Methodology to Perform the Reliability Outlook

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1 Introduction

This document outlines the assumptions, principles, and analytical approaches used in developing the Reliability Outlook. It details the methodology applied to produce the Ontario demand and supply forecast, and to conduct resource and transmission adequacy assessments for the Independent Electricity System Operator (IESO). These methodologies ensure that the Reliability Outlook provides a comprehensive view of system reliability. Over time, the approach may evolve to incorporate improved practices and reflect the most effective methods for completing the Reliability Outlook process.

For questions or comments on the *Methodology to Perform the Reliability Outlook*, please contact us at 905-403-6900 (toll-free 1-888-448-7777) or customer.relations@ieso.ca.

2 Demand Forecasting

The demand forecasts presented in the Reliability Outlook are generated to meet two main requirements: the market rules and regulatory obligations. The Ontario Electricity Market Rules[1] require that a demand forecast for the next 18 months be produced and published on a quarterly basis by a set date. The IESO is also required to file both actual and forecast demand related information with the Ontario Energy Board (OEB), the Northeast Power Coordinating Council (NPCC) and the North American Electricity Reliability Corporation (NERC). These regulatory obligations have specific needs and timelines and the IESO's forecast production schedule has been designed to satisfy those requirements.

2.1 Demand Forecasting System

Ontario Demand is the sum of coincident loads plus the losses on the IESO-controlled grid. Ontario Demand is calculated by taking the sum of injections by registered generators, plus the imports into Ontario, minus the exports from Ontario. Ontario Demand does not include loads that are supplied by generation not participating in the market. This would exclude loads served by distribution connected non-market participant generation (embedded generation) and behind-the-meter generation (load displacing generation).

The IESO forecasting system uses multivariate econometric equations to estimate the relationships between electricity demand and a number of drivers. These drivers include weather effects, economic and demographic data, calendar variables, conservation and embedded generation. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. Calibration routines within the system ensure the integrity of the forecast with respect to energy and peak demand, and zonal and system wide projections.

More pronounced load growth has begun to materialize in Ontario after a period of modest change in demand. A significant number of large loads (>20 MW) have expressed interest in, and begun the process of locating facilities within Ontario. Due to the number and size of these prospective loads, a significant amount of uncertainty and potential variability has been introduced into the demand forecast over the forecast horizon. To address this, the Reliability Outlook includes two demand forecasts:

- **Firm demand forecast** includes those large loads that are highly likely to start consuming within the forecast timeline. This is informed by where these prospective loads are in the connection process and information provided by transmitters and/or distributors. The firm demand forecast remains the information used to plan and operate the system.

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[1] IESO Market Rules, Chapter 0.5 | Power System Reliability, Section 7.1

- **Planned demand forecast** includes the loads identified in the firm demand forecast and large loads that are in the early stages of the connection process and therefore may have less certainty in terms of the load requirements and timing of the projects. The IESO deemed it prudent to account for the potential load of these less certain projects in order to assess the impacts and risks to the system.

For both of these forecasts hourly demand by zone is produced. These demand forecasts are generated based on a set of assumptions for the various model drivers.

Historic weather is used to simulate future electricity demand under a variety of weather conditions. The resulting distribution of demand as a function of weather volatility is used in probabilistic analysis and studies. However, a representative slice of that demand distribution is used in reports to illustrate a level of demand at a prescribed probability. The ones presented in this report are:

- The **normal weather** demand simulation represents the 50/50 distribution of probabilistically modelled peak and energy data. This means that 50% of observations would exceed the normal value and 50% of observations would fall below the normal value.
- The **extreme weather demand** simulation represents a 97/3 distribution of probabilistically modelled weekly peak demand data. This means that 3% of peak observations would exceed the extreme weekly peak values and 97% of observations would not exceed the extreme value. For the extreme monthly and seasonal peaks the representative simulation is 95/5.

An explanation of the weather simulations follows in section 2.3.

Conservation and demand measures are often discussed together as they both work to reduce demand. However for the purposes of forecasting, they are handled differently. Demand measures are treated as a resource and are based on market participant information and actual market experience to determine the amount of capacity available. Conservation projections, the Industrial Conservation Initiative (ICI) and time of use rates (TOU) are load modifiers and are incorporated into the demand forecast. A further discussion on demand measures can be found in section 2.4.

2.2 Demand Forecast Drivers

Consumption of electricity is modelled using six sets of forecast drivers: calendar variables, weather effects, economic and demographic conditions, load modifiers (time of use and critical peak pricing), conservation impacts and embedded generation output. Each of these drivers plays a role in shaping the results.

Calendar variables include the day of the week and holidays, both of which impact energy consumption. Electricity consumption is higher during the week than on weekends and there is a pattern determined by the day of the week. Much like weekends, holidays have lower energy consumption as fewer businesses and facilities are operating.

The hour of the day shapes demand as it reflects the activity of the population and its businesses. Demand is lowest overnight and higher throughout the day. The hours of daylight are instrumental in shaping the demand profile through lighting load. This is particularly important in the winter when sunset coincides with increases in load associated with cooking load and other return-to-home activities. Hours of daylight are included with calendar variables.

Weather effects include temperature, cloud cover, wind speed and dew point (humidity). Both energy and peak demand are weather sensitive. The length and severity of a season's weather contributes to the level of energy consumed. Weather effects over a longer time frame tend to be offsetting resulting in a muted impact. Acute weather conditions underpin peak demands.

For the Ontario Demand forecast, weather is not forecasted but instead uses historical weather to simulate demand under a variety of weather conditions. For resource adequacy assessments a distribution of weekly peaks simulated using historical weather is used to consider a full range of peak demands that can occur under various weather conditions with a varying probability of occurrence. This is discussed further in section 2.3.

Economic and demographic conditions contribute to growth in both peak and energy demand. An economic forecast is required to produce the demand forecast. Forecast data is purchased from economic service providers and are used to generate the economic drivers used in the model. Population projections, labour market drivers and industrial indicators are utilized to generate the forecast of demand. Population projections are based on the Ministry of Finance's Ontario Population Projections.

Conservation acts to reduce the need for electricity at the end-user. The IESO includes demand reductions due to energy efficiency, fuel switching and conservation behaviour under the category of conservation. Information on program targets and impacts, both past and future, are incorporated into the demand forecast.

Embedded generation reduces the need for grid supplied electricity by generating electricity on the distribution system. Embedded generation is divided into three separate components for modelling purposes – solar, wind and other. Other embedded generation includes generation fueled by biogas, natural gas and water. Contract information is used to estimate both the historical and future output of embedded generation. This information is incorporated into the demand model.

Load modifiers account for the impact of prices. The Industrial Conservation Initiative (ICI) and time of use prices (TOU) put downward pressure on demand during peak demand periods. These impacts are incorporated into the model.

Large step loads are incorporated into either the firm or planned demand forecast, based on the likelihood of their connection within the 18-month Reliability Outlook period. Their inclusion and associated load amounts are determined using information from transmitters and distributors, the Connection Assessment and Approval (CAA) process, and/or their status in the Market Registration process.

The required grid capacity and uncertain timing of connection introduce variability into the demand forecast. Consequently, they are treated as large step increases in demand and are incremental to the underlying demand growth from economic activity and population growth.

The firm demand forecast includes large loads that are highly likely to connect on schedule. The planned demand forecast captures those with less certain timing or likelihood of proceeding.

2.3 Weather Simulations

Since weather has a material impact on demand, the IESO uses historical weather data to simulate a range of potential demand outcomes capturing the variability and interplay in electricity demand, embedded solar output, embedded wind output and weather. The simulations use the last 31 years of Environment Canada weather history and shifts the data ahead and back seven days in order to capture the important weather/calendar interactions. The output results in 465 demand simulations for the forecast period. The simulated dataset generates the following output:

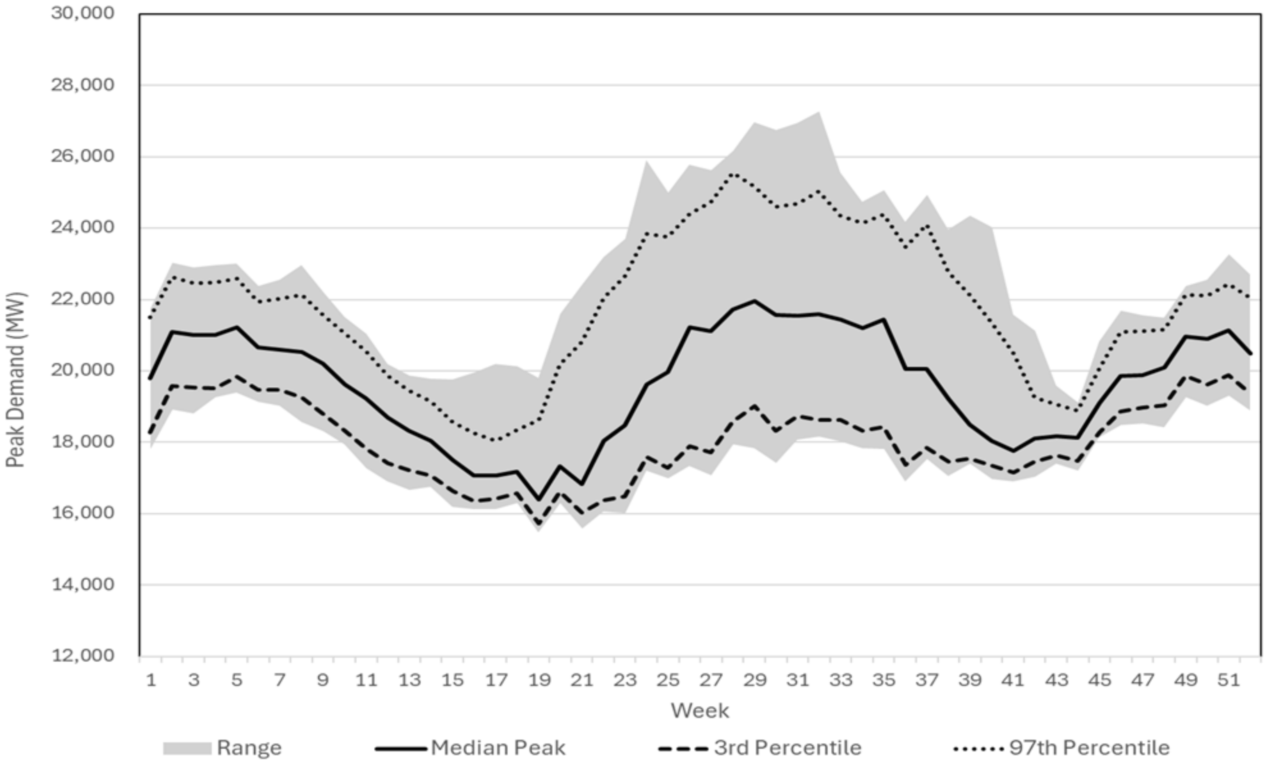
- 465 demand values for each hour of the forecast for both the system and zones
- 465 embedded solar output values for each hour of the forecast for both the system and zones
- 465 embedded wind output values for each hour of the forecast for both the system and zones

The simulated output represents a robust dataset representing the coincident impact of weather on demand with the corresponding weather impacted embedded generation (solar and wind). The dataset is used to define probabilistic distributions of peak and energy demand.

Here are some key notes on the weather simulations:

- Monthly normalization results in higher peak demands and lower minimums as compared to daily or weekly normalization. This is due to the large set of sorted and grouped data that allows for more differentiation between the weather that is most influential and the weather that is least influential. The seasonal peaks are generated via monthly normalization.
- Analysis provided for the Reliability Outlook uses the distribution function of the weekly peaks in order to determine the Reserve Above Requirement (RAR), described in more detail in section 4.4.
- When modelling energy an hourly forecast of system and zonal demand is required. To facilitate this energy modelling analysis the IESO uses monthly normalized hourly demand that represents median energy and peak demand for the month. This is a consistent approach to the development of the reference year for the Annual Planning Outlook (APO).
- For analysis that requires a set of numbers rather than a distribution, the appropriate "slice" is determined and taken from the demand distributions. **Figure 2-1** shows the range of weekly peak demands and several common "slices" – median peak demand, 3rd percentile peak demand (mild) and 97th percentile demand (severe). The desired end use underlying each analysis will help determine the appropriate "slice" or distribution of demand.
- Additionally, historic weather years are used in certain studies to meet NPCC or NERC regulatory requirements. By using historical weather years it ensures that multiple jurisdictions use consistent weather assumptions for multi-regional studies and analysis.

Figure 2-1 | Range of Weather Simulated Peak Demands



2.4 Demand Measures

The demand measures, which include dispatchable loads and Hourly Demand Response resources secured under the Capacity Auction and loads participating in Peaks Plus, are treated as resources in the assessment. As such, the reductions due to these programs are added back to the historical hourly demand. This ensures that the impacts are not counted twice – as a resource capacity and as lower demand.

These programs are summed to determine a total capacity amount. Using historical data, the IESO determines the quantity of reliably available capacity for each program and zone. Since demand management programs act like resources that are available to be dispatched, derived capacity is treated as a resource in assessments.

2.5 Updating the Demand Forecasting System

There are several tasks that are carried out on a regular basis as part of the Reliability Outlook process:

- The models are updated for actual data prior to each forecast and the equations are re- estimated. This enables the system to consistently "learn" from new data.
- The weather simulations are updated to include the most recent year's weather data.
- A new economic forecast is generated for the economic drivers in the model.
- Updated conservation data and the performance of demand measures are obtained and processed.

The system will therefore include recent experience and the forecast will be based on the most recent weather simulations and economic outlooks.

3 Supply Forecasting

To assess future resource adequacy, the IESO must make assumptions about the amount of available resources. The Reliability Outlook considers two scenarios and are defined in the following sub-section below: a firm supply scenario and a planned supply scenario.

The starting point for both scenarios is the existing installed resources. The planned supply scenario assumes that all resources scheduled to come into service are available over the assessment period. The firm supply scenario considers only those resources that have reached commercial operation status as of the time of this assessment. Generator-planned shutdowns or retirements that have a high likelihood of occurring are considered for both scenarios as well as outages submitted by generators.

3.1 Supply Forecast Assumptions

The following assumptions were used to develop the supply forecast. Additional details on assumptions are provided in the Capacity Adequacy Assessment section 4.

3.1.1 Generation and Electricity Storage Resources

All generation and electricity storage resources scheduled for development, commissioning, commercial operation, retirement, and out-of-service, and resources with expiring contracts are taken into account for the supply forecasting within the Reliability Outlook period. This includes generation and electricity storage projects in the IESO's Connection Assessment and Approval (CAA) process, those under construction, and contracted resources. Details regarding the IESO's CAA process and the status of these projects can be found on the Application Status section of the IESO website.

The two scenarios used to describe project availability in the Reliability Outlook are the following:

- The **planned supply scenario** assumes that all resources scheduled to come into service are available over the assessment period.
- The **firm supply scenario** assumes that only resources that have reached commercial operation status and completed commissioning at the time this assessment was completed are available.

Generators with expiring contracts and planned shutdowns or permanent retirements that have a high likelihood of occurring are considered for both scenarios.

Project status provides an indication of the project progress, using the following terminology:

- Under Development – projects in approvals and permitting stages (e.g., environmental assessment, municipal approvals, IESO connection assessment approvals) and projects under construction.
- Commissioning – projects undergoing commissioning tests with the IESO.
- Commercial Operation – projects that have achieved commercial operation status under the contract criteria, though some IESO's market registration requirements could still be pending.

- Expiring Contract – contracts that will expire during the 18-month period are included in both scenarios only up to their contract expiry date. Generators (including non-utility generators) that continue to provide forecast output data are also included in the planned supply scenario for the rest of the 18-month period.
- Retirement – projects scheduled for permanent shutdown.
- Facility Out of Service – projects scheduled to be shutdown for an extended period of time.

3.1.2 Generation Capability

Hydroelectric

A monthly forecast of hydroelectric generation output is developed using median historical values of production and contributions to operating reserve during weekday peak demand hours. This approach implicitly accounts for routine maintenance and forced outages, as these events are reflected in the historical data. To reflect the impact of hydroelectric outages on the Reserve Above Requirement (RAR) and allow the assessment of hydroelectric outages as per the outage approval criteria, the hydroelectric capability is also calculated, without accounting for historical outages. The dataset used spans from May 2002 and is updated annually to align with the release of the Q2 Reliability Outlook. Details on the forecast hydroelectric generation output, including the impact of planned outages and deratings over the Reliability Outlook period, are provided in section 4.5.2.

Thermal Generators

Thermal generators' capacity, planned outages and deratings are based on market participant submissions. Forced outage rates on demand are calculated by the IESO based on actual operational data. The IESO will continue to rely on market participant-submitted forced outage rates for comparison purposes.

Wind and Solar

For wind and solar generation, monthly Wind Capacity Contribution (WCC) and Solar Capacity Contribution (SCC) values are based on the weekday peak hour. WCC and SCC values are updated annually with the release of the Q2 Reliability Outlook.

3.1.3 Demand Measures

Both demand measures and load modifiers can impact demand, but differ in how they are treated within the Reliability Outlook. Demand measures, such as dispatchable loads and demand response procured through the IESO's Capacity Auction, are not incorporated into the demand forecast and are instead treated as resources. Load modifiers are incorporated into the demand forecast. The impacts of activated demand measures are added back into the demand history prior to forecasting demand for future periods.

The 2024 Capacity Auction, which secured 1,452.6 MW of winter capacity (November 1, 2025 - April 30, 2026), and the 2025 Capacity Auction, which secured 1,832.8 MW of summer capacity (May 1, 2026 – October 31, 2026) and 1,125.3 MW of winter capacity (November 1, 2026 - April 30, 2027), were included in the modelling for this Reliability Outlook. Capacity targets from the IESO's 2025 Annual Planning Outlook have been included and modelled as demand measures in the firm and planned supply scenario for the period post April 2027.

3.1.4 Firm Transactions

Capacity-Backed Exports

The IESO allows Ontario resources to participate in capacity auctions held by certain neighbouring jurisdictions, provided Ontario has sufficient supply and no reliability concerns. These auction outcomes are incorporated into supply forecasts.

New York Independent System Operator (NYISO)[2] will allow up to 13 MW of capacity-backed exports from Ontario for April 2026 and up to 4 MW of capacity-backed exports from Ontario for May 2026 until the end of Reliability Outlook period.

Capacity Sharing Agreement

A 2015 Capacity Sharing Agreement, amended and restated in 2016, with Hydro-Québec saw Ontario provide 500 MW of capacity to Quebec in the winter of 2015/16. Ontario currently has a commitment from Quebec to return 500 MW of firm capacity for four months during a summer of the IESO's choosing. The IESO had chosen to utilize 300 MW for the delivery period commencing June 1, 2026, and ending September 30, 2026, with the remaining 200 MW banked for use in a later summer.

The 2024 Capacity Sharing Agreement between the IESO and Hydro-Québec (outlined in the memorandum of understanding[3]) permits for the swap of 600 MW of capacity over a period of up to seven years, starting in winter 2024/2025. Under the agreement, the IESO will provide 600 MW to Hydro-Québec in the winter, and Hydro-Québec will provide 600 MW to the IESO in the summer. The IESO may choose to bank any amount of the 600 MW of summer capacity provided in a given year, to be used in a later summer during the agreement, allowing capacity to be saved until it is required. The IESO has chosen to bank 600 MW from the 2024 Capacity Sharing Agreement for the HQEM Delivery Period commencing May 1, 2026, and ending October 31, 2026, for use in a later summer. More information can be found in the 2023 Capacity Sharing Agreement Backgrounder.

Please note that capacity that is called upon under these agreements is already considered when determining the 1,000 MW / 2,000 MW adequacy threshold.

[2] https://icappublic.nyiso.com/ucap/public/rgt_availability_display.do

[3] https://news.ontario.ca/en/release/1003444/the-governments-of-ontario-and-quebec-support-new-electricity-trade-agreement

4 Capacity Adequacy Assessment

This section describes the criterion, tools and methodology the IESO uses to perform resource adequacy assessments.

4.1 Resource Adequacy Criterion

The IESO uses the NPCC resource adequacy design criterion as provided in the NPCC "Directory #1: Design and Operation of the Bulk Power System"[4] to assess the adequacy of resources in the Ontario Area. The NPCC resource adequacy criterion (Requirement 4 in Directory #1) states:

> R4: 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.
>
> R4.1 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.

4.2 Load and Capacity Model

The IESO uses the Load and Capacity (L&C) model to evaluate the resource adequacy for each week in the study period consistent with the NPCC resource adequacy criterion.

Figure 4-1 describes, visually, the interaction between the inputs into and outputs from L&C. The Total Resources, shown in the far left, are values used for reporting purposes and are not part of the analysis. This indicates the total resources in Ontario, without prejudice to their availability or capability to serve Ontario's load. The Available Resources, shown in the centre, are the inputs relating to generation or demand measures that can be expected to serve Ontario's load. The assumptions used to develop these inputs are described in section 4.5. At a high level, the key inputs to determine Available Resources are:

- Thermal generating units' net maximum continuous rating (MCR)
- Thermal generating units' planned outages and deratings
- Forecast hydroelectric generation output
- Wind Capacity Contribution (WCC) values

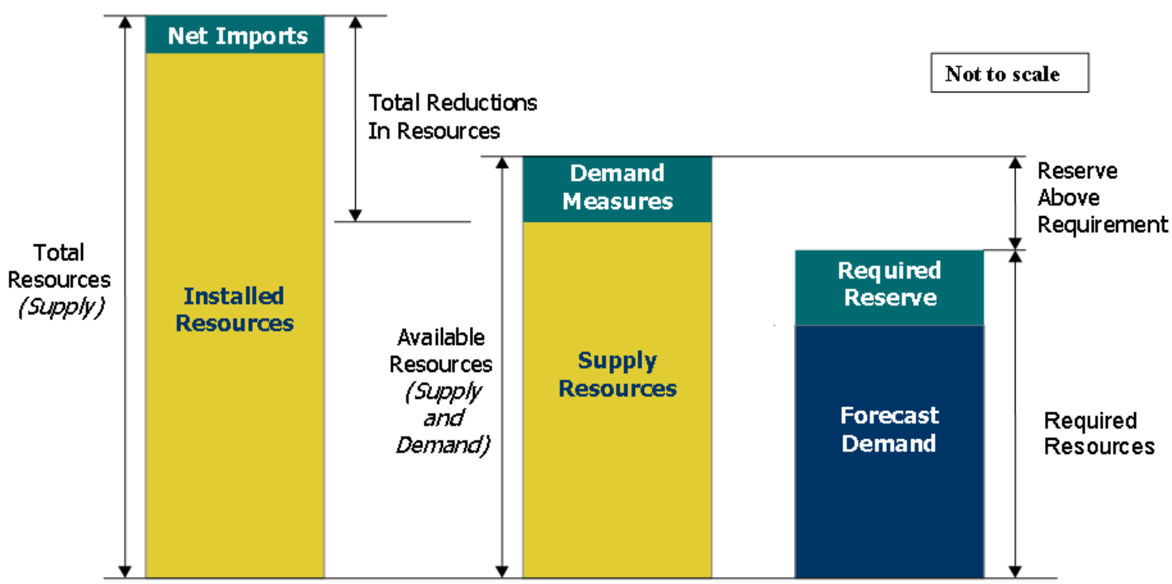
[4] NPCC "Directory #1: Design and Operation of the Bulk Power System"

- Solar Capacity Contribution (SCC) values
- The forecast demand

The output of the L&C model is the required reserve (described in section 4.4) to ensure that the resource adequacy criterion is met. The inputs that are used to determine the probabilistic required reserve are:

- The distribution of weekly peak demands
- Thermal generating units' forced outage rates on demand
- Hydroelectric resources distribution parameters and their uncertainty
- Wind resources distribution parameters and their uncertainty
- Solar resources as capacity factors at peak
- Storage resources as capacity factors at peak

Figure 4-1 | Summary of Inputs and Outputs of L&C



4.3 Data Reported in the Reliability Outlook

The following section describes data that is reported in the Reliability Outlook but is not used in the L&C tool to determine required reserve.

4.3.1 Installed Resources/Total Internal Resources

The Installed Resources (also called Total Internal Resources) is not used in the L&C tool, but rather is a value used to report the total installed capacity of resources connected to and participating in the IESO Administered Energy Market. It is made up of two components; the first is the existing supply (generation) resources, which are presented in Table 2.1 (IESO Reliability Outlook Data Tables). For the existing supply, only resources that have completed the final milestone in the Market Registration timeline are included as existing resources. The capacities of these resources (referred to here as Installed Capacity of each resource) are determined by referring to two sources of data:

- Data provided by Market Participants via Online IESO, as part of the Market Registration process: the Maximum Active Power Capability (the maximum active power capability under any conditions without station service being supplied by the unit. This value will be used to calculate the energy resource's maximum offer capability), is retrieved from the IESO's Customer Data Management System for all facilities that have completed Market Registration.
- For some resources, there may be additional restrictions on their maximum capability, as determined during commissioning. In these cases, the IESO may further reduce their Installed Capacity using information provided in their Commissioning report.

To estimate future Installed Resources on a weekly basis (as shown in Tables 3.5 and 3.6 of the IESO Reliability Outlook Data Tables), expected changes shown in Table 2.1 (IESO Reliability Outlook Data Tables) as Firm Capacity are added or subtracted from the existing supply.

4.3.2 Total Resources

The Total Resources are the summation of the Installed Resources and the Firm Net Imports.

4.3.3 Total Reductions in Resources

Where any tables in the IESO Reliability Outlook reference Reductions to Total Resources, these reductions are relative to the Total Resources described above. Reductions are made up of differences between the Total Resources and the:

- Available Capacity of Thermal Resources;
- Forecast Hydroelectric Generation Output;
- Capacity Ratings for Wind Resources;
- Capacity Ratings for Solar Resources;
- Available Demand Measures; and
- Transmission Limitations.

4.4 Outputs of the Resource Adequacy Assessment

4.4.1 Required Reserve

Reserves are required to ensure that the forecast Ontario Demand can be supplied with a sufficiently high level of reliability. The Required Resources is the amount of resources needed to supply the Ontario Demand and meet the Required Reserve as shown in **Figure 4-1**. The Reserve Above Requirement (RAR) is the difference between Available Resources and Required Resources.

In accordance with NPCC criteria outlined above, the IESO will use the firm demand forecast and firm supply scenario when assessing the most probable outcome for the 18-month period. In an effort to proactively investigate additional uncertainties in the system, the planned demand forecast and planned supply scenario is also presented for consideration.

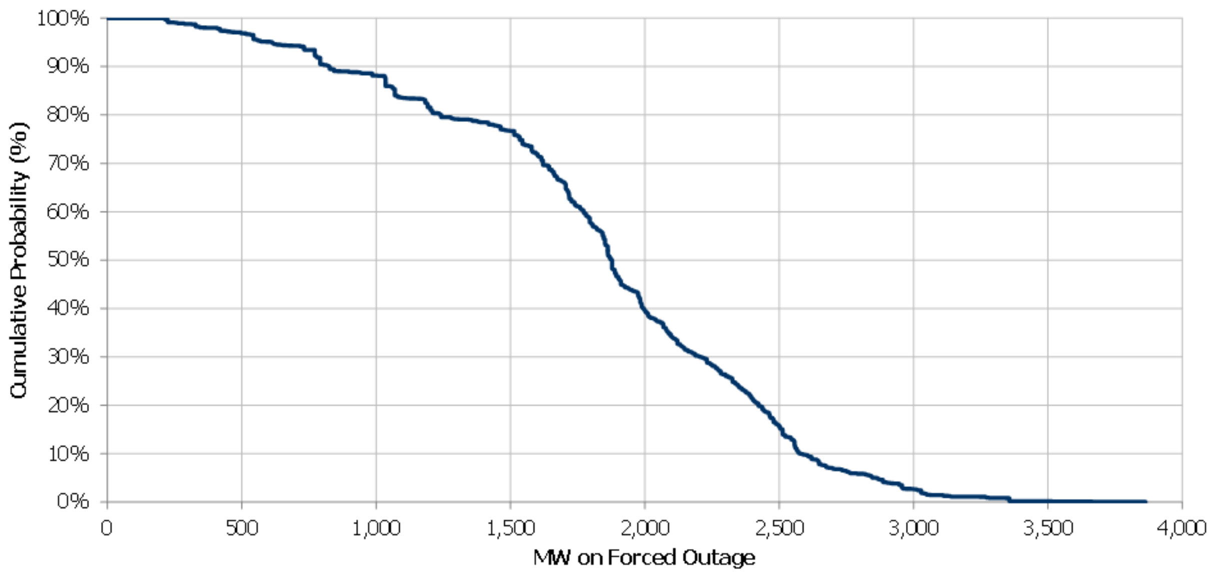
The Required Reserve is a planning parameter that, depending on the type of assessment, takes into account the uncertainty associated with demand forecasts or generator forced outages in a probabilistic or deterministic approach. The output of L&C is the amount of Required Reserve, in MW and as a percentage of forecast demand, for each week in the study period.

The amount of Required Reserve to meet the resource adequacy criterion is calculated on a week-by-week basis as the maximum of a deterministically and a probabilistically calculated reserve requirement. These two reserve requirements are described in this section.

Probabilistic Reserve Requirement

A resource adequacy criterion equivalent to a loss of load expectation (LOLE) of 0.1 days per year is used to determine the probabilistic reserve requirement for each week of the planning year. The L&C model uses the 'direct convolution' method to calculate the weekly probabilistic reserve requirement. The probabilistic reserve requirement considers multiple inputs in a probabilistic manner: distribution of demand, forced outages, and wind and hydro distributions. The details on inputs for these are described in section 4.5. The available capacity and forced outage rates on demand of thermal generation units are used to build a Capacity on Outage Probability Table (COPT) which contains the cumulative probabilities of having various amounts of generating capacity or more on forced outage. A graphical example is shown in **Figure 4-2**. Additionally it now also includes hydroelectric and wind uncertainty through probability distributions.

Figure 4-2 | Capacity on Outage Probability Table – Graphical Example



In the L&C model, a Normal or Weibull distribution of demand values around the mean demand value is assumed in each week, as described in section 4.2. The probabilistic reserve requirement calculation is executed in an iterative manner. In each iteration, an amount of Generation Reserve is assumed and an associated LOLE is calculated by convolving the variance corresponding to the peak demand value with the COPT. The iterative process is repeated with small changes to the assumed Generation Reserve until the calculated LOLE becomes equal to or less than the target. When this condition becomes true, the assumed level of Generation Reserve equals the probabilistic required reserve necessary to meet the reliability target.

Deterministic Reserve Requirement

The deterministic reserve requirement for each week is equal to the Operating Reserve (equal to the first single largest contingency plus half the size of the next largest contingency) plus the absolute value of the standard deviation in peak demand due to weather volatility.

4.4.2 Reserve Above Requirement

The Available Resources to meet the demand over the study period can then be assessed in an arithmetic calculation illustrated in **Figure 4-1**. The Reserve Above Requirement is obtained by subtracting the Required Resources (equal to the peak demand plus Required Reserve) from the Available Resources.

It should be noted that negative Reserve Above Requirement values in some weeks do not necessarily mean a violation of the NPCC resource adequacy criterion. This may only mean higher risk levels for the respective weeks. Whenever negative Reserve Above Requirement values are identified, the possible control actions to restore the reserves to required levels are considered and assessed.

When the RAR levels drops close to or below adequacy thresholds of -2,000 MW in the summer or -1,000 MW in the winter, market participants and the IESO may need to further co-ordinate outages. These thresholds represent reliance of up to 2,000 MW in the summer and 1,000 MW in the winter of supply from other jurisdictions and/or additional operating actions in order to ensure reliability, especially during periods of low reserves. The winter threshold limit is different to better reflect the lowered amount of imports to Ontario that can be relied on from other regions, compared to the summer months. Under periods of tighter supply conditions, planned generator maintenance outages are difficult to schedule. Generators are advised not to schedule outages during periods when reserves are forecast to be low, and are strongly encouraged to plan ahead and co-ordinate the timing of outages with IESO staff. Outage requests during periods when reserves fall below the adequacy threshold will be put at risk and further outage co-ordination may be required. The IESO will continue to work closely with participants that have planned outages to ensure Ontario maintains adequate reserves.

The Reliability Outlook references that the RAR is based upon "expected" weather, where expected refers to the selection of the weather data and corresponding peak demands (from all weather profiles in section 2.3) that the L&C model chooses based on an iterative analysis. Expanding on this, the weekly peak demands are represented by a distribution which is established by curve-fitting the outcome of 465 weather datasets to estimate weekly peak demand. The L&C model determines the RAR via a probabilistic assessment which involves repeated sampling of the expected peak demand probability distributions along with the probability parameters (COPT) for generators. The product of this calculation is used to calculate a loss-of load probability metric, with a requirement to have this metric meet a loss of load expectation of less than 0.1 days/year. The iterative process and rich data set means that a subset of demand and thereby historic weather is selected to achieve this reliability requirement which isn't necessarily normal or extreme. Therefore it can be statistically referred to as "expected". The peak demand distributions are covered further in section 4.5.10.

4.5 Inputs to the Resource Adequacy Assessment

For each planning week, the expected level of Available Resources is determined, considering:

- The amount of generator deratings;
- Planned and long-term unplanned generator outages;
- Generation constrained off due to transmission interface limitations;
- Any capacity imports or exports backed by firm contracts;
- Any imports identified by market participants to support planned outage requests to the IESO; and
- The assumed amount of price responsive demand.

The expected level of Available Resources is calculated using the outage profile associated with the maximum outage day in each planning week, i. e. the day with the maximum amount of unavailable generating capacity in that week. Although the weekly peak does not always occur on the maximum outage day, such coincidence is assumed for the determination of Available Resources.

4.5.1 Weekly Available Capacity for Thermal Generating Resources

The maximum capability for most thermal generating resources, such as nuclear, biofuel and gas fired generators, is affected by external factors, such as ambient temperature and humidity or cooling water temperature. To capture those variables, the Maximum Continuous Rating (or "MCR") for each thermal generator is modelled on a monthly basis.

Nuclear generators and the like whose MCR is not ambient temperature sensitive provide monthly gross MCR and their station service load in their annual Form 1230 submission, and this MCR is entered as a direct input in the L&C tool.

Fossil- or biofuel-fired generators whose MCR is sensitive to ambient temperature provide, through their annual Form 1230 submission, gross MCR at five different temperatures specified by the IESO which are used to construct a temperature derating curve. For each such generator, two monthly gross MCR values - one for the normal weather scenario and the second for the extreme weather scenario - are calculated at representative monthly temperatures using the derating curve.

Each zone's two monthly representative temperatures are determined from historical data collected from the weather station assigned to that zone based on proximity. For normal weather scenario, the zonal representative temperature is the median of the daily peak temperatures in the month in the zone. The zonal representative temperature for the extreme weather scenario is the maximum of the daily peak temperatures in the month in that zone for the months from April to October. For the months from November to March, the temperature for the extreme weather scenario is the minimum daily temperature in the month in each zone; the cold temperature is capped at -10°C.

Generators also provide their station service load annually which is allocated in proportion to the size of each unit at the station to calculate net MCR values for each unit.

The IESO updates the net MCR values annually in the second quarter using the data generators submit on Form 1230 by April 1.

If an existing generator is expected to shut down during the study timeframe, then the MCR is set to 0 MW beginning the week it is expected to expire. For example, for NUG whose contract expires during the Reliability Outlook period, its installed capacity and its rating are both set to zero beginning in the week of its contract expiry in the firm supply scenario.

Planned outages and deratings, as well as any forced outages that extend into the horizon of the 18 month Reliability Outlook period, are extracted from the IESO's outage management system. An outage profile for all thermal generators is calculated as an input into L&C using two steps:

1. Determine the maximum outage day (MOD) in each planning week. This is the day with the maximum amount of unavailable generating capacity in that week.
2. For the MOD selected, sum up the outages that occur during the daily peak window (currently hour ending 15 to 22). This is the window where the weekly peak demand is expected to occur. This ensures that outages covering the overnight off-peak hours do not affect the generation unavailability total of the MOD and consequently do not affect the Reserve Above Requirement.

4.5.2 Forecast Hydroelectric Generation Output

The forecast hydroelectric generation output is calculated using median historical values of hydroelectric production and contribution to operating reserve during weekday peak demand hours to create a dataset of historic production. The details for developing the generation output forecast are described in this section.

First, data of historical hydro production at the time of every non-holiday weekday are collected. For every non-holiday weekday since market open, the IESO selects the one individual hour that the daily peak demand occurred. The selection of the weekday peak demand hour may differ from day-to-day in the same month and can vary for the same month in different years as the demand profile changes from year-to-year. Once the daily peak is selected, the following pieces of data coincident to the peak are extracted:

- Hydro production (Allocated Quantity of Energy Injected or AQEI)
- Scheduled operating reserve in the constrained schedule
- Installed capacity
- Effects of historical outages on capability across the fleet

Since a large number of Ontario's hydroelectric generators are not run of river, this method assumes that regardless of what hour the peak may occur, the hydroelectric fleet would be scheduled in a manner that allows its output to peak coincident to when the Ontario demand peaks.

This new data set is then used to determine, on a monthly basis, the hydroelectric generation output forecast, which is shown in Table 2.3 of the Reliability Outlook. The "Historical Hydroelectric Median Contribution" is determined by:

1. For each hour in the data set, summing the hydro production and scheduled OR together ("generation output")
2. Grouping the generation output by month
3. Normalizing the generation output by the installed capacity of hydro generation. This normalization converts the generation output into a ratio of generation output to installed capacity.
4. Calculating the median for each month.
5. Multiplying each monthly capacity factor by the current hydroelectric Installed Capacity (all units currently in-service).

This calculation includes the impacts of hydroelectric outages. The expected capability of individual hydroelectric resources that were on planned outage and not injecting into the IESO grid is then estimated and added back into the historic production data. This allows the IESO to estimate the capability of the hydroelectric fleet if there were no outages. The following steps are used to "add back" the impacts of outages from the historic data. The end result of this calculation is presented in the Reliability Outlook as "Historical Hydroelectric Median Contribution without Outages."

6. For each hour since market open, the IESO retrieves the hydro capacity that was on a planned outage. This creates an hourly profile of the capacity unavailable due to outages, but it overestimates the impact, as not all generators would have been available as fuel limitations impact hydro output. Because of this, the hourly unavailable capacity as a result of planned outage is

multiplied by a capacity factor that changes by month and zone. This capacity factor is calculated from historical norms. This creates an effective loss of capability due to planned outages.

1. The amount of effective hydroelectric capability loss during the historical daily peak hour is added back to the historical contribution. This final value is the hydroelectric capability estimate assuming all units in-service. This is done to discount hydroelectric capability by the effects of future planned outages over the planning timeframe. This step is necessary to ensure assessment of hydroelectric outages and their impact on resource adequacy.

The Forecast Hydroelectric Generation Output, which is ultimately input into L&C, takes into account the impacts of planned outages and deratings on a weekly basis. The IESO performs the following steps to create this estimate:

1. Planned outages and deratings that extend into the 18 month horizon of the Reliability Outlook are extracted from the outage management system. The outages considered are only those that occur on the Maximum Outage Day of the week within the daily peak period.
2. The total reduction in the outage management system for each hydroelectric outage/derate is multiplied by a zonal capacity factor for the full duration of the outage. This capacity factor, which varies by month and zone, is derived from historical analysis of hydro. This is deemed the loss of capacity due to outages.
3. The loss of capacity from each outage/derate is summed up to determine the total loss of capacity for each week.
4. The weekly loss of capacity is subtracted for each week from the Historical Hydroelectric Median Contribution without Outages. This new value is the Forecast Hydroelectric Generation Output.

A hydroelectric distribution is constructed each month using historical AQEI plus OR scheduled, and is assumed to be normally distributed. These distributions are used to derive the required reserve calculation alongside wind and demand distributions.

4.5.3 Capacity Ratings for Wind Generation

Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators as a percentage of installed capacity. To calculate the WCC the IESO performs the following steps:

- Actual historic median wind generation contribution over the last ten years is compiled. If a wind facility was curtailed, the impacts of this foregone energy are added back to the production numbers, to estimate what the wind generator could produce at the time. The foregone energy is estimated from the 5 minute ahead wind forecast for that wind facility.
- The top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months. The demand hours are calculated for the winter and summer season, or shoulder period month.
- The dataset in step one is filtered for just the top 5 contiguous demand hours.
- The wind contribution across Ontario coincident to the demand hours previously estimated is summed together.

- The wind contribution each hour is normalized against the installed capacity of wind at the time of production.
- The median is then selected for each winter and summer season, or shoulder period month. For example, the wind generation contribution for summer is made the median generation contribution in the demand hours for June, July and August combined.
- For each week in the Reliability Outlook, the WCC is multiplied against the expected wind installed resources (this includes both existing and future wind generators).
- Additionally, wind distributions are created each month using historical AQEI production. These distributions are used in the probabilistic assessment to determine the Required Reserve. These distributions are assumed to be Weibull distributed.

4.5.4 Capacity Ratings for Solar Generation

Monthly Solar Capacity Contribution (SCC) values are used to forecast the contribution from solar generators as a percentage of installed capacity. SCC values in percentage of installed capacity are determined by calculating the median contribution during the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. A dataset comprising ten years of simulated solar production history is used for this purpose. As for wind, the top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months.

The SCC is calculated by performing the following steps:

1. The top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months. The demand hours are calculated for the winter and summer season, or shoulder period month. These hours are the same as those used for the WCC.
2. The IESO uses a dataset comprising ten years of simulated solar production history. This dataset is filtered for just the top 5 contiguous demand hours.
3. The dataset is further filtered to include only the data that represent solar output at a simulated site closest to where solar generation farms are actually installed in Ontario.
4. The solar contribution across Ontario coincident to the demand hours previously estimated is summed together. The summation is normalized against the installed capacity of solar.
5. The median is then selected for each winter and summer season, or shoulder period month.
6. For each week in the Reliability Outlook, the SCC is multiplied against the expected solar installed resources (this includes both existing and future solar generators).

4.5.5 Storage Facilities

Storage facilities are forecasted on a fleet aggregate level and are assigned an unforced capacity value for each summer and winter season at the time of weekday peak. These values will be re-evaluated once historical production data exists for these facilities.

4.5.6 Available Demand Measures

It is important to distinguish between demand measures and load modifiers. Demand measures include dispatchable loads and Hourly Demand Response (HDR) capacity secured through the Capacity Auction. Demand measures are treated as a resource. Load modifiers include embedded generation output, Time of Use Rates and the Industrial Conservation Initiative (ICI). These are incorporated into the demand forecast.

The available capacity of dispatchable loads is based on historical offers into the market. For most weeks, the average bid at weekday peak in the last twelve months is used as the available capacity. For weeks that are likely the annual peak, the IESO determines the available capacity from the offers during the top 5 demand hours of the past year. This ensures that the impacts of the ICI program are not double counted, as many dispatchable loads also participate in ICI.

The capacity secured through the Capacity Auction is discounted in the summer and in the winter from what was procured for the obligation period in each season to account for the fact that participants may not always be available. This is based on the weighted average performance of the last five DR test/activation results for each season.

4.5.7 Net Imports

The purpose of the IESO Reliability Outlook is to determine a required reserve for Ontario to be self-sufficient. Therefore, the only imports or exports considered are those backed by firm contracts/commitments. Where a contract/commitment exists, the capacity associated with it is calculated for each week of its stated deliverability period. The Net Imports are the Firm Imports less any Firm Exports. For example, if there are no Firm Imports in a given week but there is a Firm Export, then the Net Imports will be a negative number.

4.5.8 Transmission Limitations

The available capacity of thermal, hydroelectric, wind and solar resources may be subject to further reductions due to limitations of the transmission system. The IESO-controlled grid consists of a robust southern grid and a sparse northern grid. The northern grid has limitations, which potentially constrain the use of some generation capacity. As well, southern zones of the system could have some generation constrained at times, especially during outage conditions, because of the transmission interface limitations. The amount of generation constrained varies with the demand level, the amount of total generating capacity in a zone as well as the interface transfer capability. All transmission constrained generation is subtracted from the Available Resources. This becomes the final value used in calculating the Reserve Above Requirement.

4.5.9 Forced Outage Rates on Demand of Generating Units Used to Determine the Probabilistic Reserve Requirement

Equivalent forced outage rates on demand (EFORd) are used for each thermal generation unit as a measure of the probability that the unit will not be available due to forced outages and forced deratings when there is a demand for the unit to generate. The values are calculated by the IESO using a rolling five years of generator outage and operations data, consistent with IEEE Std 762[5]. EFOR data supplied by market participants will continue to be used for comparison purposes. EFORd impacts Required Reserve and does not impact the Total Reductions in Resources.

4.5.10 Demand Uncertainty Due to Weather to Determine the Probabilistic Reserve Requirement

The L&C program requires weekly peak demands for the study period. These peak demand values include loads that may be dispatched off during high price periods, loads that may simply reduce in response to high prices, and loads that may otherwise be reduced in the case of a shortfall in reserves. For modelling purposes, the total demand is assumed to be supplied, and is included in the peak demand forecast when the probabilistic reserve requirement is calculated. To meet the Required Reserve, the assessment allows that some of the reserve may be comprised of a quantity of demand that can decrease in response to market signals. The IESO forecasts the future price responsive demand levels based on Market Participant registered data and consideration of actual market experience.

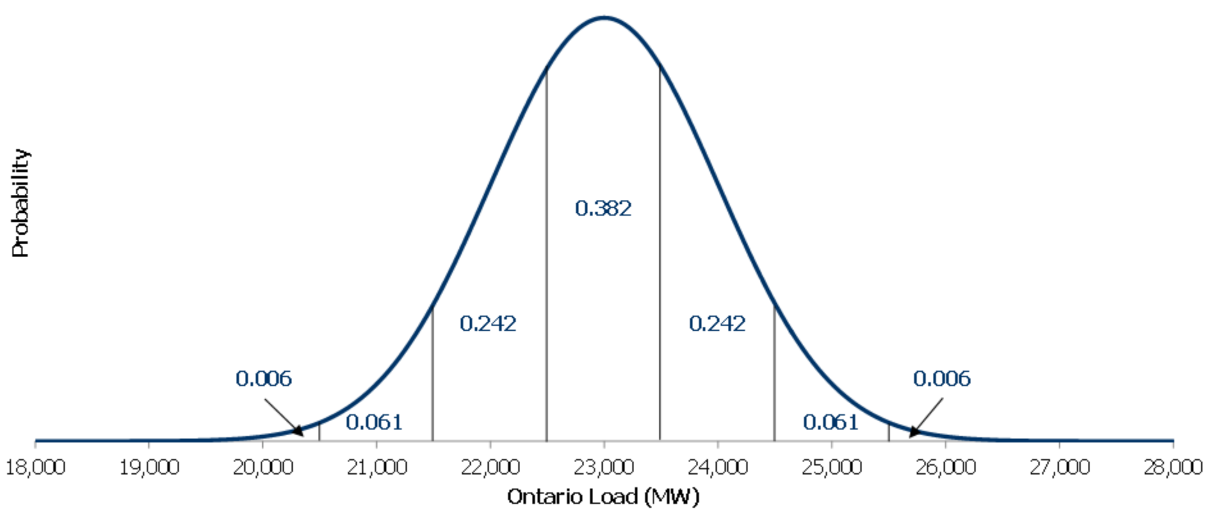
A probabilistic distribution of weekly peak demand is generated to capture the impact of weather volatility on those peaks. These distributions are generated via the weather simulations process described in section 2.3. The weather simulations process uses 31 years of weather history along with a "daily shift" component to capture increased calendar and weather interaction, resulting in 465 simulated peak demands for each week of the forecast. For each week, a distribution is fitted to the simulated sample. The L&C program can model Weibull and Normal distributions, therefore each weekly simulated dataset is assigned to either of those distributions based on fit. The vast majority are Weibull.

For the L&C model, each week's peak demand is modelled by a multi-step approximation of the distribution. Subsequently, in the probabilistic reserve requirement calculation for each planning week, multiple weather peak demand values are iteratively selected, as described in section 4.4.2, ultimately with one selected to achieve the required loss of load metric. Therefore, the analysis includes a range of demand values derived from mild to severe conditions (the expected weather).

Figure 4-3 illustrates a seven step example of such an approximation, using a weekly peak value of 23,000 MW and an associated standard deviation of 1,000 MW. In this example, the peak values considered in the probabilistic reserve requirement calculation would range from 20,000 MW to as high as 26,000 MW. Consequently, the calculated probabilistic reserve requirement reflects not only the impact of the generation mix (generator sizes and failure rates) but also the impact of uncertainties in demand related to weather. This is achieved by weighting the impact of each of the seven peak demand values by its associated probability of occurrence (shown in **Figure 4-3** under the curve).

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

Figure 4-3 | Seven-Step Approximation of Normal Distribution – Example



5 Energy Adequacy Assessments

The changing resource mix in Ontario, including the increasing penetration of variable energy resources, energy storage, and coupled with evolving demand profiles influenced by conservation and embedded generation have created the need for the IESO to assess Ontario's energy sufficiency in addition to the capacity adequacy. The Energy Adequacy Assessment (EAA) described in the following sections meets that need to assess whether the resources available over a specific assessment horizon will be sufficient to supply the forecast energy demand. Additionally, the EAA estimates the production by each resource over the assessment period to meet the projected demand based on expected resource availability.

5.1 EAA Overview

To perform the EAA, the IESO uses PLEXOS® Integrated Energy Model (Plexos) software to model and simulate the dispatch of Ontario's resources. Plexos calculates the optimal solution to the unit commitment problem by determining the commitment status (i. e. whether on or off) and production schedule of each resource in the system that minimizes total production cost subject to a set of operating constraints.

The IESO's energy model currently comprises:

- All grid-connected resources, their operating characteristics and limitations;
- Random forced outages of thermal resources;
- Planned outages of thermal resources;
- Zonal demand forecasts on an hourly granularity;
- A representation of the Ontario transmission system that may be either on a detailed nodal level, or on a zonal level; and
- Transmission element ratings and the limits of interfaces between interconnected zones.

In general, neighbouring jurisdictions are not modelled since the focus of the EAA is to determine Ontario's energy self-sufficiency. However, where firm contracts for sales or purchases exist, these are modeled as exports from or imports to a particular zone or intertie point. The energy model conducts a least-cost optimization to determine energy production over a 1 day optimization window, while respecting the thermal limits of transmission lines and transformers, the power flow limits of interfaces between transmission zones, technical limitations of each resource, and other imposed system limitations.

5.1.1 EAA Generation Methodology

In this section, the modelling of resources by fuel type in the EAA will be described in detail. These properties are updated annually unless otherwise specified. For each generation unit modelled, the installation and retirement dates are specified. Other data such as operational constraints, energy limitations, EFORd of thermal units and planned maintenance requirements, determined based on historical and/or market participant submitted information, are included depending on the generation type.

When modelling generator forced outages, a single pattern of forced outages for each thermal unit covering the entire Reliability Outlook period is selected from among a large number of candidates using a convergent Monte Carlo technique that pre-filters statistically unlikely outage patterns.

5.1.2 Combustion and Steam Units

The dispatchable gas, and oil generators, whether combustion or steam units, are modelled using a set of capacity and ramping properties, as well as price-quantity (PQ) pairs derived from historical offer data. Capacity properties establish the bounds of the dispatch whereas the heat rate equations or PQ pairs determine generator production cost.

The capacity properties are consistent with those used in capacity assessments. The Minimum Run Time (MRT), Minimum Loading Point (MLP) and ramping properties were created from market participant submitted data.

The dependencies between gas and steam units for CCGT (Combined Cycle Gas Turbine) are also modelled.

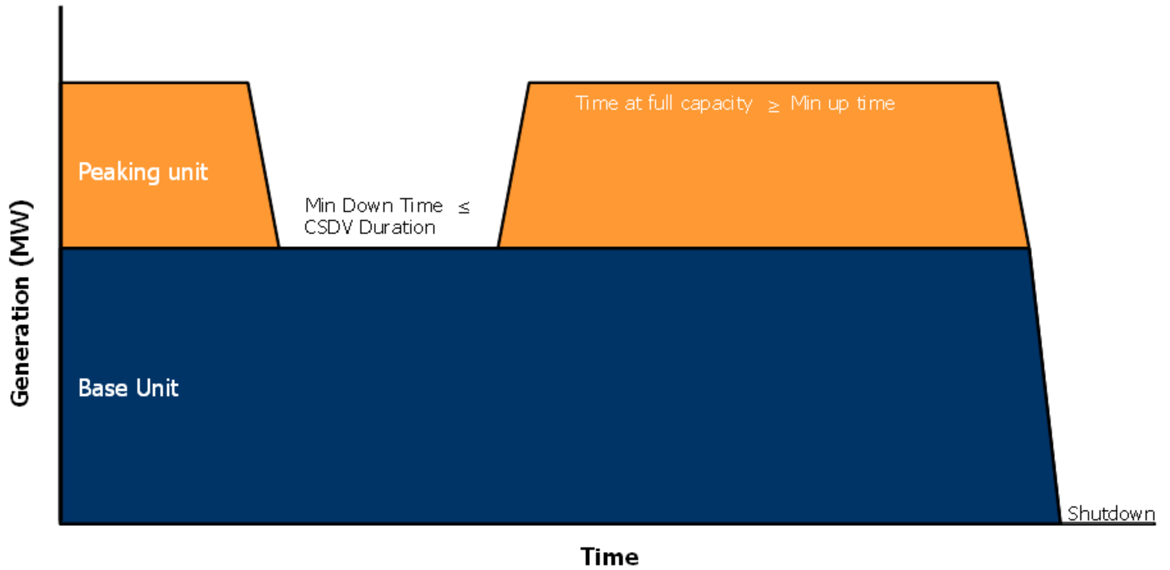
Non-dispatchable generators are modelled using a unit rating based on market participant submitted data.

5.1.3 Nuclear

Nuclear units are modelled using a set of capacity, ramping and operational properties. The capacity properties are consistent with those used in capacity assessments. Ramping limits are based on market participant information as well as empirical data.

Nuclear units have a flexible dispatch based on PQ pairs, ramping properties, and operational properties such as minimum up time and minimum loading points where applicable. See **Figure 5-1** for an illustration on how nuclear units can get dispatched.

Figure 5-1 | Nuclear Manoeuvring Unit Dispatch Illustration



5.1.4 Biofuel

Biofuel units are modelled using a unit rating and either a fixed profile or a set of price-quantity pairs: non-dispatchable units are assigned a fixed monthly or hourly production schedule based on historical market data, while dispatchable units are assigned hourly price/quantity pairs derived from historical market data.

5.1.5 Hydroelectric

Hydroelectric generators are modelled as energy-limited resources, since the hydroelectric production is limited by the amount of water available, and through the use of PQ pairs derived from historical market offer datasets. There are two key components of modelling hydroelectric generators as energy-limited resources in the model: physical characteristics of individual units and capacity and energy limitations of each unit or groups of units that belong to a region (Ontario wide) or zone (such as Northwest). These limitations (constraints) exist in the hourly, daily and monthly timeframes.

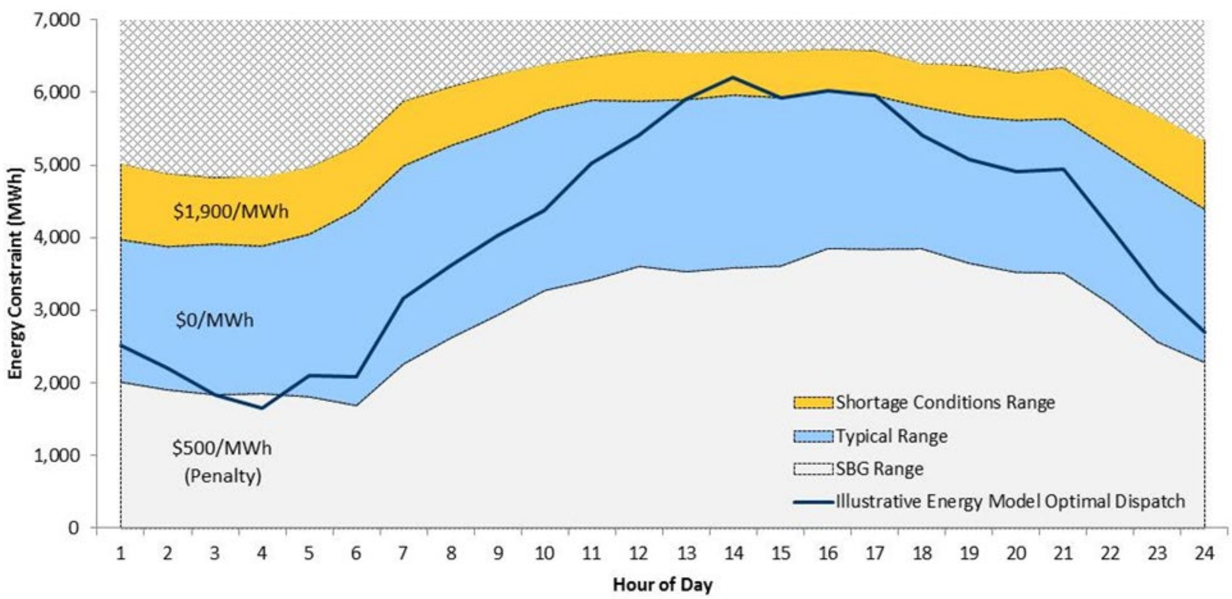
The hydroelectric run-of-the-river component for baseload units is must-run to ensure the energy model schedules this element. The dispatchable component of each unit is dispatched based on system needs and hydroelectric zonal or regional constraints.

In order to create the required unit capacity properties, historical production and operating reserve data from market opening to current is utilized. These properties are created to model seasonal, monthly and hourly trends.

Within a region or zone, hydroelectric generators do not all simultaneously peak to full capacity even when the need arises, therefore constraints are established for groups of generators to create a realistic dispatch. These constraints are created to simulate hydroelectric production during different system conditions and are based on observed hourly and daily energy upper and lower limits as well as monthly historical median hydroelectric production data from market opening to present. If future system configurations are not reflected in the historical dataset, changes to these constraints can be made in order to correctly forecast hydroelectric capability.

Figure 5-2 shows an illustrative energy modelling solution for the entire hydroelectric fleet (Ontario wide) within the established hourly constraints. In this example, the total hydroelectric production in hour ending 4 is constrained by the hourly minimum and penalized at $500/MWh for each MW below the threshold. In hour ending 14, the dispatch is constrained by the upper limit and costs $1,900/MWh yet cannot ever exceed the orange band, as that is a hard constraint. Although not visible in **Figure 5-2**, the total hydroelectric production in that day is also constrained by a daily energy limit, preventing the model from scheduling up to the maximum hourly capacity in all hours of the day, which would create an unrealistic dispatch. Finally, the total monthly production on the unit and fleet wide level cannot exceed a preset maximum based on historical trends.

Figure 5-2 | Hydroelectric Solution for a Particular Weekday vs. Hourly and Daily Energy Constraints

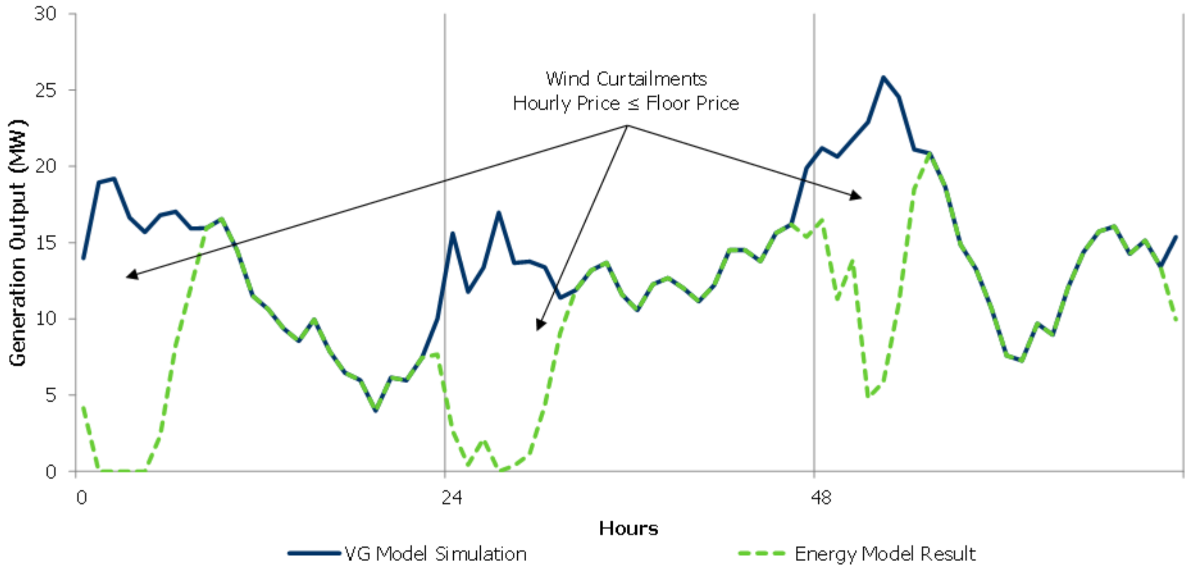


5.1.6 Wind

Wind resource output is highly random in nature and is therefore difficult to forecast beyond 48 to 72 hours. Therefore, in order to model wind capability, production profiles were simulated for Ontario's wind resources using an AWST dataset. Each existing site is mapped to a simulated site based on proximity in order to create this hourly capability profile.

The derived wind profiles represent the available wind energy at each site and wind dispatch in the energy model is constrained to match the simulated profile unless the particular wind facility is dispatched down or off in accordance with the applicable floor price as per Market Manual 0.4.3 | Operation of the Real-Time Market. See **Figure 5-3** for an illustrative example.

Figure 5-3 | Wind Simulation versus Energy Model Dispatch for a Particular Unit



5.1.7 Solar

Similar to wind resource modelling, a production profile is simulated using historical weather data. Each existing site is mapped to a simulated site based on proximity in order to derive capability profiles for each generator.

The derived solar profiles represent the available solar energy at each site and solar dispatch in the energy model is constrained to match the simulated capability profile unless the particular solar facility is dispatched-off in accordance with the applicable floor price as per Market Manual 0.4.3 | Operation of the Real-Time Market.

5.1.8 Storage

Storage battery resources are modelled using a capacity capability, a charge and discharge rate as well as having a maximum of 1-cycle per day. They are currently assumed to take 4 hours to charge and discharge with a variety of efficiency factors. These facilities will be re-evaluated once they reach in-service status with their actual production data once sufficient data becomes available.

5.1.9 Demand Measures

In addition to the capacity considerations previously described for modelling demand measures, the energy model more precisely represents the availability window of each of the demand measures.

The energy model also includes bid prices for demand response and dispatchable loads. This additional information is used by the simulation software to "activate" these resources as required in a manner approximating program rules.

5.1.10 EAA Demand Forecast Methodology

The energy adequacy assessment uses a median monthly normalized demand forecast as described in section 2. This forecast is selected from the simulated demand output by selecting the simulation that most closely captures a median monthly peak demand and median energy demand. This demand forecast includes transmission losses and incorporates the impacts of embedded generation and conservation (see section 2.2 Demand Forecast Drivers). The variance in demand due to weather volatility is not explicitly modelled as part of the EAA.

5.1.11 EAA Network Model

In assessments where a detailed nodal representation of Ontario's transmission system is required, a PSS/E[6] basecase is imported into the energy model to appropriately capture the properties and limitations of transmission elements. Specifically, using the imported PSS/E basecase, the thermal ratings of individual lines and transformers and other electrical parameters (such as resistance and reactance) are modelled. Furthermore, transmission upgrades expected over the assessment horizon are incorporated into the energy model with their respective planned in-service dates. The network model is updated periodically as required.

An optimal power flow (OPF) is performed on an hourly granularity as part of the energy simulation with the resultant dispatch subject to the operating security limits (OSL) of the network as well as the physical and operational limits of resources.

Key assumptions incorporated into the development of the transmission model are:

- Thermal limits of all transmission elements operated at 50 kV level and higher are utilized;
- Planned transmission outages are modelled based on Market Participant submitted information. Only outages for lines at a voltage level of 115 kV and higher and with a duration of five days and longer are considered;
- Operating security limits[7] of all major internal interfaces are explicitly modelled. Appropriate reductions to OSLs of major interface brought about by specific transmission outage are captured;
- Interconnection transfer capability between Ontario and neighbouring jurisdictions is assumed to be zero except when firm purchases and sales are modelled or when the benefits of non-firm transfers are being assessed;
- Transmission losses are not explicitly modelled, as losses are already accounted for in the demand forecast; and
- Unplanned outages of transmission element are not modelled.

In assessments where a zonal representation of Ontario's transmission system is used with all resources within a zone connected to a single node within that zone. Interface limits between zones are also modelled and these limits are adjusted as required to account for the impacts of planned outages on the transmission network or future system upgrades within the assessment period.

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[6] Power System Simulator for Engineering (PSS/E) is a software tool used for simulating, analyzing, and optimizing power system performance.

[7] Operating security limits are used to ensure system stability, acceptable pre-contingency and post contingency voltage levels and acceptable thermal loading levels.

5.1.12 Forecast of Energy Production Capability

In addition to the energy modelling results, the forecast energy production capability of Ontario generators is calculated on a month by month basis for IESO Reliability Outlook. Monthly energy production capabilities for the Ontario generators are calculated by the IESO. These forecasts account for fuel supply constraints, energy limitations, and both scheduled and forced outages, as well as deratings.

6 Transmission Adequacy Assessment

For the IESO Reliability Outlook, the principal purpose of the transmission adequacy assessment is to forecast any reduction in transmission capacity brought about by specific transmission outages. For a major transmission interface or interconnection, the reduction in transmission capacity due to an outage condition can be expressed as a change in the base flow limit associated with the interface or interconnection. Another purpose of the transmission adequacy assessment is to identify the possibility of any security-related events on the IESO-controlled grid that could require contingency planning by Market Participants or by the IESO. As a result, transmission outages for the period of the IESO Reliability Outlook are reviewed to identify transmission system reliability concerns and to highlight those outages that could be rescheduled.

The assessment of transmission outages will also identify any resources that may potentially be constrained off due to the transmission outage conditions. Transmitters and generators are expected to have a mutual interest in developing an ongoing arrangement to coordinate their outage planning activities. Transmission outages that may affect generation access to the IESO controlled-grid should be coordinated with the generator owners involved, especially at times when generation Reserve Above Requirement values are below required levels. The IESO reviews the integrated outage plans of generators and transmitters to identify situations that may adversely impact the reliability of the system and to notify the affected participants of these impacts.

The transmission outage plan for the period under study is extracted from the IESO's outage management system.

Ultimately, the focus of the transmission adequacy assessment for the IESO Reliability Outlook is to determine any reductions in transmission interface or interconnection capacity due to outages, and determine the impact of those reductions on reliability.

The criteria for highlighting significant outages and major transmission projects in the Reliability Outlook report are applied solely for reporting purposes. Outages are included in the report if they both reduce interface transfer capability by more than 33% of its limit and have a duration longer than three months. Major transmission projects are included in the report if they are a new 230 kV or 500 kV transmission line. These thresholds ensure that the report presents developments with a material and sustained impact on system capability for stakeholder awareness. Additional information on transmission outages and projects can be found in the Reliability Outlook Data Tables.

This section describes the methodology used to assess the transmission outage plan. The zones, interfaces and interconnections are described in the Transfer Capability Methodology document.

6.1 Assessment Methodology for the 18-Month Period

6.1.1 Transmission Outage Plan Assessment Methodology

The outage plan is filtered to contain only outages for transmission facilities with voltage levels of 115 kV and higher and with a duration of five days and longer. These outages are then sorted and grouped into tables, one table for each zone and one table for external interties. The following items are listed for each outage, with the first three items having been provided by transmitters:

- Start and finish dates;
- Outage transmission station element or elements;
- Recall time;
- Description of outage impact to IESO-controlled grid; and
- Reduction in the interconnection flow limits and/or major interface base limits (expressed in Megawatts).

The last two items are only provided if the outage affects an interconnection and/or major interface.

The planned transmission outages are reviewed in correlation with major planned resource outages and scheduled completion dates of new generation and transmission projects. This allows the IESO to identify transmission system reliability concerns and to highlight those outage plans that need to be adjusted. A change to an outage may include rescheduling the outage, reducing the scheduled duration or reducing the recall time as per the processes described in IESO Market Manuals[8].

This assessment will also identify any resources that have potential or are forecast to be constrained due to transmission outage conditions. Transmitters and generators are expected to develop ongoing arrangements and processes to coordinate their outage planning activities. Transmission outages that may affect generation access to the IESO-controlled grid should be coordinated with the generator operators involved, especially at times when a deficiency in reserve is forecast. Under the Market Rules, when the scheduling of planned outages by different market participants conflicts such that both or all outages cannot be approved by the IESO, the IESO will inform the affected market participants and request that they resolve the conflict. If the conflict remains unresolved, the IESO will determine which of the planned outages can be approved according to the priority of each planned outage as determined by the Market Rules.[9]

The IESO assigns confidentiality classification to all the elements associated with an outage based on confidentiality requirements of Market Participants' data. The outages that have one or more transmission elements classified as confidential are excluded from the published tables. More information on Ontario's ten zones, major transmission interfaces and interconnections with neighbouring jurisdictions are available in the Transfer Capability Assessment Methodology document.

Generally, assessments identify areas of the IESO-controlled grid where the projected extreme weather loading is expected to approach or exceed the capability of the transmission facilities for the conditions forecast in the planning period. In these situations there can also be an increased risk of load interruptions.

[8] IESO Market Manual, System Operations, Part 0.7.3: Outage Management

[9] IESO Market Rules, Chapter 0.5 | Power System Reliability, Sections 6.4.13 to 6.4.20

The IESO works with Ontario transmitters to identify the highest priority transmission needs, and to ensure that those projects whose in-service dates are at risk are given as much priority as practical, especially those addressing reliability needs for peak demand periods of the Reliability Outlook. The IESO's planning group identifies the transmission enhancements' location, timing and requirements to satisfy reliability standards.

7 Resource Adequacy Risks

The forecast reserve levels should be assessed bearing in mind the risks discussed below.

7.1 Severe Weather

Peak demands in both summer and winter typically occur during periods of severe weather. Unfortunately, the occurrence and timing of severe weather is impossible to accurately forecast far in advance. The impact of severe weather was demonstrated in the first week of August 2006, when Ontario established an all-time record demand of 27,005 MW. Over 3,000 MW of this demand was due to the higher than average heat and humidity.

In order to capture the impact of weather volatility on forecast reserve levels during the first 18 months, reserves were calculated using a distribution of peak demand. While the probability of severe or extreme weather occurring in every week is very small, the probability of an occurrence in any given week is greater (about 3 percent). When one looks at the entire summer or winter periods, the expectation of at least one period of severe weather becomes very likely.

The lower reserve levels, under higher levels of demand illustrates that circumstances could arise under which reliance on a combination of non-firm imports, rejection of planned generator maintenance or emergency actions may be required.

Since we have started using probability distributions for demand, severe weather and periods of high demand have been incorporated into the risk probabilistically and are no longer weather scenario based.

7.2 New Facilities

The firm supply scenario considers the existing installed resources, their status change such as retirements and shutdowns over the Reliability Outlook period and resources that reached commercial operation. On top of this, the planned supply scenario assumes that all new resources are available as scheduled. The capacity assumed for new resources is the greater of the contracted capacity, or where facilities have begun the market registration process, the capacity submitted to the IESO as part of their registration. The risk of new facilities having a delayed connection to the system is also accounted for in the 18 month horizon.

7.3 End of Life of Generation Facilities

Generation retirement risks are accounted for in the 18 month horizon in the two resource scenarios. In both the firm and planned supply scenarios, all resources are assumed to be available unless there is a confirmed retirement/refurbishment.

7.4 Generator Planned Outages

A number of large generating units perform their maintenance in the spring and are scheduled to return to service from outage prior to summer peak. Meeting these schedules is critical to maintaining adequate reserve levels. Delays in returning generators to service from maintenance outages could lead to reliance on imports and/or cancellation of other planned generator outages.

Information from the Reliability Outlook directly feeds into the IESO’s Outage Management process. Outages are assessed against the firm resource simulation that captures a weekly peak demand distribution up to 3 standard deviations below and above the mean. Up to 2,000 MW of import capability may be relied upon in the summer and up to 1,000 MW of import capability may be relied upon in the winter, therefore outages on resources (both transmission and generation) that affect resource availability beyond the estimated imports to Ontario are at risk of being rejected, revoked or recalled. Events that reduce Ontario’s ability to import power such as outages on interties, internal system constraints, and conditions of neighbouring jurisdictions will be considered, and the import assumption is adjusted accordingly between zero and two thousand megawatts.

7.5 Forecast of Generator Availability

IESO resource adequacy assessments include a probabilistic allowance for random generator forced outages of thermal generators. Along with weather-related demand uncertainty, the impact of random generator forced outages is included in the determination of required resources.

7.6 Forecast of Hydroelectric Resources

The amount of available hydroelectric generation is greatly influenced both by water-flow conditions on the respective river systems and by the way in which water is utilized. In order to capture hydroelectric variability hydroelectric distribution parameters are modelled within the Required Reserve calculation.

7.7 Forecast of Wind Resource

There is a risk that wind power output could be less than the forecast values, therefore wind distribution parameters are included in the required reserve calculation.

7.8 Capacity Limitations

There is a risk that any given generator may not be capable of producing the maximum capacity that the market participant has forecast to be available at the time of peak demand. There may be several reasons for these differences. Independent of the best efforts of generator owners to maintain generator capability, there are sometimes external factors which may impact the capability to produce.

Some outages and deratings, such as environmental limitations and high ambient temperature deratings, may be more likely to occur at roughly the same time as the extreme weather conditions that drive peaks in demand.

For example, there are risks that gas-fired generators may not be capable of producing the maximum capacity that the market participant has forecast to be available at the time of peak. The natural gas and electricity sectors are converging as natural gas becomes one of the more common fuels in North America for electric power generation. The IESO is jointly working with the Ontario gas transportation industry to identify and address issues.

7.9 Transmission Constrained Resource Utilization and Other Considerations

Transmission constraints may occur more often than expected due to multiple unplanned outages and may also have greater impact than expected on the ability to deliver generation to load centres. This is particularly true for large transformers whose repair or replacement time can be much longer than for transmission lines. Although many transmission limitations are modelled in accordance with recognized reliability standards, limitations resulting from multiple forced transmission outages can have significant impacts on resource availability.

Another key factor impacting outage management is the amount of extended forced transmission outages. With more overlapping and urgent outage requests, operating the power system is becoming increasingly difficult. Prioritizing the timely repair of a forced outage is necessary to reduce the impact on the delivery of other ongoing capital projects, and to enable other necessary maintenance outages to proceed.

Constraints may also occur due to weather conditions that result in both high demands and higher than normal equipment limitations. For example periods of low wind combined with hot weather not only cause higher demands but also result in lower transmission capability. This can affect the utilization of internal generation and imports from neighbouring systems at critical times. Transmission constraints that result from loop flows can be particularly hard to predict because they result not only from the conditions within Ontario but from the dynamic patterns that are taking place within and between other areas. Depending on the direction of prevailing loop flows, this may improve or aggravate the ability to maintain reliability.

During high demand periods, the availability of high-voltage capacitors and the capability of generators to deliver their full reactive capability also become critically important for controlling voltage to permit the higher power transfers that are required. Outages or de-ratings to these reactive resources can restrict power transfer from generators and imports, and make it difficult to satisfy the peak demands.

In considering the possibility of equipment failure, tighter supply conditions and other factors such as supply chain delays, further outage co-ordination or rescheduling may be required. Transmitters and generators are strongly encouraged to plan ahead, co-ordinate with one another, submit outage requests early, and co-ordinate with the IESO. Scheduling outages at desired times may be difficult due to the significant number of major projects that are planned for the same time. Furthermore, outages are not guaranteed as unanticipated equipment failures may change reliability assessments.

One important aspect of grid equipment outages is recall time. Recall times indicate how long it takes for equipment on outage to return to service. Minimizing recall times increases the likelihood of outages being approved. If many outages are non-recallable, it can be difficult to accommodate an additional outage to repair a critical equipment failure as there needs to be a reliable plan to reposture the system. If multiple equipment failures occur, there may be instances where outage management alone will not address the concern. Under such circumstances the IESO may need to rely on additional non-firm imports or emergency operating procedures in order to ensure reliability. More information on actions the IESO can take to ensure reliability can be found in the Market Manuals.[10]

The calculated values at the time of weekly peak for transmission constrained generation presented in the IESO Reliability Outlook Tables correspond to a generation dispatch that would maximize the possible reserve above requirements in Ontario. However, in real time operation, the actual amount of bottled generation will depend on many conditions prevailing at the time, including the local generation levels, overall generation dispatch and the direction and levels of flows into and out of Ontario. Electricity supply from some baseload generation sources may have to be decreased during times when transmission constraints and tight supply conditions prevail.

[10] IESO Market Manual, System Operations, Part 0.7.1: IESO Controlled Grid Operating Procedures

8 Glossary of Terms and Acronyms

This glossary provides definitions for acronyms and technical terms used in the Reliability Outlook Methodology.

Allocated Quantity of Energy Injected (AQEI): The measured energy injected into the grid by a generator, used for settlement and adequacy calculations.

Connection Assessment and Approval (CAA): IESO process for evaluating and approving new or modified connections to the grid.

Combined-Cycle Gas Turbine (CCGT): A facility that combines gas and steam turbines for higher efficiency.

Capacity on Outage Probability Table (COPT): A table showing cumulative probabilities of generator outages, used in reserve requirement calculations.

Demand Response (DR): the reduction of energy consumption at a facility or set of facilities through Load Reduction, use of behind-the-meter generation, or other commercially available technology that is capable of reducing the energy consumption from the IESO-controlled grid.

Equivalent Forced Outage Rate on Demand (EFORd): 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.[11]

Hourly Demand Response (HDR): a load facility registered under a demand response market participant which is providing hourly load following to the IESO.

Industrial Conservation Initiative (ICI): Ontario program that reduces peak demand by incentivizing large consumers to curtail load during system peaks.

Independent Electricity System Operator (IESO): Entity responsible for managing Ontario's power system and administering markets.

Loss of Load Expectation (LOLE): Reliability metric representing the expected number of days per year when load cannot be met (NPCC criterion: ≤0.1 days/year).

Load and Capacity Model (L&C): IESO tool for weekly resource adequacy assessments using probabilistic and deterministic reserve calculations.

Market Rules (MR): The rules made under Section 32 of the Electricity Act, 1998, together with all market manuals, policies, and guidelines issued by the IESO, as may be amended from time to time.

Maximum Continuous Rating (MCR): Maximum output a generator can sustain under normal conditions.

Minimum Loading Point (MLP): The lowest output level at which a generator can operate stably.

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[11] IEEE Power Engineering Society. (2007). IEEE 762 Standard Definitions for Use in Reporting Electric Generating Unit Reliability Availability and Productivity. Definitions, 3.

Minimum Run Time (MRT): The minimum time a generator must remain online once started.

North American Electric Reliability Corporation (NERC): Organization that develops and enforces reliability standards for the bulk power system.

Northeast Power Coordinating Council (NPCC): Regional entity responsible for reliability coordination in Northeastern North America, including Ontario.

Optimal Power Flow (OPF): Mathematical optimization to determine the most efficient dispatch of resources subject to system constraints.

Operating Security Limits (OSL): Transmission interface limits required to maintain system reliability under normal and contingency conditions.

Power System Simulator for Engineering (PSS/E): software tool used for simulating, analyzing, and optimizing power system performance.

Reserve Above Requirement (RAR): Difference between available resources and required resources for reliability. Negative values indicate elevated risk.

Solar Capacity Contribution (SCC): Expected contribution of solar generation during peak demand hours, expressed as a percentage of installed capacity.

Time-of-Use Rates (TOU): Electricity pricing that varies by time of day to influence consumption patterns.

Wind Capacity Contribution (WCC): Expected contribution of wind generation during peak demand hours, expressed as a percentage of installed capacity.

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