IESO 2009 Comprehensive Review of Resource Adequacy

Covering the Ontario Area

for the period 2010 to 2014

August 19, 2009

IESO_REP_0580 V1.2

Final Report – Approved by NPCC RCC on September 10, 2009

This page intentionally left blank.

1 EXECUTIVE SUMMARY

1.1 Major Findings

The Independent Electricity System Operator (IESO) submits this assessment of resource adequacy for the Ontario Area to comply with the Reliability Assessment Program established by the Northeast Power Coordinating Council (NPCC). This 2009 Comprehensive Review of Resource Adequacy covers the study period from 2010 through 2014, and supersedes the review conducted in 2006. The guidelines for the review are specified in the NPCC Document B-8 entitled, "*Guidelines for Area Review of Resource Adequacy*" (NPCC Open Process Review: September 1, 2008).

The IESO determined Ontario's level of reliability using the Multi-Area Reliability Simulation (MARS) program.

Since the last comprehensive review in 2006, about 4,440 MW of incremental generation capacity has been added in Ontario, and 50 MW of capacity has been retired. Capacity additions include about 3,340 MW of additional gas-fired capacity and about 880 MW of additional wind capacity. In addition, future generating resource capacity additions of 4,180 MW are under construction or planned to come into service during the study period 2010 to 2014.

In order to ensure system reliability in Ontario while supporting the coal replacement strategy, the Government of Ontario directed the Ontario Power Authority (OPA) to work with the IESO to develop an off-coal plan and to procure additional power in Ontario to address various reliability needs. It is assumed that declining amounts of coal-fired generation will be available during the study timeframe of 2010 to 2014 subject to the annual CO_2 emission limits set by the government. Under current legislation, there will be no generation from coal in 2015 and onward.

This Comprehensive Review identifies changes in assumptions from the 2006 Comprehensive Review, including changes to facilities and system conditions, generation resources availability, load forecast, electricity sector regulations, and the impact of these changes on the overall reliability of the Ontario electricity system.

This 2009 Comprehensive Review indicates that Ontario will be able to meet the NPCC resource adequacy criterion that requires an LOLE value of less than 0.1 days/year for all years from 2010 to 2014. New generation that is expected to come into service together with the general decline in forecast demand will ensure the reliability of the Ontario power system as the coal units are removed from service.

1.2 Major Assumptions and Results

This review covers the period from 2010 to 2014 inclusive. Major assumptions are summarized in Table 1.1 below:

Table 1.1 Major Assumptions

Assumption	Description
Adequacy Criterion	NPCC Loss Of Load Expectation (LOLE) requirement of not more than 0.1 days/year
Reliability Model	GE's MARS program
Load Model	8,760 hourly loads with forecast uncertainty factors
Energy Demand Growth Rate	Median Demand Growth: about -0.7% per annum High Demand Growth: about 1.0 % per annum
Generating Capacity Additions	4,180 MW by the end of 2014
Generating Capacity Retirements	Coal retirements (cumulative total MW at time of annual peak): - 2010: 0 MW - 2011: 1,676MW - 2012: 3,294 MW - 2013: 3,294 MW - 2014: 3,294 MW
Internal and Interconnection Transmission Constraints	Based on IESO normal system operating security limits
Tie Benefits	Tie Capability = 5,250 MW For all study years, 0 MW of interconnection assistance was required to meet the LOLE criterion
Emergency Operating Procedures	Initial runs had no EOPs modeled Additional runs were modeled with EOPs for calendar years when LOLE of 0.1 days/year could not be attained without EOPs
Unit Availability	Planned outages modeled: 2010 outages are based on outage submissions from market participants. 2011 to 2014 outages are based on forecast Planned Outage Factor (POF) from market participants and/or the Generic Outage Plan derived from historic outage patterns of existing units. Forced outages modeled: Based on Equivalent Forced Outage Rate (EFOR) derived from five-year history of actual forced outages. Units with insufficient historical data are based on forecast EFOR from market participants.
Conservation and Demand Management (CDM)	Conservation: Up to 3,288 MW by 2014 Demand Management: Up to 1,703 MW by 2014

There were four different sets of study conditions that the IESO prepared for modeling in MARS. In the first set of MARS runs, the calculations were performed with the assumptions listed above, without the use of any emergency operating procedures (EOPs), and with a more conservative level of available resources. These resources include all existing units and projects under contract, as well as units procured for contracts by the OPA as directed by the Ministry of Energy and Infrastructure. If the LOLE criterion could not be met under the first study set, the second set of MARS runs were performed with the assumptions listed above, with the use of EOPs. For instances where the resultant annual LOLE again exceeded criterion, a third MARS study was prepared, with EOPs modeled, and with all planned resources assumed to be available. These planned resources included conceptual projects without any OPA contracts and which might not have been be at the stage of Request for Proposal (RFP). Finally, for cases where the LOLE still exceeded criterion, a fourth MARS run was prepared with additional capacity modeled as interconnection assistance. The intent of this run was to find that amount of additional resources above the assumed resource levels that would be required to have Ontario meet the LOLE criterion. MARS results for the median and high demand growth scenarios are presented in Table 1.2. Only the first two study sets, described above, were required to achieve an LOLE of 0.1 days/year or less.

The initial set of runs under the **median demand growth** forecast shows that Ontario would meet the LOLE criterion for all years of the study period. For all calendar years, only the first set of MARS runs was required to achieve the LOLE criterion of 0.1 days/year. This was achieved without utilizing any EOPs, without any additional planned resources and without any interconnection assistance.

Under the **high demand growth** forecast assumption, Ontario would meet the LOLE criterion for all years of the study period. Only the first and second sets of MARS runs were required to achieve the LOLE criterion of 0.1 days/year. For the calendar year 2011, this was achieved without implementing any EOPs. For the calendar years 2010 and 2012 to 2014, the LOLE criterion was achieved after utilizing the EOPs. For all calendar years, additional planned resources and interconnection assistance were not required to meet the LOLE criterion.

Table 1.2 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Additional Resources (MW)	LOLE [days/year]				
			2010	2011	2012	2013	2014
Median	no	0	0.092	0.001	0.001	0.000	0.000
High	no	0	0.145	0.025	0.108	1.621	1.563
high	yes	0	0.001	-	0.001	0.001	0.002

- End of Section -

2 TABLE OF CONTENTS

1 EXECUTIVE SUMMARY I

1.1 MAJOR FINDINGS I
1.2 MAJOR ASSUMPTIONS AND RESULTS II

2 TABLE OF CONTENTS V

2.1 LIST OF TABLES VI
2.2 LIST OF FIGURES VI

3 INTRODUCTION 1

3.1 REFERENCE TO MOST RECENT NPCC COMPREHENSIVE REVIEW 1
3.2 COMPARISON OF THIS REVIEW AND PREVIOUS REVIEW 1
3.2.1 Demand Forecast 1
3.2.2 Resources Forecast 3
3.2.3 Resource Adequacy Assessment Criterion 4

4 RESOURCE ADEQUACY CRITERION 5

4.1 STATEMENT OF RESOURCE ADEQUACY CRITERION 5
4.2 STATEMENT OF HOW THE CRITERION IS APPLIED 5
4.3 RESOURCE REQUIREMENTS TO MEET CRITERION 6
4.4 COMPARISON OF IESO AND NPCC CRITERIA 6
4.5 RESOURCE ADEQUACY STUDIES DONE SINCE THE 2006 REVIEW 7

5 RESOURCE ADEQUACY ASSESSMENT 8

5.1 MEDIAN DEMAND FORECAST 8
5.1.1 LOLE Values, Median Demand Forecast 8
5.2 HIGH DEMAND FORECAST 8
5.2.1 LOLE Values, High Demand Forecast 8
5.3 CONTINGENCY MECHANISMS FOR MANAGING DEMAND AND RESOURCE UNCERTAINTIES 8
5.4 IMPACTS OF MAJOR PROPOSED CHANGES TO MARKET RULES ON AREA RELIABILITY 10

6 PROPOSED RESOURCE MIX 11

6.1 RELIABILITY IMPACTS OF CAPACITY MIX, DEMAND RESOURCE RESPONSE, AND TRANSPORTATION OR ENVIRONMENTAL CONSIDERATIONS 11
6.2 AVAILABLE MECHANISMS TO MITIGATE RELIABILITY IMPACTS OF CAPACITY MIX, DEMAND RESOURCE RESPONSE, TRANSPORTATION AND/OR ENVIRONMENTAL CONSIDERATIONS 13
6.3 RELIABILITY IMPACTS RELATED TO COMPLIANCE WITH PROVINCIAL REQUIREMENTS 14

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL 15

1.1 LOAD MODEL 15

1.1.1 DESCRIPTION AND BASIS OF PERIOD LOAD SHAPES 15
1.1.2 LOAD FORECAST UNCERTAINTY 16
1.1.3 DEMAND AND ENERGY PROJECTS OF INTERCONNECTED ENTITIES 16

1.1.4 DEMAND -SIDE MANAGEMENT 16

1.2 SUPPLY-SIDE RESOURCE REPRESENTATION 17

1.2.1 RATINGS....18
1.2.1.1 Definitions....18
1.2.1.2 Procedure for Verifying Ratings....18
1.2.2 UNAVAILABILITY FACTORS REPRESENTED....19
1.2.2.1 Type of Unavailability Factors Represented....19
1.2.2.2 Source of Unavailability Factors Represented....19
1.2.2.3 Maturity Considerations and In-Service Date Uncertainty....19
1.2.2.4 Tabulation of Typical Unavailability Factors....20
1.2.3 PURCHASE AND SALE REPRESENTATION....20
1.2.4 RETIREMENTS....20

1.3 REPRESENTATION OF INTERCONNECTED SYSTEMS....20

1.4 MODELING OF VARIABLE AND LIMITED ENERGY RESOURCES....23

1.5 MODELING OF DEMAND SIDE RESOURCES AND DEMAND RESPONSE PROGRAMS....24

1.6 MODELING OF ALL RESOURCES....24

1.7 OTHER ASSUMPTIONS....24

1.7.1 INTERNAL TRANSMISSION LIMITATIONS....24

1.8 RELIABILITY IMPACTS OF MARKET RULES....27

2.1 List of Tables

TABLE 1.1 MAJOR ASSUMPTIONS....II
TABLE 1.2 ANNUAL LOLE VALUES, MEDIAN AND HIGH DEMAND FORECAST....III
TABLE 3.1 COMPARISON OF DEMAND FORECASTS: NORMAL WEATHER WINTER PEAK....2
TABLE 3.2 COMPARISON OF DEMAND FORECASTS: NORMAL WEATHER SUMMER PEAK....2
TABLE 3.3 COMPARISON OF AVAILABLE RESOURCE FORECASTS....3
TABLE 4.1 EMERGENCY OPERATING PROCEDURE ASSUMPTIONS....6
TABLE 5.1 ANNUAL LOLE VALUES, MEDIAN AND HIGH DEMAND FORECAST....8
TABLE 6.1 ONTARIO CAPACITY MIX BY FUEL TYPE....12
TABLE 6.2 ONTARIO CAPACITY MIX BY FUEL TYPE (%)....12
TABLE A.1 CONSERVATION AND DEMAND-SIDE MANAGEMENT ASSUMPTIONS....17
TABLE A.2 NET INSTALLED CAPACITY AS OF JULY 2010....18
TABLE A.3 ONTARIO PROJECTED EQUIVALENT FORCED OUTAGE RATES....20
TABLE A.4 ONTARIO INTERCONNECTION LIMITS....22
TABLE A.5 FABC LIMITS FOR 2010 TO 2014....25
TABLE A.6 ONTARIO INTERNAL INTERFACE BASE LIMITS....27

2.2 List of Figures

FIGURE 3.1 COMPARISON OF DEMAND FORECASTS....3
FIGURE 6.1 ONTARIO CAPACITY MIX BY FUEL TYPE....13

FIGURE A.1 ONTARIO'S ZONES, INTERFACES, AND INTERCONNECTIONS 26

3 INTRODUCTION

This report is the comprehensive area review of resource adequacy for Ontario, prepared by the Independent Electricity System Operator (IESO) and submitted to the Northeast Power Coordinating Council (NPCC) in accordance with NPCC Document B-8, entitled "Guidelines for Area Review of Resource Adequacy" (NPCC Open Process Review: September 1, 2008).

The IESO is a non-profit, regulated corporation without share capital established by the Ontario Electricity Act 1998, with its Directors appointed by the government. It is responsible for the day-to-day operation of Ontario's electricity system, and is responsible for enabling, administering and operating the competitive wholesale energy markets for the province.

The information presented in this 2009 Comprehensive Review of resource adequacy covers the forecast period from 2010 through 2014.

3.1 Reference to Most Recent NPCC Comprehensive Review

The previous Comprehensive Review was submitted at the November 2006 meeting of the Reliability Coordinating Committee. Comparisons between this review and the November 2006, "IESO 2006 Comprehensive Review of Ontario Resource Adequacy for the period 2007 to 2011" are included in this report.

3.2 Comparison of This Review and Previous Review

3.2.1 Demand Forecast

The forecast of demand contains two demand forecast scenarios; a median demand growth and high demand growth. The seasonal peak demand forecasts for this 2009 review are presented in Tables 3.1, 3.2 and Figure 3.1 contrasting those peaks with the peak demand forecasts from the 2006 review.

There has been a substantial shift in the factors driving electricity demand since the 2006 review. In addition, there have been some changes in the demand forecasting methodology. The Ontario economy is going through both cyclical and structural change, significantly reducing the amount of electricity consumed in the industrial sector. This structural change is expected to contribute to lower industrial demand for a number of years, as the current economic environment leads to the realization of improved efficiencies. Additionally, conservation initiatives and the growth in embedded generation – particularly renewable energy generation – will further reduce the demand for electricity from the IESO-controlled grid. Therefore, the seasonal peaks are expected to decline through time. This is consistent with what was submitted in the 2008 Interim Review of Resource Adequacy.

Under the high demand growth scenario, peak electricity demand is expected to increase but at a modest rate. This is as a result of rebound in the energy-intensive industrial sector and lower conservation and embedded generation savings.

The peak demands will also be lower than the 2006 review due to changes in the forecast methodology. The 2006 review based its forecast on Seasonal Normal weather whereas the current review is based on Monthly Normal weather. This change in methodology reduces the peaks by roughly 100 MW.

Although point forecasts are presented for both the median and high growth scenarios, each scenario has an associated "uncertainty" distribution which recognizes the variability of demand due to weather volatility.

Both demand forecast scenarios vary from the previous review due to the inclusion of actual data. The Ontario economy, with its large, export-oriented manufacturing base has been hit particularly hard by the North American recession. This means that the levels at which the forecast is starting is much lower than in previous years.

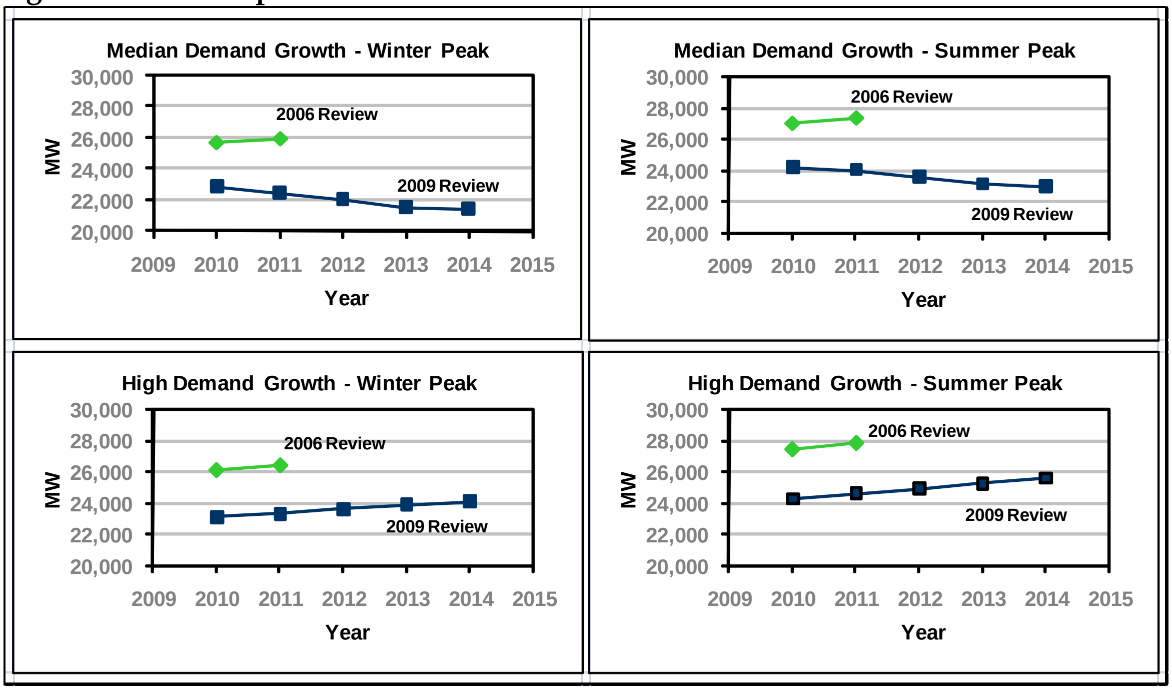
Table 3.1 Comparison of Demand Forecasts: Normal Weather Winter Peak

Year	Normal Weather Winter Peak					
	Median Demand Growth			High Demand Growth		
	2006 Review	2009 Review	Difference	2006 Review	2009 Review	Difference
2010	25,690	22,886	-2,804	26,100	23,064	-3,036
2011	25,960	22,443	-3,517	26,404	23,308	-3,096
2012		22,081			23,559	
2013		21,575			23,809	
2014		21,442			24,051	
Average Growth Rate	1.05%	-1.62%	-2.67%	1.17%	1.05%	-0.11%

Table 3.2 Comparison of Demand Forecasts: Normal Weather Summer Peak

Year	Normal Weather Summer Peak					
	Median Demand Growth			High Demand Growth		
	2006 Review	2009 Review	Difference	2006 Review	2009 Review	Difference
2010	26,973	24,160	-2,813	27,397	24,252	-3,145
2011	27,337	24,000	-3,337	27,794	24,581	-3,213
2012		23,541			24,907	
2013		23,092			25,234	
2014		22,932			25,563	
Average Growth Rate	1.35%	-1.30%	-2.64%	1.45%	1.32%	-0.13%

Figure 3.1 Comparison of Demand Forecasts



3.2.2 Resources Forecast

Table 3.3 shows the resources forecast to be available to the Ontario system at the time of the seasonal peaks assumed for this 2009 Comprehensive Review and for the 2006 Comprehensive Review.

Table 3.3 Comparison of Available Resource Forecasts

Year	Winter Peak			Summer Peak		
	2006 Review	2009 Review	Difference	2006 Review	2009 Review	Difference
2010	31,779	32,721	942	33,585	32,452	-1,133
2011	36,649	32,751	-3,898	37,099	32,194	-4,905
2012		31,778			31,243	
2013		33,280			32,316	
2014		31,806			32,739	

This 2009 Comprehensive Review assumes resource availability based on the latest available information regarding existing and future resources. Based on studies since the 2006 Comprehensive Review, assumptions estimating the amount of available capacity at peak demand have been revised for wind resources resulting in reduced levels of available capacity. Some gas and biomass projects that were previously identified to be in-service are no longer expected to contribute to the supply mix within the study period of 2010 and 2011. This has further reduced the amount of available resources at the time of summer and winter peaks within the study period. Assumptions on the operation of coal units have been revised since the time of the 2006 Comprehensive Review. In the 2006 review, all existing coal units were assumed to be available, while this 2009 review assumes that about 1,600 MW of coal-fired generation is removed from service by the time of the summer peak of 2011 as per the OPA's 2007 Integrated Power System Plan (IPSP).

3.2.3 Resource Adequacy Assessment Criterion

For both the 2006 and the current review, the assessment criterion described in Section 4.1 was used, which is the same as the NPCC resource adequacy criterion.

- End of Section –

4 RESOURCE ADEQUACY CRITERION

4.1 Statement of Resource Adequacy Criterion

The IESO uses the NPCC resource adequacy criterion from Document A-2 to assess the adequacy of resources in the Ontario control area:

> "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

4.2 Statement of How the Criterion is Applied

The reliability standard is used to assess the adequacy of available resources needed to supply the Ontario Area on an on-going basis, to identify periods of resource deficiency or surplus.

Consideration can be given to Ontario's interconnections with Manitoba, Minnesota, Québec, New York and Michigan and the resultant tie-benefits which can be assumed. However, for this study, interconnection assistance was not required. Scheduled and forced outages to Ontario generators are assessed considering submissions by generator owners, actual historic outage observations and more generalized outage factors.

If necessary, emergency operating procedures (EOPs) will be taken by the IESO to deal with a potential shortfall in reserve in the operating time frame, as summarized below. Load relief from these EOPs is assumed to be available during the five-year period, if required to meet the Loss of Load Expectation (LOLE) criterion. It should also be noted that while the list below provides the anticipated order of the control actions, the IESO may initiate control actions at any point in the hierarchy list, and may alter the order in which the control actions are implemented, depending on the specific circumstances. These actions include the following:

- reject outage applications, revoke approved outages, recall outages;
- issue general or public appeal;
- constrain dispatch of resources;
- purchase emergency energy and request emergency assistance;
- disregard 30-minute operating reserve requirement;

- implement Emergency Load Reduction Program (ELRP);
- disregard high-risk limits;
- disregard 10-minute operating reserve requirement;
- implement 3% voltage reduction;
- implement 5% voltage reduction;
- implement environmental variances;
- operate to emergency condition limits;
- implement Emergency Demand Response Program (EDRP);

Most of these actions are modeled in the MARS program by evaluating the daily LOLE at various margin states. Table 4.1 summarizes the assumptions regarding the load relief from EOPs used for this study. Several of the categories above have been aggregated for modeling purposes.

Table 4.1 Emergency Operating Procedure Assumptions

EOP Action	Load Relief (% of Demand or MW Value)
Public Appeals	1.0%
No 30m OR	473 MW
ELRP	179 MW
No 10m OR	945 MW
Voltage Reductions	2.6%
EDRP	109 MW

4.3 Resource Requirements to Meet Criterion

For the purposes of this study, the adequacy of Ontario's existing and planned resources is assessed through calculation of the annual LOLE and compared with the 0.1 days/year prescribed by the NPCC resource adequacy criterion. Initial studies were performed without any additional resources beyond the identified assumptions in Table 3.3. For all calendar years, additional resources by means of interconnection assistance were not required to meet criterion.

4.4 Comparison of IESO and NPCC Criteria

The IESO reliability criterion for this review is the same as the NPCC criterion.

4.5 Resource Adequacy Studies Done Since the 2006 Review

Adequacy assessments produced by the IESO since the last Area review include numerous 18-Month Outlooks published on a quarterly basis, three Ontario Reliability Outlooks (ORO) published between 2007 and 2008, and the first release of the Ontario Reserve Margin Requirements in 2008. All of these reports are available on the IESO website (www.IESO.ca). The 18-Month Outlooks and the ORO were submitted to the Minister of Energy and Infrastructure and filed with the Ontario Energy Board (OEB) to meet the requirements of the Ontario Market Rules and the conditions of the IESO's licence.

- End of Section -

5 RESOURCE ADEQUACY ASSESSMENT

5.1 Median Demand Forecast

On average over the forecast period, Ontario electrical energy demand is expected to decrease by about 0.7% annually under the median demand forecast.

5.1.1 LOLE Values, Median Demand Forecast

Table 5.1 shows that under the median demand growth assumption, Ontario will have adequate resources to meet the NPCC criterion through 2014. Only the first set of MARS runs was required to achieve the LOLE criterion of 0.1 days/year. This was achieved without reliance on any EOPs, without any additional planned resources and without any interconnection assistance.

5.2 High Demand Forecast

On average over the forecast period, Ontario electrical energy demand is expected to increase by about 1.0% annually under the high demand forecast.

5.2.1 LOLE Values, High Demand Forecast

Table 5.1 shows that under the high demand growth assumption, Ontario would meet the LOLE criterion for all years of the study period. Only the first and second sets of MARS runs were required to achieve the LOLE criterion of 0.1 days/year. For the calendar year 2011, this was achieved without implementing any EOPs. For the calendar years 2010 and 2012 to 2014, the LOLE criterion was achieved after utilizing the EOPs. For all calendar years, additional planned resources and interconnection assistance were not required to meet the LOLE criterion.

Table 5.1 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Additional Resources (MW)	LOLE [days/year]				
			2010	2011	2012	2013	2014
Median	no	0	0.092	0.001	0.001	0.000	0.000
High	no	0	0.145	0.025	0.108	1.621	1.563
high	yes	0	0.001	-	0.001	0.001	0.002

5.3 Contingency Mechanisms for Managing Demand and Resource Uncertainties

There are several study assumptions which may change in such a way that reserve levels in Ontario could be higher or lower than presented in this 2009 Comprehensive Review, including the amount of new generating resources available, the amount of conservation or demand response, the amount of imports and the amount of generation that may be on planned outage.

The IESO prepares an ORO for the IESO Board of Directors, the Minister of Energy and Infrastructure and the OEB, as well as market participants. The ORO provides information about the requirements for generation and transmission capacity in Ontario. These Outlooks consider elements of demand and resource uncertainty. In particular, when considering future availability of resources, the IESO includes projects that are under construction, contracted by the OPA or that are planned to be in-service. For projects that are under contract or planned to be in-service, the estimated effective date provided by the OPA is the best estimate of the date when the additional capacity is expected to be available. If a project is delayed, the estimated effective date will be the best estimate of the commercial in-service date for the project.

Requests for Proposals (RFPs) for additional generation, and demand response (DR) programs were initiated by the Ontario Government and continue to be developed and managed by the OPA. In part, the need for additional RFPs is driven by reliability assessments performed by the IESO, including this assessment. DR includes a number of different programs which are starting to play a more active role in maintaining the reliability of the system. Some wholesale consumers bid their load into the market and are responsive to price through IESO dispatch instructions. Other consumers have been contracted by the OPA to provide DR under tight supply conditions.

The 18-Month Outlooks published on a quarterly basis forecast weekly reserve levels. Generators and Transmitters use this information to plan their outages. Periods where planned outages result in inadequate resource levels are identified to the concerned generators. The total generator planned outages could range from 0 MW to over 8,000 MW depending on the time of the year. If market participants fail to proactively reschedule planned outages to mitigate concerns, the IESO may reject, revoke or recall outages in the near-term to ensure sufficient capacity is available to meet non-dispatchable demand. The relief that could be expected from this measure during peak seasons ranges from 0 to 4,000 MW. Deviations from initial generator outage plans through outage rescheduling and rejection are not always desirable. This could stretch the ability of generator owners or operators to accommodate larger number and magnitude of outages over shorter time periods and may increase forced outage occurrences. Operational experience so far indicates generator owners are usually able to adapt their outage plans.

Since market opening, there have been several different types of emergency operating procedures developed including the Emergency Demand Response Program (EDRP) and the Emergency Load Reduction Program (ELRP). The contribution that these programs are expected to make in meeting the demand-supply balance have been included in the MARS model, for calendar years when the resource adequacy criterion is not met.

The need to consider imports into Ontario to achieve the resource adequacy criterion varies depending on the calendar year under consideration and the demand assumptions. The coincident interconnection import capability is about 5,250 MW. Data collected since market opening reveals the average imports that have been attracted into Ontario with market mechanisms, and NPCC studies have been conducted to indicate an estimate of the annual tie benefits that can be expected. Both the historic import data and the estimate from the NPCC tie benefit studies are indicated later in this report (Appendix A, Section 1.3). For this review, additional resources by means of imports were not required to meet criterion in any of the calendar years.

5.4 Impacts of Major Proposed Changes to Market Rules on Area Reliability

There are currently no major proposed changes to the market rules which are expected to have significant impacts on reliability.

- End of Section -

6 PROPOSED RESOURCE MIX

6.1 Reliability Impacts of Capacity Mix, Demand Resource Response, and Transportation or Environmental Considerations

The Ontario system has a well balanced resource mix with a variety of fuel types, which helps offset the risks possibly associated with an exaggerated dependency on one principal fuel. However, possibilities exist which could drive a shift in the fuel mix and result in certain risks being realized.

Concerns about the emission of greenhouse gases and other pollutants from coal-fired electricity production have led to the provincial decision to phase-out all coal-fired units in Ontario by the end of 2014. This is in accordance with Ontario Regulation 496/07 under the Environmental Protection Act. The OEB made changes to the IESO's license, giving the IESO the authority to manage the recent policy initiatives to curb coal-fired emissions. This authority combined with existing IESO processes will maintain grid reliability while facilitating an orderly reduction in emissions.

Much of the replacement energy is expected to come from gas-fired generation. As Ontario's electricity sector becomes more dependent on natural gas as a primary fuel, the adequacy and security of natural gas supply infrastructure becomes even more critical to the reliability of the electricity system. Overall gas supply adequacy and gas transmission issues have been examined extensively since 2005 by the Ontario Gas Electric Interface Working Group. Canadian and Ontario pipeline and gas-distribution operators have implemented various tariff changes to enhance gas usage flexibility and improve firmness of supply available to generators.

Gas pipeline capacity, historically, has not limited the summer energy or capacity capability of Ontario generation fuelled solely by natural gas and is not expected to be a problem for future summers. Winter months are more prone to gas limitations as heating and gas generation may peak simultaneously. The Working Group has procedures in place for the continued monitoring of operations and identification and resolution of issues to mitigate fuel vulnerability.

There is also expected to be a significant increase in the amount of renewable generation in Ontario, in particular of wind power generation. The OPA is looking at ways to surpass the target in the August 2007 IPSP. The operational characteristics of wind differ significantly from other elements of the supply mix. The intermittent nature of wind makes it difficult to forecast wind generation with certainty.

The introduction of the OPA's Demand Response (DR) programs specifically target load reduction during hours of tight supply availability or peak periods by signalling to consumers when those demand reductions are most needed. Otherwise, load is shifted from on-peak to off-peak periods under OPA contract. The OPA DR Programs (DR1, DR2 and DR3), Peaksaver and local demand response contracts will provide relief from demand during periods of low supply.

Table 6.1 and Figure 6.1 show the expected net installed capacity mix at the time of the summer peak for each year in the study period. This is based on information regarding existing and future resources as of May 2009.

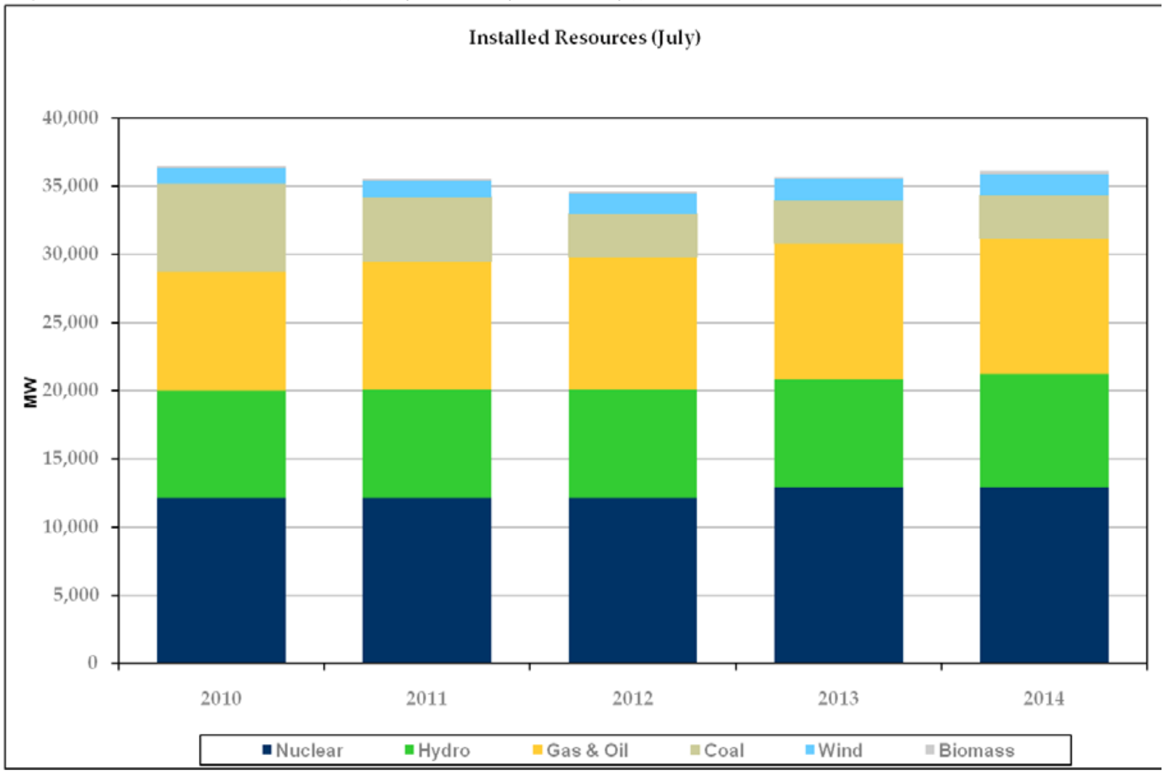
Table 6.1 Ontario Capacity Mix by Fuel Type

July Installed Resources					
Fuel Type	**2010**	**2011**	**2012**	**2013**	**2014**
Nuclear	12,176	12,156	12,156	12,926	12,926
Gas & Oil	8,762	9,402	9,795	10,025	9,905
Coal	6,434	4,758	3,140	3,140	3,140
Hydro	7,840	7,901	7,901	7,901	8,351
Wind	1,162	1,226	1,525	1,576	1,576
Biomass	110	110	110	110	211
Total	36,484	35,553	34,628	35,678	36,109

Table 6.2 Ontario Capacity Mix by Fuel Type (%)

Fuel Type \ Year	2010	2011	2012	2013	2014
Nuclear (%)	33.4	34.2	35.1	36.2	35.8
Gas & Oil (%)	24.0	26.4	28.3	28.1	27.4
Coal (%)	17.6	13.4	9.1	8.8	8.7
Hydro (%)	21.5	22.2	22.8	22.1	23.1
Wind (%)	3.2	3.4	4.4	4.4	4.4
Biomass (%)	0.3	0.3	0.3	0.3	0.6

Figure 6.1 Ontario Capacity Mix by Fuel Type



6.2 Available Mechanisms to Mitigate Reliability Impacts of Capacity Mix, Demand Resource Response, Transportation and/or Environmental Considerations

Any increase in the capacity-mix diversity would have beneficial effects on supply flexibility and environmental restrictions. Over the next few years (2010-2014), about 490 MW of new wind-powered generation is expected to be in-service in Ontario. Although the wind generation capacity contribution must be substantially discounted from the nameplate value, wind energy can successfully reduce the utilization of greenhouse gas emitting resources.

The IESO actively encourages diversity in supply options by identifying future capacity needs and engaging in dialogue with the Ontario Government, OPA, market participants and other stakeholders. As a competitive alternative to new and existing generation, the IESO promotes a balanced pursuit of supply diversity and demand management options in its Outlooks.

Assumptions around coal availability and retirements are based on OPA's first IPSP submitted to the OEB for review in August 2007. In September 17, 2008, a Directive was issued by the Minister of Energy and Infrastructure requiring the OPA to revisit the IPSP with a view to establishing new and higher targets in a number of areas with respect to renewable energy sources, conservation programs, and other initiatives. This comprehensive review includes resources based on the most recently available data associated with the OPA's working revisions to the original IPSP.

The IESO will continue to monitor the plans for Ontario's future fuel mix and consider the reliability impacts in the Ontario Reserve Margin Requirements, ORO and the 18-Month Outlooks conducted several times each year.

6.3 Reliability Impacts Related to Compliance with Provincial Requirements

In keeping with the policies of the Government of Ontario, the Ontario Regulation 496/07 under the Environmental Protection Act declared the phase-out of generation from coal in Ontario by December 31, 2014. The OEB also made changes to the IESO's license to help manage reliability while facilitating implementation of Ontario Power Generation's coal emission reduction strategy. Prior to 2014, if there are any reliability concerns, the shut-down of coal-fired units can be deferred, subject to meeting the emission targets. The greenhouse gas emissions targets implemented by the Ontario government are as follows: "soft" caps of 19.6 megatonnes (Mt) in 2009 and 15.6 Mt in 2010, which can be exceeded for reliability needs, and a "hard" cap of 11.5 Mt by 2011.

In May 2009, the Ontario Legislature passed the Green Energy and Green Economy Act (GEA). It is aimed at facilitating large-scale development of renewable energy projects across Ontario. The Act includes a proposal for a Feed-in Tariff (FIT) Program which is designed to further encourage procurement of renewable energy supply with greater geographic distribution. As with the IPSP, the IESO continues to track the progress of renewable energy projects in Ontario, and is streamlining its process to incorporate additional renewable projects in the future.

- End of Section -

APPENDIX

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

For the purposes of this study, the IESO used the Multi-Area Reliability Simulation (MARS) program. The MARS program is capable of performing the reliability assessment of a generation system composed of a number of interconnected areas and/or zones that can be grouped into pools.

A sequential Monte Carlo simulation forms the basis for MARS. In this simulation, a chronological system evolution is developed by combining randomly generated operating states for the generating units with inter-zone transfer limits and hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules that govern system operation. Various measures of reliability can be reported using MARS, including the Loss of Load Expectation (LOLE) for various time frames. The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for various reliability indices. These values can be calculated both with and without load forecast uncertainty (LFU). The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates LOLE values and can estimate the expected number of times various emergency operating procedures (EOPs) will be implemented in each zone and pool.

The first step in calculating the reliability indices is to compute the zone margins on an isolated basis for each hour, by subtracting the load for the hour from the total available capacity in the hour. If a zone has a positive or zero margin, it has sufficient capacity to meet its load. If the zone margin is negative, the load exceeds the capacity available to serve it, and the zone is in a potential loss-of-load situation. If there are any zones that have negative margins after the isolated zone margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from zones that have positive margins. There are two ways for determining how the reserves from zones with excess capacity are allocated among the zones that are deficient. In the first approach, the user specifies the priority order in which deficient zones receive assistance from zones with excess resources. The second method shares the available excess resources among deficient zones in proportion to the size of their shortfalls. Priorities within pools, as well as among pools, can also be modeled.

1.1 LOAD MODEL

1.1.1 Description and Basis of Period Load Shapes

The IESO uses a multivariate econometric model to produce the electricity demand forecast. The forecast is composed of hourly demand for Ontario and its ten zones. The model uses three broad sets of forecast drivers: calendar variables, weather effects and economic and demographic variables. Conservation and embedded generation are treated outside the model. The impacts of demand response programs are removed from the historical data and those programs are treated as resources in the forecast.

Weather is represented by a Monthly Normal weather scenario which uses 31 years of historical weather data to generate typical monthly weather. A measure of uncertainty in demand due to weather variability is used in conjunction with the Normal weather scenario to generate a distribution of possible demand outcomes.

The economic drivers are generated using a consensus of publicly available provincial forecasts, along with economic forecasts from service providers. Demographic projections are publicly available from the Ontario Ministry of Finance.

1.1.2 Load Forecast Uncertainty

Load Forecast Uncertainty (LFU) is a measure used to capture the uncertainty in demand due to variation in the weather elements. LFU represents the impact on demand due to one standard deviation in the weather elements. The LFU varies between roughly 1 and 7 percent of normal demand throughout the year. The MARS program was provided with hourly load data for the entire five-year period, as well as monthly standard deviations (SD), for each of the ten zones modeled. Reliability indices were calculated at each load level around the mean value (mean, mean ± SD, mean ± 2SD, mean ± 3SD), as well as weighted-average indices.

1.1.3 Demand and Energy Projects of Interconnected Entities

The loads and resources of interconnected entities within the Area that are not members of the Area were not considered.

1.1.4 Demand -Side Management

MARS runs were completed which modeled conservation and demand-side management estimates that have been proposed for Ontario. Demand-side management include:

- Dispatchable Loads
- Demand Response (DR) Programs: DR1, DR2 and DR3
- Local Demand Response Contracts
- Direct Load Control (e.g. Peaksaver)

The annual values assumed for conservation at the time of net peak demand and demand-side management are shown in the table below.

Table A.1 Conservation and Demand-side Management Assumptions

Year	Conservation [MW]	Demand Management [MW]
2010	373	631
2011	1,720	1,367
2012	2,329	1,528
2013	2,913	1,693
2014	3,288	1,703

1.2 SUPPLY-SIDE RESOURCE REPRESENTATION

MARS has the capability to model the following types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand management

An energy-limited unit can be modeled probabilistically as a thermal unit with an energy probability distribution or deterministically as a load modifier, or as a unit with a specified capacity and available monthly energy. Co-generation units can be modeled as thermal units with an associated hourly load. Energy-storage and demand management impacts can be modeled as load modifiers. For each unit modeled, the installation and retirement dates and planned maintenance requirements must be specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads depend on the unit type. The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis.

All thermal generators in Ontario, for each of the ten zones, were modeled on an individual unit basis. The available capacity states, state transition rates, and planned outage information were input for each thermal unit. Hydroelectric generators were modeled as energy-limited resources. Minimum and maximum ratings and energy production capabilities were input on a monthly basis for the hydroelectric generators. Wind generators were also modeled as energy-limited resources. Wind capacity contributions were input on a monthly basis with a cumulative probability density function.

1.2.1 Ratings

1.2.1.1 Definitions

The aggregated net installed capacity values for all generating units expected to be participating in the IESO markets, as of July 2010, are shown in Table A.2.

Table A.2 Net Installed Capacity as of July 2010

Fuel Type	Total Capacity [MW]
Nuclear	12,176
Gas & Oil	8,762
Coal	6,434
Hydro	7,840
Wind	1,162
Biomass	110
Total	36,484

For resources other than hydroelectric, the monthly output capabilities as submitted by market participants as of May 2009 were input into MARS. These capabilities take into account any stretch capability, output deratings given by equipment or ambient limitations, and environmental restrictions. For future resources, output capabilities based on estimates by the Ontario Power Authority (OPA) were input into MARS.

Hydraulic station minimum outputs and monthly energy production capabilities submitted by market participants are based on expected river flows. The maximum assumed contribution of hydro resources is based on the median historic contributions at the hour of the weekday peak demand from May 2002 to March 2009.

1.2.1.2 Procedure for Verifying Ratings

The Ontario Market Rules require that all generators connected to the IESO-controlled grid test their equipment to ensure compliance with all applicable reliability standards, including NPCC Directory #9 "Verification of Generator Gross and Net Real Power Capability" and Directory #10 "Verification of Generator Gross and Net Reactive Power Capability". *Market Rules Chapter 4, Section 5*

Generators communicate to the IESO any changes to their units' verified gross and net MW capabilities as part of the Outage Management Process and the Facility Registration, Maintenance and De-registration Process. *Market Manual 7.3 "Outage Management"* and *Market Manual 1.2 "Facility Registration, Maintenance and Deregistration"*

Permanent changes to equipment that affect the MW output capabilities of generating units are communicated and assessed through the Connection Assessments process. *Market Manual 2.10 "Connection Assessment and Approval Procedure"*

Generators provide to the IESO the declared seasonal net MW values for their units as part of the 18-Month Outlook process. *Market Manual 2.11 "18-Month Outlook and Related Information Requirements"*

Market Rules also authorise the IESO to test any generation facility connected to the IESO-controlled grid to determine whether such facility complies with the applicable reliability standards. *Market Rules Chapter 4, Section 5.2*

1.2.2 Unavailability Factors Represented

1.2.2.1 Type of Unavailability Factors Represented

Equivalent Forced Outage Rate (EFOR) for each unit is used that reflects both forced outages and periods of derated output. These were based on five-year history of actual forced outages unless there was insufficient data for a specific unit(s) for which data supplied by market participants was used.

Planned maintenance was modeled on a unit basis. Where available, representative outage plans supplied by market participants were used, as well as forecast Planned Outage Factors (POF) and/or the Generic Outage Plan derived from historic outage patterns of existing units.

1.2.2.2 Source of Unavailability Factors Represented

POF values used in this study are regularly provided by market participants to the IESO for its routine Outlooks. Actual outage history from which some EFORs were derived was obtained from the IESO's Integrated Outage Management System (IOMS). For units with insufficient historic data, where available, EFOR for these units were based on specific data supplied by market participants as of May 2009.

1.2.2.3 Maturity Considerations and In-Service Date Uncertainty

The MARS runs assumed new gas-fired generators to have a 1% to 5% EFOR, depending on the type of gas generator (e.g. simple cycle, combined cycle, combined heat and power). There is some uncertainty associated with the level of new unit performance. Review of actual forced outage history of gas units revealed that the forced outage rates of new gas units are expected to decline as they mature. At some point in the future, they are expected to stabilize.

In this review, forced outage rates of new gas-fired units were represented by an intermediate EFOR based on both existing older and newer gas units. There is insufficient data on actual forced outages of newer existing gas units to form the sole basis for EFORs for future new gas units. The result is shown in Table A.3.

There is some uncertainty in the date that new generating resources will come into service, and the extent to which demand side resources will come into service on schedule. For projects that are under contract or planned to be in-service, the estimated effective date provided by the OPA is the best estimate of the date when the additional capacity is expected to be available. If a project is delayed, the estimated effective date will be the best estimate of the commercial in-service date for the project.

1.2.2.4 Tabulation of Typical Unavailability Factors

The ranges of EFOR indices for fossil and nuclear units, used for this study, are contained in the table below. EFORs for nuclear, coal and gas units were derived from a five-year history of actual forced outages that reflect past experiences. EFORs for biomass and oil units were provided by market participants since the historic information was found to be insufficient.

Table A.3 Ontario Projected Equivalent Forced Outage Rates

Fuel Type	Weighted Average EFOR	Range of EFOR
Biomass	4%	2 - 8%
Coal	15%	6 - 20%
Gas	5%	1 - 5%
Nuclear	8%	3 - 30%
Oil	15%	5 - 50%

1.2.3 Purchase and Sale Representation

At present, there are no firm, expected or provisional purchases or sale contracts identified for the five-year study period. The IESO has agreements in place with neighbouring jurisdictions for emergency imports and reserve sharing, should they be required in the day-to-day operations. For all calendar years, the target resource adequacy criterion was achieved without any additional resources.

1.2.4 Retirements

All coal units are identified to be removed from service by December 31, 2014. It is assumed that coal-fired generation will continue to be available during the study period subject to annual CO2 emission targets set by the government.

1.3 REPRESENTATION OF INTERCONNECTED SYSTEMS

There are five systems with which the Ontario system is interconnected: Manitoba, Minnesota, Michigan, New York and Québec. The five interconnected systems that can provide assistance to the Ontario system are modeled as external to the Ontario pool. Neighbouring systems are treated as external areas with constant hourly loads of 1 MW.

In each of these external areas a dummy generator can be modeled, with a variable capacity up to the amounts expected to be offered into the Ontario market. The expected capacity values vary, depending on Ontario needs, but are always subject to the limitations of the transmission interconnections outlined in Table A.4. Limits apply year-round except where seasonal ratings are indicated.

The new interconnection between Ontario and Hydro Québec went into commercial operation in July 2009. This project consists of a 230 kV double circuit line between Ontario and Québec with back-to-back HVdc converters at the Outaouais substation in Québec. This new tie increases the maximum coincident import capability into Ontario by about 1,250 MW, from 4,000 MW to 5,250 MW, once both converters are in service and transmission reinforcements in Québec are complete (expected May 2010).

For this review, the five interconnected systems were not modeled in MARS since additional assistance was not required to meet the resource adequacy criterion.

Table A.4 Ontario Interconnection Limits

Interconnection	Limit - Flows Out of Ontario MW	Limit - Flows Into Ontario MW
Manitoba – Summer*(3)	262	330 (6)
Manitoba – Winter*(3)	274	342 (6)
Minnesota(3)	140	90
Quebec North (Northeast) – Summer*	95 (5)	65
Quebec North (Northeast)– Winter*	110 (4)	85
Quebec South (Ottawa) – Summer*	147	673
Quebec South (Ottawa) – Winter*	167	748
Quebec South (East) – Summer*	420	800
Quebec South (East) – Winter*	470	800
New York St. Lawrence – Summer*	330	300
New York St. Lawrence – Winter*	400	360
New York Niagara (60 Hz and 25 Hz) – Summer*	1,520 (1)	1,350 (1,7)
(Emergency Transfer Limit - Summer)	2,100 (1)	1,750 (1,7)
New York Niagara (60 Hz and 25 Hz) – Winter*	1,600 (1)	1,350 (1,7)
(Emergency Transfer Limit - Winter)	2,100 (1)	2,100 (1,7)
Michigan – Summer*(2,3)	2,080	1,640
Emergency Transfer Limit - Summer*(2,3)	2,550	1,950
Michigan – Winter*(2,3)	2,400	1,800
Emergency Transfer Limit - Winter*(2,3)	2,650	2,000

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

(1) Flow limits depend on generation dispatch outside Ontario. Values presented here are based on generation dispatch provided by New York.

(2)Normal limits are based on LT ratings and phase shifters bypassed and Emergency limits are based on ST ratings and phase shifters regulating . Flow limits vary depending on the generation dispatch within Ontario.

(3) For real time operation of the interconnection, limits are based on ambient conditions.

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

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

(6) Flows into Ontario include flows on circuit SK1.

(7) Flow Limits into Ontario are shown here without considering QFW transmission constraints within Ontario. Considering internal QFW constraints, flow limit would be 1,000 MW in summer and 1,400 MW in winter.

For the five years prior to market opening in 2002, an analysis of historical power flows on Ontario's interconnections shows that outside of summer peak demand periods, up to 1,800 MW of external generation supplied Ontario demand. From the same analysis, up to 1,400 MW external generation supplied Ontario demand during summer peak months in recent years prior to 2002.

During Ontario's summer peak demand periods of July and August, expected requirements for imports are greatest: imports are still expected to be available despite the fact that many neighbouring systems are often experiencing their peak demand. This is mainly due to the non-coincidence of the daily peak hours between Ontario and its neighbours and the availability of spare capacity from systems that are not summer peaking.

The actual hourly import levels experienced from market opening in May 2002 up to May 2009 indicate an average import level of 1,030 MW for all hours. During the 9,855 hours when Ontario demand exceeded 20,000 MW, the average import level was 1,376 MW. During the 1,008 hours when Ontario demand exceeded 23,000 MW, the average import level was 2,010 MW, and occasionally reached the Ontario coincident import capability (approximately 4,000 MW).

The addendum to the 2007 NPCC CP-8 study entitled “Review of Interconnection Assistance Reliability Benefits” published in December 2007 provided an assessment that about 5,250 MW of interconnection assistance is reasonably available to the Ontario system by 2009.

Future levels of imports into Ontario will vary depending on several factors, including the availability and willingness of resources in external jurisdictions to supply the Ontario market, and the availability of required transmission capacity.

1.4 MODELING OF VARIABLE AND LIMITED ENERGY RESOURCES

Hydroelectric generators were modeled as energy-limited resources. Minimum and maximum ratings and monthly energy production capabilities were input on a monthly basis for the hydroelectric generators. The MARS program was directed to dispatch the energy-limited resources on an as-needed basis, subject to the minimum and maximum capacity, and energy production capability limitations.

Wind generation was modeled probabilistically as a Type 1 Energy-Limited Resource with a cumulative probability density function (CPDF). The CPDF was derived by taking the median wind capacity factor from historical wind output at selected peak hours. Both modeled (10 years of history) and actual (3 years of history) wind output data was used. A conservative approach of taking the lower of the two (modeled or actual) capacity values was applied. Seasonal CPDF for summer and winter months, and monthly CPDF for shoulder months were modeled in MARS to represent various wind contribution to the system. Eleven percent of the installed wind capacity was assumed to be available at the time of summer peak, and thirty percent was assumed to be available at the time of winter peak.

1.5 MODELING OF DEMAND SIDE RESOURCES AND DEMAND RESPONSE PROGRAMS

For the resource assessments, MARS runs were modeled with dependable demand response capacity. The OPA is actively working towards reducing electricity consumption and demand through their demand response (DR) programs. In the long term, depending on the program, DR reduces demand or shifts load from on-peak to off-peak periods, which reduces the need for additional capacity.

OPA's DR1 program is a voluntary program that allows participants to receive compensation for curtailing the electricity demand of their Project. Unlike the DR1 program, the DR2 program is a non-voluntary, contractual load shifting program. Each participant must comply with their DR2 contract schedule to load shift a pre-determined amount. The DR3 program is also non-voluntary, and participants will be required to curtail their respective Projects in response to notices issued by the OPA. It is not certain how often consumers would tolerate calls for demand response, and Ontario should plan to acquire other resources rather than rely on demand response for sustained periods.

MARS runs were completed with conservation quantities up to 3,288 MW and demand-side management quantities up to 1,703 MW by 2014. The table of conservation and demand-side management assumptions are shown in Table A.1.

1.6 MODELING OF ALL RESOURCES

All generators registered in the IESO-administered market were modeled in the study according to their type, as described in Section 1.2 and 1.4.

1.7 OTHER ASSUMPTIONS

1.7.1 Internal Transmission Limitations

The Ontario IESO-controlled grid consists of a robust southern grid and a sparse northern grid. It has been modeled as a pool composed of ten zones. Figure A.1 provides a pictorial representation of Ontario's ten zones. All transmission interfaces between the ten zones within the Ontario pool were modeled as they are defined in IESO System Control Orders (SCO). No random transmission outages were modeled on the interfaces. The transfer limits were specified for each direction of the interface (positive and negative) and were changed seasonally, if necessary. The amount of assistance that deficient zones were permitted to receive from zones with excess resources was limited by the transfer limits on the interfaces, as shown in Table A.6. Limits apply year-round except where seasonal ratings are indicated. The transfer limits in the table are based on normal continuous ratings, not emergency ratings.

Scheduled return-to-service of Bruce units 1 and 2 in 2010 combined with the contracted new wind power resources in southwestern Ontario will increase generation capacity in the Bruce and Southwest zones.

The enhancement to the transmission system by building a new double-circuit 500 kV line from Bruce to Milton will accommodate the future increases to generation capacity in the Bruce area and reliably deliver the full benefits of the Bruce refurbishment project and the development of new renewable resources in southwestern Ontario. The proposed 500kV line received approval from the OEB for construction on September 15, 2008 and is expected to be completed by 2012.

In advance of the proposed 500kV line being available, up-rating of the 230 kV circuits, installation of additional high voltage shunt capacitors and voltage control facilities, and use of special protection systems (SPS) to automatically disconnect generation will reduce the potential for constrained generation. Based on studies of proposed upgrades and additions to the transmission system, new Flow Away from Bruce Complex (FABC) limits for seven and eight Bruce units in-service were applied to the study period of 2010 to 2014. The FABC limits for the study period are shown in Table A.5.

Table A.5 FABC Limits for 2010 to 2014

Year	FABC Limit (MW)
January 2010	4,160
July 2010	4,590
October 2010	4,615
2011	4,615
2012	8,100
2013	8,100
2014	8,100

The new interconnection between Ontario and Hydro Québec will also result in improvements to the local network in the Ottawa area, thereby increasing the Flow Into Ottawa (FIO) limit to about 2,900 MW from 1,900 MW.

Figure A.1 Ontario's Zones, Interfaces, and Interconnections

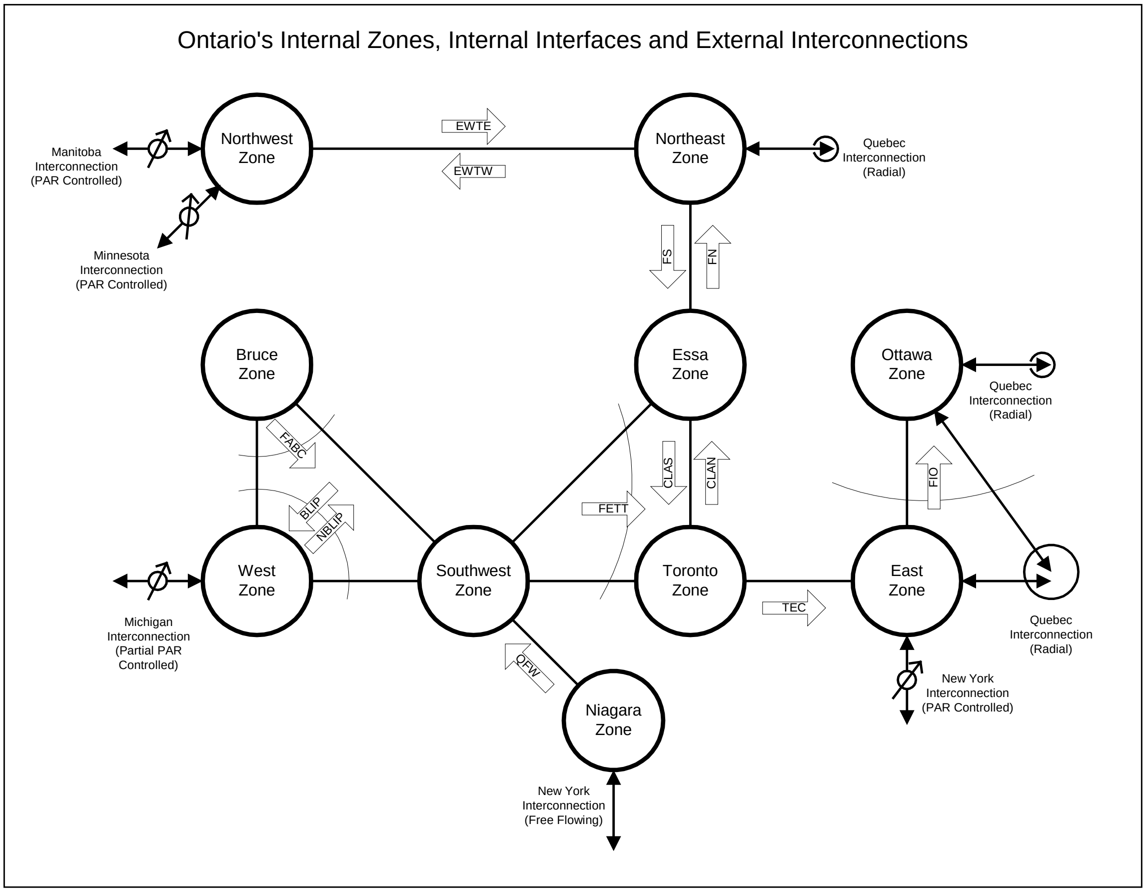


Table A.6 Ontario Internal Interface Base Limits

Interface	Operating Security Limits (MW)		
BLIP	3,500		
NBLIP	1,500		
QFW	1,750 Summer,		1,950 Winter
FABC	4,050	to	4,450 with four 500 kV Bruce units in-service
	4,400	to	4,950 with five 500 kV Bruce units in-service
	4,160	to	5,300 with six 500 kV Bruce units in-service
	4,590	to	6,500 with seven 500 kV Bruce units in-service
	4,615	to	6,500 with eight 500 kV Bruce units in-service
FETT	5,600		
CLAN	2,000		
CLAS	1,000		
FIO	2,900		
FN	1,900		
FS	1,400		
EWTE	325		
EWTW	350		

1.8 RELIABILITY IMPACTS OF MARKET RULES

There are currently no major proposed changes to the market rules which are expected to have significant impacts on reliability.

- End of Section -

- End of Document -