Independent Electricity Market Operator

18-Month Outlook:

An Assessment of the Adequacy of the Ontario Electricity System

from January 2002 to June 2003

December 17, 2001

Executive Summary

This report presents an assessment of the adequacy of resources and transmission for the Ontario electricity system for the 18-month period from January 2002 through June 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 November 13, 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 NPCC resource adequacy criteria for the next 18 months. Figure 1 illustrates the weekly resource adequacy situation for the Ontario Electricity System for two possible resource availability scenarios: a base resource scenario, which assumes all new resources come into service as forecast by market participants, and a delayed resource scenario, which assumes new resources come into service one year later than forecast. Both resource projections in Figure 1 include only available generation in Ontario and external supply pre-committed to Ontario. They do not include additional resources external to Ontario that are expected to be available.

For the upcoming winter, reserve margins are expected to be tight but adequate under both resource scenarios. For the remainder of the Outlook period, reserve levels are generally expected to exceed requirements, under the base resource scenario. Exceptions toward the end of the period are expected to be resolved by market participants in response to market opportunities. Under the delayed resource scenario, delays in additional resources coming into service would result in reserve levels lower than under the base resource scenario, particularly during the later portion of the forecast period.

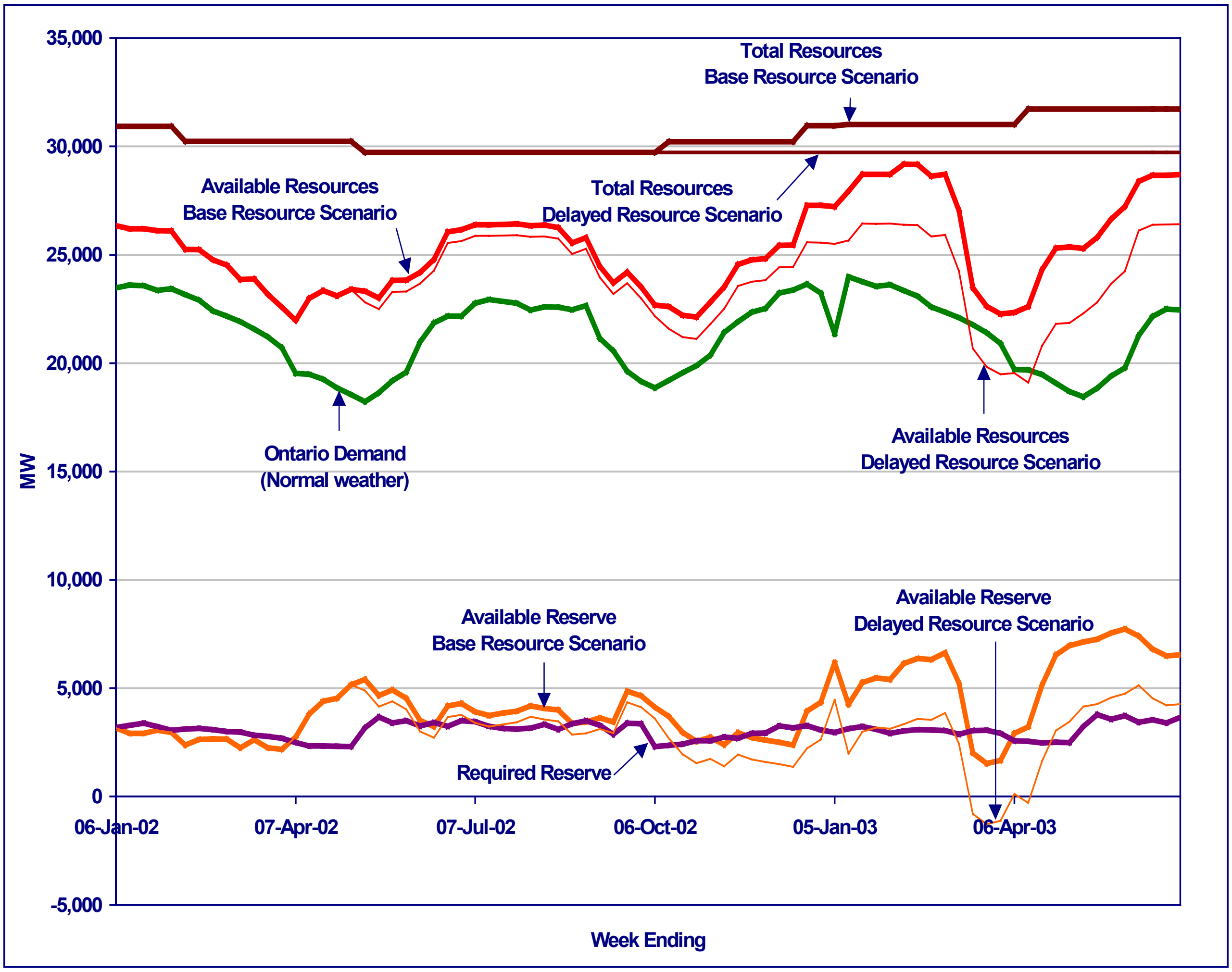
The resource adequacy assessments take into consideration the full range of expected weather conditions on a probabilistic basis. The Ontario demand forecast is presented assuming Normal weather with the effect of deviations from Normal weather on peak demands being factored into the required reserve. 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. This resource adequacy assessment and its conclusion also 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.

Generally, the electricity peak demand forecast is slightly higher than the previous demand forecast that was prepared for the 18-Month Outlook published in October 2001. This change reflects the inclusion of actual weather and demand data up to the end of August 2001. For 2002, the Normal weather winter peak is expected to be about 23,600 MW (about the same as the previous Outlook) and the summer peak is expected to be close to 23,000 MW (about 500 MW higher than the previous Outlook). The energy demand forecast is lower than the previous forecast due to slower economic growth. Economic factors are based on a consensus of four publicly available forecasts.

As in the previous 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 Outlook covers the 18-Month period from January 1, 2002 to June 30, 2003. It supercedes the report titled "An Assessment of the Adequacy of the Ontario Electricity System from October 2001 to March 2003", dated September 28, 2001. 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 identifies the resources expected to be available during the study period and Section 3 presents an assessment of the adequacy of these resources under the current generation outage program. An assessment of the adequacy of the transmission system is described in Section 4. The overall findings and conclusions related to the resource and transmission adequacy assessments are contained in Section 5.

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.

The contents of this Outlook document focus on the assessment of resource and transmission adequacy. Other supporting information, forecasts and assessments are contained in separate documents. These documents will be updated as required.

- The separate document titled "Ontario Demand Forecast from January 2002 to June 2003" (IMO_REP_0043) (found on the IMO Web site at www.theimo.com/imoweb/pubs/marketReports/18Month_ODF_2001dec.pdf) describes in detail the 18-month forecast of electricity demand for Ontario used in this Outlook. This document also identifies the methodology and assumptions used to determine the forecast, and identifies the details regarding peak and energy demand forecasts for Ontario and parts thereof. It also contains information regarding variations in demand due to weather, economic growth and calendar day types.
- The separate document titled "Methodology to Perform Resource and Transmission Adequacy Assessments" (IMO_REP_0044) (found on the IMO Web site at www.theimo.com/imoweb/pubs/marketReports/Methodology_RTAA_2001dec.pdf) contains information regarding the methodology used to perform the resource and transmission adequacy assessments in this Outlook.

Readers are invited to provide comments on this Outlook 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 Resources

This Section describes the generation resources that are considered in this Outlook based on information available to the IMO as of November 13, 2001.

2.1 Existing Installed Generation Resources

The existing installed generation within Ontario is summarized in Table 2.1. This 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.

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 begin returning to service starting in 2002[1].

The capacity of installed generation resources in Table 2.1 does not include Bruce A nuclear units, which are currently in laid-up state. Bruce units, together with other additions to generating capacity identified to the IMO via the Connection Assessment and Approval process, are added to the installed resources as they come in to service, as described in Section 2.4.

Table 2.1 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

2.2 Long Term External Transactions Outside the Province

Availability of 1,400 MW of firm capacity from outside Ontario is included in the assessment for the month of January 2002. For the period of February 2002 through April 2002, an amount of 700 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.

[1] Recent information from OPGI indicates the first Pickering A unit will begin commissioning in mid 2002. As a result, the in-service date will be later than identified to the IMO as of November 13, 2001. This information should not change the overall conclusion of this report, but will be considered in more detail in the next Outlook.

2.3 Potential New Generation Resources

In accordance with the Market Rules, Chapter 4, Section 6, anyone 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 2.2 summarizes only the potential new generation projects included in this Outlook. They have been identified to the IMO through the CAA process, as of November 13, 2001, and their estimated in-service date falls in the 18-month interval studied. In Table 2.2, 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 2.2 Potential Generation Projects in Ontario

Project Name	System Zone	Resource Type	Capacity MW	Proponent's Estimated I/S Date	CAA Status
TransAlta	West	Gas	490	2002 - Q3	SIA
Northland (Kirkland)	Northeast	Gas	48	2002 - Q4	SIA
Total			538		

Details regarding 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 "Services - Connection Assessments" link.

2.4 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 are expected to be available. Two resource scenarios are considered in the present Outlook: a Base Resource Scenario and a Delayed Resource Scenario. Both resource scenarios are based on the existing installed resources shown in Table 2.1.

Under the **Base Resource Scenario**, the capacity of the new generation projects listed in Table 2.2 is assumed to be placed in-service on the first day of the next calendar quarter shown by the estimated in-service dates (e.g. TransAlta is considered to come in service on October 1, 2002), and therefore is added to the Installed Resources for the applicable timeframe. Also, Bruce A - G3 and G4 units are added to the Installed Resources on their forecast in-service dates. Generator outages and return to service dates of generators on long-term outages are based on information received from generator operators.

The **Delayed Resource Scenario** assumes a one-year delay for the in-service dates of new generation projects and Pickering A and Bruce A nuclear units. Consequently, this scenario assumes reduced available resources by up to about 3,500 MW.

Table 2.3 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 2.1. External transactions, described in Section 2.2, are added to obtain Total Resources. Generation additions are included as mentioned above. Generator deratings, generator outages under each resource scenario, generation limitations due to transmission interface constraints and allowances for non-utility and hydroelectric generation production below rated capacity are subtracted from Total Resources to obtain Available Resources.

Table 2.3 Summary of Available Resources

Notes	Description \ Year	Winter Peak 2002		Summer Peak 2002		Winter Peak 2003	
		Base Resource Scenario	Delayed Resource Scenario	Base Resource Scenario	Delayed Resource Scenario	Base Resource Scenario	Delayed Resource Scenario
1	Installed Resources	29,523	29,523	29,523	29,523	30,811	29,523
2	Firm Imports	1,400	1,400	200	200	200	200
3	Total Resources	30,923	30,923	29,723	29,723	31,011	29,723
4	Total Reductions in Resources	4,719	4,719	3,339	3,854	3,077	4,067
5	Available Resources	26,204	26,204	26,384	25,869	27,934	25,656

Notes to Table 2.3:

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 2.1. 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. The new generation capacity is progressively included, according to estimated in-service dates in Table 2.2 or according to the assumed dates under the Delayed Resource Scenario.

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 limitations due to transmission interface constraints 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.

3.0 Resource Adequacy Assessment

This Section provides an assessment of the adequacy of the resources described in Section 2 to meet the forecast demand. The purpose of the two resource scenarios described in Section 2.4 is to present a range of possible outcomes, in recognition of the uncertainty which exists regarding the future availability of new generation. The Base Resource Scenario reflects information provided by generator operators and forms the foundation for assessment purposes. The Delayed Resource Scenario represents a pessimistic outcome. It should also be noted that the assessment of Ontario generation resource adequacy assumes 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 methodology used to carry out this assessment is described in detail in the document titled "Methodology to Perform 18-Month Resource and Transmission Adequacy Assessment" (IMO_REP_0044). Results of the adequacy assessment are described in Section 3.1, conclusions are provided in Section 5, and detailed result numbers and tables can be found in Appendix A.

3.1 Assessment of Generation Resources Adequacy

3.1.1 Weekly Margins – Load &Capacity (L&C) Program Calculations

Reserve margins for each week, for both resource scenarios studied, under normal weather conditions, are shown in Figure 3.1. The total reductions to resources are shown in Figure 3.2. Further details and explicit values are provided in Appendix A. Analysis of forecast reserve margins indicates the following:

Under the **Base Resource Scenario**, most of the forecast reserve margins are positive in the period covered by this Outlook. For the upcoming winter, reserves are expected to be tight but adequate. Sufficient control measures are expected to be available to supplement generating capacity in the few weeks with negative reserve margins exceeding 500 MW. For the remainder of the 18-month period, reserves are generally well above requirements, indicating potential opportunities for scheduling additional generator outages and/or sales outside of Ontario. Based on past experience, and information available from external systems, external resources are expected to be available during the two weeks in December 2002, when about 750 MW of additional generating capacity could be needed to maintain reserves at desired levels. In March 2003, due to a large package of generator outages, up to 1,500 MW of additional generating capacity could be required to maintain adequate reserve levels. As neighbouring systems are outside their seasonal peak demand periods, sufficient additional generating capacity is expected to be available to cover most of this need. Alternatively, Ontario-based market participants could choose to reschedule planned generator outages.

Under the **Delayed Resource Scenario**, the resource picture is identical to the Base Resource Scenario, for the first four months of 2002. 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 than under the Base Resource Scenario, starting in May 2002. No opportunities for additional generator planned outages exist in the study period without additional alternate supply as indicated by the sparse occurrence of large positive margins. This scenario would only leave minimal room for additional forced outages or permit some flexibility in rescheduling the existing planned outages. For the period of November through December 2002, up to 1,800 MW of additional generating capacity will potentially be needed to maintain desired reserve levels. This is expected to be achievable through market participants offering external capacity into the Ontario market and/or through rescheduling planned generator outages. In March and April 2003, a potential resource shortfall is shown, in which case up to 4,500 MW of additional generating capacity would need to be made available to maintain adequate reserve levels. This is due to a large assortment of planned generator outages. Rescheduling of a large portion of these generator outages, as well as external generating capacity from neighbouring systems, is expected to be sufficient to restore reserves to required levels.

The IMO will closely monitor the resource situation, especially during the end of 2002 and spring of 2003, and implement the necessary control actions if required, in accordance with the Market Rules.

3.1.2 Loss of Load Expectation (LOLE)

A number of simulations were performed using General Electric's Multi-Area Reliability Simulation (MARS) software, to calculate the Loss of Load Expectation during the study period. The simulations start from the two resource scenarios described in Section 3.4 and use the methodology described in Section 2.3 of the document "Methodology to Perform 18-Month Resource and Transmission Adequacy Assessment" (IMO_REP_0044). MARS simulation results indicate the following:

The Loss of Load Expectation (LOLE) value for 2002 is 0.074 days/year, and for the first half of 2003 is 0.036 days/year. When compared to the target values of 0.1 days/year for 2002, and 0.05 days/year for the first half of 2003, these values indicate that the Ontario electricity system meets the NPCC resource adequacy criterion during the study period. The largest contribution to each of the two risk levels is made during the months of January, February, March, and December, for 2002, and March and April, for 2003. In these months, to achieve the target LOLE values, additional capacity up to approximately the largest margin deficiencies shown in Appendix A, under each of the two resource scenarios, could be required.

3.1.3 Overall Adequacy of Energy Production Capability

An overall monthly energy adequacy assessment has been performed, based on forecast energy production capabilities of the generating units provided by their operators. Figure 3.3 depicts the energy adequacy situation under the two resource scenarios. The detailed result table can be found in Appendix A. The energy production capability is generally expected to be well above energy demand levels in each month of the Outlook period, under both the Base and Delayed Resource Scenarios. No additional energy is expected to be needed to meet the Ontario forecast energy demand, other than provided by internal resources and through energy-backed firm purchase contracts identified for the Outlook period. Although the overall monthly energy production capability is forecast to be adequate, shorter-term energy deficiencies can arise as a result of forced outage situations, extreme demands and other influencing factors. Shorter-term energy studies are undertaken closer to real-time, which provide a more detailed assessment.

3.1.4 Uncertainties in Forecast Margins and Loss of Load Expectation

Uncertainties in demands due to weather effects and uncertainties in generator forced outages have been taken into account in assessment studies, as described in Section 2.2 of the document titled "Methodology to Perform 18-Month Resource and Transmission Adequacy Assessment" (IMO_REP_0044). The Required Reserve Margin and Loss of Load Expectation (LOLE) calculations both 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 Outlooks. 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 rate uncertainties in excess of the allowance already included in the assessment can have negative impacts on reserve margins and LOLE values. 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, as considered in the Delayed Resource Scenario in the present Outlook.

3.1.5 Outage Coordination and 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, to 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, the outage coordination process established by market rules is intended to maintain 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. 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 role for additional external resources and suggest that generation impactive outages should be rescheduled to a more optimal time-period to restore the prescribed reserve levels.

Figure 3.1 18-Month Forecast of Generation Capacity Adequacy

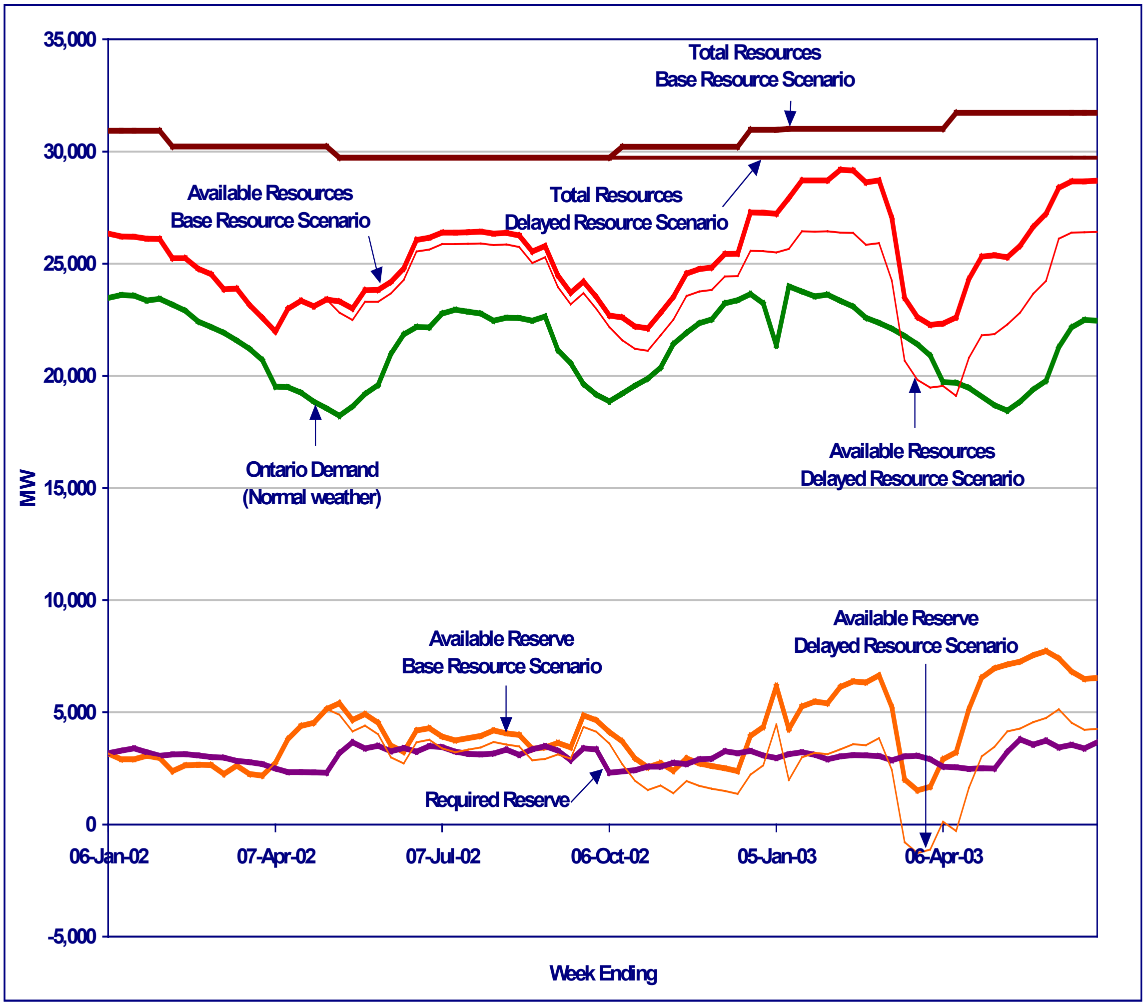


Figure 3.2 Total Reductions in Resources

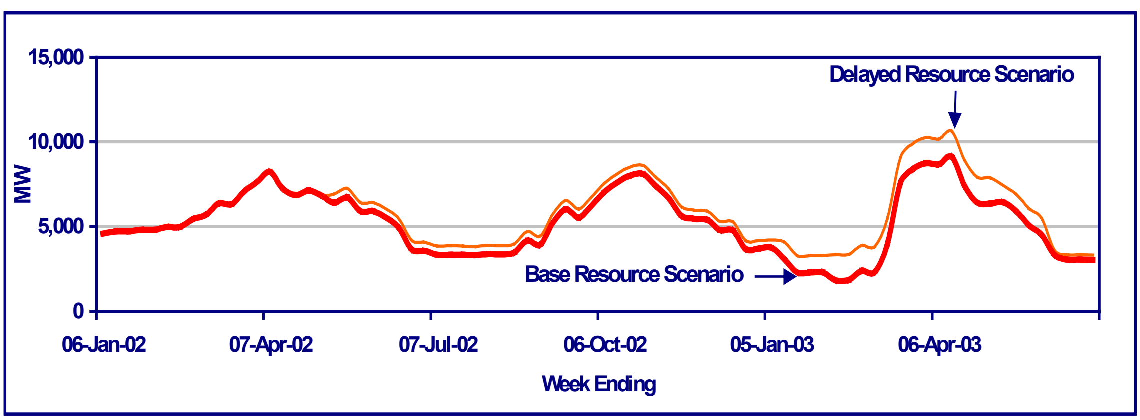
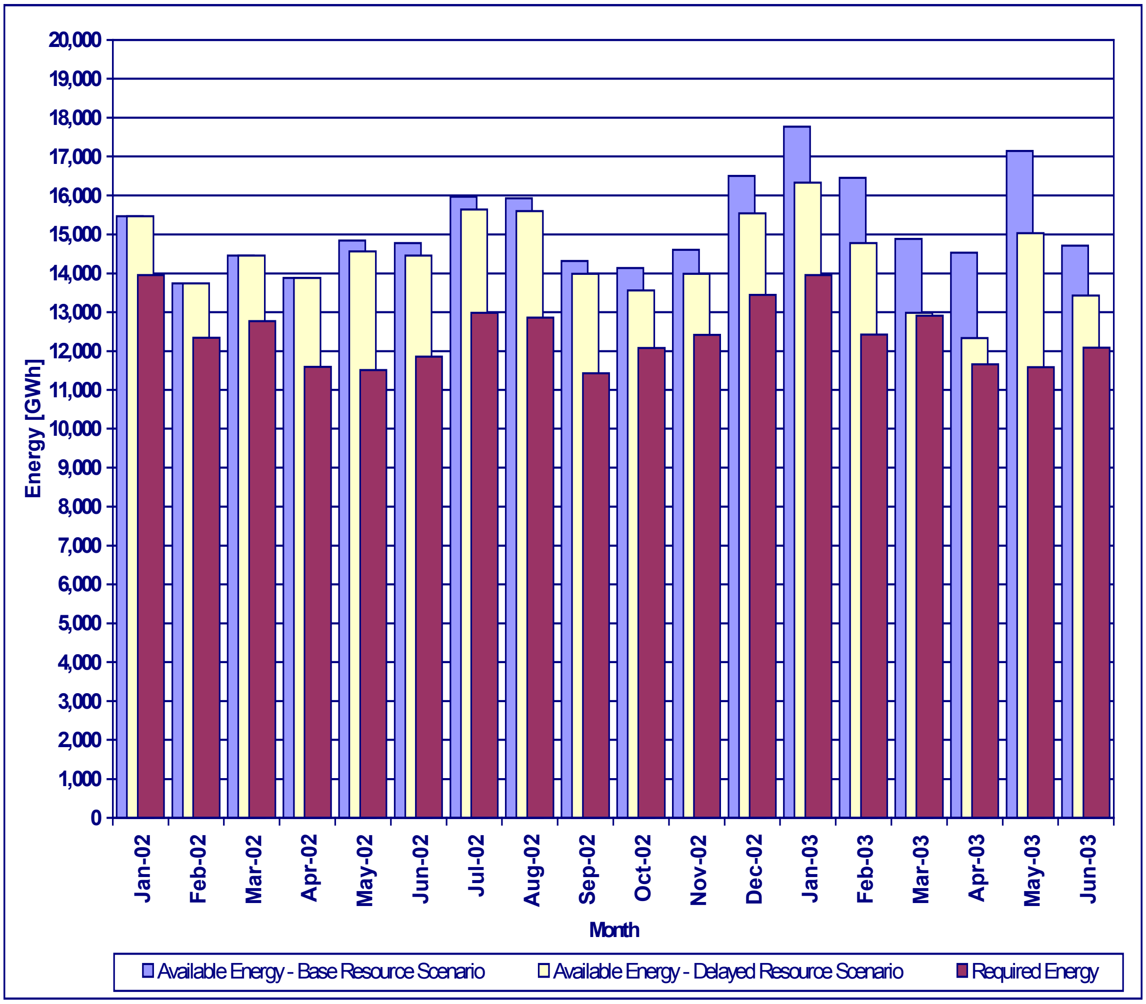


Figure 3.3 18-Month Forecast of Energy Production Capability



4.0 Transmission Adequacy Assessment

This Section provides an assessment of the adequacy of the Ontario transmission system.

4.1 Changes from the Previous 18-Month Outlook

Committed transmission projects are summarized in Appendix B by transmission zone. The projects were taken from information provided by Hydro One as of November 14, 2001. For the time period of this Outlook, Hydro One has committed transmission projects in all transmission zones except Bruce and Essa.

Most of the committed projects listed in the previous Outlook with projected in-service dates between October 1, 2001 and December 31, 2001 have been completed or are expected to be completed by the end of 2001. The reconnection of Manordale, Fallowfield, Richmond and Manotick customers stations from 115 kV circuit C7BM to 115 kV circuit W6MC has been completed except for Manordale. The reconnection of Manordale is expected to be completed by March 2002. The station refurbishment and reconfiguration of 115 kV facilities at Brockville Transformer Station (TS) is also excepted to be completed by March 2002, instead of December 2001.

Other changes in projected in-service dates include Chenaux TS project from July 2002 to July 2003, Kanata Municipal Transformer Station (MTS) project from July 2002 to June 2002, and Manby TS project from May 2002 to April 2003.

The projected in-service date of the committed transmission project associated with the TransAlta generating project in the West zone has changed from October 2002 to March 2002. 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 is expected to be upgraded. Further details on this project can be found on the IMO's web site www.theIMO.com under the "Services - Connection Assessments" link.

There are also several new committed transmission projects listed in the tables of Appendix B. The addition of a 125 MVAR capacitor bank at the Hearn Switching Station in the Toronto zone is expected to be completed by May 2003. The addition of this capacitor bank will help alleviate potential low voltage concerns during high summer demand peaks in this zone. Capacitor banks are also being added at several 115 kV stations in the Southwest and West zones. These capacitor banks will help alleviate potential low voltage concerns during high summer demands periods in the Detweiler/Seaforth and Buchanan/Scott 115 kV areas.

The status of the Ontario – Michigan interconnection modification project remains unchanged from the previous Outlook. At this time, the L4D and L51D phase shifters are not in-service. 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 L4D, the expected in-service date of the new 845 MVA phase shifter at the Lambton Thermal Generating Station (TGS) has changed from December 15, 2001 to March 1, 2002. For 230 kV circuit L51D, the failed 845 MVA phase shifter at the Lambton TGS is expected to return to service by October 2002. Complete phase shifting control of the Ontario – Michigan interconnection can only be utilized when all three phase shifters are in-service. There is an expectation that this will likely happen around October 2002.

In previous Outlooks, the FABC limit was incorrectly published as 5,200 MW. However, the Outlooks' results remain unchanged since the FABC was never limiting under the resource scenarios considered. The corrected FABC limit ranges from 4,050 MW to 4,450 MW for four Bruce B units in-service.

Another change in this Outlook has been the addition of a tenth transmission zone called "Ottawa" in the geographic depiction of Ontario's internal transmission zones. In previous Outlooks, the Ontario transmission system had been modeled by only nine internal transmission zones, where the Ottawa zone was considered part of the East zone. With the expected construction of a new High Voltage Direct Current (HVDC) interconnection between Ottawa and Quebec, this area of the province will likely have a higher profile in future transmission adequacy assessments.

The boundary between the Toronto and East zones has also been changed in this Outlook. As a result, the "Flow West Into Cherrywood" (FWIC) interface detailed in previous Outlooks has been removed. The zones are now separated by an interface called "Transfer East of Cherrywood" (TEC). This change of interfaces was made to align interfaces studied in the Outlook with those interfaces detailed in the IMO System Control Orders (SCOs). As a result of this boundary change the Darlington Nuclear Generating Station is now considered to be located in the Toronto zone, not the East zone.

Figure 3.1.1 in the IMO document "Methodology to Perform Resource and Transmission Adequacy Assessments" (IMO_REP_0044) provides a pictorial depiction of Ontario's ten zones, major transmission interfaces and interconnections with neighbouring jurisdictions.

4.2 Assessment of Transmission Outage Plan

The principal purpose of the transmission adequacy assessment is to forecast any reduction in transmission capacity brought about by specific transmission outages. For a major transmission interface or interconnection, the reduction in transmission capacity due to an outage condition can be expressed as a change in the base flow limit associated with the interface or interconnection. Another purpose of the transmission adequacy is to identify the possibility of any security-related events on the IMO controlled grid that could require contingency planning by Market Participants or by the IMO. As a result, the transmission outages are reviewed to identify transmission system reliability concerns and to highlight those outages that could be rescheduled.

Transmitters and generators are expected to have a mutual interest in developing an ongoing arrangement to coordinate their outage planning activities. Transmission outages that may affect generation access to the IMO-controlled grid should be coordinated with the generator operators involved, especially at times when generation reserve margins are below required levels. Under the Market Rules, where the scheduling of planned outages by different market participants conflicts such that both or all outages cannot be approved by the IMO, the IMO will inform the affected market participants and request that they resolve the conflict. If the conflict remains unresolved, the IMO shall determine which of the planned outages can be approved according to the precedence of each planned outage as determined by the Market Rules detailed in Chapter 5, Sections 6.4.13 to 6.4.18.

During the transitional period prior to market opening, the Hydro One Networks outage plan is the only transmitter outage plan considered in the Outlook. For this Outlook, the Hydro One outage plan submitted to the IMO on November 6, 2001 was used.

The IMO's assessment of the impact of the transmission outage plan provided by Hydro One is shown in Appendix C, Tables C5.1 to C5.10 for each transmission zone. 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. The methodology used to assess the transmission outage plan is described in a separate IMO document titled "Methodology to Perform Resource and Transmission Adequacy Assessment" (IMO_REP_0044).

In summary, only a few of the planned outages will potentially impact transmission system reliability. The outages with the highest potential impact are listed below:

Northeast Transmission Zone

The 115 kV L1S circuit outage from July 10, 2001 to January 4, 2002 affects the Quebec North interconnection. However, the outage is not expected to be limiting.

Southwest Transmission Zone

The simultaneous outages of 230 kV circuits D6V (Detweiler x Scheifele) and D7V (Detweiler x Scheifele) from January 14, 2002 to January 23, 2002 affects the limit associated with the FABC interface. These outages are not expected to be limiting. However, since the two outages are scheduled at a time where high winter demands are likely to occur, there is a concern that a contingency involving 230 kV circuits B4V or B5V will result in unacceptable voltage declines for loads local to this electrical area. As time approaches the scheduled start date of these outages, the IMO will reassess the outages to determine more accurately the possible system impacts.

West Transmission Zone

The Scott TS L23N terminal outage from January 28, 2002 to March 18, 2002 will leave 230 kV circuit L23N in-service radially from Lambton TGS. This outage affects the FABC limit. It is not expected to be limiting. However, there is a concern that a double circuit loss of 230 kV circuits L25N and L27N would leave Scott TS with no connection to Lambton TGS. Under such a scenario, the use of reactive resources at Buchanan TS is expected to be sufficient to maintain voltage levels at Scott TS within an acceptable range.

This Outlook has limited the assessment of transmission outages, to those transmission outages identified by Hydro One, which have a duration of six days or more. The IMO recognizes that there are expected to be additional outage requirements and/or changes as time approaches the Outlook study period and that transmission capacity will be impacted by outages with durations of five days or less. Prior to approving and releasing an outage, the IMO will, as required, reassess the outage for potential system impacts, taking into account all current and forecasted conditions.

4.3 System Voltage and Thermal Limits

As in previous Outlooks, 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 periods of time when the Ontario summer peak demand exceeds 25,000 MW, maintaining acceptable voltage levels may require the use of the J5D interconnection for importing power into Ontario. 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 and 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. Planned outages and restrictions on the use of the reactive capability of the Lakeview, Pickering and Darlington units should be avoided during 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.

4.4 Forced Outages

Due to a forced outage, the Whiteshell T8 transformer in Manitoba is unavailable until January 30, 2002. This has reduced the transfer capability between Manitoba and Ontario. However, the 200 MW purchase from Manitoba can be maintained. 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 March 29, 2002. This outage penalizes the FABC interface limit by 50 MW, but is not considered restrictive.

5.0 Overall Findings and Conclusions

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 NPCC resource adequacy criteria for the next 18 months.

- Adequate capacity and energy production capability is expected for the study period. The Loss of Load Expectation, (LOLE) is expected to be within the NPCC resource adequacy criterion.
- External resources are likely to be available during the periods for which negative reserve margins are forecast. During most of these periods, neighbouring systems are outside their seasonal peak demand.
- Market participant response to market signals is expected to avoid a potential capacity shortfall that has been identified for the months of April and May 2003, due to significant generation capacity that is forecast to be on planned outage. Planned outage rescheduling, in addition to supply from external resources, is expected to maintain adequate reserve levels.
- Sufficient control actions are available to manage uncertainties in demand or resource levels, which might exceed the allowances covered by the Required Reserve.
- Rescheduling of the simultaneous outages of 230 kV circuits D6V (Detweiler x Scheifele) and D7V (Detweiler x Scheifele) planned for January 2002 will eliminate voltage concerns associated with this planned outage
- The 200 MW import from Manitoba is expected to be maintained throughout the study period despite the forced outage of the Whiteshell T8 transformer that reduces the Ontario - Manitoba transfer capability and may at times limit dispatch flexibility in the Northwest zone.
- Avoiding planned outages and maximizing 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.
- Restricting planned outages to transmission facilities in the Windsor area will assist in maintaining adequate voltage levels during summer peak periods
- Rotating reactive resources in the Thunder Bay area will continue to be required to address local voltage concerns.

Appendix A Resource Adequacy Assessment Details

Table A1 Assessment of Resource Adequacy Base Resource 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
06-Jan-02	23,470	30,923	4,593	26,330	13.6	3,160	13.7	3,176	-16
13-Jan-02	23,596	30,923	4,719	26,204	12.5	2,908	14.1	3,286	-378
20-Jan-02	23,579	30,923	4,730	26,193	12.5	2,914	14.5	3,384	-470
27-Jan-02	23,354	30,923	4,809	26,114	13.3	3,060	14.0	3,226	-166
03-Feb-02	23,434	30,923	4,823	26,100	12.8	2,966	13.2	3,062	-96
10-Feb-02	23,161	30,223	4,981	25,242	10.4	2,381	13.6	3,117	-736
17-Feb-02	22,911	30,223	4,985	25,238	11.6	2,627	13.9	3,134	-507
24-Feb-02	22,406	30,223	5,449	24,774	12.1	2,668	14.0	3,087	-419
03-Mar-02	22,173	30,223	5,698	24,525	12.1	2,652	13.7	3,005	-353
10-Mar-02	21,916	30,223	6,363	23,860	10.4	2,244	13.8	2,979	-735
17-Mar-02	21,572	30,223	6,331	23,892	12.3	2,620	13.3	2,836	-216
24-Mar-02	21,208	30,223	7,073	23,150	10.7	2,242	13.3	2,785	-543
31-Mar-02	20,710	30,223	7,635	22,588	10.7	2,178	13.2	2,692	-514
07-Apr-02	19,518	30,223	8,252	21,971	14.3	2,753	13.0	2,489	264
14-Apr-02	19,489	30,223	7,229	22,994	19.8	3,805	12.1	2,326	1,479
21-Apr-02	19,249	30,223	6,883	23,340	23.2	4,391	12.4	2,343	2,048
28-Apr-02	18,856	30,223	7,125	23,098	24.5	4,542	12.5	2,320	2,222
05-May-02	18,553	30,223	6,818	23,405	28.2	5,152	12.7	2,312	2,840
12-May-02	18,219	29,723	6,402	23,321	30.1	5,402	17.7	3,165	2,237
19-May-02	18,636	29,723	6,724	22,999	25.4	4,663	20.0	3,663	1,000
26-May-02	19,188	29,723	5,916	23,807	26.0	4,919	18.0	3,401	1,518
02-Jun-02	19,581	29,723	5,905	23,818	23.5	4,537	18.2	3,504	1,033
09-Jun-02	20,975	29,723	5,537	24,186	17.0	3,511	15.7	3,253	258
16-Jun-02	21,850	29,723	4,942	24,781	15.0	3,231	15.8	3,410	-179
23-Jun-02	22,177	29,723	3,666	26,057	19.1	4,180	14.8	3,244	936
30-Jun-02	22,160	29,723	3,570	26,153	19.6	4,293	16.0	3,490	803
07-Jul-02	22,771	29,723	3,335	26,388	17.4	3,917	15.3	3,446	471
14-Jul-02	22,941	29,723	3,339	26,384	16.5	3,743	14.4	3,249	494
21-Jul-02	22,855	29,723	3,323	26,400	17.0	3,845	14.0	3,148	697
28-Jul-02	22,771	29,723	3,305	26,418	17.6	3,947	13.9	3,121	826
04-Aug-02	22,454	29,723	3,381	26,342	18.9	4,188	14.3	3,159	1,029
11-Aug-02	22,593	29,723	3,361	26,362	18.3	4,069	15.0	3,336	733
18-Aug-02	22,568	29,723	3,463	26,260	17.9	3,992	14.0	3,108	884
25-Aug-02	22,468	29,723	4,178	25,545	15.2	3,377	15.1	3,357	20
01-Sep-02	22,648	29,723	3,935	25,788	15.4	3,440	15.6	3,497	-57
08-Sep-02	21,136	29,723	5,255	24,468	17.4	3,632	15.8	3,286	346
15-Sep-02	20,560	29,723	6,020	23,703	17.0	3,443	14.2	2,870	573
22-Sep-02	19,631	29,723	5,527	24,196	25.2	4,865	17.5	3,387	1,478
29-Sep-02	19,159	29,723	6,218	23,505	24.6	4,646	17.8	3,351	1,295
06-Oct-02	18,869	29,723	7,039	22,684	22.2	4,115	12.4	2,303	1,812
13-Oct-02	19,201	30,213	7,612	22,601	19.6	3,700	12.5	2,360	1,340
20-Oct-02	19,549	30,213	8,009	22,204	15.4	2,955	12.6	2,416	539
27-Oct-02	19,873	30,213	8,092	22,121	13.0	2,548	13.2	2,577	-29
03-Nov-02	20,365	30,213	7,411	22,802	13.6	2,737	12.8	2,577	160
10-Nov-02	21,423	30,213	6,696	23,517	11.3	2,394	13.0	2,755	-361
17-Nov-02	21,915	30,213	5,654	24,559	13.6	2,944	12.4	2,688	256
24-Nov-02	22,341	30,213	5,453	24,760	12.3	2,719	13.2	2,915	-196
01-Dec-02	22,519	30,213	5,389	24,824	11.7	2,605	13.2	2,938	-333
08-Dec-02	23,227	30,213	4,785	25,428	10.9	2,501	14.2	3,252	-751
15-Dec-02	23,371	30,213	4,772	25,441	10.3	2,370	13.7	3,167	-797
22-Dec-02	23,637	30,963	3,685	27,278	16.9	3,941	14.0	3,273	668
29-Dec-02	23,226	30,963	3,694	27,269	18.9	4,343	13.4	3,073	1,270

(Table A1 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
05-Jan-03	21,340	30,963	3,748	27,215	29.3	6,175	14.1	2,962	3,213
12-Jan-03	23,984	31,011	3,077	27,934	17.9	4,250	13.2	3,122	1,128
19-Jan-03	23,753	31,011	2,292	28,719	22.5	5,266	13.8	3,226	2,040
26-Jan-03	23,539	31,011	2,298	28,713	23.6	5,474	13.4	3,106	2,368
02-Feb-03	23,615	31,011	2,290	28,721	23.2	5,406	12.5	2,916	2,490
09-Feb-03	23,346	31,011	1,827	29,184	26.6	6,138	13.2	3,031	3,107
16-Feb-03	23,091	31,011	1,851	29,160	27.9	6,369	13.6	3,094	3,275
23-Feb-03	22,599	31,011	2,384	28,627	28.4	6,328	13.8	3,069	3,259
02-Mar-03	22,360	31,011	2,309	28,702	30.1	6,642	13.8	3,055	3,587
09-Mar-03	22,100	31,011	3,978	27,033	24.0	5,233	13.2	2,873	2,360
16-Mar-03	21,771	31,011	7,539	23,472	9.3	2,001	14.2	3,040	-1,039
23-Mar-03	21,394	31,011	8,399	22,612	7.2	1,518	14.5	3,064	-1,546
30-Mar-03	20,897	31,011	8,741	22,270	8.1	1,673	14.1	2,909	-1,236
06-Apr-03	19,721	31,011	8,679	22,332	15.0	2,911	13.3	2,581	330
13-Apr-03	19,687	31,721	9,121	22,600	16.6	3,213	13.2	2,550	663
20-Apr-03	19,463	31,721	7,416	24,305	26.8	5,142	12.9	2,481	2,661
27-Apr-03	19,069	31,721	6,412	25,309	34.8	6,540	13.4	2,506	4,034
04-May-03	18,697	31,721	6,356	25,365	37.9	6,968	13.5	2,492	4,476
11-May-03	18,443	31,721	6,437	25,284	39.4	7,141	17.8	3,230	3,911
18-May-03	18,838	31,721	5,927	25,794	39.1	7,256	20.4	3,789	3,467
25-May-03	19,390	31,721	5,080	26,641	39.6	7,551	18.7	3,574	3,977
01-Jun-03	19,783	31,721	4,503	27,218	39.7	7,735	19.2	3,735	4,000
08-Jun-03	21,273	31,721	3,338	28,383	35.3	7,410	16.3	3,426	3,984
15-Jun-03	22,147	31,721	3,059	28,662	31.2	6,815	16.2	3,543	3,272
22-Jun-03	22,481	31,721	3,048	28,673	29.3	6,492	15.3	3,398	3,094
29-Jun-03	22,457	31,721	3,031	28,690	29.5	6,533	16.5	3,656	2,877

Table A2 Assessment of Resource Adequacy
Delayed Resource 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
06-Jan-02	23,470	30,923	4,593	26,330	13.6	3,160	13.7	3,176	-16
13-Jan-02	23,596	30,923	4,719	26,204	12.5	2,908	14.1	3,286	-378
20-Jan-02	23,579	30,923	4,730	26,193	12.5	2,914	14.5	3,384	-470
27-Jan-02	23,354	30,923	4,809	26,114	13.3	3,060	14.0	3,226	-166
03-Feb-02	23,434	30,923	4,823	26,100	12.8	2,966	13.2	3,062	-96
10-Feb-02	23,161	30,223	4,981	25,242	10.4	2,381	13.6	3,117	-736
17-Feb-02	22,911	30,223	4,985	25,238	11.6	2,627	13.9	3,134	-507
24-Feb-02	22,406	30,223	5,449	24,774	12.1	2,668	14.0	3,087	-419
03-Mar-02	22,173	30,223	5,698	24,525	12.1	2,652	13.7	3,005	-353
10-Mar-02	21,916	30,223	6,363	23,860	10.4	2,244	13.8	2,979	-735
17-Mar-02	21,572	30,223	6,331	23,892	12.3	2,620	13.3	2,836	-216
24-Mar-02	21,208	30,223	7,073	23,150	10.7	2,242	13.3	2,785	-543
31-Mar-02	20,710	30,223	7,635	22,588	10.7	2,178	13.2	2,692	-514
07-Apr-02	19,518	30,223	8,252	21,971	14.3	2,753	13.0	2,489	264
14-Apr-02	19,489	30,223	7,229	22,994	19.8	3,805	12.1	2,326	1,479
21-Apr-02	19,249	30,223	6,883	23,340	23.2	4,391	12.4	2,343	2,048
28-Apr-02	18,856	30,223	7,125	23,098	24.5	4,542	12.5	2,320	2,222
05-May-02	18,553	30,223	6,818	23,405	28.2	5,152	12.7	2,312	2,840
12-May-02	18,219	29,723	6,917	22,806	27.3	4,887	17.3	3,100	1,787
19-May-02	18,636	29,723	7,239	22,484	22.6	4,148	19.6	3,598	550
26-May-02	19,188	29,723	6,431	23,292	23.3	4,404	17.6	3,318	1,086
02-Jun-02	19,581	29,723	6,420	23,303	20.9	4,022	17.9	3,444	578
09-Jun-02	20,975	29,723	6,052	23,671	14.5	2,996	15.8	3,269	-273
16-Jun-02	21,850	29,723	5,457	24,266	12.6	2,716	15.9	3,418	-702
23-Jun-02	22,177	29,723	4,181	25,542	16.8	3,665	14.7	3,217	448
30-Jun-02	22,160	29,723	4,085	25,638	17.3	3,778	15.7	3,440	338
07-Jul-02	22,771	29,723	3,850	25,873	15.1	3,402	15.3	3,432	-30
14-Jul-02	22,941	29,723	3,854	25,869	14.3	3,228	14.4	3,261	-33
21-Jul-02	22,855	29,723	3,838	25,885	14.8	3,330	13.9	3,143	187
28-Jul-02	22,771	29,723	3,820	25,903	15.3	3,432	13.8	3,096	336
04-Aug-02	22,454	29,723	3,896	25,827	16.6	3,673	14.0	3,108	565
11-Aug-02	22,593	29,723	3,876	25,847	15.9	3,554	14.8	3,300	254
18-Aug-02	22,568	29,723	3,978	25,745	15.6	3,477	13.8	3,076	401
25-Aug-02	22,468	29,723	4,693	25,030	12.9	2,862	15.2	3,369	-507
01-Sep-02	22,648	29,723	4,450	25,273	13.1	2,925	15.7	3,508	-583
08-Sep-02	21,136	29,723	5,770	23,953	15.0	3,117	15.7	3,266	-149
15-Sep-02	20,560	29,723	6,535	23,188	14.5	2,928	14.2	2,885	43
22-Sep-02	19,631	29,723	6,042	23,681	22.5	4,350	17.1	3,297	1,053
29-Sep-02	19,159	29,723	6,733	22,990	21.9	4,131	17.3	3,270	861
06-Oct-02	18,869	29,723	7,554	22,169	19.4	3,600	12.0	2,221	1,379
13-Oct-02	19,201	29,723	8,127	21,596	14.3	2,695	12.2	2,314	381
20-Oct-02	19,549	29,723	8,524	21,199	10.1	1,950	12.7	2,443	-493
27-Oct-02	19,873	29,723	8,607	21,116	7.9	1,543	13.3	2,607	-1,064
03-Nov-02	20,365	29,723	7,926	21,797	8.6	1,732	13.0	2,605	-873
10-Nov-02	21,423	29,723	7,211	22,512	6.6	1,389	13.2	2,782	-1,393
17-Nov-02	21,915	29,723	6,169	23,554	9.0	1,939	12.6	2,717	-778
24-Nov-02	22,341	29,723	5,968	23,755	7.8	1,714	13.3	2,938	-1,224
01-Dec-02	22,519	29,723	5,904	23,819	7.2	1,600	13.3	2,964	-1,364
08-Dec-02	23,227	29,723	5,300	24,423	6.5	1,496	14.3	3,277	-1,781
15-Dec-02	23,371	29,723	5,287	24,436	5.9	1,365	13.8	3,191	-1,826
22-Dec-02	23,637	29,723	4,160	25,563	9.5	2,226	14.2	3,312	-1,086
29-Dec-02	23,226	29,723	4,169	25,554	11.5	2,628	13.4	3,067	-439

(Table A2 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
05-Jan-03	21,340	29,723	4,223	25,500	21.2	4,460	12.9	2,705	1,755
12-Jan-03	23,984	29,723	4,067	25,656	8.3	1,972	13.6	3,210	-1,238
19-Jan-03	23,753	29,723	3,282	26,441	12.7	2,988	13.4	3,151	-163
26-Jan-03	23,539	29,723	3,288	26,435	13.8	3,196	12.8	2,977	219
02-Feb-03	23,615	29,723	3,280	26,443	13.4	3,128	12.0	2,802	326
09-Feb-03	23,346	29,723	3,332	26,391	14.5	3,345	12.2	2,821	524
16-Feb-03	23,091	29,723	3,356	26,367	15.7	3,576	12.5	2,839	737
23-Feb-03	22,599	29,723	3,889	25,834	15.9	3,535	12.6	2,800	735
02-Mar-03	22,360	29,723	3,814	25,909	17.4	3,849	12.4	2,727	1,122
09-Mar-03	22,100	29,723	5,483	24,240	11.2	2,440	12.9	2,818	-378
16-Mar-03	21,771	29,723	9,044	20,679	-3.7	-792	14.9	3,206	-3,998
23-Mar-03	21,394	29,723	9,904	19,819	-6.0	-1,275	15.4	3,241	-4,516
30-Mar-03	20,897	29,723	10,246	19,477	-5.4	-1,120	14.9	3,065	-4,185
06-Apr-03	19,721	29,723	10,184	19,539	0.6	118	14.3	2,771	-2,653
13-Apr-03	19,687	29,723	10,626	19,097	-1.5	-290	14.3	2,764	-3,054
20-Apr-03	19,463	29,723	8,921	20,802	8.6	1,639	12.4	2,370	-731
27-Apr-03	19,069	29,723	7,917	21,806	16.2	3,037	11.2	2,102	935
04-May-03	18,697	29,723	7,861	21,862	18.8	3,465	11.0	2,021	1,444
11-May-03	18,443	29,723	7,427	22,296	22.9	4,153	15.9	2,885	1,268
18-May-03	18,838	29,723	6,917	22,806	23.0	4,268	18.7	3,463	805
25-May-03	19,390	29,723	6,070	23,653	23.9	4,563	16.9	3,230	1,333
01-Jun-03	19,783	29,723	5,493	24,230	24.4	4,747	17.4	3,398	1,349
08-Jun-03	21,273	29,723	3,618	26,105	24.5	5,132	15.1	3,169	1,963
15-Jun-03	22,147	29,723	3,339	26,384	20.8	4,537	15.0	3,284	1,253
22-Jun-03	22,481	29,723	3,328	26,395	19.0	4,214	14.1	3,135	1,079
29-Jun-03	22,457	29,723	3,311	26,412	19.2	4,255	15.4	3,407	848

Table A3 Adequacy of the Energy Production Capability

Month	Required Energy (GWh)	Available Energy Base Resource Scenario (GWh)	Available Energy Delayed Resource Scenario (GWh)	Energy Margin Base Resource Scenario (GWh)	Energy Margin Delayed Resource Scenario (GWh)
Jan-02	13,949	15,471	15,471	1,522	1,522
Feb-02	12,344	13,744	13,744	1,400	1,400
Mar-02	12,769	14,461	14,461	1,692	1,692
Apr-02	11,595	13,886	13,886	2,291	2,291
May-02	11,512	14,844	14,564	3,332	3,052
Jun-02	11,857	14,775	14,452	2,918	2,595
Jul-02	12,987	15,972	15,639	2,985	2,652
Aug-02	12,859	15,929	15,596	3,071	2,737
Sep-02	11,427	14,314	13,991	2,887	2,564
Oct-02	12,080	14,141	13,558	2,061	1,478
Nov-02	12,417	14,606	13,984	2,189	1,566
Dec-02	13,440	16,509	15,543	3,069	2,103
Jan-03	13,950	17,774	16,330	3,823	2,380
Feb-03	12,429	16,452	14,776	4,023	2,347
Mar-03	12,907	14,881	12,986	1,974	79
Apr-03	11,665	14,530	12,333	2,864	668
May-03	11,589	17,146	15,029	5,557	3,440
Jun-03	12,094	14,707	13,429	2,614	1,335

Appendix B Committed Plans – Hydro One

East Zone - Committed Plans	Projected I/S Date
Brockville TS: Refurbish station-reconfigure 115 kV facilitites.	March 31, 2002
Longueuil TS: Feeder reconfiguration: Construct a double and single circuit 44 kV line in order to split the load on M23 between itself and the idle M25. Add a tie to facilitate outage planning.	June 30, 2002
Cobden TS: Install a second 44 kV feeder.	September 30, 2002

Niagara Zone - Committed Plans	Projected I/S Date
Allanburg TS: Install 115 kV series reactors.	October 31, 2002

Northeast Zone - Committed Plans	Projected I/S Date
Ramore TS: Build a new 115/27.6 kV station.	March 1, 2002
Martindale TS - KT22: Air blast circuit breaker replacement with SF6 type.	July 1, 2002
Martindale TS - PL24: Air blast circuit breaker replacement with SF6 type.	October 1, 2002

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

Ottawa Zone - Committed Plans	Projected I/S Date
Hawthorne TS: Replace RTUs for 500 kV facilities.	March 31, 2002
Kanata MTS: Provide 230 kV connection to C3S near South March.	June 7, 2002
Lincoln Heights TS - SC1/SC2: Replace capacitor banks.	December 31, 2002
Russell TS - SC1/SC2: Replace capacitor banks.	December 31, 2002

Southwest Zone - Committed Plans	Projected I/S Date
Waterloo North Hydro MTS3: Build 230 kV 2 circuit line tap to customer's 40/66 MVA station from D6V/D7V.	March 1, 2002
Centralia TS: Install 2nd 28 kV, 21.6 MVAR LV capacitor bank.	May 30, 2002
Cambridge & North Dumfries 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
Detweiler TS - SC1: Replace capacitor bank.	June 30, 2002

Toronto Zone - Committed Plans	Projected I/S Date
Brampton MTS #1: Provide 230 kV connection from R19T/R21T to new customer owned station (between Hanlan Jct & Pleasant TS).	May 1, 2002
Sheppard TS: Add 2 x 27.6 feeder positions to T1/T2 DESN (including breakers).	May 31, 2002
Fairchild TS - SC2/TSC2: Replace capacitor bank and capacitor breaker	October 1, 2002
Cecil TS: Replace T3/T4 with larger 100 MVA units.	December 31, 2002
Manby TS: Replace end of life 230/27.6 kV T3 transformer with one of equal rating.	April 1, 2003
Hearn SS: Add a 125 MVAR capacitor bank.	May 1, 2003

West Zone - Committed Plans	Projected I/S Date
Lauzon TS: Install new feeder position	February 28, 2002
Lambton TS: Install PS4 Phase-shifter.	March 1, 2002
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.	March 1, 2002
Chatham SS: Replace existing Chatham SC22 - 230 kV, 192 MX capacitor bank.	March 15, 2002
Malden TS: Install new feeder position.	March 15, 2002
Strathroy TS: Install 2nd 28 kV, 21.6 MVAR LV capacitor bank.	May 30, 2002
Wanstead TS: Install 28 kV, 21.6 MVAR LV capacitor bank.	May 30, 2002
Lambton GS: Install selective catalytic converter on G3, replace the two 230/41.16/4.16 kV, 36/18/18 MVA reserve SST RSS1/RSS2 with larger 43/21.5/21.5 MVA units. Replace drop leads & disconnect switches RSS1-K/RSS2-P.	June 9, 2002
Windsor Brighton Beach: Establish a permanent connection to the 680 MVA station at Keith TS; 2 units at 230 kV and 1 unit at 115 kV.	April 30, 2003

Appendix C Planned Transmission Outages – Hydro One

The following tables list the planned transmission outages by transmission zone, for transmission outages with an expected duration of six days or greater.

Table C5.1 - Bruce Zone

No outages to analyze.

Table C5.2 - East Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 29-Apr-02 08:00	Fri 10-May-02 16:00	Belleville TS.T1 Whitby TS.T4 Wilson TS.T2 Wilson TS.T4 B23C	CNW	3 Hours		

Table C5.3 - Essa Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Wed 03-Jul-02 07:00	Fri 26-Jul-02 18:00	S1H	CNW	3 Hours	Affects FABC. Not expected to be limiting.	100-200 MW.

Table C5.4 - Niagara Zone

No outages to analyze.

Table C5.5 - Northeast Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Tue 10-Jul-01 06:30	Fri 04-Jan-02 16:30	L1S (Coniston x Warren)	CNW	None	Affects Quebec North transfer. Not expected to be limiting.	5 MW D4Z or H4Z in Mode 2; 15 MW D4Z in Mode 3.
Tue 02-Apr-02 09:00	Fri 26-Apr-02 15:00	Martindale TS.KT22	CNW	None		
Wed 01-May-02 08:30	Wed 29-May-02 15:00	Martindale TS.PL24	CNW	None		
Mon 03-Jun-02 08:30	Fri 28-Jun-02 15:00	Martindale TS.L24L26	CNW	None		

Table C5.6 - Northwest Zone

No outages to analyze.

Table C5.7 - Ottawa Zone

No outages to analyze.

Table C5.8 - Southwest Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 14-Jan-02 08:00	Wed 23-Jan-02 16:00	D6V (DetweilerxScheifele), D7V (DetweilerxScheifele)	CNW	6 Hours	Affects FABC. Not expected to be limiting.	300-750 MW
Tue 02-Apr-02 06:00	Tue 16-Apr-02 16:00	Detweiler TS.AL4	CNW	None		
Tue 16-Apr-02 06:00	Tue 30-Apr-02 16:00	Detweiler TS.L4L23	CNW	None		

Table C5.9 - Toronto Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Fri 26-Oct-01 05:00	Tue 01-Jan-02 17:00	Bathurst TS.T2 Bathurst TS.T4 Fairchild TS.T1 Fairchild TS.T3 C18R	DNW	3 Hours	Affects FETT. Not expected to be limiting.	150 MW
Mon 07-Jan-02 05:00	Fri 01-Feb-02 16:00	H1L_LEASIDE H3L_LEASIDE	DNW	3 Hours		
Mon 07-Jan-02 07:00	Fri 25-Jan-02 16:00	Cecil TS.T1	CNW	3 Days		
Mon 28-Jan-02 07:00	Fri 08-Feb-02 16:00	John TS.T5	CNW	3 Days		
Mon 11-Feb-02 04:00	Fri 08-Mar-02 17:00	H11L_LEASIDE H7L_LEASIDE	DNW	3 Hours		
Mon 11-Feb-02 07:00	Fri 22-Feb-02 16:00	Carlaw TS.T2	CNW	3 Days		
Mon 25-Feb-02 16:00	Fri 08-Mar-02 07:00	Lakeview SS.L23T6	CNW	None		
Mon 18-Mar-02 16:00	Fri 29-Mar-02 07:00	Lakeview SS.L23T5	CNW	None		
Mon 25-Mar-02 04:00	Thu 25-Apr-02 17:00	H6LC_LEASIDE H8LC_LEASIDE	DNW	3 Hours		
Tue 21-May-02 04:00	Thu 20-Jun-02 17:00	H6LC_LEASIDE H8LC_LEASIDE	DNW	3 Hours		
Tue 23-Jul-02 04:00	Thu 22-Aug-02 17:00	H11L_LEASIDE H7L_LEASIDE	DNW	3 Hours		

Table C5.10 - West Zone

Start Date/Time	End Date/Time	Equipment	Outage Type	Recall	Impact	Reduction in Limit
Mon 28-Jan-02 06:00	Mon 18-Mar-02 18:00	Sarnia Scott TS.L23N_Terminal	CNW	None	Affects FABC. Not expected to be limiting. Not expected to affect generation reserve requirements.	50-100 MW.
Mon 08-Apr-02 07:00	Fri 19-Apr-02 19:00	Sarnia Scott TS.KL1	CNW	None		
Mon 22-Apr-02 07:00	Fri 03-May-02 15:00	Sarnia Scott TS.PL6	CNW	None		
Mon 06-May-02 07:00	Fri 17-May-02 15:00	Sarnia Scott TS.L2L4 Sarnia Scott TS.PL4 Sunoco CTS.T2 Sarnia Scott TS.N4S_Terminal N4S	CNW	None		
Mon 06-May-02 07:00	Fri 24-May-02 17:00	Chatham SS.SC21	CNW	None		
Mon 06-May-02 08:00	Fri 31-May-02 16:00	Chatham SC21K	CNW	2 Hours		