Independent
Electricity
Market Operator

IMO Year 2000 Triennial Review of Ontario Resource Adequacy

November 29, 2000

IMO-REP-0007v1.0

1.0 EXECUTIVE SUMMARY

1.1 Major Findings

This report is a submission made by the Independent Electricity Market Operator (IMO) to the Northeast Power Coordinating Council (NPCC) of its Review of Ontario Resource Adequacy. This Year 2000 review demonstrates that the Ontario electricity system is in compliance with the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems" under the stated assumptions.

1.2 Major Assumptions and Results

The study period is Year 2001 to 2010 inclusive. Major Assumptions are summarized in Table 1 below:

Table 1.1 Major Assumptions

Assumption	Description
Adequacy Criterion	LOLP target of 1 day in 10 years
Target Reserve level for planning	Computed from LOLP target of 0.1 (days/year)
Energy Demand Growth Rate	About 0.9 % per annum under Median Demand Growth About 2.0 % per annum under High Demand Growth
Adequacy of System	Median Demand case until 2010 High Demand case until 2004
Tie Benefits	up to 800 MW assumed in 2001, 1st quarter 2002
Emergency Operating Procedures	up to 900 MW of interruptible load and voltage reduction in 2001
Unit unavailability, planned outages	modelled, Ontario Power Generation forecast values used

Under the Median forecast, and including limited interconnection assistance and no dispatchable loads beyond 2001, the available capacity is forecast to be sufficient to meet the demand for the next ten years. In Years 2002 and 2003, the resource picture improves significantly due to the planned return to service of four nuclear generating units. Growing demands will gradually reduce margins such that Ontario resources are only marginally sufficient at the end of the study period, if no additional generation is added to the system.

Table 1.2 Margins for Winter Peak – Median Demand Forecast

Year	Winter Peak Load Normal Weather	Week Ending	Available Capacity	Available Reserves	LOLP Standard	Reserve Required	% Reserve Required	Margins: Excess [+]/ Shortfall [-]
2001	22,633	21-Jan-01	26,680	4,047	0.10000	3,649	16.1%	398
2002	22,841	20-Jan-02	27,195	4,354	0.10000	3,735	16.4%	619
2003	23,055	19-Jan-03	28,349	5,294	0.10000	3,704	16.1%	1,590
2004	23,205	18-Jan-04	28,664	5,459	0.10000	3,734	16.1%	1,725
2005	23,338	16-Jan-05	28,664	5,326	0.10000	3,662	15.7%	1,664
2006	23,532	15-Jan-06	28,664	5,132	0.10000	3,655	15.5%	1,477
2007	23,739	21-Jan-07	28,664	4,925	0.10000	3,782	15.9%	1,143
2008	23,903	20-Jan-08	28,664	4,761	0.10000	3,754	15.7%	1,007
2009	24,174	18-Jan-09	28,664	4,490	0.10000	3,725	15.4%	765
2010	24,305	17-Jan-10	28,664	4,359	0.10000	3,685	15.2%	674

Table 1.3 Margins for Summer Peak – Median Demand Forecast

Year	Summer Peak Load Normal Weather	Week Ending	Available Capacity	Available Reserves	LOLP Standard	Reserve Required	% Reserve Required	Margins: Excess [+]/ Shortfall [-]
2001	21,761	22-Jul-01	26,370	4,609	0.10000	3,873	17.8%	736
2002	22,088	21-Jul-02	27,400	5,312	0.10000	4,011	18.2%	1,301
2003	22,312	20-Jul-03	28,554	6,242	0.10000	4,091	18.3%	2,151
2004	22,627	18-Jul-04	28,354	5,727	0.10000	4,068	18.0%	1,659
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2006	23,048	23-Jul-06	28,354	5,306	0.10000	4,137	17.9%	1,169
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2008	23,737	20-Jul-08	28,354	4,617	0.10000	4,208	17.7%	409
2009	23,927	19-Jul-09	28,354	4,427	0.10000	4,195	17.5%	232
2010	24,163	25-Jul-10	28,354	4,191	0.10000	4,193	17.4%	-2

For the High Demand Forecast, and excluding interconnection assistance and dispatching of price-sensitive loads, a capacity shortfall is forecast starting in the summer of Year 2005 and the winter of Year 2007 at the peak hours. Inclusion of resources from interconnection assistance and dispatching of price-sensitive load would delay the shortfall by about two years. About 3000 MW of new generation additions are undergoing preliminary assessment and, if constructed, should be sufficient to alleviate the capacity deficiency.

Table 1.4 Margins for Winter Peak – High Demand Forecast

Year	Winter Peak Load Normal Weather	Week Ending	Available Capacity	Available Reserves	LOLP Standard	Reserve Required	% Reserve Required	Margins: Excess [+]/ Shortfall [-]
2001	22,918	21-Jan-01	26,680	3,762	0.10000	3,661	16.0%	101
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2009	26,064	18-Jan-09	28,664	2,600	0.10000	3,781	14.5%	-1,181
2010	26,422	17-Jan-10	28,664	2,242	0.10000	3,750	14.2%	-1,508

Table 1.5 Margins for Summer Peak – High Demand Forecast

Year	Summer Peak Load Normal Weather	Week Ending	Available Capacity	Available Reserves	LOLP Standard	Reserve Required	% Reserve Required	Margins: Excess [+]/ Shortfall [-]
2001	22,282	22-Jul-01	26,370	4,088	0.10000	3,900	17.5%	188
2002	22,871	21-Jul-02	27,400	4,529	0.10000	4,055	17.7%	474
2003	23,363	20-Jul-03	28,554	5,191	0.10000	4,163	17.8%	1,028
2004	23,964	18-Jul-04	28,354	4,390	0.10000	4,148	17.3%	242
2005	24,413	24-Jul-05	28,354	3,941	0.10000	4,120	16.9%	-179
2006	24,965	23-Jul-06	28,354	3,389	0.10000	4,243	17.0%	-854
2007	25,559	22-Jul-07	28,354	2,795	0.10000	4,289	16.8%	-1,494
2008	26,320	20-Jul-08	28,354	2,034	0.10000	4,392	16.7%	-2,358
2009	26,833	19-Jul-09	28,354	1,521	0.10000	4,394	16.4%	-2,873
2010	27,410	25-Jul-10	28,354	944	0.10000	4,414	16.1%	-3,470

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2.1 List Of Tables

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3.0 INTRODUCTION

This report is the Independent Electricity Market Operator's Ontario Resource Adequacy review submitted to the Northeast Power Coordinating Council (NPCC) and prepared in accordance with "Guidelines for Area Review of Resource Adequacy".

The IMO 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 upcoming competitive wholesale energy markets for the province.

The information presented in this report covers the period from Year 2001 to Year 2010.

3.1 Reference to Most Recent NPCC Triennial Review

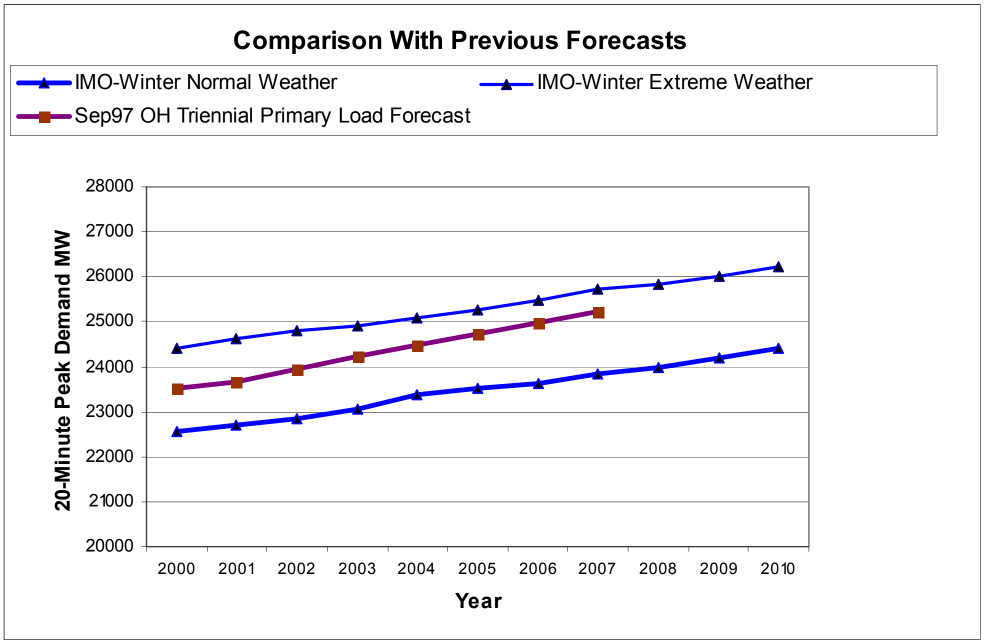
Previous reports were submitted, by Ontario Hydro, in April 1997 and September 1997, and were approved at the June 1997 and November 1997 meetings, respectively, of the Reliability Coordinating Committee. Comparisons between this review and Ontario Hydro's September 1997 Update (termed OH 1997) are contained in this report.

3.2 Comparison of This Review and Previous Review

3.2.1 Demand

Figure 3.1 displays the Winter Peak Primary Demand Forecast in the OH 1997 review and the IMO 2000 Demand Forecast. The IMO's values are based on a forecast of the normal probability distribution of the Demand in any week of the year. The values shown are the median growth scenario, normal weather value and the demand under Extreme Weather conditions (normal weather plus 2 standard deviations). The distribution represents weather conditions based on the last 30 years of record. The high growth scenario is not plotted. The OH 1997 forecast is the monthly peak Primary Demand. This previous result lies between the normal weather and Extreme weather cases presented for the 2000 Assessment. Because of the differences in normalization techniques, the two forecasts cannot be directly compared. It is estimated that the IMO's current forecast, if normalized the same way as in 1997, would be lower than the OH 1997 forecast by a small amount. The 1997 and 2000 forecasts have similar growth rates.

Figure 3.1 Comparison of Demand Forecasts



3.2.2 Resources

Table 3.1 is a comparison of the resources available to the Ontario system at the January Peak hour used in the OH 1997 Triennial Report with those used in this review. The IMO's current forecast of resources is lower than the OH 1997 forecast, due to delays in return to service of some of the Pickering A nuclear units and an assumption that the Bruce A nuclear units will be out of service during the ten-year period. Control of the Bruce plant has been leased to British Energy with the necessary approvals for transfer of control expected to be in place sometime in 2001.

Table 3.1 Comparison of Resources Forecasts at January Peak

Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
June 2000 IMO	26680	27195	28349	28664	28664	28664	28664	28664	28664	28664
OH 1997	28132	28742	30123	29969	30574	30611	31400			
Difference	-1452	-1547	-1774	-1305	-1910	-1947	-2736			

3.2.3 Reserve Adequacy Assessment Criterion

The Ontario Hydro 1997 Triennial Review was based on a 25 system-minute reserve margin criterion. A system-minute of Unsupplied Energy was defined as the quantity of energy that would not be supplied if the total system were interrupted for one minute at the time of its annual peak. This criterion was developed on the basis of balancing the incremental costs of adding generation to improve reliability with the costs to customers resulting from interruptions. The resulting reserve requirement of 22 to 24% was used by Ontario Hydro to manage the generation program.

In contrast, the IMO is required to assess the resource situation on a periodic basis and to provide this assessment to market participants and relevant regulatory and standards authorities. Market participants will use this information as input to investment decisions related to capacity additions or modifications. The IMO is using an assessment criterion, described in Section 4.1, which is based on the NPCC generation adequacy standard.

4.0 RESOURCE ADEQUACY ASSESSMENT CRITERION

4.1 Statement of Resource Adequacy Assessment Criterion

The IMO's Generation Adequacy Standard over the 10-year period is:

> "Sufficient generation reserve should be available such that, the annual loss of load probability, caused by a deficiency of generation, is less than 0.1 day per year".

Interconnection assistance and emergency operating actions are included as contingency plans only and are not normally included as generation resources in the calculation of the LOLP. In a few instances where the LOLP standard could not have otherwise been met, they have been included. These instances are described in Section 5. Planned maintenance expectations are deterministically modelled as reductions to available resources. Unscheduled reductions in generation (i.e. forced outage and derating expectations) are modelled probabilistically in the determination of the reserve requirement to meet the LOLP standard.

4.2 Statement of How the Criterion is Applied

The reliability standard is used to assess the adequacy of available generating resources, on an ongoing basis, to identify periods of potential resource deficiency and opportunities for the rescheduling of planned outages. Actions that will be taken in the operating time frame by the IMO to deal with a potential shortfall in operating reserve are summarized below for the transition period before the opening of the Ontario electricity market. After the opening of the electricity market, the actions available to the IMO will be determined by Market Rules that are currently being developed.

Actions that may be taken to provide additional operating reserve include the following (not necessarily in the order given):

- curtail export sales (capacity backed and non-capacity backed; Firm export curtailment is covered by National Energy Board licence conditions)
- purchase emergency energy
- cut interruptible loads,
- issue a customer appeal,
- implement 3% voltage reduction,
- implement 5% voltage reduction

- request assistance from adjacent control areas by voltage reduction and sharing Operating Reserve,
- operate to the minimum acceptable level of system security,
- implement rotational load shedding.

The preceding actions are not normally considered in the long range planning period except where needed to restore reserves to the levels dictated by the NPCC Standard.

4.3 Required Reserve to Meet Criterion

Generation Reserves are required for the market to supply the forecast demand with a sufficient level of reliability. The Generation Reserve Requirement is calculated from the IMO Generation Adequacy Standard. The Required Generation is that amount of generation capacity required to supply the peak demand plus meet the Generation Reserve Requirement.

4.4 Comparison of IMO and NPCC Criteria

The NPCC generation reliability criterion is as follows:

> "Each area's generation capability will be planned in such a manner that, after due allowance for scheduled maintenance, forced and partial outages, interconnections with neighboring areas and regions and available operating procedures, the probability of disconnecting non-interruptible customers due to generation deficiency, on the average, will be no more than once in ten years."

The IMO's reliability criterion is effectively the same as the NPCC criteria except that in the planning phase interconnection assistance and other operating actions are not included unless required to support expected scheduled maintenance requirements. For the years 2001 through 2010, an LOLP value of 0.1 days per year was utilized to determine the Required Reserve in each week of the year. The uncertainty in the demand forecast varies from week to week, and the available generation mix may also vary, giving rise to a different Reserve Requirement for the Peak hour of each week. The risk is thus level throughout the year. As long as the generation reserves exceed the requirement in each week, the average annual LOLP will be less than or equal to 0.1 days/year.

Any spare capacity ("Margin") above the Generation Reserve Requirement is available for generator maintenance. Historically no outages were scheduled over the peak weeks of the year unless the predicted Margin was positive or replacement capacity was available. This behaviour would be expected to continue based on perceived economic opportunities for market participants at peak times.

For periods beyond 18 months in the future, the IMO has used planned outage factors provided by Ontario Power Generation for assessing margins. These factors do not include multi-year outages which may be necessary towards the end of the ten year period but have not been identified to the IMO.

Although it is possible to predict generator outage patterns over a 10 year period based on past experience and emerging expectations, formal planning and scheduling is usually conducted on an annual or current year plus next basis. Every quarter, looking from one month in the future out 18 months, the IMO assesses the integrated generator and transmission outage plans. Periods where outages result in negative Margins are identified to generators and transmitters. If these participants fail to proactively reschedule outages to mitigate the concern, the IMO may veto the outage in the near-term to ensure sufficient capacity is available to meet non-dispatchable demand.

The Ontario system has traditionally assumed that 700 MW of interconnection assistance would be available at the peak hour in the winter. In this review, no reliance is placed on interconnection assistance, except where agreements are in place or where some assistance to support outage plans is indicated. As indicated in Section 5, such assistance may be necessary for periods in 2001 and early 2002.

4.5 Resource Adequacy Studies Done Since the 1997 Triennial Review

Prior to 2000, Ontario Hydro and its successor company, Ontario Power Generation Inc, conducted adequacy assessments. This is the first Triennial Review published by the IMO. Other adequacy assessments produced by the IMO include an 18-Month Outlook published in March 2000 and a 10-Year Outlook published in August. Both of these reports, available on the IMO website, were submitted the Minister of Energy, Science and Technology and to the Ontario Energy Board to the meet the requirements of the IMO's transitional licence. An updated 18-Month Outlook, looking at the period from October 2000 through March 2002 has recently been completed and will be available shortly on the IMO website (www.theIMO.com). Results of that assessment have been included in this review where appropriate.

5.0 RESOURCE ADEQUACY ASSESSMENT

5.1 Planned Versus Required Reserve for Reference Demand Forecast

Over the forecast period, the Ontario electrical energy use is expected to increase by about 0.9% annually, on average, in the Median Demand Forecast. The Available Capacity above or below the Required Reserves (and demand) is shown as Margin (Excess/Shortfall) in Table 5.1 (for the winter peak hour) and Table 5.2 (for the summer peak hour) for the forecast period. The Required Reserve and the percentage of demand that that value represents exhibit a fair degree of variability through time. This is primarily a function of the forced outage rate assumptions used in the model and the result of impacts relating to calendar factors and the timing of the weekly peak.

The analysis shows that the Ontario System has sufficient reserves to meet the Required Reserve level for each year during the forecast period. The Margin is low at the peak hour in winter of the Years 2001 and 2002 and again towards the end of the forecast period. The forecast Margin is higher at summer peak as compared to the winter peak, until 2004, when the situation is reversed. The Required Generation Reserves are higher in the summer mainly because of the air conditioning demand during hot and humid weather. The Load Forecast Uncertainty, which captures this weather-related effect, is modelled in the demand probability table, resulting in a higher Generation Reserve Requirement to meet the 0.1 LOLP in the summer periods (see Figure A2).

The spring of 2001 and the fall-winter of 2001/2002 represent the periods of lowest margins when planned outages are considered. Without utilizing additional resources which could be made available either through interconnections assistance, rescheduling of outages, demand management or emergency operating actions, the annual LOLP for 2001 was calculated to be 0.18 days per year. By modelling up to 1400 MW of additional resources in the spring period and 800 MW in the fall period of 2001, the annual LOLP reduces to 0.056 days per year for 2001. This level of resource augmentation is within the range considered reasonable based on past experience and previous studies conducted by NPCC.

Outage programs in the remaining years are not problematic and, therefore, no reliance on additional resources or demand management was required to be modelled.

Table 5.1 Margins for Winter Peak – Median Demand Forecast

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5.2 Available Versus Required Reserve for High Demand Forecast

In the High Demand Forecast scenario, the Ontario electrical energy use is expected to increase on average by about 2.0% annually. Generation Reserve Margins are shown in Table 5.3 (for winter peak hours) and Table 5.4 (for summer peak hours) for the forecast period. The Margin is small at the peak hour in winter of the Years 2001, 2002 and 2006 and is insufficient towards the end of the forecast period. The forecast Margin is higher at summer peak, as compared to the winter peak, until 2004, when the situation is reversed.

In the High Demand scenario, low to negative margins are forecast during the study period. Small negative margins can be accommodated without load shedding since dispatchable loads will likely respond to the resulting spot price increases and could be dispatched off. An allowance of 600 MW had been assumed in the past for similar actions. Shortages of up to 700 MW could also be accommodated by imports. However routine planned outage programs will be difficult to manage without additional resources and could leave the Ontario system maintenance bound. Therefore, additional resources are already desirable and could be required as early as Year 2005 for the High Demand Forecast scenario.

Table 5.3 Margins for Winter Peak – High Demand Forecast

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Table 5.4 Margins for Summer Peak – High Demand Forecast

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5.3 Contingency Plans

The IMO Board can initiate a capacity reserve market in order to attract additional generating capacity into the market. The mechanisms for this process will be contained in the Market Rules. In addition, the IMO prepares an annual report that will provide the IMO Board with information about the requirements for generation and transmission capacity.

At present, about 3000 MW of new generation projects have been announced and most of these projects are scheduled for operation after Year 2002. This forecast does not include any of these projects, since the required approvals have not been obtained and the IMO process for connection impact assessments is just being introduced. Rules for which projects should be included in this type of assessment are being established.

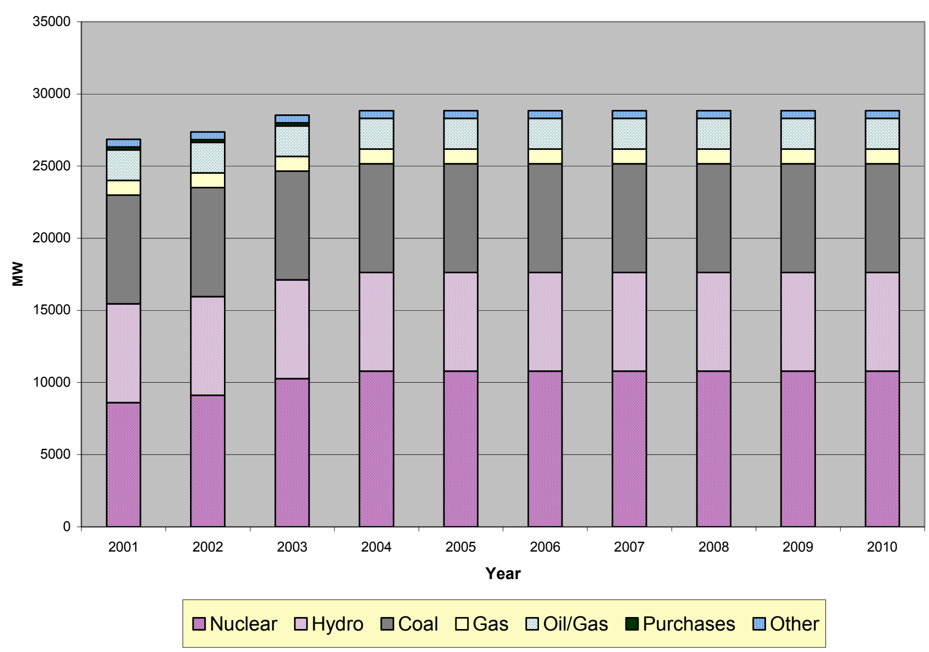
Transmission enhancements to the IMO interconnections with other control areas are also under study.

6.0 PLANNED RESOURCE CAPACITY MIX

6.1 Forecast Energy Production by Fuel Type

Market forces will govern Ontario's energy production sources in future years. The maximum generation from fossil fuels must be controlled within regulated limits for acid gas emissions. These acid gas emission amounts have been controlled in the past by use of lower sulfur coal, and use of oil/gas fired generation options. Future generation additions will be largely gas-fired units. In excess of 3000 MW of additional market driven generation has been proposed to the IMO for connection assessment. Once this generation receives the necessary approvals, it will be included in the capacity mix.

Figure 6.1 Ontario Capacity Mix by Fuel Type



Upon implementation of the Market Rules, Chapter 5 Section 7, the IMO will begin receiving capacity and energy forecast information from generator participants and will be able to produce independent mix assessments. For this review only, the IMO is utilizing the projections of Ontario Power Generation Inc.

6.2 Ontario Energy Mix by Fuel Type

The fuel mix strategy of Ontario Power Generation Inc. is considered commercially sensitive information and has not been included in this report. However, the CP-8

Working Group has been provided with this information in confidence. Once the Ontario electricity market opens, the IMO will be accountable for assessing this aspect of adequacy.

APPENDIX

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

The IMO uses a Load and Capacity (L&C) model to determine the Generation Reserve Requirements from week to week. The mix of generating plant, generating unit forced outage rates, the demand forecast and its uncertainty are inputs to the model. A Generation Adequacy Standard of 0.1 days/year is used to determine the Generation Reserve Requirement for each week of the planning year.

The probabilistic calculation of the Generation Reserve Requirement for every planning week is made as follows:

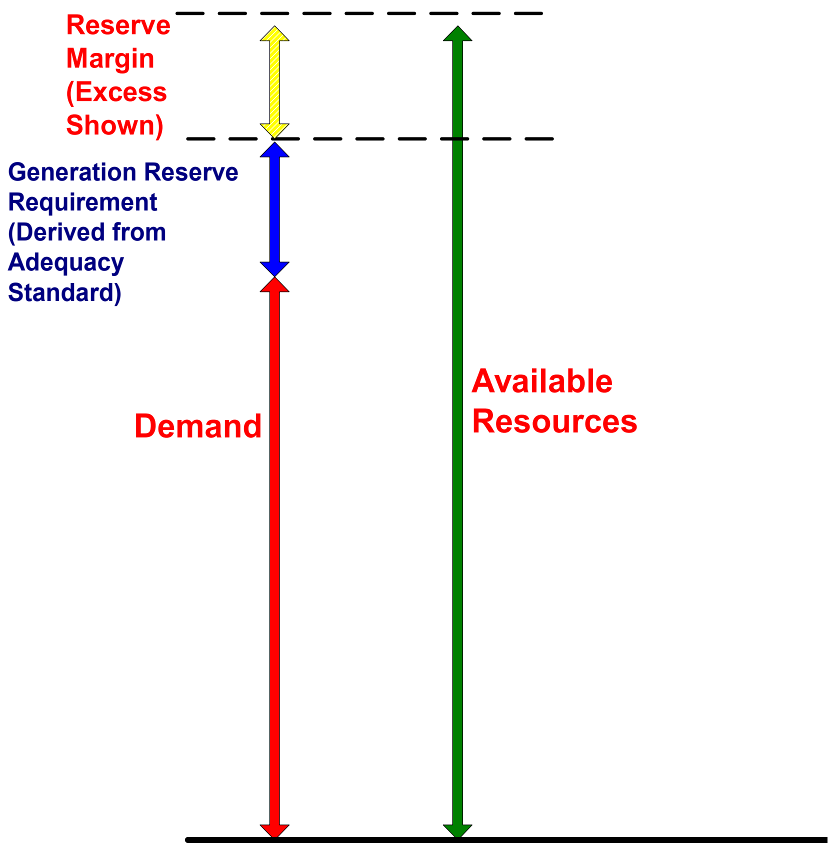
1. Based on the generating units MCR's and Forced Outage Rates, a Capacity on Outage Probability Table, in which are the probabilities of having various amounts of capacity on forced outage, is built;
2. The Generation Reserve Requirements calculation is then executed on an iterative manner. In each iteration, the Net Available Capacity is assumed and an associated $LOLP_{CALC}$ is derived, convolving the LFU corresponding to the Demand value (which assumes normal distribution) and using the Capacity on Outage Probability Table. The iterative process is carried on until the $LOLP_{CALC}$ becomes equal or less than the target of 0.1. When this condition becomes true, the respective assumed level of Net Available Capacity is the Required Net Available Capacity to meet the reliability target. From this value, by subtraction of the Demand, the Generation Reserve Requirement for the planning week is obtained.

The adequacy of the available generation facilities to meet the demand over the study period can then be assessed, in a deterministic calculation, as shown in Figure A1. For each planning week, the minimum level of the Net Available Resources is determined. The Reserve Margin is then obtained by subtraction of the Demand and the Generation Reserve Requirement from the minimum Net Available Resources. Whenever the Reserve Margin is positive the reliability criterion is met (the LOLP is less or equal than 0.1).

The actual LOLP for each planning week can then be calculated in a similar way as described above (in the paragraphs 1 and 2). This time the Available Generation Reserve is known, the LOLP is derived in one iteration, convolving the LFU corresponding to the Demand value (normal distribution assumed) and using the Capacity on Outage Probability Table.

Finally the annual LOLP can be derived using the individual LOLPs for the component planning weeks.

Figure A1 Reserve Margin



1.1 LOAD MODEL

1.1.1 Description And Basis Of Period Load Shapes

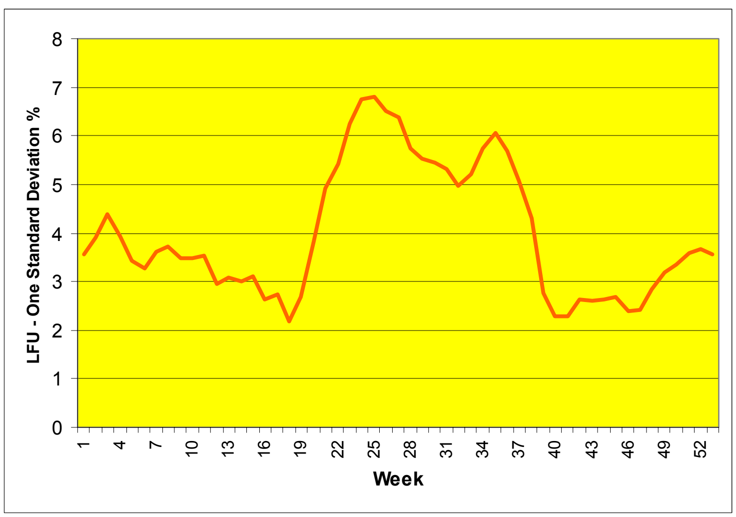
The demand model comprises weekly energy and peak demand data, plus data related to the variability of the demand in any week due to swings in the weather. Hourly and 20-minute peak data is also derived. The description of the Demand-Weather relationship is based upon a four-year record, updated annually.

The total energy demand is split into weather and non-weather components.

1.1.2 Load Forecast Uncertainty

A normal distribution of weather swings, in any week, is provided by input of the associated standard deviation. This data is obtained from 30-year weather statistics and is updated annually.

Figure A2 Weekly Demand Forecast Uncertainty due to Weather



The standard deviation of weather-related demand varies between about 2% and 7 % through the year as shown in Figure A2. The peak demand probability distribution in any week is thus available to the L&C program.

1.1.3 Discount Demand Service

The demand includes loads that are currently served under the Discount Demand Service and which can be interrupted in cases of shortfalls in reserves. They are used as a contingency measure at the assessment stage, if a reserve shortfall is indicated. In such cases, an assistance amount of 600 MW of price-sensitive dispatchable load is considered to be available.

1.2 RESOURCE REPRESENTATION

1.2.1 Unit Ratings

1.2.1.1 Definitions and Values

Thermal generating units are assumed to be capable of operating at a level equal to their normal Maximum Continuous Rating (MCR). Hydraulic station peak outputs are based on Dependable (exceeded 98 % of the time) river flows, determined from about 60 years of record. The peak and energy output of all combustion turbines varies considerably with changes in ambient air temperature and, hence, both summer and winter values are included. The aggregated Net Declared Capacity values for OPGI units and for Contract Generators are shown in Table A3. Due to the commercial sensitivity of this information, it has been aggregated into five categories.

1.2.1.2 Procedure for Verifying Ratings

The Ontario Market Rules permit various tests to be carried out by the IMO. Explicit test procedures for verifying generator ratings have not yet been developed. For this review, the IMO has used ratings which are consistent with operational experience.

Table A3 Ontario Power Generation Inc. and Contract Generator Power Stations

Resource Type	Declared Net Capacity (MW)
Nuclear	10,788
Coal	7,560
Oil & Gas	3,644
Hydroelectric	7,426
Miscellaneous (wind, waste, wood)	77

1.2.2 Unit Unavailability Factors

1.2.2.1 Type Of Unavailability Factors Represented

Derating-Adjusted Forced Outage Rates for each unit are used that reflect both forced outages and periods of derated output. These are based on unit specific data supplied by the facility owner. Historic information and forecast future performance are combined to derive the rates.

Planned maintenance is modelled on a unit basis. For the first two years of study, explicit outage plans are modelled. For the remainder of the study period, representative outage plans are used. Multi-year rehabilitation outages are explicitly represented in all years when identified by facility owners. None of this type have been identified to the IMO. The assumptions with respect to planned maintenance amount to the equivalent of a weighted average planned outage factor of about 13%.

1.2.2.2 Source Of Unavailability Factors Represented

These rates are based upon experience in Ontario and values published by NERC for the industry. Sensitivity studies were also conducted with lower and/or higher forced outage rates.

1.2.2.3 Maturing and Future Units

There are no major new resources modelled to be in service in the next ten years. Uncertainty around the return to service of four Pickering nuclear units was not identified to the IMO as a maturity concern and was not modelled. The impact of this uncertainty was qualitatively judged to be manageable through available operating actions.

1.2.2.4 Tabulation of Typical Unavailability Factors

Typical forecast DAUFOP and DAFOR indices for fossil, nuclear and hydroelectric units are contained in Table A5 and reflect a combination of past experience and expected future experience. Combined cycle information is taken from NERC data.

Table A4 Ontario Projected Forced Outage Rates

Fuel Type	Typical DAFOR/DAUFOP
Nuclear	8-10%
Coal	5-10%
Oil/ Gas	5-10%
Hydroelectric	<3%
Miscellaneous	<5%

1.2.3 Purchase and Sale Representation

An existing contract for the purchase of 200MW of firm capacity and energy from Manitoba Hydro, which expires on October 31, 2000, was considered for this assessment.

1.2.4 Retirements

No unit retirement plans have been identified for the study period. Ontario Market Rules require generation and transmission owners give the IMO at least 6 months notice of retirements.

1.3 Representation Of Interconnected Systems

There are effectively three systems that can provide assistance to Ontario, namely, USA, Quebec and Manitoba, as shown in Figure A3. For this study, interconnection assistance above contracted amounts is not included, except as a contingency measure in cases where a reserve shortfall is indicated due to outage plans. Up to 800 MW of additional purchases are considered outside of the winter and summer peak periods in 2001 and first quarter of 2002. Up to 700 MW of assistance has typically been available over winter peak periods, but reliance on this amount was not indicated for the median growth scenario

1.4 Modeling Of Limited Energy Resources

The Load and Capacity model assumes that energy limited hydroelectric sources are operated in such a manner as to conserve the energy to minimize load cuts, rather than in an economic mode, respecting both capacity and energy limits. In the determination of target reserves to meet resource adequacy criterion, energy constraints are not a significant factor for a credible range of load forecasting errors.

1.5 Modeling Of Demand Side Management

Up to 900 MW of load which is currently served under the Discount Demand Service (DDS) and which can be interrupted in cases of shortfalls in reserves is considered only until late spring, 2001. DDS loads are modelled only if a reserve shortfall is indicated and interconnection assistance in Section 1.3 has been applied. In such cases, an assistance amount of 600 MW of interruptible load is considered to be available. The 600 MW value is derived from a 60% non-coincidence factor which is consistent with previous operating experience.

1.6 Modeling Of Non-Utility Resources

Currently Hydro One administers the Contract Generators on behalf of OEFC. The amount of non-utility resources included in this study is the net declared capacity available from the Contract Generators (see Table A4), aggregated by fuel type.

1.7 Other Assumptions

1.7.1 Internal Transmission Limitations

The Ontario IMO Controlled Grid consists of a robust southern grid and a sparse northern grid. Studies were carried out for extreme flow patterns: no operating security limits were determined to be binding on the 60 Hz portion of the southern grid. The northwestern part of the northern grid has limitations which result in bottling of about 200 MW of thermal generating capacity and the Niagara 25-hz system has about 120 MW of hydraulic generating capacity bottled. These limitations were included in the Capacity analysis.