Independent Electricity Market Operator

10-Year Outlook:

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

from January 2003 to December 2012

Independent
Electricity
Market Operator

Executive Summary

This report presents an assessment of the security and adequacy of the Ontario Electricity System for the 10-year period from 2003 to 2012. 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.

Based on existing and proposed facilities, Ontario is expected to have a reliable supply of electricity during the forecast period under a wide-variety of conditions. Opportunities also exist for additional enhancements to improve the efficiency of the Ontario electricity market.

The assessments in this report were made based on a number of key planning assumptions. Assuming a median growth scenario, the energy demand is forecast to grow over the study period from 151 terawatt-hours (TWh) in 2003 to 164 TWh in 2012, at an average annual growth rate of 0.9%. Peak demands are forecast to increase from about 24,000 MW in 2003 to 26,000 MW in 2012 at an average annual growth rate of 0.9%. Under normal weather conditions, Ontario is expected to be summer peaking by 2008. However, given the high variability of summer peak demands, there is a possibility that actual summer peaks may be higher than the winter peaks in some or all of the years before 2008, as has been the case in the recent past. In addition to the median forecast, low and high demand growth scenarios were produced. The low growth scenario exhibits an average annual energy growth rate of 0.7%, and the high growth scenario exhibits an average annual growth rate of 1.4%.

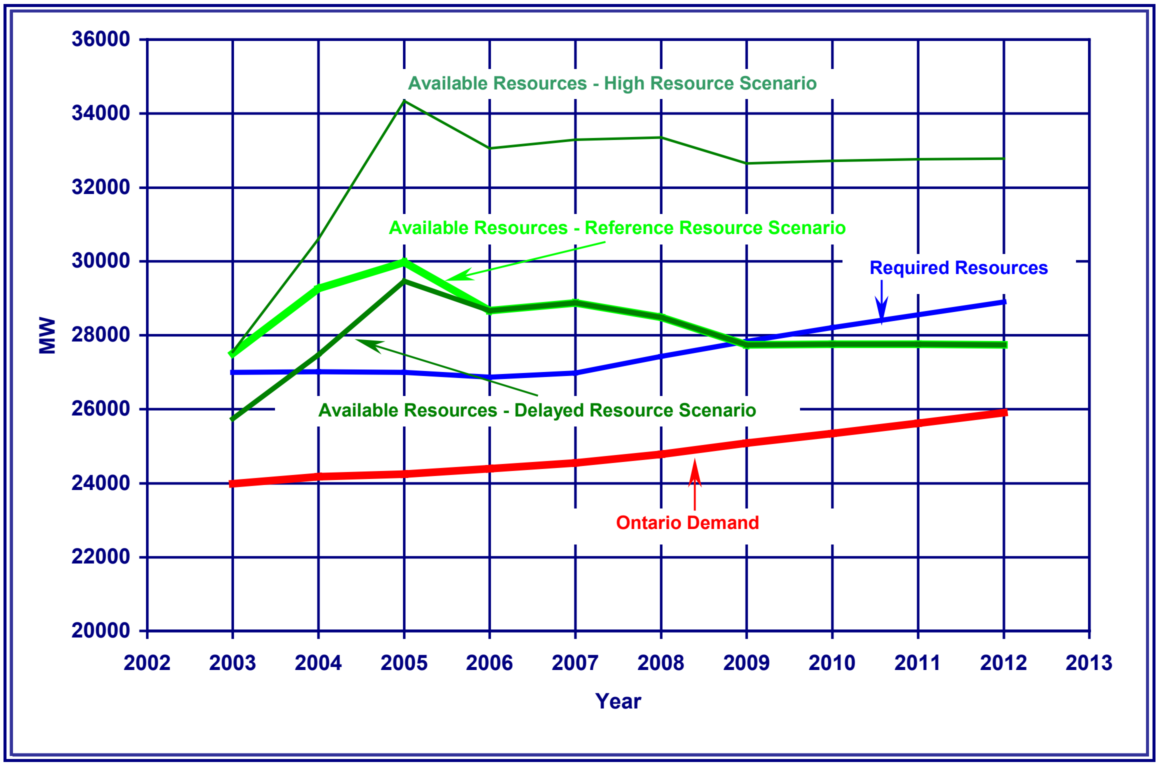
About 6,200 MW of generation additions are proposed for the period 2002 to 2005. For resource adequacy assessment purposes, three possible resource availability scenarios are modeled. A Reference Resource Scenario is considered, which assumes returning nuclear units and new generation resources currently under construction in Ontario come into service as forecast by market participants. A Delayed Resource Scenario is considered, which assumes the same additional generation resources come into service one year later than forecast. A High Resource Scenario is also considered, which assumes all additional generation resources proposed to the IMO under the Connection Assessment and Approval process come into service as forecast by market participants. Each resource scenario includes only available generation in Ontario and external supply pre-committed to Ontario. The resource scenarios do not include additional resources external to Ontario that are expected to be available.

The Northeast Power Coordinating Council (NPCC) reliability standard, based on a Loss of Load Expectation (LOLE) of not more than once in 10 years, is forecast to be met throughout the study period based on resources within and external to Ontario that are expected to participate in the Ontario market.

Under the Reference Resource Scenario with median demand growth, additional resources within Ontario are forecast to be required for reliability purposes beginning in 2009. These additional resources could take the form of new generation or price responsive demand. Figure 1 shows graphically a summary of the annual peak outlook assuming a median demand growth, and showing the three scenarios of resource availability.

In addition to considering the adequacy of existing generation, this Outlook estimates the collective impact of all proposed new generation projects, as identified to the IMO through the Connection Assessment and Approval process. If all generation proposals are built and operated, the amount of generation that is exclusively gas fuelled would increase from 6% to 21% of the installed capacity within Ontario by 2005. Another 6% of the installed capacity would be dual-fuelled with gas. Other jurisdictions in the Northeast U.S. are projecting a similar increasing dependency on gas-fired generation and have raised concerns regarding the ability of the current and planned gas pipeline infrastructure to meet increased demands due to new gas-fired generation. In recognition of this concern, the IMO has initiated a multi-region study to assess the adequacy of the existing and planned gas pipeline infrastructure. This study is expected to be completed in 2003.

Figure 1 Annual Peak Resource Outlook – Median Demand Growth



The transmission system studied in this Outlook is capable of supplying loads in the various transmission zones under the generation and demand scenarios considered.

Construction of a 1,250 MW High Voltage Direct Current (HVDC) interconnection between Ontario and Quebec near Ottawa is expected to be completed during the forecast period. This new interconnection will substantially improve transfer capabilities between the two provinces. For purposes of this assessment, the interconnection is assumed to be in-service starting the second quarter of 2004.

In the course of undertaking Connection Assessment and Approval studies for several recent proposals related to supply in the greater Toronto area, concerns have been identified regarding the future supply capability of the existing facilities in this area. These concerns arise from operational requirements to respect the capabilities of transmission facilities in the face of increasing load and generation in the area. These capabilities begin to be of concern during summer peak demand conditions beginning in 2004, but stopgap measures could be implemented to manage these concerns until about 2006. Some of the solutions available to alleviate these concerns may take several years to complete. Because of the lead-times for implementation, market participants considering projects, in addition to those currently under study, should submit them to the IMO for assessment as early as possible.

Existing congestion is likely to continue on the East-West (EW) transmission interface emanating from the Northwest zone when supplying energy to southern Ontario.

If all of the generator additions proposed under the IMO CAA process in the South-western Ontario area come into service, congestion of up to 2,400 MW can be expected on the Negative Bruce Longwood Input (NBLIP) interface at times when the Toronto area is being supplied from the West. Transmission reinforcements would relieve this potential congestion.

Caution and Disclaimer

The contents of these materials are for discussion and information purposes and are provided "as is" without representation or warranty of any kind, including without limitation, accuracy, completeness or fitness for any particular purpose. The Independent Electricity Market Operator (IMO) assumes no responsibility to you or any third party for the consequences of any errors or omissions. The IMO may revise these materials at any time at its sole discretion without notice to you. Although every effort will be made by the IMO to update these materials to incorporate any such revisions it is up to you to ensure you are using the most recent version.

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1.0 Introduction

This report presents a 10-year forecast and assessment of the adequacy of the generation and transmission facilities in Ontario. Its primary purpose is to provide input to market participants for long-term planning and investment decisions.

This report incorporates the information received from market participants, between December 2001 and February 2002. It supercedes the previous 10-Year Outlook published by the IMO on June 29, 2001.

The focus of this Outlook is to provide insight into potential investment opportunities, including the need for new or modified IMO-controlled grid facilities to maintain the reliability of the system and to assist the IMO-administered markets to operate efficiently. An outlook period of ten years spans the lead-time to install most new generation and transmission facilities. The assessment of generation adequacy is based upon ensuring that sufficient resources are available to meet the forecast demand plus required reserves. Ontario generation that is available to operate is assumed to supply Ontario demand. The assessment of the adequacy of transmission is based upon ensuring that sufficient transmission capability is available to transmit power to loads in a secure manner with an acceptable degree of reliability.

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 2003 to December 2012" (IMO_REP_0049) (found on the IMO Web site at www.theimo.com/imoweb/pubs/marketReport/10Year_ODF_2003jan.pdf) describes in detail the forecast of electricity demand for Ontario used in this Outlook. The document provides 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 Demand Forecasts, Resource Adequacy Assessments and Transmission Adequacy Assessments" (IMO_REP_0044) (found on the IMO Web site at www.theimo.com/imoweb/pubs/marketReports/Methodology_RTAA_2002apr.pdf) contains information regarding the methodology used to perform the demand forecasts, and resource and transmission adequacy assessments in this Outlook.

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 Resources

This section describes the generation resources that are forecast to be available in the ten-year study period.

Section 2.1 describes the capacity of the existing installed generation resources that are included in the study. Section 2.2 describes the external transactions (imports and exports) that are considered. Section 2.3 summarizes new generation projects in Ontario, which have been identified to the IMO through the Connection Assessment and Approval (CAA) process. Section 2.4 provides an overall summary of the total resources included in the study, taking into account the existing generation, external transactions and the generation resource additions and retirements under various scenarios.

2.1 Existing Generation Resources Included in the Study

The existing installed generation included in the study is summarized in Table 2.1. 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 and result in a total installed capacity of 29,622 MW. Excluded from the study are retired generators, embedded generators that are not managed by Ontario Electricity Financial Corporation (OEFC) or generation not directly connected to the IMO-controlled grid.

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 A 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 into service, as described in Section 2.4.

Table 2.1 Existing Installed Resources Assumed in Study

Resource Type	Total, MW	# of Stations	Size Range, MW
Nuclear	10,808	4	515 - 881
Coal	7,553	5	155 - 490
Oil / Gas	3,662	30	0.43 - 525
Hydroelectric	7,522	127	0.04 - 136
Miscellaneous (wind, waste, wood, etc.)	77	7	1 - 40
Total	29,622	173	<1 - 881

Changes from the Previous 10-Year Outlook

The previous 10-Year Outlook reported installed generation resources totaling 29,492 MW. Differences are due to reallocation among resource types and minor changes in the rating for some generating units.

2.2 External Transactions Outside the Province

Purchases of 200 MW are assumed delivered to Ontario until October 31, 2003, and have been explicitly included in all resource availability scenarios studied. No sales have been explicitly identified.

2.3 Potential New Generation Resources

In accordance with the Market Rules set for the new Ontario marketplace, 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 potential new generation projects that were in the CAA queue as of February 4, 2002.

Table 2.2 Potential Generation Projects in Ontario

Project Name	System Zone	Resource Type	Capacity MW	Proponent's Estimated I/S Date
Transalta - SRCP	West	Gas	490	2002 - Q3
Northland (Kirkland)	Northeast	Gas	48	2002 - Q4
AGSTAR	West	Gas	88	2003 - Q1
Sithe Goreway	Toronto	Gas	932	2003 - Q2
Northland (Thorold)	Niagara	Gas	273	2003 - Q3
ATCO	West	Gas	578	2004 - Q1
AGSTAR	West	Gas	538	2004 - Q1
Sithe Southdown	Toronto	Gas	763	2004 - Q1
Enron Canada	West	Gas	505	2004 - Q2
Calpine Canada	West	Gas	870	2004 - Q3
Imperial Oil	West	Gas	98	2004 - Q3
OPGI - Hearn	Toronto	Gas	550	2004 - Q4
AES	West	Gas	530	2005 - Q1
Total			6263	

Note to Table 2.2:
Transalta –SRCP stands for Transalta – Sarnia Regional Cogeneration Project, previously identified as Transalta.

Details about the CAA process, the status of all current applications, 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.

2.4 Summary of Generation Resource Scenarios Assumed in the Study

In assessing future resource adequacy, it is necessary to make a number of assumptions regarding the magnitude of supply resources that will be available. This Outlook assumes three different scenarios regarding the installed resources.

Tables 2.3 and 2.4 show the three generation resource scenarios assumed in the study, at the time of the winter and summer peak demands. These scenarios have been developed starting from the existing installed generation resources shown in Table 2.1.

Under the **Reference Resource Scenario** existing Ontario resources are assumed to be in-service for the duration of the study period, except for Lakeview units, which are assumed to be out of service beginning May 1, 2005. Purchase amounts that are assumed to be available to Ontario include 200 MW for the period of January through October 2003. Pickering A units and Bruce A units are assumed to come into service on the dates that the facility owners or operators have indicated. This resource scenario includes only those generation projects listed in the CAA queue where the connection applicant has indicated that construction is in progress or has been completed. Such resources are assumed to come into service on the date indicated by the connection applicant.

Under the **Delayed Resource Scenario** existing Ontario resources are assumed to be in-service for the duration of the study period, except for Lakeview units, which are assumed to be out of service beginning May 1, 2005. Purchase amounts that are assumed to be available to Ontario include 200 MW for the period of January through October 2003. This resource scenario assumes that Pickering A units, Bruce A units and projects in the CAA queue that are under construction are delayed from coming into service by one year from the date that the facility owner, operator or connection applicant has indicated. No other new generation facilities are assumed to come into service in this resource scenario.

Under the **High Resource Scenario** existing Ontario resources are assumed to be in-service for the duration of the study period, except for Lakeview units, which are assumed to be out of service beginning May 1, 2005. Purchase amounts that are assumed to be available to Ontario include 200 MW for the period of January through October 2003. This resource scenario assumes that Pickering A units and Bruce A units come into service on the dates that the facility owners or operators have indicated. All proposed new generation facilities identified in the CAA queue are assumed to come into service on the date indicated by the connection applicant, under this resource scenario.

Table 2.3 Summary of Installed Generation Resource Scenarios Assumed in the Study (at Winter Peak)

Notes	Description \ Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1	Existing Installed Resources as of February 2002	29,622	29,622	29,622	29,622	29,622	29,622	29,622	29,622	29,622	29,622
2	Installed Resources Increment Under Reference Resource Scenario	1,240	1,990	1,990	842	1,170	1,170	420	420	420	420
3	Installed Resources Increment Under Delayed Resource Scenario	0	1,240	1,990	842	1,170	1,170	420	420	420	420
4	Installed Resources Increment Under High Resource Scenario	1,288	3,331	7,233	6,615	6,943	6,943	6,193	6,193	6,193	6,193
5	Firm Import	200	0	0	0	0	0	0	0	0	0
6	Reference Resource Scenario	31,062	31,612	31,612	30,464	30,792	30,792	30,042	30,042	30,042	30,042
7	Delayed Resource Scenario	29,822	30,862	31,612	30,464	30,792	30,792	30,042	30,042	30,042	30,042
8	High Resource Scenario	31,110	32,953	36,855	36,237	36,565	36,565	35,815	35,815	35,815	35,815

Table 2.4 Summary of Installed Generation Resource Scenarios Assumed in the Study (at Summer Peak)

Notes	Description \ Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1	Existing Installed Resources as of February 2002	29,622	29,622	29,622	29,622	29,622	29,622	29,622	29,622	29,622	29,622
2	Installed Resources Increment Under Reference Resource Scenario	1,990	1,990	842	1,170	1,170	1,170	420	420	420	420
3	Installed Resources Increment Under Delayed Resource Scenario	0	1,990	842	1,170	1,170	1,170	420	420	420	420
4	Installed Resources Increment Under High Resource Scenario	3,058	5,715	6,615	6,943	6,943	6,943	6,193	6,193	6,193	6,193
5	Firm Import	200	0	0	0	0	0	0	0	0	0
6	Reference Resource Scenario	31,812	31,612	30,464	30,792	30,792	30,792	30,042	30,042	30,042	30,042
7	Delayed Resource Scenario	29,822	31,612	30,464	30,792	30,792	30,792	30,042	30,042	30,042	30,042
8	High Resource Scenario	32,880	35,337	36,237	36,565	36,565	36,565	35,815	35,815	35,815	35,815

Notes to Tables 2.3 and 2.4:

1. Existing Installed Resources as of February 2002: Represent the total capacity of the existing installed generation resources in Ontario as described in section 2.1. This value includes all the generation in Ontario, except Bruce A, retired generation and embedded generators not managed by OEFC or generation not directly connected to the IMO-controlled grid.

2. Installed Resources Increment Under Reference Resource Scenario: Represents the installed resources increments to the existing resources, at the winter/summer peaks, as described in the 'Reference Resource Scenario' paragraph.

3. Installed Resources Increment Under Delayed Resource Scenario: Represents the installed resources increments to the existing resources, at the winter/summer peaks, as described in the 'Delayed Resource Scenario' paragraph.

4. Installed Resources Increment Under High Resource Scenario: Represents the installed resources increments to the existing resources, at the winter/summer peaks, as described in the 'High Resource Scenario' paragraph.

5. Firm Import: Represents the amount of external capacity considered to be reliably committed to Ontario under existing contracts/agreements.

6. Reference Resource Scenario: Is the sum of lines 1, 2 and 5 above.

7. Delayed Resource Scenario: Is the sum of lines 1, 3 and 5 above.

8. High Resource Scenario: Is the sum of lines 1, 4 and 5 above.

3.0 Resource Assessment

This section provides an assessment of the adequacy of the resources described in Section 2 to meet the forecast demand. Capacity and energy production capability analyses were performed using the Load and Capacity program (L&C), General Electric's Multi-Area Reliability Simulation program (MARS), and spreadsheets. The methodology and tools used to carry out these analyses are described in detail in the document titled "Methodology to Perform Demand Forecasts, Resource Adequacy Assessments and Transmission Adequacy Assessments" (IMO_REP_0044). The resource availability scenarios are described in Section 3.1, while results of the adequacy assessment are described in Section 3.2. Conclusions are provided in Section 5, and detailed result numbers and tables can be found in Appendix A.

3.1 Modeling Approach

The resource availability scenarios used in the capacity and energy production capability analyses were created using the installed generation resources derived in the three resource scenarios in Section 2.4. For each resource scenario, 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 were combined with installed generation resources.

For 2003 only, specific participant generator outage plans have been used. For the period 2004 through 2012, explicit generator outage plans are unavailable. For these years it is necessary to model a hypothetical outage plan which reflects known cyclic outages (such as nuclear station vacuum building inspections) and planned outage factors supplied by generator participants. This is referred to as a "generic" outage plan to reflect the fact the majority of assumptions are modeled repetitively for nine of the ten years studied. In the generic outage plan, approximately 800 MW of generating capacity was considered to be on planned outage over the winter peak periods, with 1,300 MW assumed on outage over the summer peak periods. However, should outage durations grow, as might be required for rehabilitation activities or for installation of emission reduction facilities, the IMO expects increasing pressure to accommodate more outages over peak periods. As reserve margins increase, through the addition of resources to the IMO-controlled grid, the ability to accept outages over peak periods will improve. The IMO deals with the scheduling of explicit outage plans in the 18-Month Outlooks, where participants are expected to request outage time based on the availability of suitable resource margins.

In terms of transmission interface limitations, it should be noted that the resource availability improvement is not always equal to the amount of generation additions, especially under the High Resource Scenario. For example, in the West zone, if all of the proposed generation additions are built, a substantial amount of West zone generation may be constrained as a result of congestion on the Negative Buchanan Longwood Input (NBLIP) transmission interface. The potential amount of limited generation varies between 0 MW and about 2,400 MW, depending on the demand level and the total amount of generating capacity in the West zone. Congestion will be greatest during low demand or off-peak periods, which presents the opportunity for generators to perform maintenance. See Section 4 for transmission related aspects of congestion on this interface.

The forecast demand scenarios used to perform the adequacy assessment are the low, median and high demand growth scenarios, under normal weather conditions. Comprehensive analyses were carried out for all combinations of the three demand growth scenarios and the three resource scenarios.

3.2 Assessment of Resource Adequacy

3.2.1 Generating Capacity Adequacy Assessment - L&C and MARS Calculations

The L&C calculations were performed using the three resource scenarios described in Section 2.4; the need for additional resources was then assessed whenever negative margins were shown. The MARS calculations were performed in two steps. In the first step, the same resources as in the L&C calculations were modeled in MARS. In the second step, additional resources were included in any scenario for which the annual LOLE was greater than 0.1 days/year. The additional resource amounts were modeled on a monthly basis, with the purpose of reducing the highest monthly LOLE values such that the annual LOLE becomes less or equal to 0.1 days/year. The second step was repeated, with increasing amounts of additional resources, until all annual LOLE values became less or equal to 0.1 days/year. Graphical results of the L&C program calculations, at summer and winter peaks, are shown in Figure 3.1. Result tables and more technical details can be found in Appendix A.

Capacity Adequacy under Reference Resource Scenario

The Reference Resource Scenario should provide adequate reserve levels in all years under the low demand growth scenario. L&C and MARS simulation results do not indicate a significant need for additional capacity, in order to meet the 0.1 days/year target each year, until 2011. Under the median demand growth scenario, reserve levels are expected to become lower than desired in 2009, with increasing deficiencies going out toward 2012, which indicates a need for additional resources. These may come from new Ontario generation, or demand side management programs. Any combination of these measures which totals 1,500 MW would be sufficient to restore reserves to desired levels over seasonal peak periods.

Under the high demand growth scenario, reserves would be low, starting early in 2008, causing an increasingly large need for additional resources. Up to 3,500 MW of additional capacity would need to be made available to Ontario by 2012 in order to maintain reserves at desired levels. This amount of additional resources would have to come from new Ontario generation or demand side management programs.

Capacity Adequacy under Delayed Resource Scenario

Differences between the Delayed and Reference Resource Scenarios exist only for the first three years of the study period. The two resource scenarios are identical afterwards. Therefore, the comments below will refer to the first three years of the 10-year study period, the comments under the Reference Resource Scenario are valid for the same period under the Delayed Resource Scenario, for 2006 and beyond.

A detailed discussion of the first nine months of 2003 is contained in the 18-Month Outlook. Up to 3,500 MW of short-term additional capacity may be required to maintain reserves at desired levels under the high demand growth scenario. No additional resources are deemed necessary for 2004 and 2005 to maintain adequate reserve levels under the low and median demand growth scenarios. Up to about 1,000 MW of short-term additional capacity could be required under the high demand growth scenario for short periods outside seasonal peaks to ensure adequate reserve levels.

In the first three years of the study period, the early development of demand side management programs or materialization of new generation projects other than the ones considered under this resource scenario, would substantially reduce the potential requirement for capacity supplies external to Ontario.

Capacity Adequacy under High Resource Scenario

Under the High Resource Scenario, the resource adequacy picture in 2003 and beyond looks to be more than sufficient to meet the demands of Ontario, even with the higher projected growth. Up to 1,000 MW of short-term additional capacity may be required in the spring of 2003, under the high demand growth scenario only, to maintain the annual LOLE within 0.1 days/year.

Should the High Resource Scenario materialize, greater flexibility for outage scheduling and a higher potential for exports to external markets will exist.

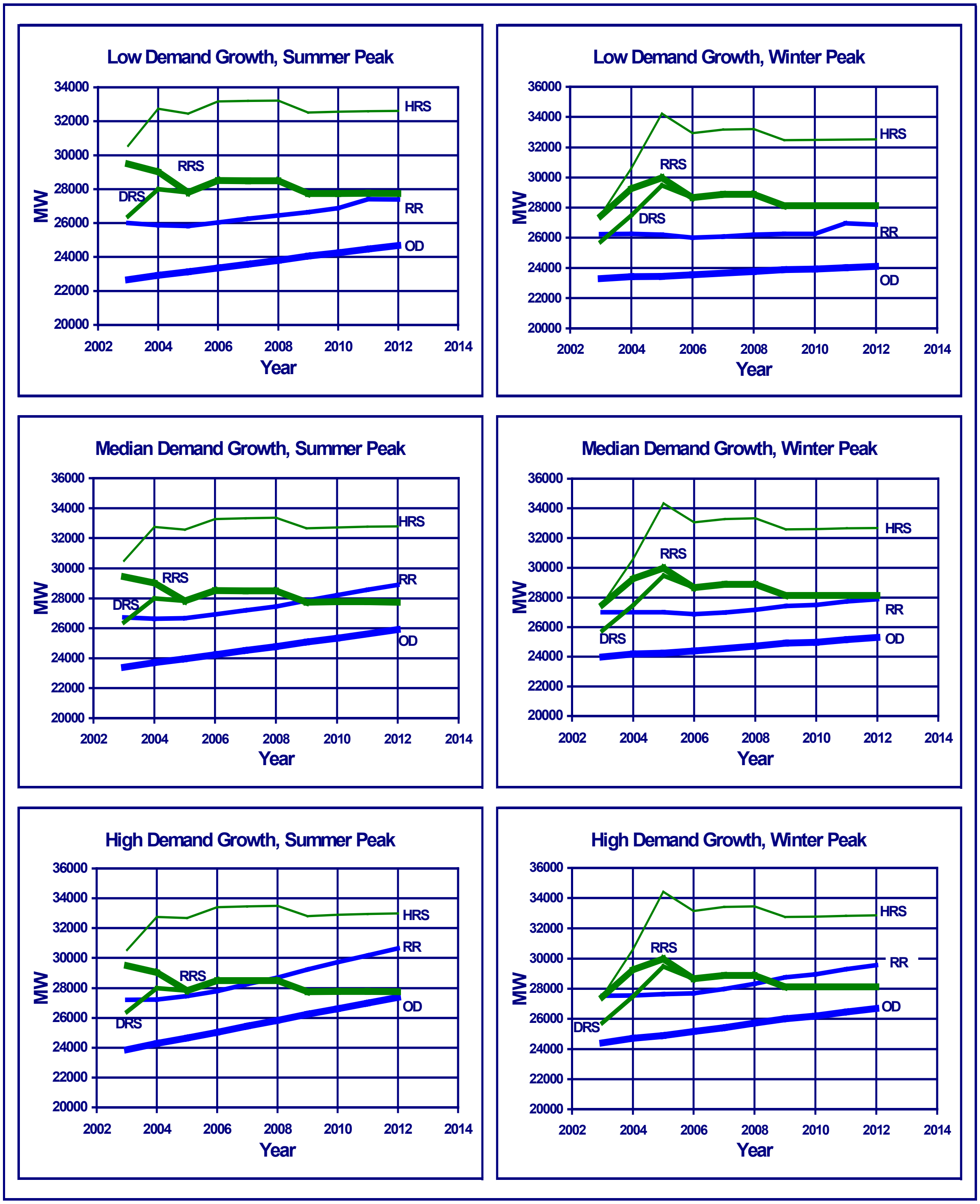
Other Scenarios

There are several other situations that could cause the amount of the available resources to change from the assumptions used in the analysis above. Typical changes to the assumed available generation, such as delays in generation construction, generating unit retirements, different planned maintenance schedules or higher forced outages, could change the reserve margin values substantially. To illustrate the impact these risks might have on reserve margins, Tables A13 to A18 are provided in Appendix A and include the resulting reserve margins if the available generation resources are lower by 1,000 MW and 2,000 MW, respectively, than the forecast amount under the Reference Resource Scenario. It should be recognized that there are also various scenarios that could result in improvements in the reliability in the Outlook period such as additional generation facilities proposed and placed in-service.

3.2.2 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 3.2 depicts the energy adequacy situation for the combination of all demand growth and resource scenarios. Detailed result tables, with an annual resolution, 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 all demand growth and resource scenarios. 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.

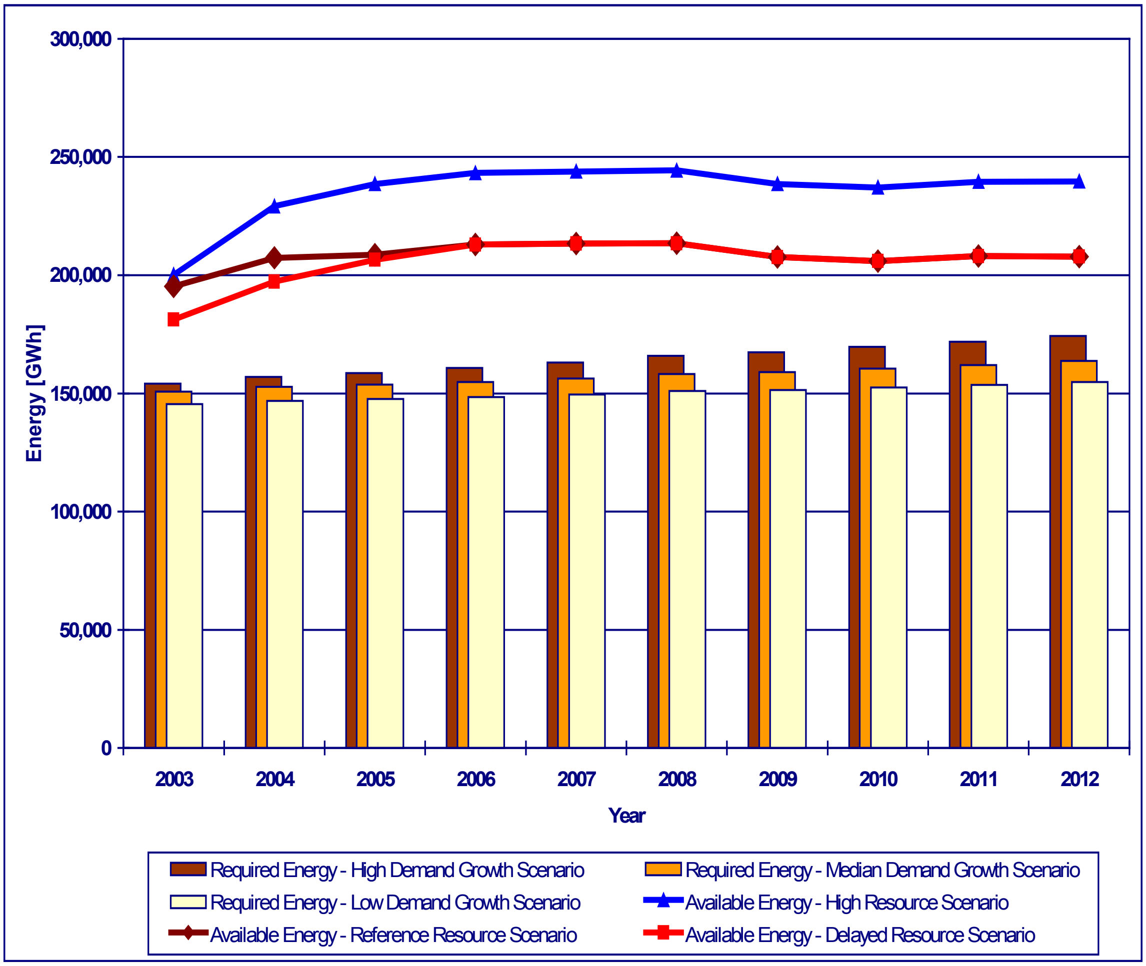
Figure 3.1 Resource Adequacy Assessment Graphs



Notes to Figure 3.1:

RRS – Represents the Available Resources under Reference Resource Scenario.
DRS – Represents the Available Resources under Delayed Resource Scenario.
HRS – Represents the Available Resources under High Resource Scenario.
OD – Represents the Ontario winter/summer peak demand.
RR – Represents the generation resources required to meet the peak demand and the Generation Reserve Requirement

Figure 3.2 Energy Production Capability Assessment Graph



4.0 Transmission Adequacy Assessment

4.1 Introduction

Transmission adequacy assessment is based on the need to ensure that sufficient transmission capability is available to deliver power to loads in conformance with NPCC or other applicable system security criteria. The continued use of Special Protection Systems such as generation rejection and load rejection is assumed in the determination of sufficiency.

Figure 4.1 provides a simplified depiction of Ontario's major internal transfer interfaces and Ontario's points of interconnection with neighbouring control areas. The internal interfaces are also used to define the boundaries of internal zones, called transmission zones. This simplified depiction of Ontario is used to assist in understanding the analytical evaluations of the Ontario transmission system.

The principal purpose of the transmission adequacy assessment is to identify any areas where supply reliability may potentially be at risk and to identify investment opportunities to improve system operating efficiency or market efficiency. These aspects could be due to a combination of factors such as load growth or reduction of generation capability within a certain area or the inability of generation which is located within adjacent transmission zones to provide the required level of support to an area due to transmission system limitations. This assessment is found in Section 4.2.1. Areas studied include the ten transmission zones depicted in Figure 4.1.

In addition, the impact of specific contingencies on the ability of the existing transmission facilities to supply certain 230 and 115 kV loads is examined. The intention of this assessment is to provide a starting point for evaluating supply reliability of the IMO controlled grid. The IMO recognizes that further discussions with transmitters are required to establish a supply reliability standard or criteria for this purpose. Section 4.2.2 details this assessment.

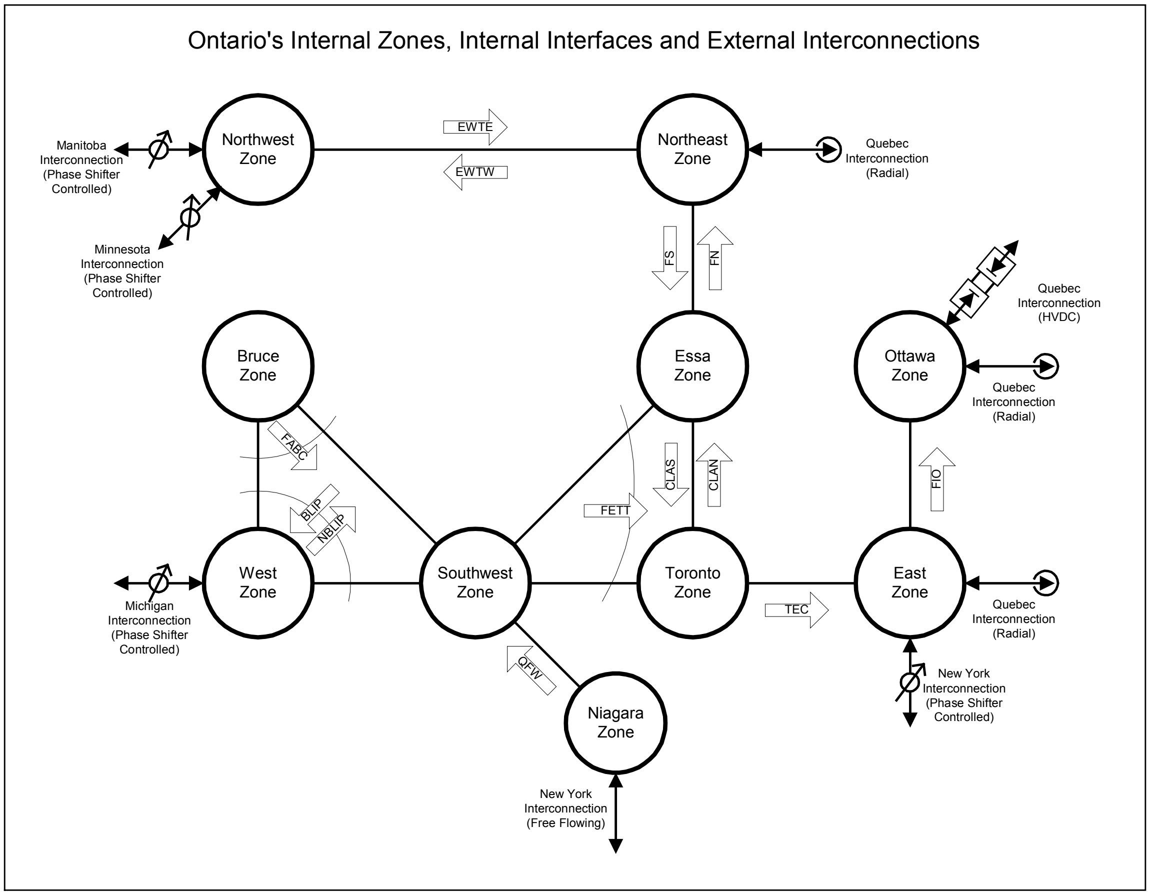
Another purpose of the transmission adequacy assessment is to identify transmission interfaces that have the potential to become congested and thus reduce market efficiency. This assessment is described in Section 4.3.

Section 4.4 discusses the steady state voltage support adequacy of the 500 kV and 230 kV transmission networks of the IMO-controlled grid.

Section 4.5 provides an assessment on current and future concerns relating to certain transmission zones. Further details on the impact of new generation and transmission projects are discussed in Section 4.6. Conclusions are provided in Section 5.0.

Transmission adequacy is assessed using the various resource scenarios described in Section 2.4. These include the restart of two Bruce A units, the return to service of four Pickering A units, and the assumption that Lakeview Thermal Generating Station will cease operation in 2005.

Figure 4.1 Ontario's Zones, Interfaces and Interconnections



The methodology used to assess the transmission adequacy is described in a separate IMO document titled "Methodology to Perform Demand Forecasts, Resource Adequacy Assessments and Transmission Adequacy Assessments" (IMO_REP_0044).

Section 4.0 does not exhaustively assess all areas of the IMO-controlled grid. It is possible that other deficiencies in the IMO-controlled grid may exist or emerge.

4.2 Supply Reliability Assessment

4.2.1 Zonal Supply Reliability Assessment

For the selected years, 2003, 2005 and 2012, each transmission zone is studied by considering a possible, but relatively extreme condition in which the demand-supply balance in the zone is most challenging to meet. For most zones, an extreme condition is modeled by a low resource supply at the time of peak demand. To simulate this, the two largest units within a zone are removed from service for various resource scenarios. This situation is not expected to be common, but is possible. For the Northeast and Northwest zones, an extreme condition is modeled by reducing all hydroelectric generation to zero during off-peak demand periods such as those experienced overnight. This is simulation is more extreme than would typically be experienced in these zones.

For all zone analyses in 2003, an extreme condition is studied using the Delayed and Reference Resource Scenarios. For all the 2005 analyses, an extreme condition is studied using the Reference Resource Scenario. For all the 2012 analyses, an extreme condition is studied using the Reference and High Resource Scenarios. For 2012, reasonable stressing of the transmission system could not be achieved for the Reference studies when the two largest units within a zone are removed from service due to system capacity deficiencies. As a result these studies are discarded. Similarly for 2012, the Reference study is discarded for the case when no hydroelectric generation is assumed for the combined Northeast and Northwest zones.

A summary of the findings by zone is provided below. In all the zone analyses, the demand-supply balance in the zone is referred to as the zone margin.

For the **Bruce zone**, and for the **Niagara zone**, after removing from service the two largest units within the zone, a generation surplus within the zone remains for all years studied. This situation requires no transfers from adjacent zones.

For the **East zone** analyses, removing from service the two largest units within the zone results in a generation deficit within the East zone, with the result that transfers are required from the adjacent zones. In all cases, there is sufficient transmission capacity available on the major interfaces to carry the required transfers. The lowest zone margin occurs in 2005 under the Reference Resource Scenario when all units at Lakeview Thermal Generating Station (TGS) are assumed to be out of service. Transfers up to the limits occur on the East-West Transfer East (EWTE) and Flow South (FS) interfaces. In 2012, transfers up to the limit also occur on the Negative Buchanan Longwood Input (NBLIP) interface.

For the **Essa zone** analyses, removing from service the two largest units within the zone requires transfers from other zones to meet the demand within the Essa zone. In all cases, there is sufficient transmission capacity available on the major interfaces to carry the required transfers. The lowest zone margin occurs in 2003 using the Delayed Resource Scenario. Transfers up to the limit occur on the EWTE interface. For the 2012 zone analysis, transfers up to the transmission limit are also observed on the NBLIP interface.

For the **Ottawa zone** analyses, removing from service the two largest units results in no generation within the zone. In all cases, there is sufficient transmission capacity available to supply the required transfers. The lowest zone margin occurs in 2003 using the Delayed Resource Scenario. Coincident with the incorporation of the Quebec HVDC interconnection, facility improvements at the Hawthorne Transformer Station are expected to increase the Flow Into Ottawa (FIO) interface limit to 3,000 MW. With the corresponding increase in the FIO limit, the Ottawa zone margins increase for the 2005 and 2012 resource scenarios. For all analyses, transmission flows are up to the limit on the EWTE and FS interfaces. For the 2012 zone analysis, transmission flows are up to the limit on the NBLIP interface.

For the **Southwest zone** analyses, removing from service the two largest units within the zone requires transfer from other zones to meet the demand in the Southwest zone. In most analyses, there is sufficient transmission capacity available to supply the required transfers. However, for the 2003 analysis under the Delayed Resource Scenario, there is insufficient transmission capacity available on the EWTE and FS interfaces to carry the required transfers. It should be recognized that this is a relatively extreme scenario that is modeled. There is a low probability that this result will emerge as a real concern because of the assistance available from the interconnections (which is not modeled). For all the other cases, which exhibit sufficient transmission capacity, transmission flows reach the limits on the EWTE and FS interfaces and on the NBLIP interface in 2012.

For the **Toronto zone** analyses, removing the two largest units within the zone requires transfers from other zones to meet the demand within the Toronto zone. The generation deficit is most significant in 2005 when Lakeview TGS is assumed to be out of service. However, there is sufficient transmission capacity to supply the required deficit from adjacent zones. The local deficiency is reduced significantly in 2012, with the inclusion of the proposed Sithe and OPGI generation projects. For all the Toronto zone analyses, transmission flows reach the limit on the EWTE and FS interfaces. In 2012, transmission flows also reach the limit on the NBLIP and Flow East Towards Toronto (FETT) interfaces.

For the **West zone** analyses, removing from service the two largest units within the zone results in a generation deficit that requires transfers from adjacent zones to meet the West zone demand. For the 2003 zone analysis using the Delayed Resource Scenario, there is insufficient transmission capacity available on the EWTE and FS interfaces to supply the required transfers. For all other scenarios the transmission capacity is sufficient. Transmission flows are up to the limit on the EWTE and FS interfaces for all years studied. In 2012, a local generation surplus requiring no transfers from adjacent zones results with all local proposed generation projects in-service.

For the**, Northeast and Northwest zones**, removing the two largest units within each zone results in a local generation surplus requiring no transfers from adjacent zones for the selected years and various resource scenarios. For these zones, an additional scenario was studied.

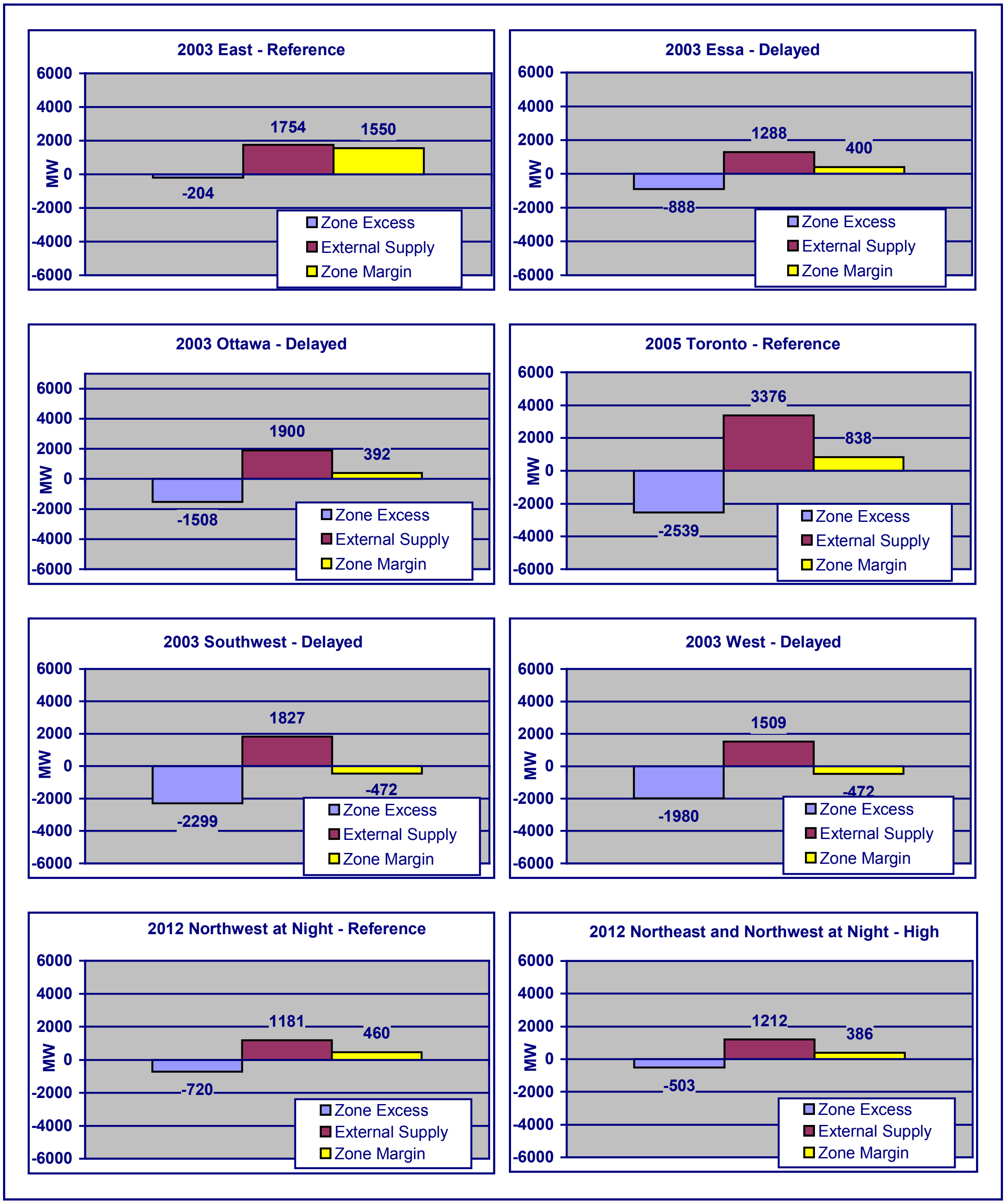
For the **Northeast zone nighttime** analyses, removing all the hydroelectric generation within the zone results in a generation deficit that requires transfers from adjacent zones to meet the Northwest zone demand. In all cases, there is sufficient transmission capacity available to supply the required transfers. The lowest zone margin occurs in 2012 using the Reference Resource Scenario. Transmission flows up to the limit occur on the EWTE and CLAN interfaces for most of the resource scenarios and on the NBLIP and FETT interfaces for the 2012 High Resource Scenario.

For the **combined Northeast and Northwest zones nighttime** analyses, removing all the hydroelectric generation also results in a generation deficit that requires transfers from adjacent zones. In all cases, there is sufficient transmission capacity available to supply the required generation deficit in the combined zones. The lowest zone margin occurs in 2012 using the High Resource Scenario. Transmission flows up to the limit occur on the CLAN interfaces for all resource scenarios and on the NBLIP and FETT interfaces for the 2012 High Resource Scenario.

The most challenging capacity balance in each of the above analyses is summarized in Figure 4.2. The Zonal Excess is the generation within the zone minus the demand within the zone. The External Supply provides an indication of how much generation could be transferred into the zone, and is calculated by taking the lower of the interface transmission capability limit into the zone and the excess generation capacity that is available in adjacent zones. The Zone Margin is the difference between the External Supply and the Zone Excess. The corresponding resource scenario, either ‘Reference’, ‘Delayed’ or ‘High’, is indicated for each deficit zone.

The years 2003, 2005 and 2012 are used in this assessment because they capture the various demand, generation and transmission conditions that are likely to stress the Ontario Electricity System. Although the 2003 Southwest and West zone analyses using the Delayed Resource Scenario show insufficient transmission capability to supply the required transfers, there a low probability that this will emerge as real concern because import assistance is not considered in this assessment. Since most of the results for the selected years are adequate, it is concluded that the capability of the transmission system is adequate to supply the demands within each of the ten transmission zones for the period 2003 to 2012. However constraints are expected on individual interfaces under the circumstances described above.

Figure 4.2 Zonal Supply Reliability – Median Demand Growth, Extreme Weather Scenario



4.2.2 Contingency-Based Supply Reliability Assessment

In addition to examining the specific zones of Ontario defined by major transmission interfaces, supply reliability of the IMO-controlled grid is evaluated by considering the impact of specific contingencies on the load supplied. The contingencies that are assessed include faults or outages to any transformer, double circuit line, bus or any two cables in the same trench. Based on each contingency the resulting impact on load supplied is estimated by considering the extent to which load is interrupted, and the duration of such interruption. The most reliable area supply is one in which there is a continuous supply to the load, despite the contingency.

The 230 kV transmission network of the IMO-controlled grid was evaluated starting in 2003. The results indicate that in some cases more than 500 MW of load will be interrupted for specific double circuit contingencies in the Toronto zone. Requests for additional detailed information will be considered by the IMO on a case-by-case basis. There are no other facilities or group of facilities within the 230 kV transmission network of the IMO-controlled grid that are forecast to result in an interruption of greater than 500 MW for the specified contingencies.

Using the Delayed Resource Scenario for 2003, the Reference Resource Scenario for 2005 and the High Resource Scenario for 2012 at summer peak demands, the impact of a transformer contingency on specific 230 kV to 115 kV transformation points on the IMO-controlled grid was also studied. On loss of an autotransformer within a 230/115 kV transformation point, the remaining autotransformers at the transformation point should continue to supply the required load. Assuming a 10-Day Limited Time Rating (LTR) for the remaining autotransformers, the ability of each transformation point to supply the summer peak demand for the selected resource scenario and year is assessed. The acceptable duration of any load interruption will depend on the amount of load interrupted. However, for the purposes of this analysis, any transformation point that is unable to supply the required load is denoted in Table 4.1 as a potential concern.

Table 4.1 Contingency-Based Supply Reliability - Specific 230/115 kV Transformation Points

230/115 kV Transformation Point	Transmission Zone	Resource Scenarios		
		2003 - Delayed	2005 - Reference	2012 - High
Scott T5 Scott T6	West	Potential concern	Potential concern	Potential concern
Keith T11 * Keith T12 Lauzon T1 Lauzon T2	West	Potential concern	Potential concern	
Buchanan T2 Buchanan T3 Buchanan T4	West	Potential concern	Potential concern	Potential concern
Seaforth T5 Seaforth T6	Southwest			
Detweiller T2 Detweiller T3 Detweiller T4	Southwest			
Allanburg T1 Allanburg T2 Allanburg T3 Allanburg T4	Niagara	Potential concern	Potential concern	Potential concern
Beach T1 Beach T7 Beach T8	Southwest		Potential concern	Potential concern
Burlington T4 Burlington T6 Burlington T9 Burlington T12	Southwest	Potential concern	Potential concern	Potential concern
Manby East T7 Manby East T8 Manby East T9	Toronto			
Manby West T1 Manby West T2 Manby West T12	Toronto			
Leaside T11 Leaside T12 Leaside T14 Leaside T15 Leaside T16 Leaside T17	Toronto			
Essa T1 Essa T2	Essa	Potential concern	Potential concern	Potential concern
Dobbin T1 Dobbin T2 Dobbin T5	East			
Hawthorne T4 Hawthorne T5 Hawthorne T6	Ottawa	Potential concern	Potential concern	Potential concern
Merivale T21 Merivale T22	Ottawa	Potential concern	Potential concern	Potential concern

Note: * Keith and Lauzon autotransformers are grouped as a single point.

At the Scott, Buchanan, Allanburg, Burlington, Essa, Hawthorne and Merivale transformation points, on the loss of an autotransformer, there is a potential problem for the remaining autotransformers to supply the required load during summer peak demand conditions, for each selected year and resource scenario.

A certain fault at the Beck 1 Generating Station could overload the Allanburg 230/115 kV autotransformers under peak demand conditions. Depending on the amount of overload on the autotransformers, it might be necessary to interrupt load in the Allanburg 115 kV local area. Requests for additional detailed information will be considered by the IMO on a case-by-case basis.

The impact of a contingency on the ability of transmission facilities to supply loads continuously should be eventually determined by the establishment of a supply reliability criteria that can be applied to all areas of the IMO-controlled grid. The intention of this assessment is to present some results which can be used to stimulate future discussions with transmitters.

4.3 Congestion Assessment

Transmission flows are determined by the pattern of loads and generation, and the characteristics of the transmission system at any given time. Each of these factors is inherently somewhat unpredictable due to the effect of random forced outages on generation and transmission facilities and the effect of weather on load levels. If additional generation is added to appropriate points on the system in future years, the level of system flows on constrained interfaces would generally be expected to reduce and congestion would tend to be relieved. Conversely, if too much generation is added to a transmission zone, it could increase the level of system flows on the connecting transmission transfer interface, thereby, creating or aggravating congestion. In these instances the incorporation of additional transmission capacity on the interface might be necessary to alleviate this problem.

With the opening of the Ontario Electricity Market, an additional level of uncertainty is added because bid and offer prices, rather than traditional economic dispatch principles, will determine the dispatch of generation. The behaviour of Ontario market participants can only be predicted based on experiences in other markets until local bid/offer experience is observed and analyzed. This makes it very difficult to forecast congestion on the Ontario transmission system with any degree of accuracy.

The approach taken in this Outlook is identified in a separate IMO document titled “Methodology to Perform Demand Forecasts, Resource Adequacy Assessments and Transmission Adequacy Assessments” (IMO_REP_0044). The results of that analysis follow.

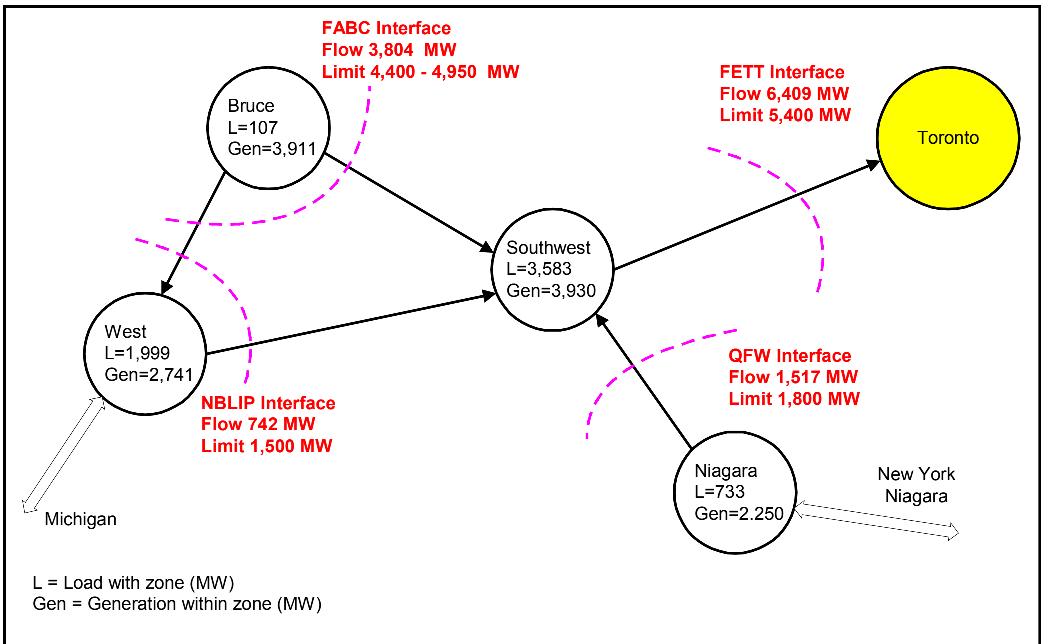
4.3.1 “Snapshot” Congestion Assessment

Assuming all generators in-service for zones outside of the Toronto zone, for both the Reference and High Resource Scenarios, the Ontario electric system model is “stressed” by artificially simulating high deliveries into the Toronto zone from adjacent zones. The capability of the transmission from the north, west and east relative to the load center is then individually analyzed for possible congestion. Because off-peak load conditions are assumed in the areas external to the Toronto zone, the projected congestion values represent the upper bound expected. The impact of import and export transfers is not considered in this assessment.

4.3.1.1 System Stressed from West of Toronto

The conditions in this scenario are displayed in Figure 4.3 for 2003 for the High Resource Scenario. Power is supplied from the Bruce, Niagara, West, and Southwest zones towards Toronto stressing the Flow East Towards Toronto (FETT) interface. Imports and exports from Michigan are assumed to be zero. For the conditions identified in Figure 4.3, the available flow on this interface exceeds the FETT limit by 1409 MW, indicating the potential for constrained generation.

Figure 4.3 Congestion Test, High Resource Scenario – West of Toronto



Maximum Western Generation and 80% of 2003 Winter Peak Demand

Under this study scenario, no power can be imported from the USA at New York-Niagara and/or Michigan without displacing Ontario generation since the FETT interface is already congested. A power import greater than 758 MW via the Michigan interconnection would result in congestion on the Negative Buchanan Longwood Input (NBLIP) interface out of the West zone. An import greater than 283 MW via the New York-Niagara interconnection would result in congestion on the Queenston Flow West (QFW) out of the Niagara zone.

The study did not consider the impact of Lake Erie Circulation (LEC). LEC is a power flow created by parallel path flows between Michigan and New York that circulates through Ontario. The flow (not shown) can circulate through Ontario in a clockwise direction, in at Michigan and out at New York-Niagara, or in counterclockwise direction, in at New York-Niagara and out at Michigan. Generally, LEC can be controlled within required limits. Counterclockwise LEC would add to any flow on the QFW interface, but would reduce the flow on the NBLIP interface.

It is anticipated that the Ontario – Michigan phase angle regulators will control LEC by about 600 MW and reduce the incidence of constrained operation of QFW interface.

The study scenario was repeated for 2004 to 2012. Particular attention was paid to new Windsor-Sarnia generation facilities proposed for the West zone. Figures 4.4 and 4.5 show the potential congestion on the NBLIP and FETT transmission interfaces, respectively, assuming existing operating limits on the interfaces.

For the 'West of Toronto' analysis using the Reference Resource Scenario, no congestion is observed on the NBLIP interface for the study period of 2003 to 2012. However, congestion is still observed on the FETT interface, but the amount is significantly lower than in the High Resource Scenario. Figures for this analysis are not provided.

In summary, congestion is likely to occur on the NBLIP interface with the proposed Windsor-Sarnia generation facilities. The potential for congestion on the FETT interface increases during high generation levels west of Toronto. During import conditions and high generation levels west of Toronto, congestion is very likely to occur on the NBLIP and FETT interfaces. In addition, during import conditions on the New York – Niagara interconnection, congestion is also likely to occur on the Queenston Flow West (QFW) interface. Adding transmission capacity may relieve congestion on the NBLIP, FETT and QFW interfaces.

Figure 4.4 Potential Congestion on NBLIP Interface, High Resource Scenario – 2003 to 2012

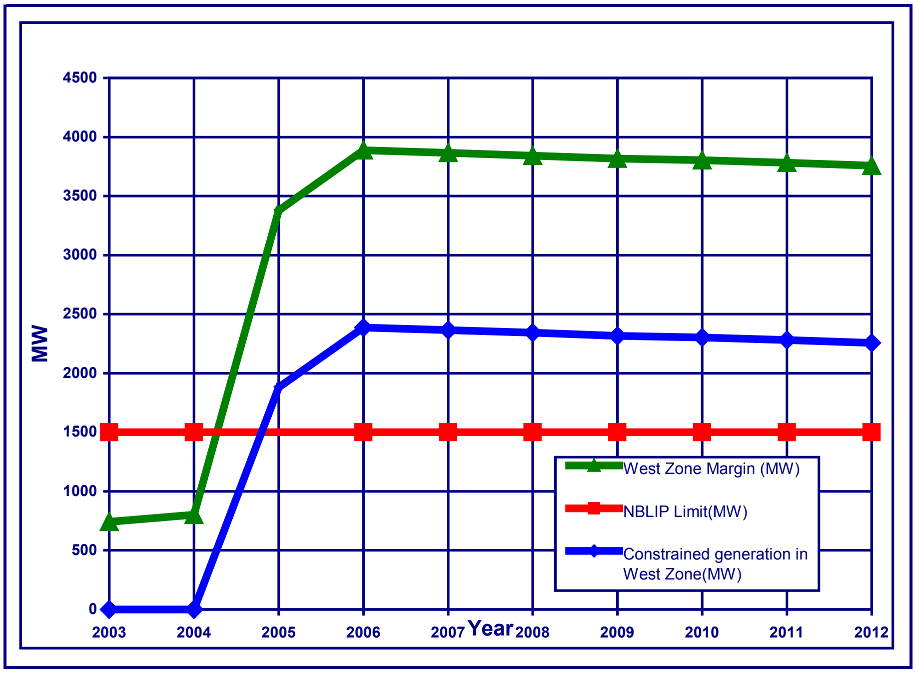
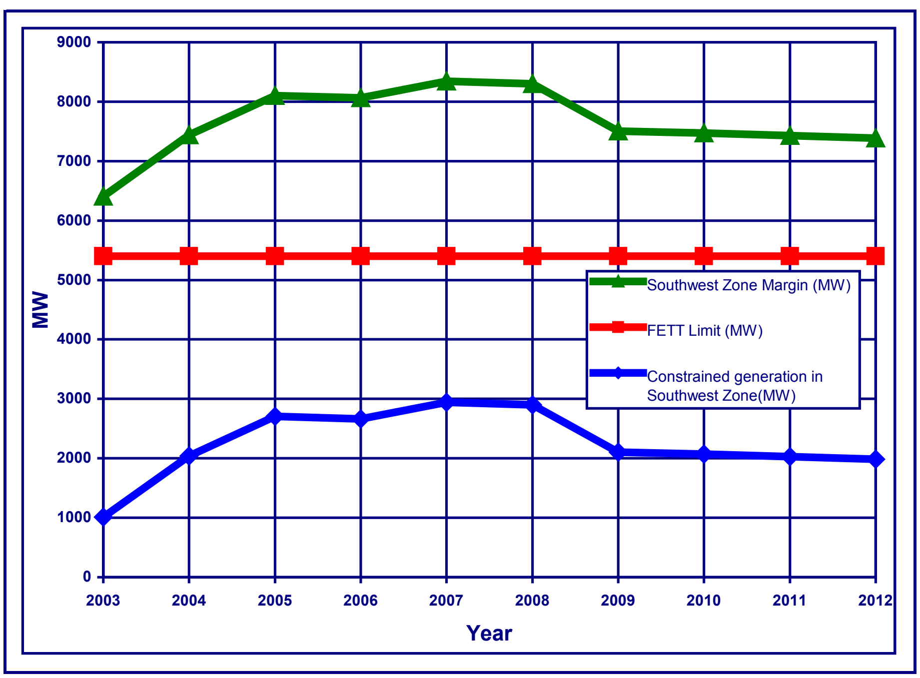


Figure 4.5 Potential Congestion on FETT Interface, High Resource Scenario – 2003 to 2012

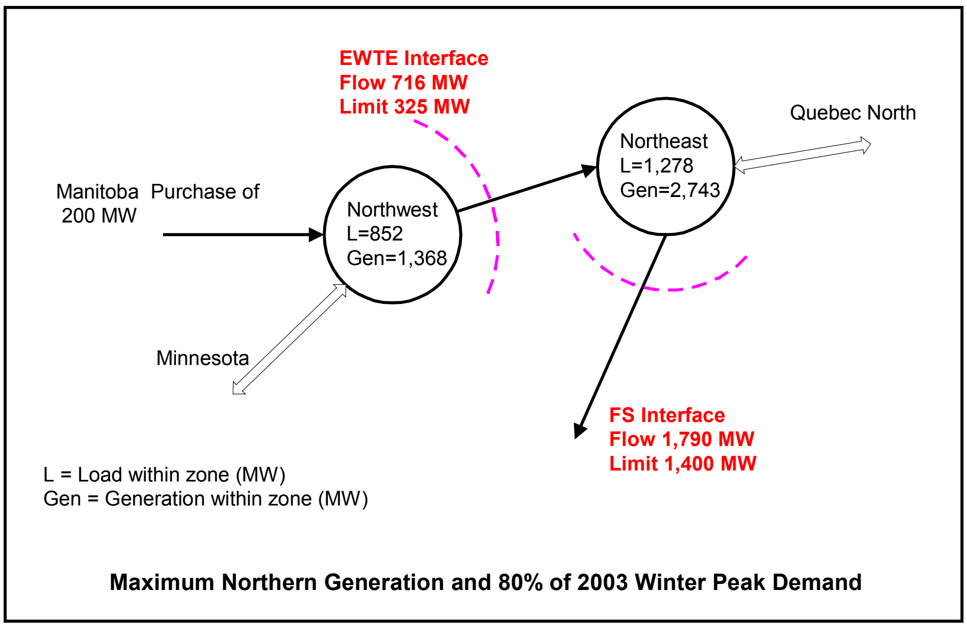


4.3.1.2 System Stressed from North of Toronto

The conditions in this scenario are shown in Figure 4.6 for 2003 for the High Resource Scenario. The Minnesota and Quebec-North imports and exports are assumed to be zero. With a Manitoba import of 200 MW and local generation in the Northwest of 1,368 MW, there is 716 MW of excess generation in the Northwest, of which only 325 MW can flow to the Northeast zone, leaving 391 MW of excess power in the Northwest zone. Under these specific conditions, congestion occurs on the East-West Transfer East (EWTE) interface.

The East-West flow towards the east of 325 MW adds to the Northeast zone excess. As a result, 1,790 MW are available to flow south on the Flow South (FS) interface. Since this available flow exceeds the FS limit of 1,400 MW, there is 391 MW of constrained generation in the Northeast zone.

Figure 4.6 Congestion Test, High Resource Scenario – North of Toronto



The study scenario was repeated for 2004 to 2012 with the inclusion of the proposed Northland Power generation addition to Kirkland Lake Generating Station (GS). In all cases, congestion is likely to occur on the EWTE and the FS interfaces as shown in Figures 4.7 and Figures 4.8, respectively.

Even without the proposed generation addition at Kirkland Lake, as studied in the Reference Resource Scenario, there is still congestion on the FS interface. Congestion on the EWTE interface does not change using the Reference Resource Scenario because the total available generation in the Northwest zone does not change from the High Resource Scenario. Figures are not provided for the analysis using the Reference Resource Scenario.

High hydroelectric generation output at spring freshet, combined with lower Northeast demand levels and imports from Quebec, can also result in congestion on the Flow South interface. Import conditions on the Manitoba and Minnesota interconnections, and high generation levels in the Northwest zone will exacerbate congestion on the EWTE interface. To alleviate congestion on the EWTE interface, power may be directed towards Manitoba and Minnesota, depending upon the prevailing prices. Congestion may also be relieved by adding transmission circuits to the EWTE interface. For the FS interface, congestion may be relieved by adding transmission circuits to the interface.

Figure 4.7 Potential Congestion on EWTE Interface, High Resource Scenario – 2003 to 2012

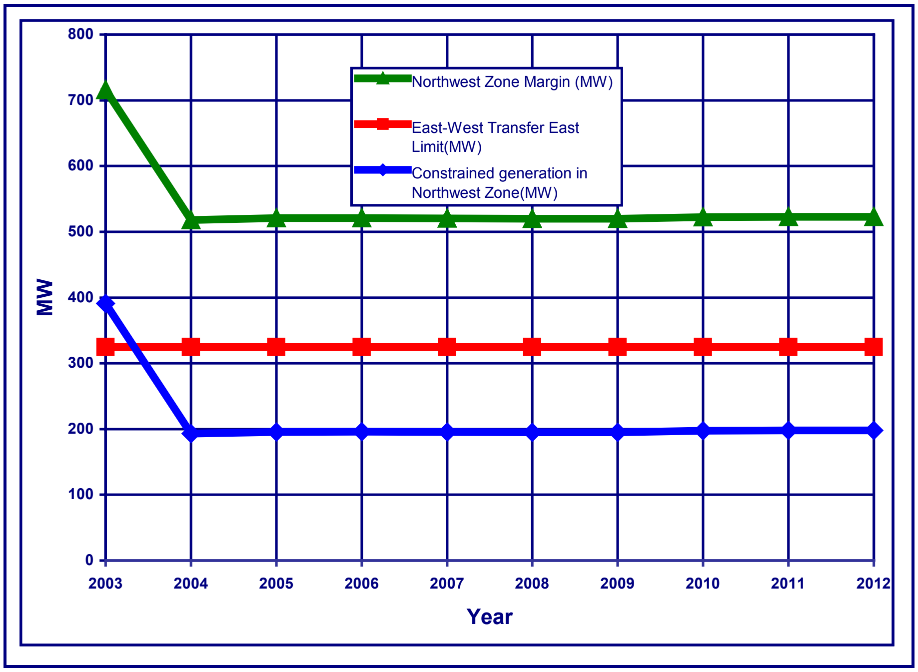
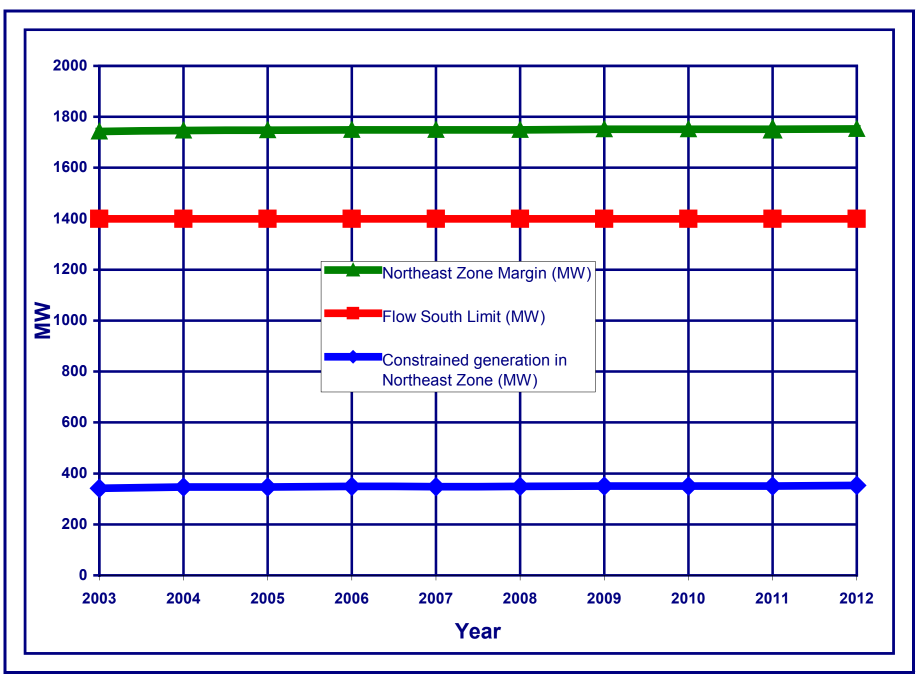


Figure 4.8 Potential Congestion on FS Interface, High Resource Scenario – 2003 to 2012



4.3.1.3 System Stressed from East of Toronto

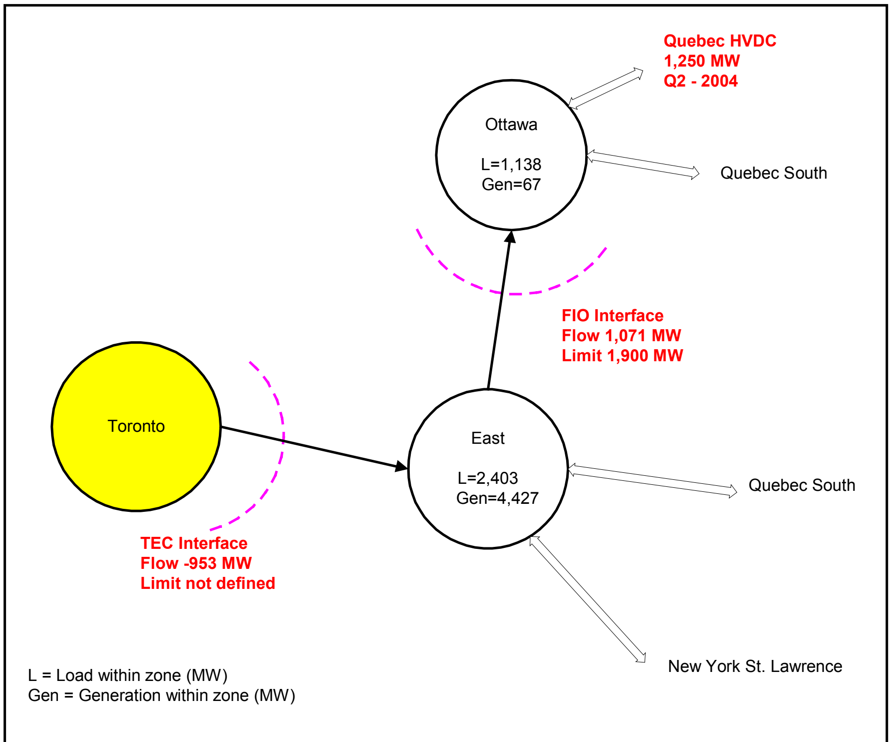
For the conditions shown in Figure 4.9 for 2003, 1,071 MW flows on the Flow Into Ottawa (FIO) interface between the East and Ottawa zones. The FIO flow subtracts from the East zone excess and the resultant flow on the Transfer East of Cherrywood (TEC) interface is -953 MW. The Quebec-South and New York-St. Lawrence imports and exports are assumed to be zero. No operating security limits have been defined for the TEC interface because the present and historical flow levels, in either direction, do not cause congestion.

The study scenario was repeated for 2004 to 2012. For the same reasons cited for the 2003 study, congestion is not expected to be a concern.

Results of the 'East to Toronto' analysis using the Reference Resource Scenario are the same, as there are no changes in the available generation in the East and Ottawa zones.

Maximum imports from Quebec-South, New York-St. Lawrence and the proposed Quebec HVDC interconnection will potentially increase flow on the TEC interface by up to -2,600 MW whenever there is a local East zone excess of generation. If these increased flows on the TEC interface develop, the IMO will identify, develop and implement appropriate operating limits for such transfers.

Figure 4.9 Congestion Test, High Resource Scenario – East of Toronto



Maximum Eastern Generation and 80% of 2003 Winter Peak Demand

4.3.2 MARS Congestion Assessment

Using Ontario generators only, the GE MARS software was also used to assess the potential duration of transmission congestion under specific generator dispatch patterns which tend to stress transmission utilization, and maximize congestion. The MARS software allows for a projection of expected hours of congestion but does not accommodate development of a congestion level duration curve.

Like the "Snapshot" congestion assessment in Section 4.3.1, the Ontario electric system model is "stressed" separately from the north and west relative to the load center in the Toronto zone for selected years, 2003, 2005 and 2012, of the study period. A high supply of resources (all generators in-service) is also assumed for both the High and Reference Resource Scenarios. The scenario for deliveries from the zones in the east toward the Toronto zone is not analyzed in this assessment because congestion is not expected to occur under these conditions. The impact of LEC and import and export transfers is not considered in this assessment.

4.3.2.1 System Stressed from West of Toronto

Under the High Resource Scenario, there is a maximum potential for flows on the NBLIP interface to be congested fifty percent of time in 2005 and seventy-five percent of time in 2012. Congestion on the NBLIP interface is not expected to occur in 2003. The maximum potential for congested flows on the FETT interface varied from fifteen percent of time in 2003 to thirty-five percent of time in 2005 and 2012.

Under the Reference Resource Scenario, congestion on the NBLIP interface is observed five percent of time in 2005 and thirty percent of time in 2012. Congestion on the FETT interface occurred from five to fifteen percent of time.

Based on these results, the NBLIP has the potential to be constraining more often than the FETT interface.

4.3.2.2 System Stressed from North of Toronto

The results of this assessment under the High and Reference Resource Scenarios are very similar given that the two resource scenarios only differ by 48 MW, due to the addition of the proposed Northland (Kirkland) generation project in the High Resource Scenario. As a result, only the High Resource Scenario results will be described.

The maximum potential for congestion on the EWTE interface varied from twenty-five to fifty percent of time for the years studied. Congestion on the FS interface varied from five to ten percent of time.

In summary, the ETWE interface has the potential to be constraining more often than the FS interface.

4.4 Steady State Voltage Support Adequacy

Appendix 4.3, Reference #1 of the Ontario Market Rules require that "connected wholesale customers and distributors connected to the IMO-controlled grid shall operate at a power factor within the range of 0.9 lagging to 0.9 leading as measured at the defined meter point". However, it may be necessary to dispatch the power system such that some defined meter points will be operated at a power factor greater than 0.9 lagging in order to satisfy the minimum continuous voltage requirements as identified in Appendix 4.1, Reference #2 of the Market Rules. Appendix B in Metering Manual Part 3.6 "Conceptual Drawing Review" shows illustrative examples of defined meter points. This procedure document can be viewed at the IMO web site www.theIMO.com under the "Services – Metering" web page.

The purpose of this assessment is to identify those transmission zones and the associated power factor required at transformer station defined meter points within the zone in order that the minimum continuous voltage requirements of the IMO-controlled grid are met. Load flow studies for 2003, 2005 and 2012 at summer peak demand conditions are completed using the Delayed, Reference and High Resource Scenarios, respectively. For each study, a 0.9 lagging power factor is assumed as the starting power factor for each zone.

During the August 2001 summer peak, low voltage capacitors and reactive power from generators were used to increase the power factor, and maintain voltages at typical operating levels. Table 4.4 shows the zonal power factors that correspond roughly to the voltage profile and power flows experienced during this summer peak. Note that for the Bruce and Northwest zones, the 2001 August power factors were below the minimum requirement of a 0.9 lagging power factor to maintain typical operating voltage levels.

Table 4.4 Steady State Voltage Support – Summary of Power Factors

Transmission Zone	2001 August Summer Peak (Power Factor)	Resource Scenarios		
		2003-Delayed (Power Factor)	2005-Reference (Power Factor)	2012-High (Power Factor)
Bruce	0.83	0.9	0.9	0.9
East	0.91	0.9	0.9	0.92
Essa	0.91	0.9	0.9	0.9
Niagara	0.93	0.9	0.9	0.9
Northeast	0.91	0.9	0.9	0.9
Northwest	0.89	0.9	0.9	0.9
Ottawa	0.97	0.9	0.9	0.93
Southwest	0.94	0.9	0.92	0.95
Toronto	0.93	0.9	0.92	0.93
West	0.94	0.92	0.92	0.9

The 2001 August summer peak zonal power factors can be compared to the results of the specific resource scenarios to estimate the need for future reactive resources.

For the 2003 summer peak analysis using the Delayed Resource Scenario, the power factor in the West zone must be raised from 0.9 to 0.92 lagging to satisfy the minimum market rule voltage requirement. Voltages in the vicinity of Buchanan, Detweiler, Orangeville, Beach, Burlington, Richview and Claireville 230 kV Transformer Stations (TSs) are projected to be four to five kV below values seen during the 2001 summer peak. These voltages would be near the lower end of the acceptable market rule range. The Beach and Burlington 115 kV voltages are just above the minimum market rule requirement of 113 kV.

For the 2005 summer peak analysis under the Reference Resource Scenario and exports on the Quebec HVDC interconnection, the power factor must be raised from 0.9 to 0.92 lagging in the West, Southwest and Toronto zones. Like the 2003 analysis, voltages in the vicinity of Buchanan, Detweiler, Orangeville, Beach and Burlington 230 kV TSs are projected to be about 5 kV below values seen during the 2001 summer peak. As in the 2003 analysis, these voltages would be near the lower end of the acceptable market rule range. The 230 kV voltages near Keith and Lauzon TSs are projected to be below the minimum required values identified in the 'Windsor Area Operating Limits' System Control Order.

For the 2012 summer peak analysis under the High Resource Scenario and exports on the Quebec and Lake Erie HVDC interconnections, to satisfy the minimum voltage requirement, power factors must be raised to 0.93 in the Ottawa and Toronto zones, to 0.95 in the Southwest zone and to 0.92 in the East zone. The 230 kV voltages in the vicinity of Buchanan, Detweiler, Orangeville, Beach and Burlington TSs are projected to be about 10 kV below values seen during the 2001 summer peak. These voltages would be at the lower end of the acceptable market rule range. With no exports on the Quebec and Lake Erie HVDC interconnections, minimum voltage requirements in the East, Ottawa and Southwest zones would be met with lower power factors. The proposed generation projects in the West zone result in voltage levels above minimum requirements with a power factor of 0.9 lagging.

The above analyses show that at minimum power factors, the IMO-controlled grid would be operated at voltage levels at or near the lower end of the acceptable market rule range. These lower voltage levels could potentially have adverse affects on some electricity customers. The analyses also show that even with the all the proposed generation projects, additional reactive resources would be required in the Southwest and East zones near 2012. Additional reactive resources may also be required in the Toronto zone by 2012. If proposed generation projects in the Toronto zone do not come into service, additional reactive resources may be required sooner than 2012.

4.5 Zone Assessments

This Section provides general assessments on the current and future concerns relating to certain transmission zones. A forecast regarding the operation of the Ontario – Michigan interconnection under full phase angle regulator control is also provided in Section 4.5.7.

4.5.1 Bruce Zone

The current practice of automatically arming Bruce units for generation rejection to improve the transfer capability of the Flow Away from Bruce Complex (FABC) interface is very effective in maintaining reliability, relieving congestion and minimizing manual interventions. The automatic arming feature will not be part of the IMO's Energy Management System. The Ontario real-time electricity markets will require "linearized" operating security limits. In general these "linearized" limits will be more restrictive than past practice. For these reasons, the FABC interface might become more limiting in the future because the maximum limit value for FABC is not expected to be as high as in the past.

4.5.2 East and Ottawa Zones

The frequent use of load rejection schemes at the Dobbin, Sidney, Port Hope and Frontenac TSs to respect single element contingencies with all elements in-service, suggests that the transmission system at these stations needs to be reinforced.

4.5.3 Niagara Zone

The Queenston Flow West (QFW) interface has often been limiting under hot, windless weather conditions when importing from New York via the Niagara interconnection. Without expanding the thermal capability of the QFW interface, adding generation east of the QFW interface does not increase generation availability as import capability from New York is correspondingly reduced. If the proposed Northland Power generation project at Thorold is dispatched along with all existing the resources within the Niagara zone, the amount of power that could flow into Ontario over the New York-Niagara interconnection would be reduced.

4.5.4 Northeast Zone

The loss of a single 500 kV circuit (P502X) leaves most of the Northeast with only one 115 kV connection (D3K) to the rest of the Ontario transmission system. To secure the operation of this zone, a Special Protection System (SPS) enforces a load-generation balance following the loss of circuit P502X. In practice, generation rejection is armed most days and load rejection is armed most nights. Given that the operation of the Northeast zone relies so heavily upon an SPS for a single element contingency, the existing transmission infrastructure provides a relatively lower level of reliability. The SPS is complicated in that the generation rejection at many different sites has to be very well coordinated. As a result, the SPS has not always been able to produce the desired outcome.

Contingencies involving P502X or D501P without generation rejection cause many thermal overloads.

4.5.5 Northwest Zone

Several customers in this zone have already indicated that the existing Market Rules regarding minimum voltage will not meet their requirements. Some customers lack the under load tap changing transformers that would allow them to compensate for transmission system voltages. Higher than minimum voltages can be maintained at an additional cost by constraining the output of specific generation or other rotating reactive resources.

Near Thunder Bay, voltages are maintained using the Thunder Bay generating and condensing units. If neither generating unit is on line, arrangements can be made to ensure the condensing unit is dispatched to support voltages but at an additional cost. During times when the need for the condenser is greatest it may not be available because it requires the Thunder Bay G2 unit to start. The IMO suggests that market participants may wish to pursue options to alleviate this operating condition in the Thunder Bay area.

Near Kenora, operation of Caribou Falls and Whitedog Falls generating units may be required for control of local power inflows under some load conditions. Under these conditions, there may be an additional cost if it is necessary to constrain-on generation.

In the late 1990s, a contingency in the Mid-Continent Area Power Pool (MAPP) region resulted in the collapse of the Northwest transmission system. The Northwest system will be reinforced to withstand MAPP design criteria contingencies, but the timetable for this reinforcement has not been established.

4.5.6 Toronto Zone

As detailed in Section 4.6.6, the IMO has concerns regarding the long-term supply reliability of the greater Toronto area (GTA).

During August 2001 when peak demands exceeded 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 B and Darlington generating 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 B and Darlington units should be avoided during summer peak periods.

The IMO has concerns regarding the existing connection arrangement for the four 500/230 kV autotransformers at Cherrywood TS. These autotransformers are switched as pairs through their 500 kV breakers and this means that two autotransformers can be lost simultaneously. With some local generating facilities operating at less than full output during the August 2001 hot weather conditions, the Cherrywood autotransformers were operated at power levels near, but below, their continuous ratings. On loss of a pair of autotransformers during these conditions, the remaining autotransformers could have become overloaded. Depending on the amount of overload, some load might have to be disconnected. With the return to service of the four units at Pickering A Nuclear Generating Station (NGS), the transfers through the autotransformers at Cherrywood TS are expected to reduce, so the consequences of losing two autotransformers simultaneously will become less of a concern. However, during the next vacuum building outage at Pickering NGS the transfers through the autotransformers could increase sufficiently to become a potential problem. Therefore, it is recommended that the situation be reviewed, and if warranted, the retermination of these autotransformers should proceed so that they are switched separately.

4.5.7 West Zone

For the study period of this report, the Ontario – Michigan phase angle regulators (PARs) are assumed in-service. With full PAR control of the Ontario – Michigan interconnection, Lake Erie Circulation (LEC) will be controlled by an amount up to about 600 MW. Improved control of LEC should allow scheduled power flows to be maintained at the Ontario – Michigan interconnection. With scheduled power flows maintained on the Ontario – Michigan interconnection, the combined Michigan/New York by Ontario transfer capability will be less affected by parallel path flows. This will provide more opportunities for coincident Ontario exports of up to approximately 5,800 MW and imports of up to approximately 3,900 MW.

Although not presently respected, double circuit contingencies near the Windsor area could cause the entire area to collapse or interrupt a significant portion of the load. Since these contingencies could have a significant adverse impact on the Michigan control area, the Windsor area should be operated to respect double circuit contingencies.

In addition, the existing use of the Windsor Area Overload Protection Scheme to respect single element contingencies indicates the existing transmission infrastructure in this area is inadequate. Given that loads in this area are expected to increase during the Outlook study period, the occurrence of thermal overloads as a result of single element contingencies will also likely increase. The commercial operation of the new proposed generation projects in this area will also rely heavily upon Special Protection Systems for single element contingencies.

The ampacity of 115 kV circuit J4E may be insufficient to accommodate future load growth in the Windsor area.

4.6 Impact of Proposed New Generation and Transmission Projects

All proposed new generation and transmission projects that will be connected to the IMO-controlled grid must be assessed via the IMO Connection Assessment and Approval (CAA) process, pursuant to Market Rules, Chapter 4, Section 6.

Potential new generation resources are detailed in Section 2.0, Table 2.2.

The impact on the IMO-controlled grid of some projects for which an assessment has been completed is briefly summarized in the following sections. Complete details can be obtained at the IMO web site www.theIMO.com under the "Services – Connection Assessments" web page.

4.6.1 Quebec HVDC interconnection Project

Hydro One Networks plans to build a 1,250 MW High Voltage Direct Current (HVDC) interconnection with Quebec. Two 230 kV circuits are required for this project, each approximately 35 kilometers long, starting from the Hawthorne Transformer Station (TS) in Ottawa, running through Gamble Junction and then crossing over the Ottawa River to Outaouais Substation in Quebec. Pending regulatory approvals, the proponent has indicated a probable in-service date of the second quarter of 2004. The Ontario Energy Board has given Hydro One Networks a Leave-to-Construct approval for this project.

New facilities will be added at Hawthorne TS to accommodate the new circuits and the expected increase in power flow through the station. The new facilities will also include two new shunt capacitors rated at 200 MVAr each.

At the Outaouais Substation, Hydro Quebec will install two single pole 625 MW HVDC converters. New transmission circuits will also be built by Hydro Quebec to improve the security of supply to Outaouais Area.

The proposed facilities will have no adverse impact on the adequacy or the performance of the Ontario transmission system. In fact, the proposed facilities should improve the reliability of the Ottawa transmission zone during import conditions as it provides greater supply diversity. The Flow Into Ottawa (FIO) transfer limit will increase from 1,900 MW to 3,000 MW.

The HVDC interconnection will affect the transfer capability of the Ontario – New York-St. Lawrence interconnection during conditions of simultaneous maximum imports/exports. Under these conditions, the Ontario – New York St. Lawrence interconnection will become thermally overloaded for the loss of the HVDC interconnection. Currently, the transfer limit on the Ontario – New York-St. Lawrence interconnection is based on the loss of one of the companion 230 kV circuits, L33P or L34P. With the addition of the HVDC interconnection, the transfer capability limit of this interface will have to be based on the loss of the HVDC interconnection. If under certain scenarios, the import or the export to New York becomes limited due to the HVDC transaction with Quebec, then the transfer on the HVDC interconnection may have to be restricted. It is estimated that without mitigating measures, the HVDC interconnection could restrict the flow at New York-St. Lawrence interconnection by up to 100 MW. It is expected that any operating restrictions required to remove New York transfer limitations will not have a material effect on the utilization of this interconnection. In addition, if full utilization of the Ontario – Quebec interconnection is desired, then Hydro One Networks could consider the addition of the loss of the HVDC interconnection to the Saunders generation rejection scheme.

4.6.2 TransAlta (Sarnia Regional Cogeneration Plant), Enron Canada (Lambton), AES (Leamington) and ATCO (Brighton Beach) Generation Projects

These four projects have been proposed for incorporation into the West transmission zone.

Construction of the TransAlta – Sarnia Regional Cogeneration Plant (SRCP) project in Sarnia is currently underway and full commercial operation is scheduled to commence in October 2002. This project is to be incorporated into Scott Transformer Station (TS) via the existing 230 kV circuits N6S and L23N (which is to be redesignated as N7S once the radial section between Scott TS and the Imperial Oil Complex has been reterminated on to a new busbar position).

Construction of the ATCO – Brighton Beach project in Windsor is scheduled to commence in the spring of 2002. Two of the generating units of this project are to be incorporated into the 230 kV busbar at Keith TS, while the remaining unit is to be incorporated into the 115 kV busbar.

The scheduled in-service date for the AES project near Leamington, which is to be incorporated on to circuits C23Z and C24Z via a new 12km double-circuit line, has been deferred until Q1-2005.

The scheduled in-service date for the Enron Canada project in Sarnia has also been deferred until Q2-2004. This project, which is to be incorporated directly into the 230 kV busbar at Lambton TGS, is being reassessed by the IMO. This reassessment is being undertaken to determine whether a proposed change to a combined-cycle development from the original all gas-turbine proposal, with no accompanying change in the total capacity, will have any impact on the results from the earlier system impact assessment study.

Special Protection Systems (SPSs) have been specified for the incorporation of these generating facilities to address the thermal overloads that have been identified under contingency conditions. These SPSs, which are to be armed prior to the actual contingency occurring, are intended to initiate automatic generation rejection and/or cross-tripping of selected circuits so as to respect the thermal ratings of the various system elements, in response to different system contingencies.

A separate SPS has been specified for the incorporation of the TransAlta project, to recognize contingencies involving the 230 kV circuits that terminate at Scott TS, as well as contingencies on the Ontario – Michigan Interconnection, B3N.

For the incorporation of the ATCO Project, a separate SPS has also been specified to recognize contingencies involving the 230 kV and 115 kV facilities in the Keith area, together with those involving the Ontario – Michigan Interconnection, J5D. This SPS, which is intended to replace the existing Windsor Area Overload Protection Scheme, is to be contingency-based rather than being initiated by thermal overloads on either of the two autotransformers at Keith TS or on the local 115 kV circuits. The need for a contingency-based SPS has arisen from an IMO requirement to have advance information on the response (arming) that has been selected for different contingencies in order to satisfy the contingency monitoring that is performed by the IMO's Energy Management System.

This latter SPS will also need to be expanded to address additional contingency conditions once a commitment is made to proceed with the incorporation of the AES Project.

A new SPS will also need to be specified for the Enron Canada project to address contingencies involving the 230 kV circuits that terminate at Lambton TGS, as well as the two Ontario – Michigan Interconnections, L4D and L51D.

While the deployment of these SPSs will allow greater utilization of the existing transmission facilities, they impose a greater operational burden on the system operators, while also increasing the risk to the system should they malfunction or be armed inappropriately. They should therefore be recognized as stopgap measures to address inadequate transmission until such time as appropriate reinforcement of the system can be identified and constructed.

Furthermore, once the TransAlta and ATCO projects are both in-service, the transfer capability of the existing transmission facilities between Lambton TS and Buchanan TS will be fully utilized during those periods when maximum transfers are being made into Ontario via the Ontario – Michigan interconnection. This will mean that, should any additional generating capacity be developed west of London, either generation dispatch or transfers into Ontario would need to be restricted.

Since the transfer capability of the existing transmission facilities is limited by the pre-contingency flows and the requirement that these respect the continuous thermal ratings of the existing circuits, there is no scope for increasing the limit by employing an SPS. Consequently, should further generating capacity be developed, then in order to allow full dispatch of the available resources, reinforcement of the existing transmission system would be necessary. If this reinforcement were to involve the construction of new transmission circuits then this would have the added benefit of reducing the reliance on SPSs to manage expected post-contingency overloads.

Similarly, once the TransAlta and ATCO projects are both in-service, the transfer capability of the existing transmission facilities east of Buchanan TS (the NBLIP interface) will be fully utilized during those periods when maximum transfers are being made into Ontario via the Ontario – Michigan interconnection. Should further generating capacity be developed in the west transmission zone, then in order to allow full dispatch of the available resources, reinforcement of this interface would be necessary.

4.6.3 Sithe (Goreway) and Sithe (Southdown) Generation Projects

These two projects are to be incorporated into the Toronto transmission zone.

A Leave-to-Construct hearing was held at the Ontario Energy Board in January 2002 for the Sithe-Goreway generation project and, subject to receipt of formal approval, engineering and design work is expected to commence in the spring of 2002. This project is to be connected to the existing 230 kV circuits V72R and V73R, between Bramalea TS and Claireville TS. Start of full commercial operation is scheduled to occur in Q3-2004.

The proposed Sithe-Southdown generation project is expected to follow the Sithe-Goreway project about one year later. This project is to be connected to the existing 230 kV circuits, B15C and B16C, between Oakville TS and Applewood Junction.

During high load levels, the Toronto transmission zone will still be deficient in generation even with these two projects in-service. As a result, there will be no congestion issues associated with these projects. In addition, these projects are not expected to adversely impact the major transfer interface limits of the system. The Sithe projects will improve the reliability of load supply in the Toronto zone and will mitigate the voltage control concern in the Toronto zone by providing additional reactive power. The projects will also help alleviate the potential overloading problems on the Claireville 500 kV autotransformers as the demand increases. Furthermore, the projects will also help alleviate transmission restrictions during outages to generation units and/or transmission facilities critical for supply to the Toronto zone.

The addition of further generating capacity or changes in the transmission system configuration near Claireville TS could increase the fault level beyond the capability of the existing equipment at Claireville. If this were to happen, it is expected that it would be necessary to operate with the Claireville 230 kV busbar “split”. Should the proposal to “split” the Claireville busbar be adopted, then some reconfiguration of the existing circuits and the retermination of the idle 230 kV V75R circuit to Richview would be required to maintain transfer capabilities. However, further detailed engineering may identify other options to address the fault level concerns.

4.6.4 Northland Power (Kirkland Lake) Generation Project

This project is to be incorporated in the Northeast transmission zone.

Northland Power’s proposal is to increase the capacity of the existing Kirkland Lake Generating Station (GS) by adding a sixth generating unit at the site. Three of the five existing units are connected to 115 kV circuit D3K which connects to Kirkland Lake Transformer Station (TS) and Dymond TS. The remaining two units are connected to 115 kV circuit K2. The new generating unit is to be connected to 115 kV circuit D3K via a new transformer. The expected in-service date is Q4-2002.

The proposed generator at Kirkland Lake GS will result in a reduction of the existing system transfer capability under conditions of high flow south on 500 kV circuit P502X, and 115 kV circuits A8K and A9K. Therefore, operating restrictions will be imposed on Kirkland Lake GS. For flows south of 750 MW or higher, the total output of Kirkland Lake GS will be limited to 106 MW to prevent the tripping of D3K for the loss of P502X. For flows south less than 750 MW, generation run back of up to 41 MW will be required at Kirkland Lake GS for the loss of P502X.

Installing a second 115 kV circuit between Kirkland Lake TS and Dymond TS, in parallel with D3K would eliminate the operating restrictions on Kirkland Lake GS.

The project is not expected to adversely impact the East – West Transfer and Flow North/Flow South Transfer interface limits. It is also expected that there will be no congestion issues associated with this project on the Flow North/Flow South Transfer interface.

4.6.5 Ontario Power Generation Inc. (Hearn) Generation Project

Ontario Power Generation Inc. (OPGI) has proposed a 550 MW combined-cycle generation project at their Hearn Thermal Generating Station (TGS) in the Portlands area of Toronto. The scheduled in-service date for the new facility is Q4-2004.

The incorporation of this project has been shown to increase the fault levels within the immediate area and as a result require twenty-six of the 115 kV breakers at Leaside Transformer Station (TS) to be replaced with higher rated units, together with a further seven 115 kV breakers at Hearn TGS.

The outages required for this work may be challenging to complete in time to allow the scheduled in-service date to be met.

However, should OPGI decide to proceed with this project, then not only would it increase the load-meeting capability in the Toronto transmission zone, but it would also provide voltage support.

4.6.6 Greater Toronto Area Projects

The IMO has recently conducted Connection Assessments for the Ontario Power Generation Inc. (OPGI) new generation project at Hearn Thermal Generating Station (TGS); the Hydro One project to quarter Terauley Transformer Station (TS); the Hydro One project to increase the capacity of the step-down transformers at Cecil TS; the Hydro One project to install a 125 MVAr capacitor bank at Hearn TGS; and the Hydro One proposal to retire the synchronous condensers at Manby TS.

In the course of undertaking these Assessments some concerns regarding the supply capability of the existing transmission facilities in the greater Toronto area (GTA) have been identified. These concerns arise from the conflicting requirements -

- to operate with many of the 115 kV busbars “open” so that the fault interrupting capability of the existing circuit breakers is respected, and
- to operate with many of the 115 kV busbars “closed” so that the transfer capability of the existing transmission facilities is sufficient to supply the loads that have been forecast for the immediate future, while respecting the thermal ratings of the circuits, and in order that the load meeting capability of the existing facilities will be maximized by maintaining balanced loads on individual circuits.

The IMO has therefore concluded that immediate action is required to implement measures that will ensure that the increasing loads within the GTA can continue to be supplied under contingency conditions. These measures could include one or more of the following, or any other proposal that will provide an enhanced supply capability to the GTA:

- Install the additional generating capacity at Hearn TGS as proposed by OPGI. This would require a substantial number of circuit breakers at Leaside TS and Hearn TGS to be replaced.
- Reinforce the existing transmission facilities to increase their load-meeting capability. The installation of additional 230 kV transmission facilities between Cherrywood TS and Leaside TS together with additional 230/115 kV transformer capacity at Leaside TS is expected to require a substantial number of circuit breakers at Leaside TS (and possibly also at Hearn TGS) to be replaced.
- Establish a third supply into the GTA and transfer some of the loads that are currently supplied from Leaside TS and Manby TS to this new supply.

The rationale for these conclusions has been summarized below:

- In order to avoid overloading either of the two cable circuits between Cecil TS and Terauley TS under contingency conditions involving the companion circuit, Terauley TS will need to be quartered and the 115 kV busbars operated "open", as has been proposed by Hydro One. This work is scheduled to be completed by Q4-2002.

  This would allow approximately half the load at Terauley TS to be supplied from Cecil TS while the remainder would be supplied from the 115 kV busbar at Hearn TGS, via Esplanade TS. With an increase in the amount of load being supplied via Hearn TGS, it will also be necessary to operate with this busbar and the 115 kV busbar at Leaside TS "closed" to avoid post contingency overloading of the Leaside to Hearn circuits.

  However, even with these busbars operated "closed" post-contingency loadings of up to 98% of the continuous rating of the circuits in the area have been identified for the summer-2004. This indicates that even under 'ideal' conditions there is little spare capacity in the existing 115 kV transmission system in the Leaside sector to accommodate future increases in load.

All the following items assume that the 115 kV busbars at Terauley TS are quartered and operated open.

- With the return to service of the four generating units at Pickering A Nuclear Generating Station (NGS) scheduled for 2003/2004, the fault levels in the area will increase and it will be necessary to operate with the 115 kV busbars at both Leaside TS and Hearn TGS "open" in order to respect the fault interrupting capability of the existing circuit breakers at Leaside TS.
- If the four units at Pickering A NGS were not being returned to service, then the current requirement to operate with the 115 kV busbar at Leaside "open" (while that at Hearn TGS remains "closed") has been shown to result in post-contingency overloads of around 6% on the continuous rating of the 115 kV circuits, under single-circuit contingency conditions, for the loads that have been forecast for summer-2004. Under double-circuit contingency conditions these overloads increase to 27%. Furthermore, in successive years the extent of the overloads will increase with increasing load in the area.

  Hydro One has indicated that until a permanent solution can be implemented they plan to manage these overloads by arranging to transfer approximately 90 MW of the load at Esplanade TS to the adjacent sector supplied from Manby West TS, immediately post-contingency, or respecting shorter-time thermal limits. However, it is expected that the Manby sector will only be able to accommodate transfers of this magnitude up to 2006, as loads continue to increase in this sector.

- Installing the additional generating capacity at Hearn TGS as proposed by OPGI, would result in increased fault levels and require twenty-six of the existing 115 kV circuit breakers at Leaside TS and a further seven of the 115 kV breakers at Hearn TGS to be replaced. With these breakers replaced it would still be necessary to operate with the 115 kV busbars at Leaside TS and Hearn TGS "open" whenever the new generating capacity is dispatched.

  If it were to be considered necessary to be able to avoid having to "open" the 115 kV busbars at Leaside TS and at Hearn TGS whenever the new generation capacity at Hearn TGS is dispatched, then the two remaining breakers at Leaside TS and the remaining twelve breakers at Hearn TGS would also need to be replaced.

  In order for this new generating facility to contribute to the load-meeting capability of the Leaside sector it would need to be constrained-on during critical load-supply periods.

- In the absence of any new generation capacity, further reinforcement of the Leaside sector as detailed below (or through equivalent measures) would appear to be required to increase its load-meeting capability:
  1. Upgrade and/or install new 115 kV transmission facilities to augment the existing facilities in the Leaside sector.
  2. Install additional 230/115 kV transformer capacity at Leaside TS.
  3. Install additional 230 kV transmission facilities between Cherrywood TS and Leaside TS.

  The installation of additional transformer capacity at Leaside TS and/or the installation of additional 230 kV transmission facilities between Cherrywood TS and Leaside TS is also expected to trigger a requirement to replace breakers at Leaside TS and possibly at Hearn TS as a result of the increased fault levels that would arise.

- Since reinforcement of the existing transmission facilities in the Leaside sector to increase its load-meeting capability are expected to require extensive breaker replacement work to be completed to ensure that the fault interrupting capacity of the existing breakers is not exceeded, then an alternative that should be considered would involve the installation of a third supply into the GTA.

  The installation of a third supply into the GTA was recommended in the 1995 TIES (Toronto Integrated Electrical Services) Study as the preferred plan for meeting the future load growth within the GTA. A third supply would allow a portion of the load that is currently supplied from Cherrywood TS, via Leaside TS, to be transferred to it. This would avoid the need to reinforce the Cherrywood to Leaside TS corridor, while also allowing the 115 kV busbars at Leaside TS and Hearn TGS to be operated "open", thereby avoiding any increase in the fault level and the need to replace breakers.

  While the installation of a third supply into the GTA would meet the future supply requirements of the GTA, the IMO has concerns regarding the time that would be required to implement such a plan. The situation within the GTA is expected to become critical once the four units at Pickering A NGS are returned to service. In the absence of any new facilities to augment the supply to the GTA, it will be necessary to operate with the 115 kV busbar at Hearn TGS "closed" to minimize the risk of supply interruptions. The IMO will therefore need to review the operating requirements for the area in order to address the increased fault levels that will occur, upon the return to service of the Pickering A units. One option may involve imposing a restriction on the maximum voltage at which the 115 kV busbar at Leaside TS can be operated when all generating facilities are in-service. Should this approach be adopted then this may also require the installation of further shunt capacitance at Hearn TGS and/or Leaside TS beyond the 125 MVAr that is currently proposed for installation at Hearn TGS in May 2003 to support the voltages in the Hearn area.

- The installation of a third supply into the GTA would also permit a portion of the load that is currently supplied from Manby West TS to be transferred to it. Based on the latest load forecast, reinforcement of the Manby sector is required immediately in order to meet the IMO's criterion that restoration of the supply to loads in excess of 250 MW is to be possible through switching (i.e. within a maximum of 30 minutes), following a double-circuit contingency. Since the Leaside sector has no capability to accommodate transferred loads, then in order to meet this criterion the remaining facilities in the Manby sector would need to be capable of supporting all of the local load, and presently, they are not.

  While the existing facilities in the Manby sector have been shown to be adequate to sustain the forecast loads under single-circuit contingency conditions, the situation is expected to become critical for these contingencies towards the end of the decade as the area loads in the area increase.

  It is also worth noting that should OPGI decide to proceed with the installation of additional generating capacity at Hearn TGS, then one way to avoid extensive replacement of circuit breakers at both Leaside TS and Hearn TGS, should a decision be made to proceed with a third supply into the GTA, would be to incorporate these new generation facilities via this new connection. It is expected that the time required to establish a third supply into the GTA could be comparable with the time required to undertake the necessary breaker replacement work at Leaside TS and Hearn TGS, so it would not necessarily involve any further delay in placing these facilities in-service.

4.6.7 Lake Erie HVDC Interconnection

There is a proposal by Hydro One and TransEnergie US to construct a 990 MW HVDC interconnection, which would start at the Nanticoke Thermal Generating Station (TGS) and then cross Lake Erie. The proponents of this project have indicated an in-service date of the second quarter of 2004.

The addition of the proposed interconnection will have no adverse impact on the transfer capability and performance of the Ontario transmission system. However, fault levels at Nanticoke TGS will increase. As a result, the fault interrupting capability of certain Nanticoke 230 kV breakers will be exceeded. Mitigating measures will be required to reduce fault levels at Nanticoke.

5.0 Overall Observations, Findings and Conclusions

Based on existing and proposed facilities, Ontario is expected to have reliable supply of electricity for the ten-year study period under a wide variety of conditions. Opportunities also exist for additional enhancements to improve the efficiency of the Ontario electricity market. The NPCC reliability standard, based on an annual Loss of Load Expectation of 1 day in 10 years, is forecast to be met throughout the study period.

In addition to the return to service of Pickering A and two of the Bruce A units and addition of the Transalta – Sarnia Regional Cogeneration Plant in the first three years, about 3,500 MW of over 6,200 MW of generation projects submitted to the IMO for Connection Assessment and Approval (CAA) would need to materialize in the last years of the study period, especially under the high demand growth scenario, to maintain reserve levels at the reliability standard and avoid dependency on external resources.

The development of additional price sensitive demand or dispatchable demand by market participants would contribute to an easing of resource adequacy concerns in the case of fewer than required generation additions. Similarly, a substantial amount of external supply from neighbouring areas, if attracted through market price signals, should be able to reach the Ontario demand areas via the available interconnection and transmission capacity. Quantities in the range of 3,000 MW or more for either of these options (or a combination thereof) would substantially offset the need for new generation. These alternatives are particularly attractive in the short-term because they require little or no lead-time to establish.

If all generation proposals are built and operated, the amount of generation that is exclusively gas fueled will increase from 6% to 21% of the installed capacity within Ontario by 2005. Another 6% of the installed capacity will be dual-fuelled with gas. Many other jurisdictions are concerned with the gas supply issue, and it has been raised in various forums such as NPCC and NERC. The IMO has initiated a multi-region study to assess the adequacy of the existing and planned gas pipeline infrastructure and to assess the impact of gas pipeline contingencies on electricity system reliability.

As a competitive alternative to new and existing generation, the IMO believes market participants should vigorously pursue price responsive demand management options. Demand management is most frequently viewed from one or more of three perspectives: the first being price responsive demand (dispatchable or self-scheduled) which reacts to market price signals; the second being demand curtailment; and the third being energy conservation. Each of these options can have a role to play in the demand and supply balance of the Province. Energy conservation can be implemented individually or collectively, at any time, not only in response to price but for other reasons such as environmental concerns. Demand curtailment relies on a broader-based decision process integrated with appropriate deployment technology; introduction of new measures requires some lead-time for development of the necessary infrastructure. Price responsive demand requires not only the technical infrastructure for conveying price signals and implementing dispatch but also an appropriately structured market. To harvest the fruits of this latter demand option at the individual consumer level will require technological advances as well as full retail access to hourly pricing.

In the generic outage plan, approximately 800 MW of generating capacity was considered to be on planned outage over the winter peak periods, with 1,300 MW assumed on outage over the summer peak periods. However, should outage durations grow, as might be required for rehabilitation activities or for installation of emission reduction facilities, the IMO expects increasing pressure to accommodate more outages over peak periods. As reserve margins increase, through the addition of resources to the IMO-controlled grid, the ability to accept outages over peak periods will improve.

Based on the results of the zonal supply reliability assessments conducted, it is concluded that the transfer capability of the major interfaces is adequate to supply the demands within each of the ten transmission zones for the period 2003 to 2012.

The impact of a contingency on the ability of transmission facilities to supply loads continuously should be determined by the establishment of a supply reliability criteria that can be applied to all areas of the IMO-controlled grid.

Under all facilities in-service conditions, constrained generation is expected to occur due to transfer limits on some of the major transmission interfaces. In particular, existing congestion is likely to continue on the East-West (EW) transmission interface, while congestion of up to 2,400 MW can be expected to develop on the Negative Bruce Longwood Input (NBLIP) interface if all of the generator additions proposed under the IMO CAA process in the South-western Ontario area come into service. Some of interfaces will have the potential to be more constraining than others.

Additional reactive resources may be required in the Southwest and East transmission zones by 2012. In the Toronto transmission zone, any reductions to the present reactive capability during summer peak demand conditions may result in voltage levels below minimum required levels. As demand in the Toronto zone increases, the reactive capabilities of this zone must also increase to mitigate any voltage concerns during summer peak demand conditions. Restrictions on the use of any local generation, especially Lakeview or Pickering, would increase the need for additional reactive supply. However, if all proposed reactive resources go in-service as scheduled, the reactive capability of this zone should be sufficient until around 2012.

There are significant concerns regarding the supply capability of the existing facilities in the greater Toronto area. The concerns arise from conflicting requirements to operate with many of the 115 kV busbars open to respect the increased fault levels that will occur once the four Pickering A units return to service, or closed to be able to supply forecasted demands. These capabilities begin to be of concern during summer peak demand conditions in 2004, but stopgap measures could be implemented to manage these concerns until about 2006. Some of the solutions available to alleviate these concerns may take several years to complete. Because of the potentially long lead-times for implementation, market participants considering projects, in addition to those currently under study, should submit them to the IMO for assessment as early as possible.

The frequent use of special protection systems and schemes at certain transmission facilities in the East, Northeast and West zones suggest that the reliability of these areas could be improved if the transmission network is reinforced.

Near Thunder Bay, voltages are maintained at required levels by using the Thunder Bay generating and condensing units. Market participants may wish to pursue options to alleviate this operating condition.

The existing connection of the four 500/230 kV autotransformers at the Cherrywood Transformer Station should be reviewed, and if warranted, the retermination of these autotransformers should proceed.

The ampacity of 115 kV circuit J4E may be insufficient to accommodate future load growth in the Windsor Area.

Appendix A – Resource Adequacy Assessment Details

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1.0 Resource Adequacy Assessment Tables

The following tables provide numeric results of the resource adequacy assessment. They support Figure 3.1 and 3.2 in Section 3.2 and the statements made in Section 3.2.1 to 3.2.2.

Table A1 Reserve Margins Under Low Demand Growth, Summer Peak, Reference Resource Scenario

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	22,676	13-Jul-03	29,481	7,105	3,628	31.8	16.2	3,477
2004	22,926	11-Jul-04	29,028	6,402	3,233	28.3	14.3	3,169
2005	23,130	17-Jul-05	27,815	4,985	3,005	21.8	13.2	1,980
2006	23,353	16-Jul-06	28,499	5,446	2,984	23.6	12.9	2,462
2007	23,576	15-Jul-07	28,495	5,219	2,982	22.4	12.8	2,237
2008	23,807	13-Jul-08	28,486	4,979	2,937	21.2	12.5	2,042
2009	24,051	12-Jul-09	27,745	3,994	2,887	16.8	12.2	1,107
2010	24,248	18-Jul-10	27,752	3,804	2,938	15.9	12.3	866
2011	24,467	17-Jul-11	27,755	3,588	3,236	14.8	13.4	352
2012	24,677	15-Jul-12	27,740	3,363	3,006	13.8	12.3	357

Table A2 Reserve Margins Under Low Demand Growth, Winter Peak, Reference Resource Scenario

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	23,296	12-Jan-03	27,441	4,445	3,228	19.3	14.0	1,217
2004	23,415	11-Jan-04	29,259	6,144	3,137	26.6	13.6	3,007
2005	23,442	16-Jan-05	29,975	6,833	3,054	29.5	13.2	3,779
2006	23,544	15-Jan-06	28,662	5,418	2,770	23.3	11.9	2,648
2007	23,646	14-Jan-07	28,875	5,529	2,735	23.7	11.7	2,794
2008	23,768	13-Jan-08	28,875	5,407	2,734	23.0	11.6	2,673
2009	23,901	11-Jan-09	28,120	4,519	2,646	19.1	11.2	1,873
2010	23,908	17-Jan-10	28,120	4,512	2,648	19.1	11.2	1,864
2011	24,013	16-Jan-11	28,120	4,407	3,250	18.6	13.7	1,157
2012	24,102	15-Jan-12	28,120	4,318	3,057	18.1	12.8	1,261

Table A3 Reserve Margins Under Median Demand Growth, Summer Peak, Reference Resource Scenario

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	23,404	13-Jul-03	29,419	6,315	3,628	27.3	15.7	2,687
2004	23,711	11-Jul-04	29,027	5,616	3,230	24.0	13.8	2,386
2005	23,959	17-Jul-05	27,814	4,155	3,006	17.6	12.7	1,149
2006	24,230	16-Jul-06	28,498	4,568	2,984	19.1	12.5	1,584
2007	24,503	15-Jul-07	28,495	4,292	2,983	17.7	12.3	1,309
2008	24,787	13-Jul-08	28,485	3,998	2,945	16.3	12.0	1,053
2009	25,087	12-Jul-09	27,743	2,956	3,047	11.9	12.3	-91
2010	25,342	18-Jul-10	27,755	2,713	3,163	10.8	12.6	-450
2011	25,623	17-Jul-11	27,754	2,431	3,232	9.6	12.8	-801
2012	25,903	15-Jul-12	27,739	2,136	3,295	8.3	12.9	-1,159

Table A4 Reserve Margins Under Median Demand Growth, Winter Peak, Reference Resource Scenario

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	23,984	12-Jan-03	27,506	3,822	3,312	16.1	14.0	510
2004	24,175	11-Jan-04	29,259	5,384	3,135	22.6	13.1	2,249
2005	24,245	16-Jan-05	29,975	6,030	3,051	25.2	12.7	2,979
2006	24,394	15-Jan-06	28,662	4,568	2,769	19.0	11.5	1,799
2007	24,545	14-Jan-07	28,875	4,630	2,736	19.1	11.3	1,894
2008	24,720	13-Jan-08	28,875	4,455	2,742	18.2	11.2	1,713
2009	24,908	11-Jan-09	28,120	3,512	2,803	14.3	11.4	709
2010	24,973	17-Jan-10	28,120	3,447	2,816	14.0	11.4	631
2011	25,138	16-Jan-11	28,120	3,282	2,876	13.2	11.6	406
2012	25,297	15-Jan-12	28,120	3,123	2,884	12.5	11.5	239

Table A5 Reserve Margins Under High Demand Growth, Summer Peak, Reference Resource Scenario

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	23,870	13-Jul-03	29,479	5,909	3,629	25.1	15.4	2280
2004	24,286	11-Jul-04	29,027	5,041	3,228	21.0	13.5	1813
2005	24,650	17-Jul-05	27,814	3,464	3,102	14.2	12.7	362
2006	25,040	16-Jul-06	28,499	3,759	3,036	15.2	12.3	723
2007	25,431	15-Jul-07	28,496	3,365	3,122	13.4	12.4	243
2008	25,828	13-Jul-08	28,487	2,959	3,158	11.6	12.4	-199
2009	26,237	12-Jul-09	27,746	1,809	3,307	7.0	12.8	-1498
2010	26,600	18-Jul-10	27,758	1,458	3,425	5.5	13.0	-1967
2011	26,982	17-Jul-11	27,757	1,075	3,506	4.0	13.1	-2431
2012	27,347	15-Jul-12	27,742	695	3,589	2.6	13.3	-2894

Table A6 Reserve Margins Under High Demand Growth, Winter Peak, Reference Resource Scenario

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	24,412	12-Jan-03	27,441	3,329	3,420	13.8	14.2	-91
2004	24,710	11-Jan-04	29,259	4,849	3,134	19.9	12.8	1,715
2005	24,891	16-Jan-05	29,975	5,384	3,052	21.9	12.4	2,332
2006	25,157	15-Jan-06	28,662	3,805	2,831	15.3	11.4	974
2007	25,425	14-Jan-07	28,875	3,750	2,860	14.9	11.4	890
2008	25,712	13-Jan-08	28,875	3,463	2,906	13.6	11.4	557
2009	26,009	11-Jan-09	28,120	2,411	3,027	9.4	11.8	-616
2010	26,180	17-Jan-10	28,120	2,240	3,063	8.7	11.8	-823
2011	26,446	16-Jan-11	28,120	1,974	3,148	7.5	12.0	-1,174
2012	26,693	15-Jan-12	28,120	1,727	3,160	6.5	12.0	-1,433

Table A7 Reserve Margins Under Low Demand Growth, Summer Peak, Delayed Resource Scenario

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	22,676	13-Jul-03	26,405	4,029	3,273	18.0	14.6	756
2004	22,926	11-Jul-04	27,998	5,372	3,184	23.7	14.1	2,188
2005	23,130	17-Jul-05	27,815	4,985	2,996	21.8	13.1	1,989
2006	23,353	16-Jul-06	28,499	5,446	2,984	23.6	12.9	2,462
2007	23,576	15-Jul-07	28,495	5,219	2,982	22.4	12.8	2,237
2008	23,807	13-Jul-08	28,486	4,979	2,937	21.2	12.5	2,042
2009	24,051	12-Jul-09	27,745	3,994	2,887	16.8	12.2	1,107
2010	24,248	18-Jul-10	27,752	3,804	2,938	15.9	12.3	866
2011	24,467	17-Jul-11	27,755	3,588	3,236	14.8	13.4	352
2012	24,677	15-Jul-12	27,740	3,363	3,006	13.8	12.3	357

Table A8 Reserve Margins Under Low Demand Growth, Winter Peak, Delayed Resource Scenario

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	23,296	12-Jan-03	25,746	2,750	3,229	12.0	14.0	-479
2004	23,415	11-Jan-04	27,474	4,359	2,960	18.9	12.8	1,399
2005	23,442	16-Jan-05	29,460	6,318	3,025	27.3	13.1	3,293
2006	23,544	15-Jan-06	28,662	5,418	2,770	23.3	11.9	2,648
2007	23,646	14-Jan-07	28,875	5,529	2,735	23.7	11.7	2,794
2008	23,768	13-Jan-08	28,875	5,407	2,734	23.0	11.6	2,673
2009	23,901	11-Jan-09	28,120	4,519	2,646	19.1	11.2	1,873
2010	23,908	17-Jan-10	28,120	4,512	2,648	19.1	11.2	1,864
2011	24,013	16-Jan-11	28,120	4,407	3,250	18.6	13.7	1,157
2012	24,102	15-Jan-12	28,120	4,318	3,057	18.1	12.8	1,261

Table A9 Reserve Margins Under Median Demand Growth, Summer Peak, Delayed Resource Scenario

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	23,404	13-Jul-03	26,404	3,300	3,396	14.3	14.7	-96
2004	23,711	11-Jul-04	27,997	4,586	3,184	19.6	13.6	1,402
2005	23,959	17-Jul-05	27,814	4,155	3,002	17.6	12.7	1,153
2006	24,230	16-Jul-06	28,498	4,568	2,984	19.1	12.5	1,584
2007	24,503	15-Jul-07	28,495	4,292	2,983	17.7	12.3	1,309
2008	24,787	13-Jul-08	28,485	3,998	2,945	16.3	12.0	1,053
2009	25,087	12-Jul-09	27,743	2,956	3,047	11.9	12.3	-91
2010	25,342	18-Jul-10	27,755	2,713	3,163	10.8	12.6	-450
2011	25,623	17-Jul-11	27,754	2,431	3,232	9.6	12.8	-801
2012	25,903	15-Jul-12	27,739	2,136	3,295	8.3	12.9	-1,159

Table A10 Reserve Margins Under Median Demand Growth, Winter Peak, Delayed Resource Scenario

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	23,984	12-Jan-03	25,746	2,062	3,391	8.7	14.3	-1,329
2004	24,175	11-Jan-04	27,474	3,599	3,060	15.1	12.8	539
2005	24,245	16-Jan-05	29,460	5,515	3,023	23.0	12.6	2,492
2006	24,394	15-Jan-06	28,662	4,568	2,769	19.0	11.5	1,799
2007	24,545	14-Jan-07	28,875	4,630	2,736	19.1	11.3	1,894
2008	24,720	13-Jan-08	28,875	4,455	2,742	18.2	11.2	1,713
2009	24,908	11-Jan-09	28,120	3,512	2,803	14.3	11.4	709
2010	24,973	17-Jan-10	28,120	3,447	2,816	14.0	11.4	631
2011	25,138	16-Jan-11	28,120	3,282	2,876	13.2	11.6	406
2012	25,297	15-Jan-12	28,120	3,123	2,884	12.5	11.5	239

Table A11 Reserve Margins Under High Demand Growth, Summer Peak, Delayed Resource Scenario

Year	Summer Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	23,870	13-Jul-03	26,403	2,833	3,492	12.0	14.8	-659
2004	24,286	11-Jul-04	27,997	4,011	3,192	16.7	13.3	819
2005	24,650	17-Jul-05	27,814	3,464	3,102	14.2	12.7	362
2006	25,040	16-Jul-06	28,499	3,759	3,036	15.2	12.3	723
2007	25,431	15-Jul-07	28,496	3,365	3,122	13.4	12.4	243
2008	25,828	13-Jul-08	28,487	2,959	3,158	11.6	12.4	-199
2009	26,237	12-Jul-09	27,746	1,809	3,307	7.0	12.8	-1498
2010	26,600	18-Jul-10	27,758	1,458	3,425	5.5	13.0	-1967
2011	26,982	17-Jul-11	27,757	1,075	3,506	4.0	13.1	-2431
2012	27,347	15-Jul-12	27,742	695	3,589	2.6	13.3	-2894

Table A12 Reserve Margins Under High Demand Growth, Winter Peak, Delayed Resource Scenario

Year	Winter Peak Demand	Week Ending	Available Resources	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Margin MW
2003	24,412	12-Jan-03	25,746	1,634	3,477	6.8	14.4	-1,843
2004	24,710	11-Jan-04	27,474	3,064	3,180	12.6	13.0	-116
2005	24,891	16-Jan-05	29,460	4,869	3,024	19.8	12.3	1,845
2006	25,157	15-Jan-06	28,662	3,805	2,831	15.3	11.4	974
2007	25,425	14-Jan-07	28,875	3,750	2,860	14.9	11.4	890
2008	25,712	13-Jan-08	28,875	3,463	2,906	13.6	11.4	557
2009	26,009	11-Jan-09	28,120	2,411	3,027	9.4	11.8	-616
2010	26,180	17-Jan-10	28,120	2,240	3,063	8.7	11.8	-823
2011	26,446	16-Jan-11	28,120	1,974	3,148	7.5	12.0	-1,174
2012	26,693	15-Jan-12	28,120	1,727	3,160	6.5	12.0	-1,433

Table A13 Change in Reserve Margins from Reference Resource Scenario, Low Demand Growth, Summer Peak

Year	Reserve Margin, MW				
	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Delayed Resource Scenario	High Resource Scenario
2003	1,477	2,477	3,477	756	4,545
2004	1,169	2,169	3,169	2,188	6,894
2005	-20	980	1,980	1,989	6,622
2006	462	1,462	2,462	2,462	7,133
2007	237	1,237	2,237	2,237	6,940
2008	42	1,042	2,042	2,042	6,774
2009	-893	107	1,107	1,107	5,872
2010	-1,134	-134	866	866	5,678
2011	-1,648	-648	352	352	5,198
2012	-1,643	-643	357	357	5,229

Table A14 Change in Reserve Margins from Reference Resource Scenario, Low Demand Growth, Winter Peak

Year	Reserve Margin, MW				
	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Delayed Resource Scenario	High Resource Scenario
2003	-783	217	1,217	-479	1,265
2004	1,007	2,007	3,007	1,399	4,348
2005	1,779	2,779	3,779	3,293	8,039
2006	648	1,648	2,648	2,648	6,930
2007	794	1,794	2,794	2,794	7,097
2008	673	1,673	2,673	2,673	6,998
2009	-127	873	1,873	1,873	6,221
2010	-136	864	1,864	1,864	6,221
2011	-843	157	1,157	1,157	5,536
2012	-739	261	1,261	1,261	5,659

Table A15 Change in Reserve Margins from Reference Resource Scenario, Median Demand Growth, Summer Peak

Year	Reserve Margin, MW				
	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Delayed Resource Scenario	High Resource Scenario
2003	687	1,687	2,687	-96	3,755
2004	386	1,386	2,386	1,402	6,111
2005	-851	149	1,149	1,153	5,908
2006	-416	584	1,584	1,584	6,378
2007	-691	309	1,309	1,309	6,142
2008	-947	53	1,053	1,053	5,923
2009	-2,091	-1,091	-91	-91	4,820
2010	-2,450	-1,450	-450	-450	4,517
2011	-2,801	-1,801	-801	-801	4,208
2012	-3,159	-2,159	-1,159	-1,159	3,886

Table A16 Change in Reserve Margins from Reference Resource Scenario, Median Demand Growth, Winter Peak

Year	Reserve Margin, MW				
	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Delayed Resource Scenario	High Resource Scenario
2003	-1,490	-490	510	-1,329	558
2004	249	1,249	2,249	539	3,590
2005	979	1,979	2,979	2,492	7,346
2006	-201	799	1,799	1,799	6,194
2007	-106	894	1,894	1,894	6,316
2008	-287	713	1,713	1,713	6,164
2009	-1,291	-291	709	709	5,190
2010	-1,369	-369	631	631	5,130
2011	-1,594	-594	406	406	4,934
2012	-1,761	-761	239	239	4,796

Table A17 Change in Reserve Margins from Reference Resource Scenario, High Demand Growth, Summer Peak

Year	Reserve Margin, MW				
	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Delayed Resource Scenario	High Resource Scenario
2003	280	1,280	2,280	-659	3,348
2004	-187	813	1,813	819	5,538
2005	-1,638	-638	362	362	5,218
2006	-1,277	-277	723	723	5,631
2007	-1,757	-757	243	243	5,206
2008	-2,199	-1,199	-199	-199	4,816
2009	-3,498	-2,498	-1,498	-1,498	3,573
2010	-3,967	-2,967	-1,967	-1,967	3,176
2011	-4,431	-3,431	-2,431	-2,431	2,768
2012	-4,894	-3,894	-2,894	-2,894	2,353

Table A18 Change in Reserve Margins from Reference Resource Scenario, High Demand Growth, Winter Peak

Year	Reserve Margin, MW				
	Reference Resource Scenario -2000 MW	Reference Resource Scenario -1000 MW	Reference Resource Scenario	Delayed Resource Scenario	High Resource Scenario
2003	-2,091	-1,091	-91	-1,843	-43
2004	-285	715	1,715	-116	3,056
2005	332	1,332	2,332	1,845	6,784
2006	-1,026	-26	974	974	5,469
2007	-1,110	-110	890	890	5,427
2008	-1,443	-443	557	557	5,137
2009	-2,616	-1,616	-616	-616	4,009
2010	-2,823	-1,823	-823	-823	3,833
2011	-3,174	-2,174	-1,174	-1,174	3,524
2012	-3,433	-2,433	-1,433	-1,433	3,305

Table A19 Adequacy of Energy Production Capability

Year	REQUIRED ENERGY (GWh) for various demand growth scenarios			AVAILABLE ENERGY (GWh) for various resource scenarios		
	Required Energy Low Demand Growth Scenario (GWh)	Required Energy Median Demand Growth Scenario (GWh)	Required Energy High Demand Growth Scenario (GWh)	Available Energy Reference Resource Scenario (GWh)	Available Energy Delayed Resource Scenario (GWh)	Available Energy High Resource Scenario (GWh)
2003	145,427	150,744	154,150	195,226	181,237	200,148
2004	146,919	152,678	156,885	207,347	197,267	229,167
2005	147,575	153,634	158,670	208,656	206,477	238,620
2006	148,449	154,861	160,770	212,973	212,973	243,281
2007	149,552	156,327	163,104	213,393	213,393	243,928
2008	151,053	158,238	165,866	213,440	213,440	244,272
2009	151,476	159,052	167,459	207,610	207,610	238,576
2010	152,457	160,458	169,644	205,956	205,956	237,142
2011	153,503	161,951	171,885	208,093	208,093	239,513
2012	154,774	163,762	174,350	207,889	207,889	239,611

Note to Table A19:
For each year, the required energy under each demand growth scenario can be compared to the available energy under each resource scenario.