PUBLIC

REPORT

Ontario Reserve Margin Requirements

2014-2018

Issue 1.0

October 25, 2013

This report provides Ontario's Reserve Margin Requirements to meet the NPCC resource adequacy criteria over the next five years.

Disclaimer

The posting of documents on this Web site is done for the convenience of *market participants* and other interested visitors to the *IESO* Web site. Please be advised that, while the *IESO* attempts to have all posted documents conform to the original, changes can result from the original, including changes resulting from the programs used to format the documents for posting on the Web site as well as from the programs used by the viewer to download and read the documents. The *IESO* makes no representation or warranty, express or implied, that the documents on this Web site are exact reproductions of the original documents listed. In addition, the documents and information posted on this Web site are subject to change. The *IESO* may revise, withdraw or make final these materials at any time at its sole discretion without further notice. It is solely your responsibility to ensure that you are using up-to-date documents and information.

This document may contain a summary of a particular *market rule*. Where provided, the summary has been used because of the length of the *market rule* itself. The reader should be aware, however, that where a *market rule* is applicable, the obligation that needs to be met is as stated in the "Market Rules". To the extent of any discrepancy or inconsistency between the provisions of a particular *market rule* and the summary, the provision of the *market rule* shall govern.

Document Name	Ontario Reserve Margin Requirements
Issue	Issue 1.0
Reason for Issue	To meet the requirements of section 8.2 of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)
Effective Date	October 25, 2013

Table of Contents

List of Tables

1. Executive Summary

Through the annual release of the "Ontario Reserve Margin Requirements", the IESO reports the operational planning reserves ("reserve margins") needed in Ontario over the following five years. This report fulfills the requirements of Section 8.2 of the IESO's *Ontario Resource and Transmission Assessment Criteria*[1]. The calculated reserve margins were determined in accordance with the NPCC[2] resource adequacy design criterion stated in NPCC Regional Reliability Reference Directory # 1: *Design and Operation of the Bulk Power System*.

Reserve margin is the amount of supply resources in excess of demand that is required to meet the reliability criterion of an annual loss of load expectation (LOLE)[3] of 0.1 days per year. It is generally expressed as a percentage of annual peak demand and represents the reserve level needed to meet this resource adequacy criterion.

The IESO derives the annual reserve margins using a probabilistic multi-area simulation program that includes detailed load and generation information and simplified transmission models of the Ontario system. For this study, Ontario's resource self-sufficiency is being assessed, so imports from neighbouring Planning Coordinator areas are not relied upon in the calculation of reserve margins. Consequently, the study does not model the five external areas that are interconnected to Ontario.

Table 1 presents the results of the study.

Table 1: Reserve Margin Percentage by Year

Reserve Margin [%]	2014	2015	2016	2017	2018
Available[4] resources required above peak demand (%)	18.6	18.7	18.0	19.1	19.2

– End of Section –

[1] IMO_REQ_0041 "Ontario Resource and Transmission Assessment Criteria" is available from www.ieso.ca

[2] Northeast Power Coordinating Council (www.npcc.org)

[3] LOLE is a common reliability index used to assess generating capacity adequacy. It represents the number of days per year, on average, in which the load exceeds the available generating capacity, and hence, there is an expectation that firm load will be disconnected to resolve resource deficiencies.

[4] Available capacity is the installed capacity minus allowances made for seasonal derates, planned outages and the capacity of energy-limited resources. See Appendix A for assumptions on generation resources.

2. Methodology

The guidelines for calculating the annual reserve margins are provided in Section 5.2 of NPCC Regional Reliability Reference Directory # 1: *Design and Operation of the Bulk Power System*. This directory also defines the acceptable level of risk of disconnecting firm load due to resource deficiencies:

> *"The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. 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 Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."*

In this study, the reserve margin in any year is defined as the minimum amount of supply resources in excess of the demand during the most challenging period of the year, required to maintain an annual loss of load expectation (LOLE) of approximately 0.1 days per year. It is generally expressed as a percentage of demand at the time of the annual peak.

The most challenging period of the year is the time where the highest LOLE is assessed to occur which would usually be expected to be at the time of system peak. However, this may not necessarily be the case if planned resource outages or other system conditions significantly reduce the resources available to supply the demand over a particular period outside of the peak period.

In deriving the annual reserve margins, the IESO uses General Electric's Multi-Area Reliability Simulation (GE-MARS)[5] program, a probabilistic simulation program that is widely used within NPCC and the industry.

The IESO's MARS model includes detailed load and generation information, and a simplified transmission representation of the Ontario system. This model could also include simple representations of the five external areas to which Ontario connects. For this report, however, imports from neighbouring Planning Coordinator areas are not relied upon in the calculation of reserve margins so these external areas are not modeled.

To accurately reflect available capacity during the most challenging period of the year, the MARS program is capable of modeling scheduled and unscheduled generation outages, energy and capacity limitations of renewable resources, transmission limits, as well as

[5] http://www.ge-energy.com/products_and_services/

capacity and/or load relief from emergency operating procedures (EOPs). Demand uncertainty that results from the variability of the weather conditions that drive demand, can also be modeled.

The above-mentioned modeling capabilities were applied as required in the current study in assessing Ontario's resource adequacy. An overview of the key assumptions used to perform the simulations is provided in Appendix A.

For each study year, an initial simulation was run with specific basecase assumptions for available capacity. LOLE results were then compared to the NPCC criterion of 0.1 days/year to assess the adequacy of the basecase system. In instances where the basecase results exceeded the LOLE criterion, the resource planned outage schedule was adjusted with the aim of reducing the system risk, as described in Section A.2 of the Appendix. The analysis was repeated on the modified-basecase system and these results are recorded in Table 2.

Table 2: Modified-Basecase LOLE Results and Reserve Margins

	2014	2015	2016	2017	2018
LOLE (days/year)	0.013	0.081†	0.061	0.071	0.099
Available Capacity (MW)‡	28,780	24,630	28,479	27,299	26,949
Demand during Week of Highest LOLE (MW)	22,937	19,258	22,802	22,549	22,610
Reserve Margin (MW)	5,843	5,372	5,677	4,750	4,339
Reserve Margin – (modified-basecase) (%)	25.5	27.9	24.9	21.1	19.2

† The most challenging week occurred in April driven by the generator planned outage schedule.

‡ Available capacity is the installed capacity minus allowances made for seasonal derates, planned outages and the capacity of energy-limited resources. See Appendix A for assumptions on generation resources.

From Table 2 it can be seen that Ontario satisfies the NPCC criterion over the planning period assuming planned resources are delivered on time. EOPs were not required to achieve these results.

It should be noted that planned outage schedules submitted by market participants significantly influenced the calculated LOLE values and for several years over the review period, it was necessary to adjust the timing of these outages to satisfy the NPCC criterion. In this regard the year 2015 presented particular challenges, with a heavy maintenance schedule in the spring that includes numerous overlapping planned outages and potential station outages. After adjusting the planned outage schedule to partially reduce overlaps, the most challenging week of the year was still assessed to be in late April, rather than in July when the highest peak loads are forecast.

Table 2 also highlights that reserve margins in the modified-basecase system are expected to decline over the review period to the extent that by 2018, the planned resource stack only just satisfies the LOLE criterion.

Once the basecase assessment was completed, the criteria assessment was conducted in which each year's simulation was re-run in an iterative fashion while reducing the available resources until an LOLE of 0.1 days/year (+/- 0.005) was achieved. The reserve margin for each study year was then calculated at that particular level of available resources. The results of this procedure and the calculated reserve margins are presented in Section 3 of this report.

For more information on the IESO's MARS simulation approach, see IESO_REP_0266 *Methodology to Perform Long Term Assessments*.

– End of Section –

3. Reserve Margin Results

Several resource mix scenarios could be used to meet the LOLE target of 0.1 days/year (+/- 0.005). The results of the simulations based on one possible resource mix in each year are presented in Table 3. They include, for each year of the study period, the resultant LOLE, required available resources, projected peak demand in the highest LOLE week and reserve margin values expressed in both megawatts and percent of peak demand.

Table 3: Summary of Reserve Margins to meet Target LOLE[6]

	2014	2015	2016	2017	2018
LOLE (days/year)	0.099	0.099	0.100	0.101	0.099
Available Capacity (MW)	27,209	27,131	26,914	26,850	26,949
Demand during Week of Highest LOLE (MW)	22,937	22,851	22,802	22,549	22,610
Reserve Margin (MW)	4,272	4,280	4,112	4,301	4,339
Reserve Margin (%)	18.6	18.7	18.0	19.1	19.2

The required available capacity is an amount of supply resources equal to the sum of the peak demand during the highest LOLE week and reserve margin. The reserve margin represents the minimum required resources in excess of the peak demand, needed to satisfy the NPCC resource adequacy criterion over the next five years. These values take into account demand uncertainty, scheduled and unscheduled generation outages, seasonal capacity derates, energy and capacity limitations of renewable resources and major transmission interface limits.

Over the five-year study period, reserve margins vary between 18.0% and 19.2% influenced by the changing composition of the installed resources, demand levels and resource outage schedules. In each year, the most challenging week coincided with the week of the forecast system peak in July.

Since Ontario's reserve margin requirements over the study period may be significantly impacted by future changes to generator outage plans, the IESO conducts this annual review of reserve requirements to capture changes as Market Participants routinely update their outage data.

[6] These results are based on the assumption that all planned resources for the next five years are delivered on time.

Conclusions

As planned, the Ontario system satisfies the NPCC resource adequacy criterion over the 5-year study period 2014 through 2018 without reliance on EOPs, assuming all new resources are delivered on time.

Further, Ontario's required reserve margin averages approximately 18.7% over the same period.

– End of Section –

Appendix A: Key Modeling Assumptions

A.1 Generation Resources

This study considered all existing resources as well as new resources that were committed or planned as of May 2013, to come into service over the period 2014 to 2018.

Wind

Wind resources were modeled probabilistically on a zonal basis as Type 1 Energy-Limited Resources 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 (7 years of history) wind output data were used. A conservative approach of taking the lower of the two (modeled or actual) capacity values was applied. Seasonal CPDFs for the summer and winter, and separate monthly CPDFs for the shoulder months were modeled in MARS to represent the capacity contribution of wind resources to the system. A Wind Capacity Contribution (WCC) of 13.6% of installed wind capacity was assumed to be available at the time of summer peak.

Solar

Solar resources were modeled as load modifiers with production (MW contribution) calculated from projected installed capacities and monthly Solar Capacity Contribution (SCC) factors (% of installed capacity). SCC factors were determined from 10 years of modeled historic data by calculating the historic median solar contribution during the top 5 contiguous demand hours of the day for each winter and summer season, and for each shoulder period month. This resulted in seasonally normalized values for summer and winter and monthly normalized values for shoulder months. As actual solar production data becomes available in future, the process of picking the lower value between actual historic solar data, and the modeled 10-year historic solar data will be incorporated into the SCC methodology until 10 years of actual solar data is accumulated. At that point the modeled solar data will be phased out of the SCC calculation methodology.

Hydroelectric

Hydroelectric resources were modeled in MARS as capacity-limited and energy-limited resources. Minimum and maximum capacity values and monthly energy values were provided for each transmission zone. Maximum capacity values were based on median monthly contributions at the time of system weekday peaks plus a contribution to operating reserve. Minimum values and monthly energy values were based on Market Participant submitted data for existing stations. For new hydroelectric projects, the contribution factor was based on the average contribution factors of existing projects in the zone where the new project is to be sited. Contribution factors ranged from 67% to 77% of installed capacity.

Thermal Resources

Five resource types were modeled as thermal resources, viz. nuclear, coal, gas, oil and biomass. The capacity values for each unit were based on monthly maximum capacity ratings contained in Market Participant submissions. The only coal-fired resource modeled in the study was Thunder Bay G2 and this was assumed to cease operation by the end of 2014.

Equivalent Forced Outage Rates (EFORs) for both new and existing units were based on five-year history of actual forced outages. For units with insufficient historical data, EFORs supplied by Market Participants were used in the study.

Interconnection Support

Although the NPCC criterion for resource adequacy assessments allows for reliance on interconnection support, imports from Ontario's five interconnected neighbours were not considered in this analysis. This is consistent with the approach used in the development of other IESO reliability assessments (e.g. 18-Month Outlook and the Ontario Reliability Outlook), where imports from neighbouring Planning Coordinator areas are not relied upon to meet peak demand in the planning timeframe but rather left as an additional resource to be used in real-time operations, as required.

A.2 Planned Outages

Planned outages were in general based on outage submissions from Market Participants as of April 2013. During the basecase assessment and to the extent possible, planned outages were modeled as submitted within the limitations of the MARS software. However, in instances where the planned outage schedule included multiple overlapping outages that significantly increased system LOLE and dictated the most challenging week, adjustments to the timing of the relevant outages were made based on technical judgement. These adjustments were intended to reflect the improved coordination that would ordinarily be achieved through the IESO's outage management process which seeks to ensure that equipment outages do not impact the reliability of the IESO-controlled grid.

During the criteria assessment, as resources were removed to bring the system LOLE to 0.1 days/year, the planned outage schedule was further modified as necessary to minimize the impact of planned outages on system LOLE and thereby facilitate further resource removals. These additional outage schedule adjustments were made in keeping with the previously stated approach, and avoid the artificial inflation of reserve requirements by an outage schedule that in reality, would be better coordinated closer to real-time through the outage management process. Notwithstanding the adjustments to timing, the full outage duration needs of participants were still accommodated.

For those generating units with no specified outages over the planning period, the planned outages were based on forecast Planned Outage Factors (POFs) submitted by Market Participants and/or a generic outage plan derived from historic outage patterns of existing units. Planned and forced outage impacts for hydro and wind were assumed to be already accommodated in the capacity assumptions used.

A.3 Transmission Limits (Interface and Zonal)

The Ontario transmission system was represented by ten interconnected zones with all transmission limits between the zones modeled consistent with the IESO's 18-Month Outlook published on May 24, 2013. No changes to these limits were modeled over the study period.

A.4 Demand Forecast

In the MARS program, demand was modeled as an hourly profile for each day of each year of the study period. In the present study, the modeled demand already takes into account the effects of target conservation programs. The methodology used to generate these forecasts is described in Reference 2. The assumptions are consistent with those applied in preparing the forecast for the 18-Month Outlook published on May 24, 2013. An allowance for load forecast uncertainty was also modeled as described below.

Table A1: Annual Energy and Peak Demand including impacts of Conservation

Year	Demand Forecast	
	Energy (TWh)	Peak (MW)
2014	141.1	22,937
2015	137.3	22,851
2016	134.4	22,801
2017	131.6	22,549
2018	131.7	22,610

Load Forecast Uncertainty (LFU)

Load forecast uncertainty (LFU) arises due to variability in the weather conditions that drive future demand levels. LFU was modeled in MARS through the use of probability distributions. These distributions were derived from observed historical variation in weather conditions that are known to effect demand, viz. temperature, humidity, wind speed and cloud cover. Provincial-wide LFU distributions were developed for every month of the year and applied to all ten transmission zones.

A.5 Emergency Operating Procedures

Emergency Operating Procedures (EOPs) are available to help deal with potential shortfalls in reserve in the operating time frame. As summarized below, these procedures include reductions in operating reserves (OR), dispatch of generator stretch capability, voltage reductions and public appeals. This approach is approved for operational planning as indicated in the NPCC Regional Reliability Reference Directory #1 – *Design and Operation of the Bulk Power System*.

Table A2: Emergency Operating Procedures and their Aggregate Impact†

EOP Measure	EOP Demand Reduction	
	% of Demand	MW
Public Appeals	1.0	
No 30-minute OR		473
Generator Stretch Capability		228
No 10-minute OR		945
Voltage Reductions	2.1	
Total Impact	3.1	1,646
Less OR Requirement		-1,418
Net Impact in Analysis	**3.1**	**228**

† Although 30-minute and 10-minute OR are included in this list of EOPs, the analysis does not impose a requirement to provide for OR since only loss of load events are being considered. Therefore, the net benefit of applying EOPs in the analysis excludes relaxation of OR requirements.

– End of Section –

References

No.	Document Name	Document ID
1	Ontario Resource and Transmission Assessment Criteria	IMO_REQ_0041
2	Methodology to Perform Long Term Assessments	IESO_REP_0266
3	Design and Operation of the Bulk Power System	NPCC Regional Reliability Reference Directory # 1

– End of Document –