Independent Electricity Market Operator

Methodology to Perform Demand Forecasts, Resource Adequacy Assessments and Transmission Adequacy Assessments

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1.0 Introduction

This document describes the methodology used to perform the Ontario demand forecast, and the associated resource and transmission adequacy assessments for the 18-Month Outlook and the 10-Year Outlook. Over time, the methodology may change to reflect the most appropriate approach to complete the Outlook process.

2.0 Demand Forecasting Methodology

2.1 Demand Forecasting System

The Ontario electricity demand is the sum of coincident loads plus the losses on the IMO-controlled grid. Ontario demand does not include loads that are supplied by embedded generation nor those excluded from the IMO-controlled grid.

The IMO utilizes a forecasting system developed in conjunction with Regional Economic Research. The system utilizes multivariate econometric equations to estimate the relationships between energy and peak demand and a number of analytical factors or drivers. The drivers that the system includes are weather effects, economic data and calendar variables. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. Several calibration routines within the system ensure the integrity of the forecast with respect to energy and peak demand, and zonal and system wide projections.

The forecasting system produces the following output:

- 20-minute peak demand;
- hourly energy demand by zone;
- load forecast uncertainty presented in MW but representing one standard deviation in the underlying weather elements.

For the purpose of analysis several weather scenarios and economic scenarios are utilized. The Base Case demand forecast is generated using the Median economic forecast in conjunction with Normal weather. An explanation of the weather scenarios – Normal and Extreme – follow in Section 2.3: Weather Scenarios. Economic scenarios are only used in the 10-Year Assessment process.

2.2 Demand Forecast Drivers

Consumption of energy is modeled using three sets of forecast drivers: calendar variables, weather effects and economic conditions. Each of these drivers is embedded in the forecasting system and each plays a role in shaping the results.

Calendar variables include the day of the week and holidays, both of which impact energy consumption. Generally, electricity consumption is higher during the week than on weekends and there is a pattern determined by the specific day of the workweek. Holidays act much like weekends, in that energy consumption is lower on holidays. The reason for this relationship is that industrial load is lower on holidays and weekends as fewer facilities are operating.

Hours of daylight are key in shaping peak demand. For example, after the sun has set, electricity demand is higher due to the need for electric lighting. This is particularly important in winter when sunset coincides with increases in load associated with cooking load and return to home activities. Hours of daylight are included with calendar variables since forecasting both is very straightforward.

Weather effects include measures of temperature, cloud cover, wind speed and dew point. Both energy and peak demand are weather sensitive. The length and severity of a season's weather contributes to the level of energy consumed and acute weather conditions usually underpin the seasonal peaks.

For purposes of the demand forecast, weather is not forecasted but weather scenarios based on historical data are utilized in place of a forecast of weather. Load Forecast Uncertainty (LFU) is used as a measure of the impact that variations in weather have on demand. It should be recognized that for resource adequacy assessments, a Normal weather forecast is used in conjunction with LFU to consider a full range of peak demands that can occur under various weather conditions with a varying probability of occurrence.

Economic conditions contribute to growth in both energy and peak demand. To produce a demand forecast, an economic forecast of various drivers is required. A consensus of four major, publicly available provincial forecasts is utilized to generate the economic drivers used in the model. The two key drivers are Ontario employment and Ontario housing stock, both of which contribute to the demand for energy.

For the 10-Year forecasts, longer-term economic forecasts are required. Since publicly available forecasts usually cover two years, there is a requirement for economic forecasts for year three and beyond. To fill this void, Statistics Canada Population Projections are used to derive economic variables for the latter part of the forecast.

In addition to the Median Growth scenario, High and Low Growth scenarios are generated. The High Growth scenario is based on historical economic data - that which exhibited the strongest growth - high growth population projections and increased penetration of electric end-uses. The Low Growth scenario embodies historical recession data in the first few years of the forecast and is then based on the low growth population projections.

2.3 Weather Scenarios

Weather scenarios are constructed on a weekly basis, starting on Monday and ending on Sunday. For each year of historical weather data the observations are divided up into weeks. The first week of the year is the first week with the majority of its days in the new calendar. Therefore, the earliest the first week could start would be December 29th and the latest would be January 4th. Starting with week 1, each of the daily observations are sorted from highest to lowest within each week for the entire 30-year weather history.

The Normal weather is simply the average of the 30-year history. Using temperature as an example, the average of the coldest day in Week 1 for each year from 1972 through to 2001 will become the coldest day of Week 1 of the Normal weather scenario. The average of the next coldest day for each year of Week 1 will become the second coldest day of Week 1 of the Normal weather scenario. This is repeated for all of the days in all of the weeks, resulting in a Normal weather year. For summer values, the hottest days would be averaged to determine the hottest days within the Normal weather scenario.

For the Extreme weather scenario, the historical data is ranked as with the Normal weather. However rather than taking the average of the ranked data, the Extreme weather scenario is based on the maximum values for the summer and the minimum values for the winter. In this way, the Extreme scenario will contain the most severe historical conditions for each week. This approach is adopted to acknowledge the fact that although the probability of observing a once in thirty year event is small for each week, the chance of getting a once in thirty year event over the course of the year is significantly higher. For example, within the Extreme weather scenario the most severe weather days in each of the 52 weeks can be attributed to one of the 30 years of history. In doing so, 25 out of the total of 30 years of weather history would account for at least one weekly "peak" weather day.

The Normal and Extreme weather are mapped to individual weekdays in a conservative approach to ensure that peak maximizing weather would not be masked by weekends or holidays. This allows for more consistent inter-week comparison and produces a smoother weekly profile.

Load Forecast Uncertainty (LFU) is used to account for the uncertainty associated with the variability of weather. LFU represents the variation in peak demand based on one standard deviation in the weather inputs. Unlike the weather scenarios, which are derived to provide point forecasts under different weather conditions, LFU is used to develop distributions of possible outcomes around those point forecasts. For example, actual weather has a 50/50 probability of being higher or lower than the Normal weather scenario. For the weekly peak plus the LFU, actual weather would have roughly an 85/15 chance of being lower/higher than the Normal weather plus uncertainty that underpins the forecast. The Extreme weather scenario does not directly translate into probabilistic terms since it is based on severe historic weather conditions. However, the Extreme weather scenario approximates the Normal weather forecast plus two standard deviations in the weather elements. The exact probability one can associate with the Extreme weather scenario varies by week. In some weeks the Extreme weather value lies outside of two standard deviations, whereas in other weeks it lies within two standard deviations. This is not illogical in that for any given week, as history may have provided an unusual weather episode that will not be surpassed for many years, whereas another week may not have encountered an unusual weather episode.

2.4 Updating the Demand Forecasting System

There are several tasks that are carried out on a regular basis as part of demand forecasting activities.

- The weather scenarios are updated on an annual basis. The aim is to do this prior to each 10-Year forecast.
- 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. This is not problematic as long as the system is stable, which it is.

3.0 Resource Adequacy Assessment Methodology

This section describes the criterion, tools, and methodology the IMO uses to perform resource adequacy assessments. In Section 3.1 the NPCC resource adequacy criterion is described, as provided in the NPCC "Document A-2 Basic Criteria for Design and Operation of Interconnected Power Systems". Sections 3.2 and 3.3 briefly describe the L&C and MARS software tools, and the way they are used in the resource adequacy assessment process. Section 3.4 describes the methodology used to assess energy production adequacy.

3.1 Resource Adequacy Criterion

The IMO uses the following NPCC resource adequacy criterion to assess the adequacy of resources in the Ontario control area:

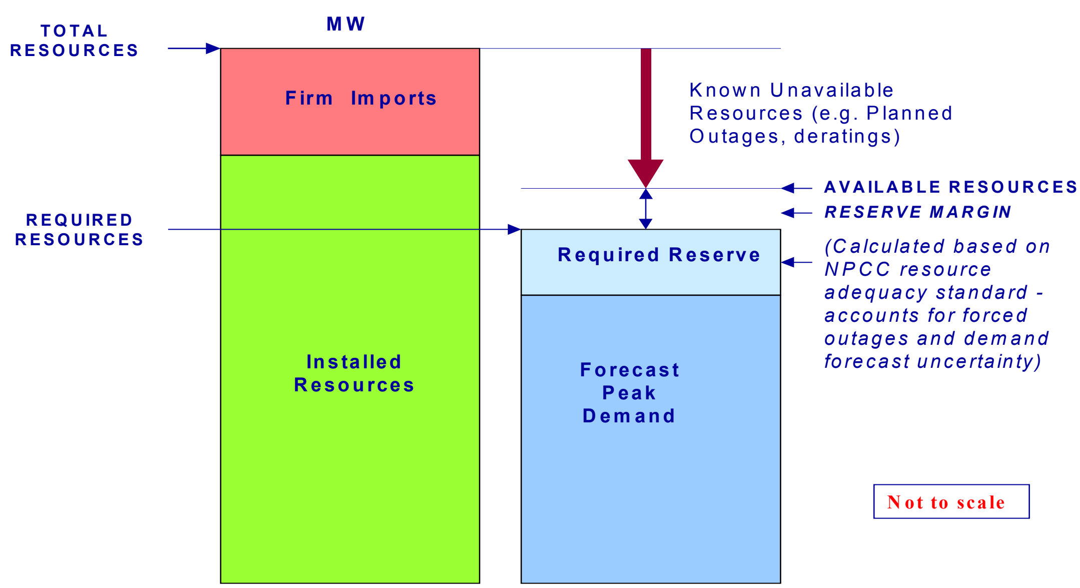
"… resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years ".

The IMO reports on resource adequacy relative to an NPCC-accepted variation of this criterion, which considers a Loss of Load Expectation of not more than 0.1 days per year.

3.2 Required Reserves

Reserves are required to ensure that the forecast demand can be supplied with a sufficiently high level of reliability. The amount of Required Reserve to meet the requirements of the NPCC resource adequacy criterion is calculated on a week-by-week basis, as described in Section 3.2.1.

Figure 3.1 Reserve Margin



The Required Resources are the amount of resources needed to supply the peak demand and meet the Required Reserve, as shown in Figure 3.1, and the Reserve Margin is the difference between Available Resources and Required Resources.

It should be noted that the Required Reserve is a planning parameter. In day to day operation the available resources must cover the demand plus the Operating Reserve, which for Ontario is about 1,350 MW, depending on the size of the largest generating units in service.

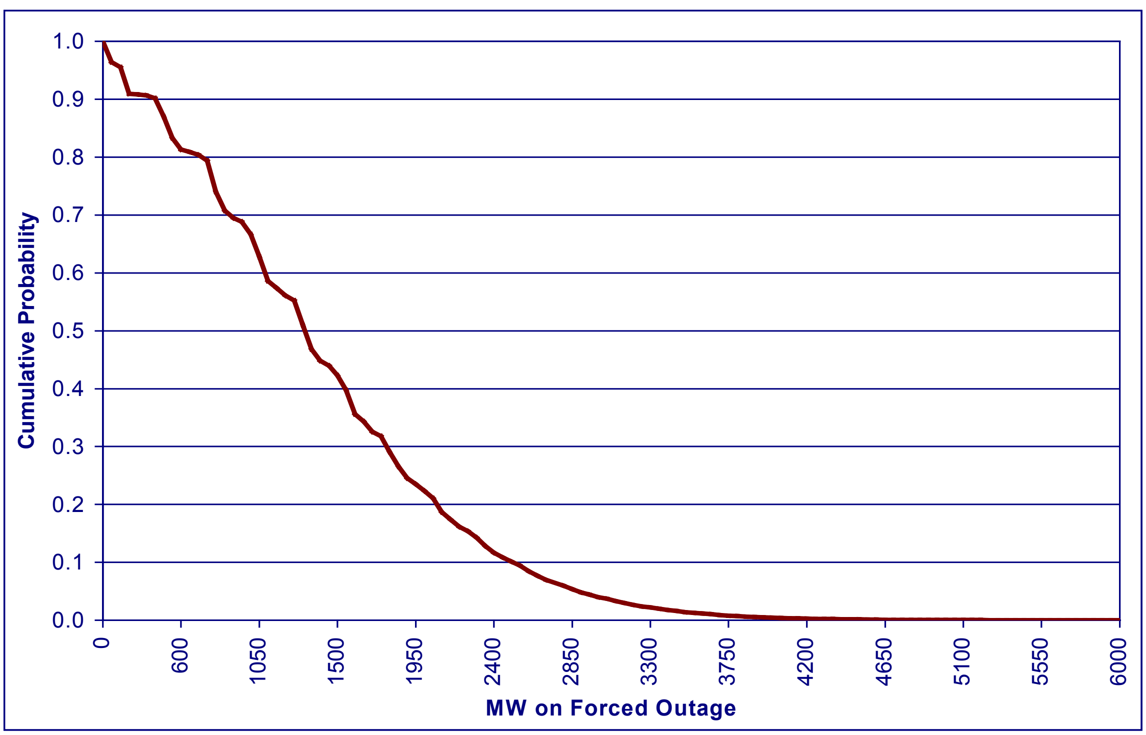
3.2.1 Load and Capacity Model

The IMO uses the Load and Capacity (L&C) model to determine the Required Reserves from week to week. Each thermal generating unit's maximum continuous rating (MCR), hydroelectric dependable capacity, planned outages, deratings, and forced outage rates, as well as the demand forecast and its uncertainty are inputs to the model. A resource adequacy criterion equivalent to an annual loss of load probability (LOLP) of 0.1 is used to determine the Reserve Requirement for each week of the planning year. The program uses the 'direct convolution' method to calculate the weekly Reserve Requirement.

The probabilistic calculation of the Required Reserve for each planning week is performed as follows:

Based on the generating units MCR and forced outage rates, a Capacity on Outage Probability Table (COPT) is built, in which the cumulative probabilities of having various amounts of generating capacity on forced outage are determined and stored. A graphical example is shown in Figure 3.2.

Figure 3.2 Capacity on Outage Probability Table – Graphical Example



In the Load and Capacity model, a normal distribution of demand values around the mean demand value is assumed, as described in Section 3.2.2. The Required Reserve calculation is executed in an iterative manner. In each iteration, an amount of Generation Reserve is assumed and an associated $LOLP_{CALC}$ is derived, convolving the LFU corresponding to the 20-minute peak demand value with the Capacity on Outage Probability Table. The iterative process is repeated with small changes to the assumed Generation Reserve until the $LOLP_{CALC}$ becomes equal or less than the target. When this condition becomes true, the assumed level of Generation Reserve equals the Required Reserve necessary to meet the reliability target.

The adequacy of the available resources to meet the demand over the study period can then be assessed, in a deterministic calculation, as shown in Figure 3.1. For each planning week, the minimum level of Available Resources is determined, starting with the total resources then subtracting generator deratings, planned and long term unplanned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity. The minimum level of Available Resources is calculated on the "maximum outage day", which is the day with the maximum amount of unavailable generating capacity in that planning week, although the weekly 20-minute peak does not always occur on the maximum outage day. The Reserve Margin is then obtained by subtracting the Required Resources (equal to 20-minute peak demand plus the Required Reserve) from the Available Resources.

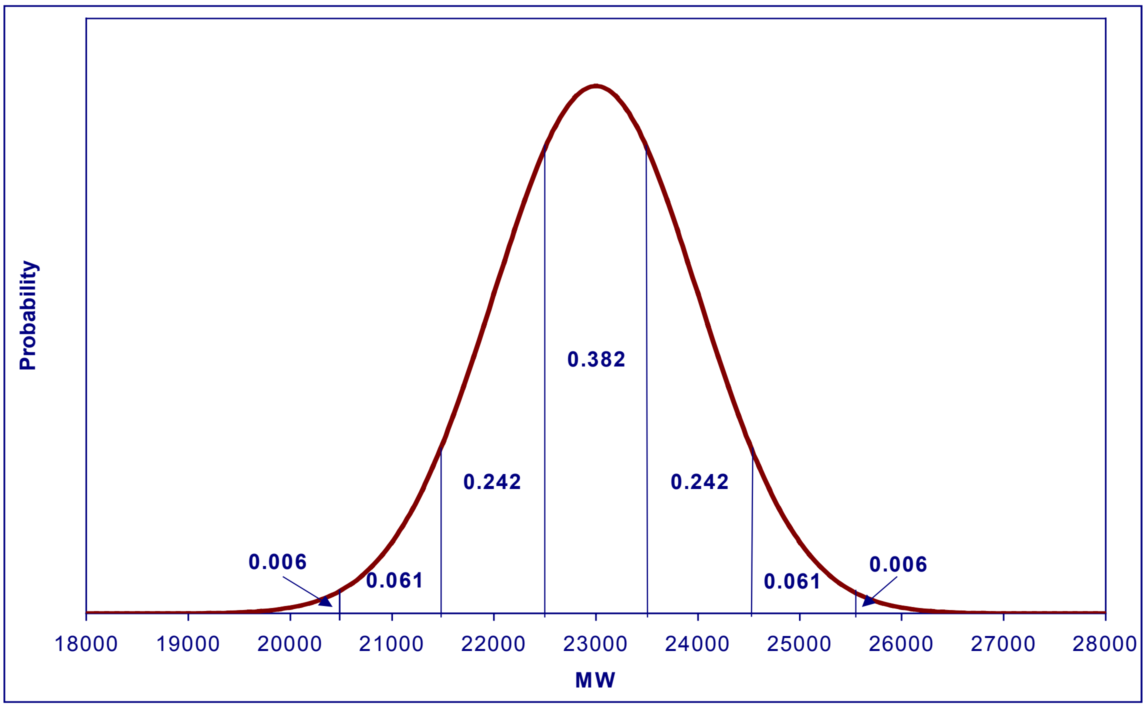
It should be noted that negative Reserve Margins in some weeks do not necessarily mean a violation of the NPCC resource adequacy criterion. They only mean possible higher risk levels for the respective weeks. Whenever negative Reserve Margins are identified, the possible control actions to restore the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

3.2.2 Representation of Demand and Its Uncertainty Due to Weather

The L&C program requires weekly 20-minute 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 modeling purposes, the total demand is assumed to be supplied, and is included in the peak demand forecast when the Required Reserve is probabilistically 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. A value of 300 MW is estimated, based on past operational experience. The IMO expects to be in a better position to forecast the future price responsive demand levels as Market Participant registration progresses and market experience is gained.

The Load Forecast Uncertainty (LFU) for each week, due mostly to weather swings, is represented by the associated standard deviation, assuming a normal probability distribution. This data is obtained from 30-year weather statistics and is updated annually. The weather-related standard deviation varies between about 2% and 7% through the year. For each weekly 20-minute peak demand, as the mean value, and its LFU, as the standard deviation, the model builds a multi-step approximation of the normal distribution. Subsequently, in the Required Reserve calculation for each planning week, not only the mean value of the peak demand is included, but also a range of peak demand values, ranging from mild to extreme demand values. Figure 3.3 illustrates a seven-step example of such an approximation, using a weekly 20-minute peak value of 23,000 MW and an associated LFU value of 1,000 MW. In this example, the peak values considered in the Required Reserve calculation would range from 20,000 MW to as high as 26,000 MW. Consequently, the calculated Required Reserve 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, by averaging the impact of the peak demand values around the forecast mean value, weighted by their associated probabilities of occurrence (shown in Figure 3.3 under the curve).

Figure 3.3 Seven-Step Approximation of Normal Distribution - Example



3.2.3 Representation of Generation Resources

Unit Ratings

Thermal generating units are assumed to be capable of operating at a level equal to their normal Maximum Continuous Rating (MCR) or as otherwise identified to the IMO. Hydroelectric station peak outputs are based on one hour sustainable capability determined from about 30 years of record; these values are provided by the generation plant owners. The peak and energy output of all combustion turbines varies considerably with changes in ambient air temperature and, hence, both summer and winter capacity values are included.

Forced Outage Rates of Generating Units

Derating-Adjusted Forced outage rates that are used for each unit reflect both forced outages and periods of derated output. The values are provided by the generation plant owners, based on past experience modified to reflect forecast improvements from maintenance activities or declines due to age or need for repair.

3.2.4 Representation of Interconnected Systems

There are five interconnected systems that could provide additional resources to supply Ontario, namely, New York, Michigan, Quebec, Minnesota and Manitoba. The Ontario total coincident import capability is approximately 3,900 MW.

In the probabilistic calculation of reserve requirements, the interconnected systems are modeled as fictitious generators having forced outage rates assigned. Therefore, the calculated Required Reserve levels take into account the potential need for external generating capacity.

At the deterministic calculation stage, Available Resource values include external purchases that are backed by firm contracts. The inclusion of only firm purchases in the assessment represents a conservative assumption. Therefore, whenever reserves are lower than required, the necessary level of assistance from neighbouring systems is estimated as a possible control action. The confidence level in the availability of such an assistance level is also assessed, using past operational information, as well as latest load and capacity reports issued by the neighbouring jurisdictions, in which forecast levels of spare capacity are included.

3.2.5 Representation of the Transmission System

The IMO-controlled grid consists of a robust southern grid and a sparse northern grid. The northwestern part of the northern grid has limitations, which potentially limit the use of generation capacity. The total amount of generation limitations depends on the load and resource levels. The operation of some 25-hz generation in Niagara zone is limited by frequency changer capability. Also, as new generation projects materialize, the relatively large generation capacity additions in the West zone of the system would cause the operation of some West zone generation to be limited at times, because of the NBLIP transmission interface limitation. The amount of generation limitations varies with the demand level and the amount of total generating capacity in the West zone. All generation limitations are subtracted from the Available Resources when calculating the Reserve Margins.

3.3 Multi-Area Reliability Simulation (MARS) Approach

The GE Multi-Area Reliability Simulation (MARS) program allows the reliability assessment of a generation system composed of a number of interconnected areas and/or zones that can be grouped into pools. The Ontario electricity system has been modeled as a pool composed of ten zones. Figure 4.1.1 provides a pictorial depiction of Ontario's ten zones.

3.3.1 MARS Model

A sequential Monte Carlo simulation forms the basis for MARS. In this simulation, chronological system histories are developed by combining randomly generated operating histories for the generating units with inter-zone transfer limits and hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules that govern system operation.

Various measures of reliability can be reported using MARS, including the Loss of Load Expectation (LOLE) for various time frames.

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for various reliability indices. These values can be calculated both with and without load forecast uncertainty (LFU). The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates LOLE values and can estimate the expected number of times various emergency operating procedures will be implemented in each zone and pool.

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

3.3.2 Representation of Demand and Its Uncertainty Due to Weather

The MARS program requires mean hourly load data, as well as a monthly standard deviation (SD), for each zone modeled. The reliability indices are calculated at each load level around the mean value (mean, mean $\pm$ SD, mean $\pm$ 2SD, mean $\pm$ 3SD), as well as the average indices.

Hourly loads for each of the ten Ontario zones are modeled, for the study period, and a seven-step normal distribution is calculated for each of the ten zone loads. A graphical example is provided in Figure 3.3, in Section 3.2.2.

3.3.3 Representation of Generation Resources

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

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

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

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

3.3.4 Representation of Interconnected Systems

The five interconnected systems that can provide assistance to the Ontario system are modeled as areas external to the Ontario pool (composed of the ten zones).

Neighbouring systems are modeled as external areas with constant hourly loads of 1 MW. In each of these external areas a dummy generator is modeled, which has a variable capacity up to the amounts expected to be offered into the Ontario market. The expected capacity values are based on past operational experience and latest load and capacity reports issued by the respective system operators, with the limitations outlined in Section 3.3.5.

3.3.5 Representation of the Transmission System

The transmission system between interconnected zones can be modeled through transfer limits on the interfaces between pairs of zones. Also, transfer limits on groups of interfaces can be defined. The transfer limits are specified for each direction (positive and negative) of the interface and are changed monthly if necessary. Random forced outage rates are modeled on the interfaces in the same manner as the outages on thermal units, through the use of state transition rates. The amount of assistance deficient zones will receive from zones with excess resources is limited by the transfer limits on the interfaces.

All transmission interfaces between the ten zones within Ontario pool are modeled as they are defined in System Control Orders (SCO). Seasonal base limits are implemented for each interface. The tie lines with the neighbouring systems are modeled, along with their seasonal transfer limits, taking into account the total Ontario import capability. Therefore, the amount of external capacity available to Ontario at any moment will not exceed the total tie lines transfer capability. No random outages are modeled on the interfaces.

3.4 Adequacy Assessment of Energy Production Capability

The adequacy of the energy production capability is assessed on a month-by-month basis. For each month in the study period, the forecast energy demand is compared with the energy production capability of the generators in Ontario and the energy-backed, firm purchase contracts with external jurisdictions. Monthly energy production capability values for the Ontario generators are provided by their owners or operators. They account for fuel supply limitations, scheduled and forced outages and deratings, environmental, regulatory and citizenship restrictions.

The monthly amount of generation limitations due to transmission constraints is subtracted from the total monthly available energy.

The need for additional energy, from outside Ontario, is assessed if the energy demand in a month exceeds the energy production capability of the above mentioned resources.

4.0 Transmission Adequacy Assessment Methodology

4.1 Assessment Methodology for the 18-Month Outlook

For the 18-Month 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 is to identify the possibility of any security-related events on the IMO controlled grid that could require contingency planning by Market Participants or by the IMO. As a result, transmission outages for the period of the 18-Month Outlook are reviewed to identify transmission system reliability concerns and to highlight those outages that could be rescheduled.

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 IMO controlled-grid should be coordinated with the generator owners involved, especially at times when generation reserve margins are below required levels. The IMO reviews the integrated 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.

During the transitional period prior to Market opening, an 18-Month rolling outage plan is submitted by Hydro One Networks to the IMO on a monthly basis. Section 4.1.1 describes the methodology used to assess the transmission outage plan.

4.1.1 Transmission Outage Plan Assessment Methodology

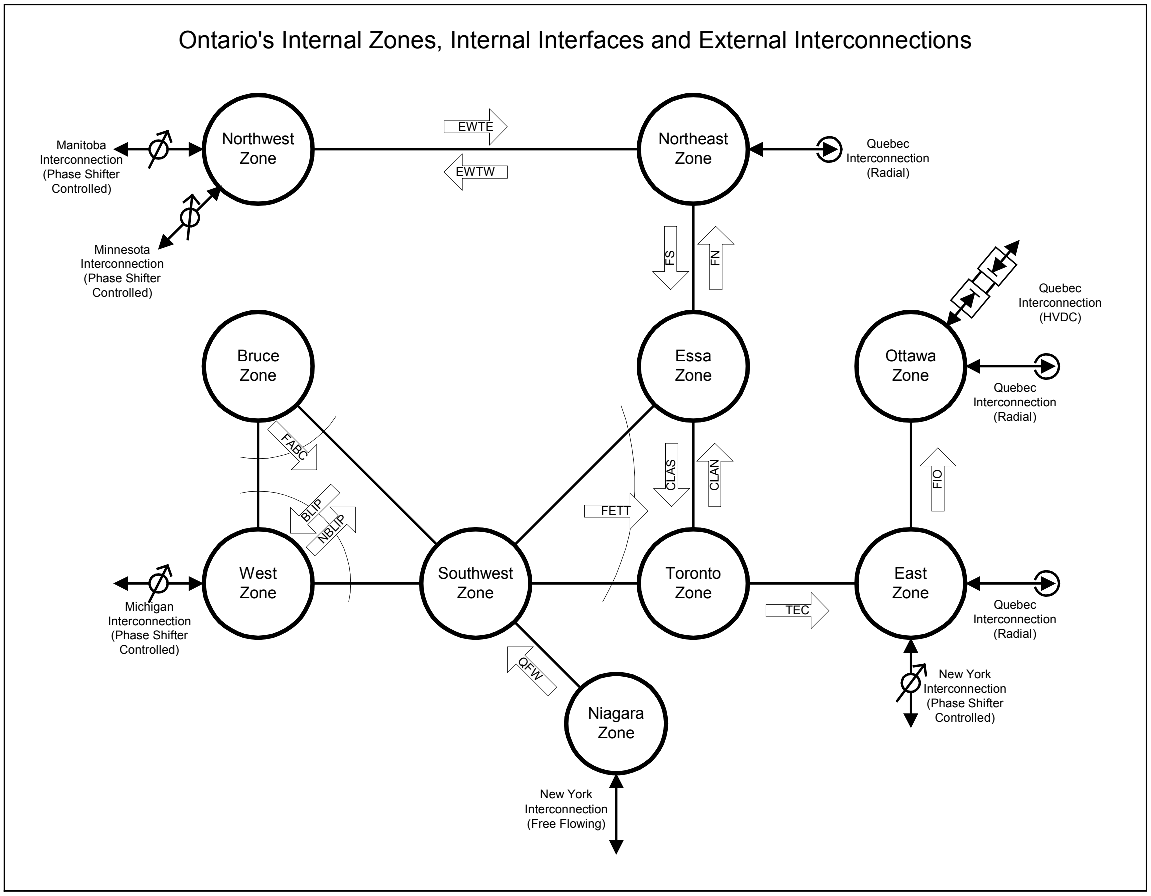
The outage plan is filtered to contain only outages for transmission facilities with voltage levels of 115 kV and higher and with a duration longer than five days. These outages are then sorted and grouped into tables, one table for each zone. The following items are listed for each outage, with items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

1) Start and finish dates,
2) Description of outaged transmission element or elements,
3) Outage type (DNW - Daily Not Weekends; DWW - Daily With Weekends; CNW - Continuous Not Weekends; CWW - Continuous With Weekends),
4) Recall time,
5) Description of outage impact to IMO-controlled grid, and
6) Reduction in the interconnection flow limits and/or major interface base limits (expressed in Megawatts).

Items 5 and 6 are only provided if the outage affects to an interconnection and/or major interface. For these outages, if the recall time is greater than 36 hours and if the limit is penalized greater than 10%, there is an additional assessment, as required, to indicate the potential for constrained generation, the impact on generation reserve requirements and any local minimum generation requirements.

Figure 4.1.1 provides a pictorial depiction of Ontario's ten zones, major transmission interfaces and interconnections with neighbouring jurisdictions.

Figure 4.1.1 Ontario's Zones, Interfaces, and Interconnections



4.2 Assessment Methodolgy for the 10-Year Outlook

An annual transmission adequacy assessment is undertaken as part of the 10-Year Outlook process. The overall assessment provides input to relevant standards authorities, with respect to their responsibilities for reviewing the status of reliability within each control area. Transmission adequacy assessment is based on the need to ensure that sufficient transmission capability is available to deliver power to demands in conformance with NPCC or other applicable system security criteria. The assessment also may provide input to market participant and connection applicants with respect to long-term planning and investment decisions.

The assessment may identify the potential need for IMO-controlled grid investments or other actions by market participants to maintain reliability of the IMO-controlled grid and to permit the IMO-administered markets to function efficiently. The assessment also provides input to the

IMO Board, the OEB and the Ontario Government regarding projected transmission adequacy. The conclusions and recommendations contained in the 10-Year Outlook are available for use in proceedings before the OEB or other governmental or regulatory authorities with responsibilities for reviewing proposals to construct generating or transmission facilities.

Another purpose of the transmission adequacy assessment is to identify transmission interfaces that have the potential to become congested and thus reduce market efficiency.

Changes to transmission adequacy may occur over time, due to a combination of factors such as load growth, changes to generation capability, transmission equipment reliability, and the overall transmission facility configuration and operation.

To perform the overall assessment of transmission adequacy, there are a number of assessments with narrower focus that can be considered. Assessments of supply reliability, voltage support adequacy, and congestion all contribute to the overall transmission adequacy assessment. In addition, a summary of the assessments of the impact of proposed new generation and transmission projects is provided.

Supply reliability assesses the capability of transmission between specific zones of Ontario, and assesses how generation can be adequately transmitted from the generation sources to the loads, to assess to what extent loads in Ontario can be supplied reliably, under various scenarios with existing and planned facilities. Supply reliability is considered for specific defined zones of Ontario, and for certain specific local areas. The present Outlook does not completely assess the adequacy of all of the 115 kV transmission supply in the IMO-controlled grid, nor does it completely address the adequacy of transmission supply to all local areas in the province. The absence of these assessments in this Outlook does not imply that deficiencies in these areas do not exist. Future 10-Year Outlooks will attempt to more fully assess all significant areas of the province.

Voltage support adequacy assesses the extent to which voltage levels on the IMO-controlled grid are expected to be maintained within acceptable ranges.

Congestion studies assess to what extent transmission interfaces are expected to be utilized, and is considered to be one measure of market efficiency.

4.2.1 Models for Transmission Adequacy Assessment

The zones within Ontario that are specifically modeled in the Outlook studies are shown in Figure 4.1.1. These zones are defined in an attempt to specifically model the interfaces that are most likely to be limiting for an enduring period of time. As time progresses, some new limits may become more limiting, while other limits may become less limiting. However, changes to the interfaces that are modeled must be carefully considered.

In addition, load flows may be completed for selected years of the Outlook period. The specific years that are studied are selected to try to identify when there may be potential voltage problems and where there is a possible risk of violation of existing operating security limits. The conditions under study are intended to stress the power system.

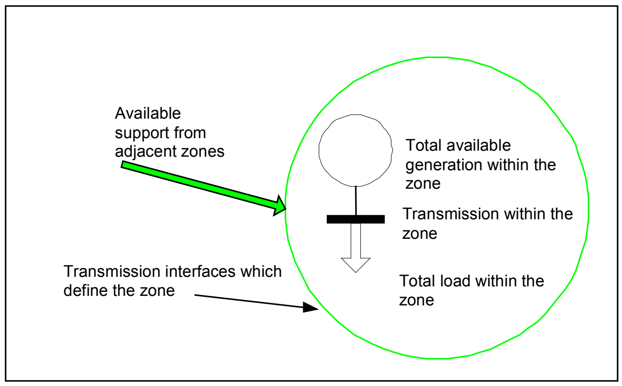
Transmission adequacy can be assessed assuming various resource availability scenarios. The assessments made may assume various different resource availability scenarios, and may consider both existing operable generation and new generation projects that have been identified to the IMO under the Connection Assessment and Approval (CAA) Process.

4.2.2 Supply Reliability Assessment

4.2.2.1 Zonal Supply Reliability Assessment

The assessment of area supply reliability within each of the defined transmission zones is based on the conceptual model shown in Figure 4.1.

Figure 4.2 Conceptual Reliability Model of a Transmission Zone



In testing the extent to which available support from adjacent zones may be required and available in the future, several assumptions are made, in selecting the input conditions for the model. These input conditions are intentionally selected to stress the need for support from adjacent zones. They represent conditions that were used in the past, in the design of the Ontario transmission system and in the design of supply to local load areas. Generally, such input conditions have a low probability of occurrence and are not typical conditions. Nevertheless, these assumptions are considered appropriate for purposes of assessing the reliability of the transmission system because stress conditions can occur from time to time.

The need for support from an adjacent transmission zone is greatest when the zone under study has a relatively low supply of resources from within. For each resource scenario, a low supply of resources is simulated by removing the two largest units within a zone from service. This condition can occur when one of the largest units is on planned outage, and another unit becomes forced out of service, for example. All other generation is assumed to be operating at installed capacity. For some zones, where there is a high concentration of hydroelectric units, a low supply of resources in each resource scenario is better represented by assuming no hydroelectric production. For example, in the Northeast zone analysis, nighttime conditions are studied since current operating practice is to operate the hydroelectric generation output at a minimum and the need for support from outside the zone is the highest at off-peak times. A combined analysis of the Northwest and Northeast zones during nighttime conditions is also performed.

For these studies, transmission interface limits within a zone are ignored, and the transmission system within the zone is assumed to be adequate to supply all demands within the zone, and any generation within a zone is assumed to be available at the zone interface(s).

Using the Median Growth, Extreme Weather scenario, the summer peak demand for each transmission zone is used in the assessment. For the nighttime scenarios, the demand values were scaled down to represent off-peak conditions.

The available support from adjacent zones is determined as follows. For the zone under study, available generation and demand within the zone are set at the levels described above and the amount of generation surplus or deficiency for each zone is calculated. Surplus generation within zones is then "transported" to deficient zones, to the extent possible, while respecting the operating security limits associated with the interfaces that define zonal boundaries. Most interface limits are independent of summer or winter conditions, except for the Queenston Flow West (QFW) and Flow East Towards Toronto (FETT) interfaces. Since summer peak demands are used in the analyses, summer limits are used for the QFW and FETT interfaces. These summer limits on these interfaces are more restrictive than their associated winter limits. The FETT interface limit is also varied according to the number of Nanticoke units and large generating units east of FETT that are in-service.

Each transmission zone is studied for selected years of the Outlook period, in search of the scenarios that result in the lowest zone margin, or periods when there is a deficiency within zones. A summary is presented to show the periods when the margin is the lowest, or where there is a deficiency, in the years that have been specifically studied.

4.2.2.2 Contingency-Based Supply Reliability Assessment

In addition to examining the specific zones of Ontario defined by major transmission interfaces, supply reliability of certain transmission facilities of the IMO-controlled grid is evaluated by considering the impact of specific contingencies on the load supplied. The contingencies that are assessed include faults or outages to any transformer, double circuit line, bus or any two cables in the same trench. Based on each contingency the resulting impact on load levels is estimated by considering the extent to which load is interrupted, and the duration of such interruption. In general, the greater the load affected, the shorter the duration of the interruption is desired. The most reliable area supply is one in which continuous supply to the load continues, despite the contingency. For other contingencies, it is recognized that load may be restored after a period of time to allow for switching operations to occur. Depending on the size of the load affected by the contingency, and on what type of contingency has occurred, various switching times can be expected.

The intention of this assessment is to provide a common starting point for evaluating the supply reliability of local areas. The IMO recognizes that further discussions with transmitters is required to establish a supply reliability standard or criteria for local areas in the IMO-controlled grid.

4.2.3 Congestion Assessment

Transmission flows are determined by the pattern of loads and generation, and the characteristics of the transmission system at any given time. Each of these factors is inherently somewhat unpredictable due to the effect of random forced outages on generation and transmission facilities and the effect of weather on load levels. With the opening of the Ontario Electricity Market, an additional level of uncertainty is added because bid and offer prices, rather than traditional economic dispatch principles, will determine the dispatch of generation. Without any history of market operation, congestion on the Ontario transmission system is very difficult to forecast with any degree of accuracy. If additional generation is added to appropriate points on the system in future years, the level of system flows would generally be expected to reduce and congestion would tend to be relieved. Conversely, if too much generation is added to a transmission zone, it could increase the level of system flows on the connecting transmission transfer interface, thereby, creating congestion. The incorporation of additional transmission capacity on the interface would alleviate this problem.

The conditions under which congestion is expected are identified, with any assessment of the percent of time such conditions are expected to occur. In general, the amount of congestion, the frequency, and the duration will depend on specific bid and offer conditions within Ontario, and the level of transactions between Ontario and the surrounding jurisdictions. For various scenarios, various levels of congestion occur. Various changes to generation, demand, or transmission can change the frequency, duration and/or magnitude of congestion. Various changes that could be made to the system to can be identified by the IMO or by any transmitter or market participant.

The congestion assessment is performed using two approaches. The first approach takes a ‘snapshot’ of possible flows on the major interfaces. The second approach uses the GE MARS software program. Both approaches attempt to test tests the flexibility of various transmission interfaces to transfer power for generators who want to maximize their generation output in response to market prices.

4.2.3.1 ‘Snapshot’ Congestion Methodology and Assumptions

Assuming a high supply of resources (all generators in-service) in various resource scenarios, the Ontario electric system model is “stressed” separately from the north, west and east relative to the load center in the Toronto zone, which is generally deficient in generation.

In each analysis, demand levels were set at 80% of the winter peak demand levels from the Median Demand Growth, Normal Weather scenario to reflect an off-peak demand level, which represents circumstances for which high congestion is expected. For each year and scenario studied, the total operable generation in each transmission zone is used, based on the specific resource availability scenarios under study.

Base transmission interface limits, assuming all elements in-service, were used for assessing congestion on the transmission interfaces. Local transmission interface limits within a zone were ignored, but it should be recognized that these local limits could reduce the actual amount of generation available at the zone interface(s).

Similar to the supply reliability assessment methodology, the available generation and demand within the zone are set at the levels described above and the amount of generation surplus or deficiency for each zone is calculated. Surplus generation within a zone is then “transported” to adjacent zones relative to the load center in the Toronto zone, to the extent possible, while respecting the operating security limits associated with the interfaces that define zonal boundaries.

4.2.3.2 MARS Congestion Methodology and Assumptions

The GE MARS software package can also be used to perform an assessment of transmission congestion. A more complete description of the MARS software can be found in Section 3.3 of this document.

The MARS software methodology expands on the snapshot approach to consider not one demand level, but the entire hour by hour variation in demand over the period studied. Hourly demand values, under the Median Demand Growth, Normal Weather Scenario, are used.

The MARS approach also considers the variable capability of generating units, as determined by generating unit ratings, energy production capabilities, the unit outage schedule, and transition rates of the generating units, in a fully sequential Monte Carlo simulation.

Scenarios are created in an attempt to stress the capability of specific transmission interfaces, to give an indication of the extent to which such interfaces are capable of accommodating these higher than normal flow conditions. Such scenarios are not expected to be typical conditions.

All the generators in one zone of the system are removed from service (e.g. in Toronto zone in Figure 4.1.1). This artificially creates a need for generating capacity to be transferred from other zones of the system. In these other zones the generating capacity availability pattern is determined by MARS, using the Monte Carlo simulation.

To create the greatest stress on specific transmission interfaces, only a subset of transmission interfaces are modeled to be in service. (For an assessment of the interfaces supplying Toronto, these include FABC, NBLIP, QFW, and the Southwest to Toronto interface. These interfaces are shown in Figure 4.1.1). All other interfaces are removed from service. Consequently, any surplus generating capacity can only be transferred to the deficient zone through the selected interfaces that remain in-service in the study scenario.

Base transmission interface limits, assuming all elements in-service, are used for assessing congestion on the transmission interfaces. Local transmission interface limits within a zone are ignored, but it should be recognized that these local limits could reduce the actual amount of generation available at the zone interface(s).

The output results of this simulation are annual interface flow summaries that provide an indication to the degree to which these transmission interfaces would be able to transfer all generating capacity surplus at any time, under these extreme study conditions.

4.2.4 Steady State Voltage Support Adequacy

Steady state voltage support adequacy assesses the extent to which voltage levels on the IMO-controlled grid are expected to be maintained within acceptable ranges.

Appendix 4.3, Reference #1 of the Ontario Market Rules require that “connected wholesale customers and distributors connected to the IMO-controlled grid shall operate at a power factor within the range of 0.9 lagging to 0.9 leading as measured at the defined meter point”. However, it may be necessary to dispatch the power system such that some defined meter points will be operated at a power factor greater than 0.9 lagging in order to satisfy the minimum continuous voltage requirements as identified in Appendix 4.1, Reference #2 of the Market Rules.

Using the High Growth, Extreme Weather Demand Scenario at summer peak conditions, the assessment identifies those transmission zones and the associated power factor required for the whole zone in order that the minimum continuous voltage requirements of the IMO-controlled grid are met. Load flow studies under various resource scenarios are conducted for specific years that capture the various demand, generation and transmission conditions that are likely to stress the Ontario electricity system. For each study, a 0.9 lagging power factor is assumed as the starting power factor for each transformer station defined meter point within a zone. If the minimum voltage requirements within a zone cannot be met, the power factor at each defined meter point is increased until the minimum voltage requirements are met. These study scenarios are also completed using various assumptions related to the level of imports or exports that may stress the power system. The extent to which the problems will arise will depend on the percent of time such conditions will occur in the future.

4.2.5 Zone Assessments

General assessments relating to current and future concerns are provided for specific transmission zones.

4.2.6 Impact of Proposed New Generation and Transmission Projects

The impact to the IMO-controlled grid for projects that are identified in the Connection Assessment and Approval (CAA) process are summarized in the 10-Year Outlook. Complete details can be obtained at the IMO web site www.theIMO.com under the "Services – Connection Assessments" web page.