Ontario Reserve Margin Requirements

2018 - 2022

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1. Executive Summary

Through the annual release of the *Ontario Reserve Margin Requirements* (ORMR) report, the IESO communicates Ontario's planning reserve margins required over the next five years to reliably supply the province's forecast demand, as required in Section 8.2 of the IESO's *Ontario Resource and Transmission Assessment Criteria*[1].

Reserve margin requirements are calculated to satisfy the Northeast Power Coordinating Council (NPCC) resource adequacy design criterion stated in NPCC Regional Reliability Reference Directory # 1: *Design and Operation of the Bulk Power System*[2]. The reserve margin requirement in any year is the amount of supply resources in excess of the annual peak demand needed to meet the NPCC reliability criterion of an annual loss of load expectation (LOLE)[3] of 0.1 days/year. It is expressed as a percentage of annual peak demand.

The IESO uses the General Electric Multi-Area Reliability Simulation (GE-MARS) program to derive annual reserve margin requirements. The MARS model includes the available capacity and operational characteristics of existing and planned resources; capacity and energy limitations of renewable resources; resource planned outages and equivalent forced outage rates on demand; retirement and refurbishment schedules; interface limits between Ontario's 10 electrical zones; demand forecast and forecast uncertainty over the study horizon.

Ontario's Reserve Margin Requirement to meet an annual LOLE of 0.1 days/year averages approximately 17.7 percent over the five-year study period. Table 1 below presents the annual reserve margin requirement results of the study.

Table 1: Ontario Reserve Margin Requirements by Year

Year	2018	2019	2020	2021	2022
Reserve Margin (%)	**18.2**	**17.7**	**17.4**	**17.4**	**17.9**

Further, the Ontario system is expected to satisfy the NPCC resource adequacy criterion over the five-year study period 2018 to 2022, without reliance on emergency operating procedures or emergency capacity support from neighboring Planning Coordinator Areas, assuming all planned resources are delivered on time.

– End of Section –

1 IMO_REQ_0041 "Ontario Resource and Transmission Assessment Criteria" can be found at www.ieso.ca
2 NPCC Directory # 1: *Design and Operation of the Bulk Power System*, can be found at www.npcc.org
3 LOLE is a common reliability index used to assess resource adequacy. It represents the number of days per year, on average, in which the demand exceeds the available resource capacity, and hence, there is an expectation that firm load will be disconnected to resolve resource deficiencies.

2. Introduction

Through the annual release of the *Ontario Reserve Margin Requirements* (ORMR), the IESO reports the planning reserves ("reserve margins") required in Ontario over the next five years to reliably supply Ontario's forecast demand. This report fulfills the requirements of Section 8.2 of the IESO's *Ontario Resource and Transmission Assessment Criteria*[1].

Reserve margin requirements are determined in accordance with the Northeast Power Coordinating Council (NPCC) resource adequacy design criterion stated in Regional Reliability Reference Directory # 1: *Design and Operation of the Bulk Power System*[2]. The criterion states as follows:

"Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year."

Directory #1 further states that in meeting this requirement, the Planning Coordinator or Resource Planner shall *"make due allowances 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."*

The LOLE represents the number of days per year on which supply is expected to be insufficient to meet demand.

The reserve margin requirement in any year is the amount of resources in excess of the annual peak demand needed to meet the reliability criterion of an annual LOLE of 0.1 days/year.

Currently, Ontario's reserve margin requirements are determined without reliance on emergency operating procedures or support from neighboring Planning Coordinator Areas through non-firm imports. However, experience shows that Ontario's interconnections can be relied on during times of need and that occasional use of the interties to support Ontario's reliability is feasible. In light of this, the IESO is continuing to investigate the potential for considering non-firm imports to reduce future reserve margin requirements where the level of assumed interconnection support must reflect prevailing conditions, e.g. expected transfer capabilities between Ontario and neighboring areas as well as declining trends in anticipated reserve margins across North America.

– End of Section –

[1] IMO_REQ_0041 "Ontario Resource and Transmission Assessment Criteria" can be found at www.ieso.ca

[2] NPCC Directory # 1: *Design and Operation of the Bulk Power System*, can be found at www.npcc.org

3. Reserve Margin Study Methodology

In deriving the annual reserve margin requirements, the IESO uses General Electric's Multi-Area Reliability Simulation (GE-MARS) program, a probabilistic simulation tool that is widely used in the industry.

The IESO's MARS model includes detailed demand and resource information and a simplified 10-zone transmission network with inter-zonal transfer limits included. For more information on the IESO's MARS simulation approach, see *IESO_REP_0266 Methodology to Perform Long Term Assessments*[1].

3.1 Study Inputs[2]

To accurately reflect the available capacity of existing and planned resources and forecast demand over the study horizon, the following details are modelled:

- Monthly maximum continuous ratings (MCR) of thermal units (nuclear, gas, oil and biofuel) based on information provided by market participants (MPs);
- Planned outage schedules of thermal units as supplied by MPs or estimated by the IESO;
- Equivalent Forced Outage Rates on demand ($EFOR_d$) of thermal units, calculated by the IESO based on actual (historical) forced outage data and energy production data;
- Energy and capacity limitations of renewable resources (hydro and biofuel) provided by MPs or calculated by the IESO;
- Effective capacity available from demand measures: Demand Response Auction (DRA), Dispatchable Loads and Capacity-Based Demand Response (expires in October 2018);
- Variability in the production capability of wind resources;
- Expected hourly production capability of solar resources including monthly and seasonal variations;
- Ontario's 10 major electrical zones with defined inter-zonal transmission limits;
- Hourly coincident demand forecasts for Ontario's 10 electrical zones; and
- Load forecast uncertainty driven primarily by weather variability that affects demand.

The target in-service dates of planned resources are also reflected in the study. Planned retirements and long-term refurbishment outages of existing resources over the planning horizon are also scheduled according to their expected out-of-service and return-to-service dates.

Also modelled in MARSs is the Ontario-Quebec Electricity Trade Agreement under which Ontario will make 500 MW of capacity available to Quebec from December to March until 2023.

A more detailed description of the study methodology and key model assumptions is provided in Appendix A.

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[1] http://www.ieso.ca/en/sector-participants/planning-and-forecasting/18-month-outlook
[2] The study inputs were finalized based on the information available to the IESO as of July 31st, 2017.

3.2 Basecase and Criteria Assessment Methodology

Basecase Assessment

In conducting the analysis for each study year, an initial simulation is performed with the system "as-is" (the Basecase system) and the LOLE results are noted. The adequacy of the Basecase system is evaluated by comparing the LOLE for each year to the NPCC criterion of 0.1 days/year. In instances where the Basecase results exceed the LOLE criterion, adjustments to the timing of planned outages are made as described in Section A.1 of the Appendix to produce a Modified Basecase. The aim of these changes is to reduce the annual system risk below the threshold of 0.1 day/year, thereby demonstrating compliance with the NPCC Directory #1 requirement.

Criteria Assessment

The goal of the Criteria Assessment is to determine the minimum amount of Ontario resources needed to satisfy the LOLE criterion of 0.1 days/year. Starting with the Modified Basecase system for each year, this assessment is performed by re-running the simulation repeatedly in an iterative fashion while reducing the available resources until an LOLE of 0.1 days/year (+/- 0.005) is achieved.

During the Criteria Assessment, several factors are considered when deciding on which candidate resources should be removed in any year. These include:

- Equivalent forced outage rate on demand ($EFOR_d$) – units with higher $EFOR_d$ are prime candidates for removal since their effective load-carrying capability (ELCC), i.e., the increase in system load that can be served at a particular reliability level after including the unit, is lower than units with a lower $EFOR_d$. Thus, removing a unit with a comparatively lower ELCC (high $EFOR_d$) will have a lesser impact on system LOLE than a unit of higher ELCC (lower $EFOR_d$), thereby allowing for removal of even more capacity until the LOLE criterion is achieved.
- Location – resources located in an export-congested zone are also suitable candidates for removal since congestion on the transmission interface means units at that location do not benefit the system to the same extent as units located elsewhere.
- Unit size – during the unit removal process, units of smaller size and comparatively lower $EFOR_d$ may have to be removed in preference to larger units of higher $EFOR_d$, simply because removing the larger unit will cause the system LOLE to exceed the 0.1 days/year target.

By following the above guidelines, the Criteria Assessment will yield a near minimal resource requirement. The Reserve Margin Requirement for each year is then calculated as the difference between the available resources and the annual peak demand. Reserve Margin Requirements and the results of the Modified Basecase analysis are presented in Section 4.

– End of Section –

4. Reserve Margin Study Results

Based on the methodology described previously, several resource mix scenarios could be used to meet the LOLE target of 0.1 days/year (+/- 0.005). By applying the guidelines outlined in Section 3.2, a near minimal reserve margin requirement in each year is achieved. The results are presented in Table 2. For each year of the study period, they include the resultant LOLE, required available resources, projected system peak demand and required reserve margins expressed in both megawatts and percent of peak demand.

In each year, the system peak demand is forecast to occur in July.

Table 2: Summary of Reserve Margin Requirements[1]

	2018	2019	2020	2021	2022
LOLE (days/year)	0.100	0.100	0.100	0.100	0.100
Required Capacity at Peak (MW)	26,460	26,251	26,080	25,947	25,952
Annual Peak Demand (MW)	22,379	22,295	22,209	22,101	22,017
Reserve Margin Requirements (MW)	**4,081**	**3,956**	**3,871**	**3,846**	**3,935**
Reserve Margin Requirements **(%)**	**18.2**	**17.7**	**17.4**	**17.4**	**17.9**

The reserve margin requirement represents the minimum resources in excess of the peak demand that are needed to satisfy the NPCC resource adequacy criterion in each of the next five years. These values take into account forecast demands (including peak demand and load shape) and load forecast uncertainty; scheduled and unscheduled generation outages; nuclear refurbishment schedules; seasonal capacity derates; energy and capacity limitations of renewable resources; and major transmission interface limits.

The required capacity is an amount of supply resources equal to the sum of the annual peak demand and the reserve margin requirement.

Over the five-year study period, the required reserve margins vary between 17.4 percent and 18.2 percent. The average Ontario Reserve Margin Requirement over this period is approximately 17.7 percent of annual forecast peak demand. Year-to-year variations are influenced primarily by changes in annual demand forecasts and generator planned outage schedules. For example, a demand profile with a higher load factor[2] or an increase in the average generation capacity on planned outage will tend to increase reserve requirements.

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

[2] Load factor is defined as the ratio of the 'average' load to the 'maximum' load. A higher load factor indicates that the demand is relatively constant, while a low load factor indicates that the high demand is only set occasionally.

For completeness, the available reserve margins for the next five years determined from analysis of the Modified Basecase are presented in Table 3. The results of Table 3 show that Ontario satisfies the NPCC criterion over the planning period under the assumed conditions.

Table 3: Modified Basecase LOLE Results and Reserve Margins

	2018	2019	2020	2021	2022
LOLE (days/year)	0.029	0.006	0.007	0.031	0.037
Available Capacity at Peak (MW)	27,478	28,306	27,961	26,775	26,799
Annual Peak Demand (MW)	22,379	22,295	22,209	22,101	22,017
Reserve Margin (MW)	5,099	6,011	5,752	4,674	4,782
Reserve Margin (Modified Basecase) (%)	**22.8**	**27.0**	**25.9**	**21.1**	**21.7**

– End of Section –

5. Conclusions

Ontario's Reserve Margin Requirement to meet an annual LOLE of 0.1 days/year averages approximately 17.7 percent over the five-year study period.

The Ontario system satisfies the NPCC resource adequacy criterion over the five-year study period 2018 to 2022, without reliance on emergency operating procedures or emergency capacity support from neighboring Planning Coordinator Areas, assuming all planned resources are delivered on time.

– End of Section –

Appendix A: Key Modelling Assumptions

A.1 GENERATION RESOURCES

This study considers all existing resources as well as planned resources expected to come into service over the period from 2018 to 2022. Planned resources include those that are committed (signed contracts) and directed as of April 2017. Planned retirements expected to occur over this timeframe are also considered, as are the refurbishment schedules of Ontario's nuclear fleet.

Wind

Wind generation is expected to grow in the period of the study. By the end of 2022, about 5,000 MW of grid-connected wind-powered generation is expected to be in-service in Ontario. Given the variability of wind speeds, wind generators are modelled probabilistically on a zonal basis as energy-limited resources with a cumulative probability density function (CPDF) that represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The CPDFs vary by month and season.

The CPDFs are constructed based on the contribution of wind resources during a contiguous five-hour window of highest daily demand for the summer and winter seasons, and for each month of spring and fall.

In the analysis referred to above, the determination of the five-hour window with the highest average demand is based on an analysis of the last five years of historical demand data.

Solar

Grid-connected solar resources are modelled on an aggregated zonal basis in 4 separate zones. For each zone, the contribution of solar resources is modelled as a fixed hourly profile that varies by month and season. The MW production is calculated from projected installed capacities and hourly solar contribution factors applicable to each zone and for each month or season. Hourly solar contribution factors are in turn determined from an analysis of 10 years of simulated historical data by calculating the hourly median solar contribution for each month and season. As actual solar facility production data is accumulated over the coming years, the IESO will gradually make a transition to full reliance on actual operating history when determining zonal solar capacity factors.

Hydroelectric

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each electrical zone. Maximum capacity values are based on historical median monthly production plus the contribution of hydro resources to the operating reserve market at the time of system weekday peaks. Minimum capacity values are based on the 25th percentile of historical production during hours ending one through five for each month. Monthly energy values are based on historical monthly median energy production since market opening.

For new hydroelectric projects, the maximum capacity value is derived based on the average monthly capacity factor at the time of system peak in the zone where the new project is located. The minimum capacity value and the monthly energy value are calculated using the methodology described above based on the historical production data of a similarly sized generator in the zone where the new project is located.

Thermal Resources

Nuclear, gas, oil and biomass resources are modelled as thermal resources, with their capacity values based information provided by market participants.

Starting in 2016Q4, the IESO has transitioned to using Equivalent Forced Outage Rate on demand ($EFOR_d$). $EFOR_d$ is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate[1]. It is the most appropriate metric for modelling the forced outage rates given the capabilities of the assessment tools used by the industry. $EFOR_d$ of existing units are derived based on an analysis of a rolling five-year history of actual forced outage data and the generator's energy production data. For existing units with insufficient historical data, and for new units, $EFOR_d$ values of existing units of similar size and technical characteristics are used while recognizing the higher failure rate during the early operating period.

Demand Measures

Demand measures, i.e. Dispatchable Loads, Capacity-Based Demand Response (CBDR), and DRA are not incorporated into the demand forecast; they are treated as generation resources.

The effective capacity available from Dispatchable Loads is determined based on an analysis of historical bid-quantity data for peak demand hours submitted by market participant. In MARS, Dispatchable Loads are modelled as resources that are available at all times and are represented as monthly capacity values aggregated for each transmission zone.

The effective capacity of CBDR and DRA resources is determined based on an analysis of the historical performance of the participants in these programs. In MARS, CBDR and DRA are modelled as capacity that is available at all times and are represented as monthly values aggregated for each transmission zone. However, unlike Dispatchable Loads, a monthly limit is imposed on the number of activations of each resource.

[1] IEEE Std 762 - IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity

Planned Outages

Planned outages are in general based on outage submissions from market participants as of mid-2017. During the Basecase Assessment and to the extent possible, planned outages are modelled as submitted, within the limitations of the MARS software. However, in instances where the planned outage schedule includes multiple overlapping outages that significantly increase system LOLE, adjustments to the timing of the relevant outages are made based on technical judgement. These adjustments are 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 unduly impact the reliability of the IESO-controlled grid.

During the Criteria Assessment, as resources are removed to bring the system LOLE to 0.1 days/year, the planned outage schedule is further modified as necessary to minimize the system LOLE and thereby facilitate further resource removals. These additional outage schedule adjustments are 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 each facility are still accommodated.

For those generating units with no specified outages over the planning period, planned outages are 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 are assumed to be already accommodated in the energy/capacity assumptions used.

A.2 TRANSMISSION LIMITS

The Ontario transmission system is represented by 10 interconnected zones with transmission limits between the zones explicitly modelled. The limits modelled are the operating security limits (OSL) specified for each interface and any projected limit increase due to future transmission system enhancements is appropriately represented.

A.3 INTERCONNECTION SUPPORT

Although the NPCC resource adequacy criterion allows for reliance on interconnection support when evaluating system LOLE, the current study does not rely upon non-firm imports when determining Ontario's reserve margin requirements.

After years of transition during which the Ontario power system ended its reliance on coal-fired generation, incorporated significant amounts of new or refurbished generation and completed reinforcements of the transmission system, the performance of the new supply mix is now more predictable and better understood. The IESO intends to further evaluate the reliability benefits offered by the interties and may, as deemed appropriate, incorporate potential interconnection support in determining Ontario's future reserve margin requirements.

A.4 DEMAND FORECAST

In the MARS program, demand is modelled as an hourly profile for each day of each year of the study period. In the present study, the modelled demand already takes into account the effects of target conservation programs and embedded generation. The methodology used to produce these forecasts is described in *Methodology to Perform Long Term Assessments (Reference # 2)*. An allowance for load forecast uncertainty is also modelled as described below. The annual energy consumption and peak demand for each year of the planning horizon are provided in Table A1.

Table A1: Annual Energy Consumption and Peak Demand

Year	Demand Forecast	
	Energy (TWh)	Peak (MW)
2018	136.5	22,379
2019	135.1	22,295
2020	133.8	22,209
2021	133.0	22,101
2022	132.8	22,017

Load Forecast Uncertainty

The Load Forecast Uncertainty (LFU) curve is a probabilistic model representing probability of occurrence of various peak demands. The uncertainty in peak demand is mainly due to random weather fluctuations, and does not include any long-term economic influence. The temperature combined with the other load-contributing weather factors is denoted as Temperature Variable (TV). THI – temperature-humidity index, one of the variants of TV, is used for the study. Historical weather is used to simulate a set of peak loads with all other variables being equal. A Poisson distribution is used to deduce the expected peak loads for each probability bin from the expected rates of occurrence of peak loads belonging to each bin.

A zonal LFU curve is developed for every month of the year and applied to each transmission zone.

A.5 EMERGENCY OPERATING PROCEDURES

Emergency operating procedures (EOPs) are available to help mitigate potential resource shortfalls in the operating time frame. As summarized below, these procedures include 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*.

The order of initiating EOP actions is as follows:

- Public appeal;
- 3% voltage reduction;
- 5% voltage reduction.

Table A2 summarizes the assumptions regarding the load relief from EOPs.

Emergency operating procedures are currently not considered in the ORMR study since they are held back as additional measures to be deployed as required during real-time operations.

Table A2: Emergency Operating Procedures and their Net Impact

EOP Measure	EOP Impact†	
	% of Demand	MW
Public Appeals	1.0	
No 30-minute OR (473 MW)		0†
No 10-minute OR (945 MW)		0†
Voltage Reductions	2.1	
Aggregated Net Impact	**3.1% Reduction in Demand**	

† 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
4	IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity	IEEE Std 762™-2006

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