - Flows Into Ontario MW
Manitoba – Winter*	300/190**	369/259**
Manitoba – Summer*	288/163**	343/218**
Minnesota ⁽³⁾	150	100
Quebec North – Winter*	115 ⁽⁴⁾	78
Quebec North – Summer*	107 ⁽⁵⁾	64
Quebec South - Winter*	452	1,328
Quebec South - Summer*	432	1,328
New York St. Lawrence	400	400
New York Niagara (60 Hz and 25 Hz) – Winter* ⁽¹⁾	2,100	1,650
New York Niagara (60 Hz and 25 Hz) – Summer* ⁽¹⁾	2,100	1,400
Michigan – Winter* ^(2,3)	2,400/2,700***	1,600/1,750***
Michigan – Summer* ^(2,3)	2,350/2,450***	1,500/1,650***

* Summer Limits apply from May 1 to October 31. Winter Limits apply from November 1 to April 30.

** For the Ontario-Manitoba interconnection, the displayed values are, respectively, before and after January 30, 2002 which is the expected return to service date of Whiteshell T8 transformer.

*** For the Ontario-Michigan interconnection, the displayed values are, respectively, before and after all three phase shifters are in-service and operational.

(1) Limits are based on thermal ratings and 75% of pre-load. Summer limits are based on 0-4 km/hr wind speed and 30 Deg.C ambient temperature. Winter limits are based on 0-4 km/hr wind speed and 10 Deg.C ambient temperature.

(2) Limits are based on thermal ratings and 75% of pre-load. Summer limits are based on 0-4 km/hr wind speed and 35 Deg.C ambient temperature. Winter limits are based on 0-4 km/hr wind speed and 10 Deg.C ambient temperature.

(3) For day to day operations of the interconnection, limits are based on ambient conditions such as wind speed, temperature and pre-loads.

(4) Limit based on 0-4 km/hr wind speed and 10 Deg.C or less ambient temperature.

(5) Limit based on 0-4 km/hr wind speed and 30 Deg.C or less ambient temperature.

4.0 Committed Projects – Hydro One

East Zone - Committed Plans		Projected I/S Date
Manordale, Fallowfield, Richmond and Manotick: Reconnect customer stations from C7BM to W6MC. Replace 1500 ft of W6MC 477 kcmil conductor entering Merivale TS with 1192.5 kcmil.		October 30, 2001
Belleville TS - H1H2: Oil circuit breaker replacement.		November 30, 2001
Brockville TS: Refurbish station-reconfigure 115 kV facilities.		December 31, 2001
Merivale TS SC11: Capacitor bank replacement.		December 31, 2001
St. Isidore TS: Replace switch D5A-48 with circuit-switcher.		December 31, 2001
Chenau TS: Add 2 x 230 kV breakers.		July 31, 2002
Kanata MTS: Provide 230 kV connection to M32S near South March.		July 31, 2002
Essa Zone - Committed Plans		Projected I/S Date
Minden TS T1-A: Switch replacement.		October 31, 2001
Minden TS T2-H: Switch replacement.		October 31, 2001
Niagara Zone - Committed Plans		Projected I/S Date
Allanburg x Niagara: Remove idle 115 kV line - A1T.		December 30, 2001
Crowland TS: Decommission/remove 115 kV & 27.6 kV 25 Hz facilities.		December 31, 2001
Northeast Zone - Committed Plans		Projected I/S Date
Calstock DS: Install new 115 kV - 25 kV DS connected to H2N.		December 31, 2001
Northwest Zone - Committed Plans		Projected I/S Date
Weyerhaeuser Canada: Provide connection to Truss Joist Plant off 115 kV circuit K7K near Kenora.		March 6, 2002
Pikangikum: Connect customer 12/16/20 MVA, 120-25 kV station to 115 kV circuit E2R near Ear Falls. The customer will be located approximately 150 km from tap point.		January 1, 2003
Southwest Zone - Committed Plans		Projected I/S Date
Elmira TS T1-1: Switch replacement.		October 31, 2001
Elmira TS T2-1: Switch replacement.		October 31, 2001
Hamilton Elgin: Install 115 kV bus interconnections between the HL3 and HL4 bus.		December 31, 2001
Newton TS SC1/SC2: Capacitor bank replacement.		December 31, 2001
Cambridge & NorthDumfries Hydro MTS #1: Build 230 kV 2-circuit line tap (M20/21D) to customer's owned station; 2 x 50/83 MVA, 230-27.6 kV transformer.		June 1, 2002

Toronto Zone - Committed Plans	Projected I/S Date
Manby TS 38-K8B: Switch replacement.	October 31, 2001
Manby TS T13-A1: Switch replacement.	October 31, 2001
Manby TS T14-H1: Switch replacement.	October 31, 2001
Richview TS L24L71-24: Switch replacement.	October 31, 2001
Richview TS L5L14-5: Switch replacement.	October 31, 2001
Oakville #2 TS: Install LV capacitors:28 kV, 21.6 MVAR.	December 31, 2001
Wilson TS SC3: Capacitor bank replacement.	December 31, 2001
Brampton MTS #1: Provide 230 kV connection from R19T/R21T to new customer owned station (between Hanlan Jct & Pleasant TS).	May 1, 2002
Manby TS: T3 replacement; increase capacity from 40 MVA to 50/83 MVA.	May 1, 2002
Cecil TS: Replace T3/T4 with larger 100 MVA units.	December 31, 2002

West Zone - Committed Plans	Projected I/S Date
Ford Annex CTS: Provide connections to 115 kV E8F/E9F cables.	October 1, 2001
Wanstead TS T1-L: Switch replacement.	October 31, 2001
Lauzon TS SC1: Capacitor bank replacement.	December 31, 2001
London Clarke TS: Install LV capacitors; 2 x 28 kV, 21.6 MVAR.	December 31, 2001
Strathroy TS: Install LV capacitors; 28 kV, 21.6 MVAR.	December 31, 2001
TransAlta NUG in Sarnia: Establish permanent 580 MVA connection, install 2 x 230 kV breakers at Scott. Reterminate N6S. Reterminate section of L23N (going to IOL) at Scott and rename as N7S. Disconnect "DOW Chemical" from N6S.	October 7, 2002

5.0 Planned Transmission Outages

Table D5.1 Transmission Outages Bruce Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 10-Sep-01 08:00	Fri 19-Oct-01 16:00	Bruce A AL569	CWW	6 weeks	Affects Flow Away from Bruce Complex (FABC). Longwood T4 also out of service (o/s) forced. Not expected to be limiting.	No additional reduction to FABC limit.

Table D5.2 Transmission Outages East Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 17-Sep-01 08:00	Fri 12-Oct-01 16:00	X522A	NA	Not specified; assumed 'NONE'		
Mon 01-Oct-01 08:00	Fri 12-Oct-01 16:00	Hawthorne QLT4 BREAKER	CWW	48 HOURS		
Mon 15-Oct-01 08:00	Fri 21-Dec-01 16:00	Circuit P4S section Dale Jct. X Vernonville Jct.	CNW	Not specified; assumed 'NONE'		
Mon 29-Oct-01 08:00	Fri 23-Nov-01 16:00	L24A	NA	Not specified; assumed 'NONE'		

Table D5.3 Transmission Outages Essa Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 24-Sep-01 07:00	Fri 05-Oct-01 15:00	D2M	DNW	1 HOUR		
Mon 08-Oct-01 07:00	Fri 19-Oct-01 15:00	D3M	DNW	1 HOUR		
Tue 09-Oct-01 08:00	Fri 26-Oct-01 17:00	Essa HT4 BRKR	DNW	4 hours		
Mon 22-Oct-01 07:00	Wed 31-Oct-01 15:00	D4M	DNW	1 HOUR		

Table D5.4 Transmission Outages Niagara Zone

No outages to analyze.

Table D5.5 Transmission Outages Northeast Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Tue 10-Jul-01 08:00	Fri 14-Dec-01 16:30	CKT L1S WARREN X CONISTO	CWW	NONE	Affects Quebec North transfer. Not expected to be limiting.	5 MW D4Z or H4Z in Mode 2; 15 MW D4Z in Mode 3.
Mon 15-Oct-01 08:00	Fri 02-Nov-01 16:00	Martindale TS DH	CWW	NONE		
Sat 15-Dec-01 07:00	Fri 21-Dec-01 17:00	CKT D2L CRYSTAL X HERRID	DWW	8 HRS		

Table D5.6 Transmission Outages Northwest Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Tue 04-Sep-01 07:00	Thu 18-Oct-01 18:00	A6P Circuit PATS#1 X RESERVE	CWW	NONE		
Mon 10-Sep-01 07:00	Fri 02-Nov-01 18:00	M2D Circuit M2D-1 X M2D-D	CWW	NONE	Affects Northwestern System. Circuit K21W also o/s. May constrain Northwest generation. Not expected to affect generation reserve requirements.	No additional reduction to limits with K21W O/S for OMTE, OMTW, EWTVW, EWTE, MPFN & MPFS.
Mon 22-Oct-01 07:00	Thu 06-Dec-01 18:00	R9A Circuit PINE X ALEX	CWW	NONE		
Sat 01-Dec-01 08:00	Sat 15-Dec-01 18:00	Avenor Tbay G4 (18 MW)	CWW	NONE		

Table D5.7 Transmission Outages Southwest Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Fri 01-May-98 06:56	Mon 31-Dec-01 18:00	HL4 Sect Stirton X Elgin	CWW	NIL		
Thu 20-Sep-01 09:00	Wed 03-Oct-01 15:00	Seaforth KT1L7 BKR	CWW	2 DAYS		
Thu 04-Oct-01 09:00	Fri 19-Oct-01 15:00	Seaforth DT2L18 BKR	CWW	2 DAYS		
Mon 15-Oct-01 08:00	Fri 26-Oct-01 17:00	Bronte S4Y	CWW	2 days		
Sat 17-Nov-01 08:00	Fri 07-Dec-01 17:00	Trafalgar K1K2 BREAKER	CNW	5 DAYS		

Table D5.8 Transmission Outages Toronto Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Tue 15-May-01 13:00	Mon 31-Dec-01 16:00	Hearn T5A5	CWW	Not specified; assumed 'NONE'		
Tue 15-May-01 13:00	Mon 31-Dec-01 16:00	Hearn T5H2JK	CWW	Not specified; assumed 'NONE'		
Fri 18-May-01 19:15	Sun 23-Dec-01 18:00	Gerrard A2 bus	CWW	Not specified; assumed 'NONE'		
Mon 17-Sep-01 08:00	Fri 16-Nov-01 17:00	Claireville AL586 BREAKER	CNW	5 DAYS		
Tue 18-Sep-01 07:00	Fri 05-Oct-01 06:00	CKT V73R section twr 84 x Richview	CWW	None	Affects FETT. V72R & C18R also out of service (o/s) from Oct 1 to Oct 5. Not expected to be limiting.	Sept 18 to Sept 30 - 100 MW; Oct 1 to Oct 5 - 200 MW
Mon 24-Sep-01 05:00	Fri 02-Nov-01 17:00	CKT C7E, C5E	CNW	Not specified; assumed 'NONE'		
Mon 24-Sep-01 05:00	Fri 05-Oct-01 16:00	Charles T4, T2	CNW	18 HRS		
Mon 01-Oct-01 06:00	Fri 19-Oct-01 16:00	John T4	CWW	3 DAYS		
Mon 01-Oct-01 12:00	Fri 12-Oct-01 07:00	CKT V72R section Richview x Twr 209	CWW	None	Affects FETT. V73R & C18R also o/s from Oct 1 to Oct 5. C18R also o/s from Oct 6 to Oct 12. Not expected to be limiting.	Oct 1 to Oct 5 - 200MW; Oct 6 to Oct 12 - 150MW
Mon 01-Oct-01 16:00	Fri 19-Oct-01 07:00	CKT C18R section Richview x Twr 209	CWW	None	Affects FETT. V73R & V72R also o/s from Oct 1 to Oct 5. V72R also o/s from Oct 6 to Oct 12. C12R also o/s Oct 15. C12R & C20R also o/s from Oct 16 to Oct 19. Not expected to be limiting.	Oct 1 to Oct 5 - 300 MW; Oct 6 to Oct 12 - 200 MW; Oct 13 & 14 - 150 MW; Oct 15 - 225 MW; Oct 16 to Oct 19 - 300 MW
Mon 08-Oct-01 07:00	Sun 14-Oct-01 17:00	Richview H1L11 BREAKER	DNW	None		
Mon 15-Oct-01 08:00	Tue 01-Feb-11 17:00	Esplanade C5E, BREAKR C5E	DNW	8 hours		
Mon 15-Oct-01 12:00	Fri 26-Oct-01 07:00	CKT C12R section Richview x Twr 209	CWW	None	Affects FETT. C18R also o/s Oct 15. C18R & C20R also o/s Oct 16 to Oct 19. C20R also o/s Oct 20 to Oct 26. Not expected to be limiting.	Oct 15 - 225 MW; Oct 16 to Oct 19 - 300 MW; Oct 20 to Oct 26 - 225 MW
Tue 16-Oct-01 07:00	Fri 09-Nov-01 15:00	CKT C20R section Richview x Twr 209	DNW	3 hours	Affects FETT. C18R & C12R also o/s Oct 16 to Oct 19. C12R also o/s Oct 20 to Oct 26. C18R & V71R also o/s from Oct 29 to Nov 8. C18R also o/s Nov 9. Not expected to be limiting.	Oct 16 to Oct 19 - 300 MW; Oct 20 to Oct 26 - 225 MW; Oct 27 & 28 - 150 MW; Oct 29 to Nov 8 - 300 MW; Nov 9 - 225 MW
Fri 19-Oct-01 22:00	Thu 25-Oct-01 06:00	Whitby Cogen NUG (50MW)	CWW	NONE		
Mon 29-Oct-01 16:00	Fri 09-Nov-01 07:00	CKT C18R section Richview x Twr 209	CWW	None	Affects FETT. C20R & V71R also o/s Oct 29 to Nov 8. C20R also o/s Nov 9. Not expected to be limiting.	Oct 29 to Nov 8 - 300 MW; Nov 9 - 225 MW
Mon 29-Oct-01 17:00	Thu 08-Nov-01 07:00	CKT V71R	CWW	8 hours	Affects FETT. C20R & C18R also o/s. Not expected to be limiting.	300 MW
Mon 05-Nov-01 05:00	Fri 14-Dec-01 17:00	CKT H11L HEARN X MAIN, H7L HEARN X MAIN	CNW	Not specified; assumed 'NONE'		
Thu 08-Nov-01 05:00	Fri 30-Nov-01 16:00	CKT L4C, Charles T1, T4	CNW	18 HRS		
Mon 19-Nov-01 05:00	Fri 30-Nov-01 16:00	CKT L12C, Charles T3, FTR	CNW	18 HRS		
Mon 19-Nov-01 05:00	Fri 30-Nov-01 17:00	Cecil L8L12, CKT L8L12 CECIL X CHARLES, H8LC CECIL X GERRARD JUNCTION	CNW	Not specified; assumed 'NONE'		
Mon 03-Dec-01 06:00	Fri 14-Dec-01 16:00	CKT L9C CHARLES X LEASIDE, Charles T4	CNW	18 HRS		

Table D5.9 Transmission Outages West Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 10-Sep-01 07:00	Fri 12-Oct-01 17:00	Lambton T6	CWW	None		
Mon 24-Sep-01 07:00	Fri 12-Oct-01 15:00	Buchanan HL37 BKR	CNW	8 HRS		
Mon 24-Sep-01 07:00	Fri 02-Nov-01 17:00	Buchanan SC22	CWW	None		
Mon 15-Oct-01 07:00	Fri 26-Oct-01 15:00	Buchanan L5L37 BKR	CNW	8 HRS		
Mon 29-Oct-01 07:00	Fri 09-Nov-01 15:00	Buchanan L42L45 BKR	CNW	8 HRS		
Mon 29-Oct-01 07:00	Wed 14-Nov-01 17:00	Chatham SC21	CWW	None		