Methodology to Perform Long Term Assessments

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Caution and Disclaimer

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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.

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2.0 Demand Forecasting Methodology

2.1 Demand Forecasting System

The 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 generators that are registered to participate in the IESO-administered markets, plus the imports into Ontario, minus the exports from Ontario. Ontario Demand does not include loads that are supplied by embedded generation. The IESO forecasting 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 a forecast of hourly demand by zone. From this forecast the following information is available:

- 60-minute peak demand;
- 60-minute minimum demand;
- 60-minute coincident and non-coincident peak demand by zone;
- energy demand by zone.

Utilizing various weather scenarios, the following information is also generated:

- load forecast uncertainty (LFU) presented in MW and representing one standard deviation in the underlying weather elements;
- expected seasonal peak.

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 Weekly Normal weather. An explanation of the weather scenarios follow in Section 2.3: Weather Scenarios. Multiple economic scenarios are only used in the 10-Year Assessment process.

A quantity of price-sensitive demand is also forecast based on market participant information and actual market experience.

2.2 Demand Forecast Drivers

Consumption of electricity 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 (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 however, weather effects over a year tend to be offsetting resulting in a minimal net impact. Acute weather conditions usually underpin the seasonal peaks.

For purposes of the Ontario 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 Weekly Normal weather forecast is used in conjunction with Weekly 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 peak and energy 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 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 defined by two principle concepts - the normalization period and the method of selecting values from that normalization period. The normalization period refers to how weather data is grouped. For weekly resource adequacy assessments, the IESO uses demand values based on Weekly normalized weather, however the IESO also generates demand values based on Monthly and Seasonally normalized weather. In terms of the method of selecting values, we look at the minimum (Mild), the median (Normal), the median plus one standard deviation (Normal + 1 LFU) and the maximum (Extreme) weather impacts for each normalization period.

In order to gain a better understanding of the weather scenarios, it is best to look at how a scenario is developed. For this example we will look at the Monthly Normal weather for January.

The IESO uses 31 years of weather data to generate Normal weather scenarios. For each historical day, the daily weather can be converted into a "weather factor" based on wind, cloud, humidity and temperature conditions for that day. This weather factor represents the impact on electricity demand, in MW, given those weather conditions. Therefore, each day in January from 1973 to 2003 is converted into a number based on that day's weather. Then, within each month, the 31 days are ranked from highest to lowest. Next, the median value of the highest ranked days becomes the highest ranked day in the Normal month. The median value of the second highest ranked days becomes the second highest ranked day in the Normal weather. This is repeated until 31 Normal days are generated for January. This is depicted in Figure 2.1

Figure 2.1 Creating Monthly Normal Weather - January

					Year				
Rank	**1973**	**1974**	**1975**	**1976**	**2001**	**2002**	**2003**	**2004**	**Median**
1	4,791	4,427	5,569	**4,921**	5,219	4,985	5,321	4,857	4,921
2	4,395	4,393	5,482	4,705	4,989	4,822	5,317	4,522	4,764
3	4,373	4,310	5,201	4,517	4,850	4,285	4,845	4,383	4,450
4	4,272	4,057	4,912	3,994	4,799	4,255	4,292	4,081	4,264
5	4,042	4,002	4,703	3,971	4,630	4,126	4,291	3,847	4,084
26	2,179	2,413	2,987	2,206	2,457	2,685	2,068	2,451	2,432
27	2,168	2,099	2,892	2,174	2,348	2,441	1,934	2,447	2,261
28	1,807	1,954	2,821	1,840	2,344	1,797	1,680	2,173	2,344
29	1,770	1,952	2,644	1,775	2,330	1,756	1,366	2,125	1,863
30	1,692	1,902	2,345	1,402	2,180	1,558	1,185	1,803	1,747
31	1,394	1,788	2,009	1,202	1,893	**1,452**	1,111	1,692	1,452

The median number 4,921 corresponds to January 21st, 1976. Therefore, the "coldest" day in the Monthly Normal weather scenario for January is represented by the weather experienced on that date. Similarly, the mildest day in the Monthly Normal weather scenario for January is represented by January 4th, 2002.

This process is repeated for all the months of the year to finish generating the Monthly Normal weather. The process is the same for Seasonal and Weekly Normal weather. In order to generate the Extreme weather scenarios, the maximum value is taken rather than the median in the above example. Likewise, the Mild scenario is based on minimum values and the Normal + 1 LFU scenario is based on the median plus one standard deviation.

The demand values presented in the Outlook documents are based on Weekly normalization unless otherwise specified. Weeks start on Monday and end on Sunday. The first week of the year is that week which contains the first Thursday of the year, or, equivalently, contains January 4th.

Once the representative days are determined for the weather scenarios, they need to be mapped to the dates that are to be forecasted. The weather scenarios are mapped to individual days in a conservative approach ensuring 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.

The different normalization periods and values provide different probabilistic outcomes. Which weather scenarios are utilized depends on the purpose of the study being performed. Extreme weather scenarios would not be appropriate for an annual energy analysis as the probability of observing Extreme weather each week over an entire year is very unlikely. However, using Extreme weather to analyze the summer peak demand may be more appropriate as the likelihood of getting one day with "severe" conditions is much higher.

In conducting the weekly resource adequacy assessments in the 18-Month Outlook documents, demand forecasts based on Weekly Normal weather and Weekly Normal LFU is utilized. Load Forecast Uncertainty (LFU) is used to account for the uncertainty associated with the variability of weather. 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. The Weekly Normal weather and the associated LFU are therefore used on a probabilistic basis.

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 is approximately equal to the Normal weather forecast plus two standard deviations. The exact probability associated with the Extreme weather scenario varies by week, month or season. In some instances the Extreme weather value lies outside of two standard deviations, whereas in other cases it lies within two standard deviations. This is not illogical in that for any given week or month, history may have provided an unusual weather episode that will not be surpassed for many years, whereas another week or month may not have encountered an unusual weather episode.

2.4 Demand Response

Within the market, there exist programs that allow load participants the option to respond to price signals. Dispatchable Loads and the Transitional Demand Response Program are examples of these. In addition to these programs, there is an amount of responsiveness that would not be part of a formal program. This can occur in a number of forms, whether by monitoring the price of electricity and adjusting demand or through load shifting in order to avoid peak times.

In assessing the reliability of the electricity system it is necessary to develop a methodology to quantify the amount of demand response. Dispatchable loads or dispatchable demand represent the most significant portion of demand response. Of particular concern is the quantity of dispatchable demand that can be deemed dependable or the amount of dispatchable load that can be considered to be available to be dispatched off during peak conditions. This quantity is referred to as dependable demand response capability.

Based on historical data we calculate the dependable demand response capability percentage – the dispatchable loads offered into the market at peak times divided by the total amount of dispatchable demand on the system. This percentage is then applied to a projection of dispatchable demand, which is based on existing levels of dispatchable demand and incorporates information from market participants about their future intentions with respect to dispatchable loads. The dependable demand response capability is the product of the dispatchable demand projection and the historic percentage. The IESO updates both the projection and the percentage as part of the Outlook process.

2.5 Updating the Demand Forecasting System

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

- 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.

- The weather scenarios are updated to reflect the sensitivity of the system to weather conditions and to include the most recent weather data.
- A new economic forecast is generated for the economic drivers in the model

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

- End of Section -

3.0 Resource Adequacy Assessment Methodology

This section describes the criterion, tools, and methodology the IESO 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 Load and Capacity (L&C) and Multi Area Reliability Simulation (MARS) software tools, and the way they are used in the resource adequacy assessment process. Section 3.4 describes the methodology used to forecast the energy production capability.

3.1 Resource Adequacy Criterion

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

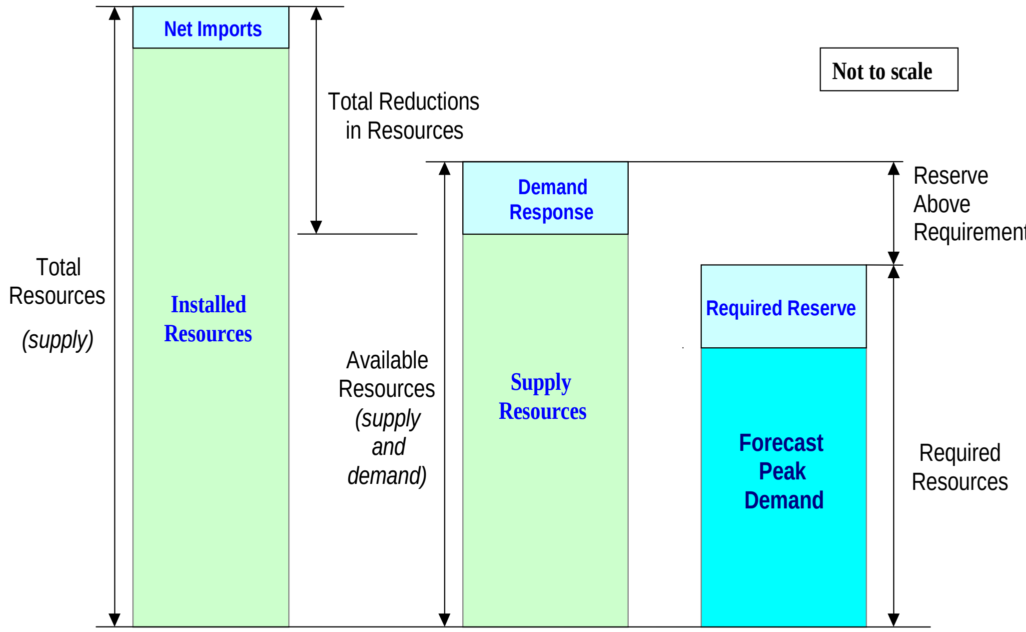
"… resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting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

The IESO 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 Ontario Demand can be supplied with a sufficiently high level of reliability. The amount of Required Reserve to meet the NPCC resource adequacy criterion is calculated on a week-by-week basis, as described in Section 3.2.1.

Figure 3.1 Reserve Above Requirement



The Required Resources are the amount of resources needed to supply the peak Ontario Demand and meet the Required Reserve. As shown in Figure 3.1, the Reserve Above Requirement is the difference between Available Resources and Required Resources.

The Required Reserve is a planning parameter that is at least as large as the amount required to meet the NPCC resource adequacy standard. In the mid-term planning horizon (beyond the next 33 days), a probabilistic approach is used, which considers the uncertainty associated with demand forecasts and generator forced outages. The value for Required Reserve from this approach is then compared with results from a deterministic calculation used for near-term planning (within the next 33 days). The Required Reserve reported for each period in the Outlook tables is the greater of the probabilistic or the deterministic values. These requirements are described in more detail in Section 3.2.1.

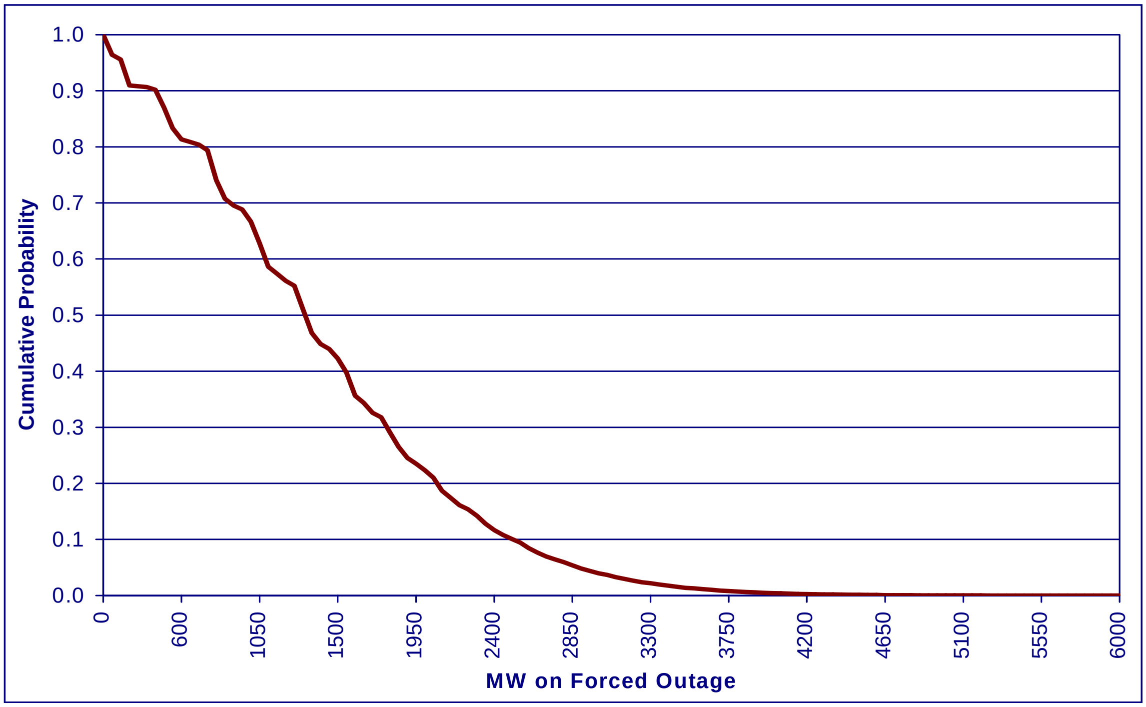
3.2.1 Load and Capacity Model

The IESO uses the Load and Capacity (L&C) model to determine the Required Reserve for each week in the study period. 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.

The weekly Required Reserve is the maximum of a deterministically and a probabilistically calculated reserve requirement.

A resource adequacy criterion equivalent to an annual 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 program uses the 'direct convolution' method to calculate the weekly probabilistic reserve requirement. Based on the generating units Maximum Continuous Rating (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 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 LFU corresponding to the 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 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.

The deterministic reserve requirement for each summer week is equal to the Operating Reserve (approximately 1,580 MW, depending on the size of the largest generating units in service) plus half the MCR of the largest available generating unit plus the absolute value of the load forecast uncertainty (LFU). The deterministic reserve requirement for each winter week is equal to the Operating Reserve (approximately 1,580 MW, depending on the size of the largest generating units in service) plus the MCR of the largest available generating unit plus the absolute value of the load forecast uncertainty (LFU).

The adequacy of the available resources to meet the demand over the study period can then be assessed, in an arithmetic calculation illustrated in Figure 3.1. 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 imports or exports into or out of Ontario (as identified by market participants to the IESO),
- and an assumed amount of price sensitive demand.

Under the present procedures in the Ontario market, there are no exports that are considered to continue if the Ontario non-dispatchable demand is not served. Therefore, the current Outlook does not include any exports from Ontario in the assessment of overall resource adequacy.

In the 18-Month Outlook report, reserve levels are presented without any imports assumed to be reliably available. For a specific outage assessment in the 18-month timeframe, the current procedures will consider that imports up to 700 MW may be considered available plus any imports that generators have confirmed they will make to support a planned outage request, according to the applicable market manuals.

The expected 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 peak does not always occur on the maximum outage day, such coincidence is assumed for the determination of Available Resources. The Reserve Above Requirement is then obtained by subtracting the Required Resources (equal to the peak demand plus Required Reserve) from the Available Resources.

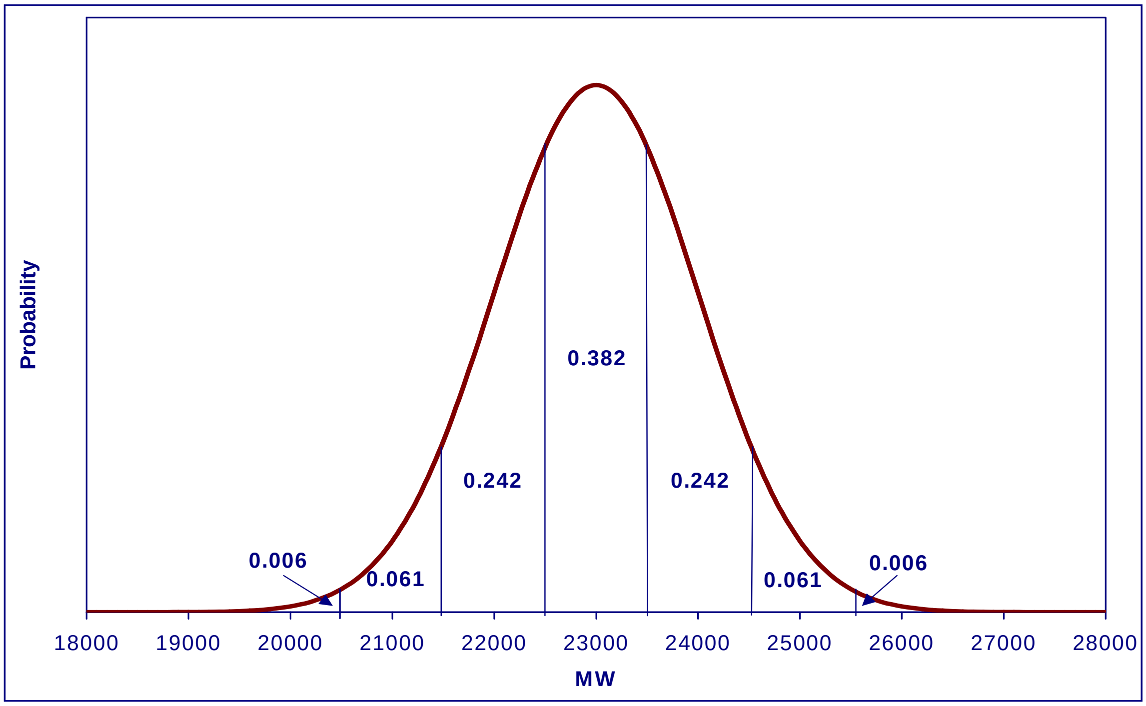
It should be noted that negative Reserve Above Requirement values in some weeks do not necessarily mean a violation of the NPCC resource adequacy criterion. This may only mean higher risk levels for the respective weeks. Whenever negative Reserve Above Requirement values are identified, the possible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

3.2.2 Representation of Demand and Its Uncertainty Due to Weather

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 modeling 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.

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 deviations vary between about 2% and 7% of their associated mean demand values through the year. Each week's peak demand is modeled by a multi-step approximation of a normal distribution whose mean is equal to the forecast weekly peak and whose standard deviation is equal to the LFU. Subsequently, in the probabilistic reserve requirement 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 peak value of 23,000 MW and an associated LFU value 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, 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 IESO. 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. When forecast forced outage rates are not available, forced outage rates compiled from generating units past performance information are used.

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.

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 considered 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 IESO-controlled grid consists of a robust southern grid and a sparse northern grid. 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 the 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 Above Requirement.

3.3 Multi-Area Reliability Simulation (MARS) Approach

The 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 IESO-controlled grid has been modeled as a pool composed of ten zones. Figure 4.1.1 provides a pictorial representation of Ontario's ten zones.

3.3.1 Multi-Area Reliability Simulation (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 ± SD, mean ± 2SD, mean ± 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 probabilistically 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 Forecast of Energy Production Capability

The forecast energy production capability of the Ontario generators is calculated on a month-by-month basis, for 18-Month Outlooks only. Monthly energy production capabilities for the Ontario generators are provided by market participants or calculated by the IESO. 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.

- End of Section -

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 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 18-Month 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 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 18-month period under study is extracted from the IESO Integrated Outage Management System (IOMS). 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. The outage plan is also filtered to include those outages associated with a major project. 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 transmitters:

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,

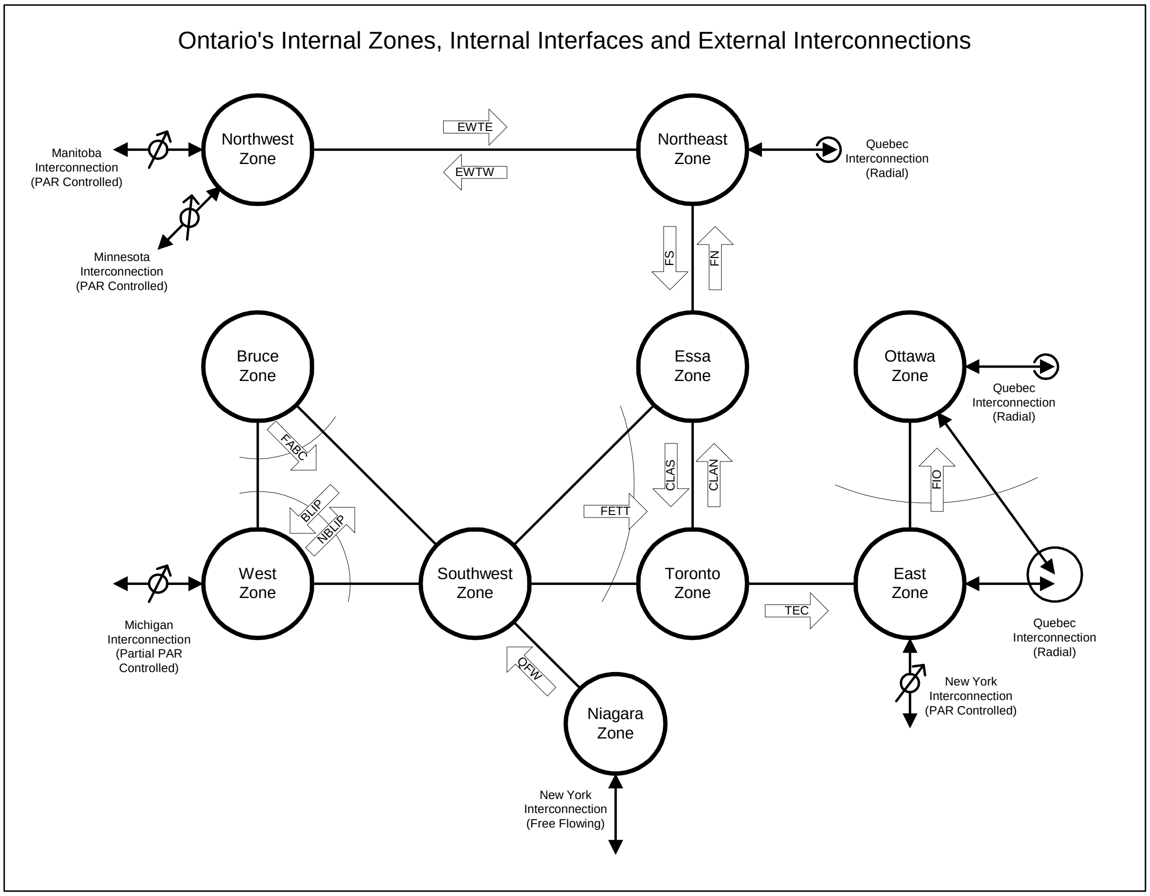
5) Description of outage impact to IESO-controlled grid, and

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 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

A transmission adequacy assessment is undertaken as part of the 10-Year Outlook process.

The overall assessment provides input to market participants and connection applicants with respect to long term planning. The assessment may also identify the potential need for IESO-controlled grid investments or other actions by market participants to maintain reliability of the IESO-controlled grid and to permit the IESO-administered markets to function efficiently. The assessment also provides input to the IESO 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.

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, contingency-based supply reliability, voltage level adequacy and congestion all contribute to the overall transmission adequacy assessment. In addition, a summary of the impact of proposed generation and transmission projects is provided where applicable.

Contingency-based supply reliability assesses the extent to which load pockets in Ontario can be supplied reliably, under various scenarios with existing and planned facilities.

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

Congestion studies assess the extent to which major transmission interfaces have the potential to become congested and thus reduce market efficiency.

The present Outlook does not completely assess the adequacy of all of the 115 kV transmission supply in the IESO-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.

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.

Load flow studies, where appropriate, with various assumptions related to the level of imports or exports are 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. In addition, the specific years that are studied also capture planned transmission facilities that significantly change the overall configuration of the transmission network. The conditions under study are intended to stress the power system.

Transmission adequacy can be assessed assuming various transmission network scenarios and resource availability scenarios. The various resource availability scenarios may consider both existing operable generation and new generation projects that have been identified to the IESO under the Connection Assessment and Approval (CAA) Process. Likewise, the various transmission network scenarios may consider both existing transmission facilities and new transmission projects that have been identified to the IESO under the CAA Process.

The transmission adequacy assessment assumes that all transmission facilities are in-service, and assumes the continued use of Special Protection Systems such as generation rejection and load rejection in the determination of sufficiency.

4.2.3 Contingency-Based Supply Reliability Assessments

Supply Deliverability Assessment

The supply deliverability of certain transmission facilities of the IESO-controlled grid is evaluated by considering the impact of a specific contingency on the load supplied.

Specifically, those load pockets on the IESO-controlled grid that are 250 MW or higher are evaluated. The load pockets are determined by aggregating the forecast load supplied by certain transmission facilities on a double circuit line. The contingency that is assessed is a fault or outage to the double circuit line. Based on this 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.

Using the High Growth, Extreme Weather Demand Scenario at summer peak conditions, this Supply Deliverability Assessment is completed in accordance with the IESO Supply Deliverability Guidelines.

Thermal Rating Assessment

The thermal overload capability of autotransformers and transmission circuits of the IESO-controlled grid is evaluated by considering the impact of specific contingencies and the resulting post-contingency flow on the facilities remaining in-service.

For 500 kV and 230 kV autotransformers, the loss of one autotransformer at the various transformation points on the IESO-controlled gird is evaluated to determine if the post-contingency flows on the remaining autotransformers are above their 10-Day Limited Time Ratings (LTRs).

For 500 kV, 230 kV and 115 kV transmission circuits, the loss of one circuit is studied to determine if any of the resulting post-contingency flows on the remaining transmission circuits are above their continuous ratings.

In addition, for autotransformers and transmission circuits, the loss of a double circuit line and a circuit plus a breaker-fail operation is studied to determine if any of the resulting post-contingency flows on the remaining autotransformers and circuits are above their 15-Minute LTRs.

Using the High Growth, Extreme Weather Demand Scenario at summer peak conditions, the Contingency-Based Supply Reliability assessment is completed in accordance with Section 4.7 of the IESO Transmission Assessment Criteria Document.

4.2.4 Voltage Level Adequacy

Voltage level adequacy assesses the extent to which pre-contingency steady state voltage levels on the IESO-controlled grid are expected to be maintained within acceptable ranges.

For those selected years of study in the near-term of the Outlook period, a billing power factor is assumed. The billing power factor will be determined by the load power factor in the 'base case' load flow and having all low voltage shunt capacitor banks in-service.

For those selected years of study later in the Outlook period, a 0.9 lagging power factor is assumed for each transformer station defined meter point within a zone. Appendix 4.3, Reference #1 of the Ontario Market Rules require that "connected wholesale customers and distributors connected to the IESO-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.

In all studies, if the minimum System Order Control or market rule voltage requirements at a station cannot be met under the power factor assumptions, the station is identified in the assessment. The extent to which the problems will arise will depend on the percent of time such conditions will occur in the future.

Using the High Growth, Extreme Weather Demand Scenario at summer peak conditions, the voltage level adequacy assessment is completed in accordance with Section 4.2 of the IESO Transmission Assessment Criteria Document.

4.2.5 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.

4.2.5.1 GE Multi-Area Production Simulation (MAPS) Congestion Approach

The MAPS software program allows for detailed modeling of the economic operation of a power system composed of a number of interconnected areas and/or zones that can be grouped into pools. The MAPS software integrates highly detailed representations of a system's load, generation and transmission into a single simulation. This enables calculation of hourly production costs in light of the constraints imposed by the transmission system on the economic dispatch of generation.

The MAPS software approach utilizes hourly resolution in the demand forecast over the entire study period. Hourly demand values under the Median Growth, Normal Weather Demand Scenario are used.

The MAPS approach considers the variable capability of generating units, as determined by unit ratings, unit energy production capabilities, unit cycling capabilities, fuel price forecasts, unit outage schedule, and unit forced outage rates.

The MAPS approach also allows for blocks of power that represent a source of generation or an additional load to be modeled as an hourly modifier. A megawatt value, a schedule, and its associated costs describe an hourly modifier.

To simulate the economic operation of a power system, the MAPS program starts with the preparation of hourly load models for the various interconnected systems. Once the load models are completed, MAPS then creates a generator maintenance schedule for the study period to minimize spinning reserve requirements. Once all the units have been scheduled for maintenance, MAPS schedules hourly modifiers and hydroelectric resources on an hourly basis to shave peak loads. Finally, MAPS simulates an hourly thermal unit production by using a cost commitment and dispatch process to schedule thermal generating units on an hourly basis against the remaining load levels in the load models.

The MAPS commitment and dispatch process starts by creating a priority list. The priority list identifies the thermal generating units that are available to serve the load during that hour. The order of the units within this list is based on a unit's full-load cost. A unit's full-load cost is based on the full-load fuel cost plus, if defined, the variable operating and maintenance cost, start-up costs and emission cost. Using the priority list, MAPS commits on an hourly basis the full capacity of the thermal units based on economic order while recognizing transmission constraints. This process continues until the sum of the continuous ratings of the committed units is greater than or equal to the load, and the sum the of the maximum ratings of the committed units is greater than or equal to the load plus required spinning reserve.

Using the list of committed thermal units, MAPS dispatches units on hourly basis to meet the loads by loading the committed units to their minimum operating points. The incremental operating sections of each of the units are then deterministically loaded in order of increasing cost until all the load in the study system is served while recognizing transmission constraints. Forced outages are incorporated stochastically by stimulating random outages. Using the forced outage rates that have been defined for each thermal unit and a random number generator, units are outaged for random intervals throughout the study period.

As shown in Figure 4.1.1, the IESO-controlled grid has been modeled as a pool composed of ten zones with nine major interfaces. The thermal generators in Ontario, for each of the ten zones, are modeled on an individual unit basis. Hydroelectric generators, for each of the ten zones, are modeled as energy-limited resources. The resource availability scenario determines what generators are considered in an assessment.

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 interconnected systems of New York, New England, Mid-Atlantic Area Council (MAAC), and East Central Area Reliability Council (ECAR) have also been included, such that flows to and from New-York and Michigan are modeled. Imports from Manitoba are also included as an hourly modifier, while imports from and exports to Quebec are modeled to be zero. Imports from and exports to Minnesota are not included.

MAPS input data, such fuel price forecasts, demand forecasts, unit heat rate data, unit maintenance schedules and unit forced outage rates, is obtained from market participant confidential information submitted to the IESO and is supported by GE supplied data with IESO and public domain information where available.

The output results of this simulation are annual interface flow summaries indicate the degree to which these transmission interfaces would be able to transfer surplus generating capacity from one zone to another.

4.2.6 Zone Assessments

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

4.2.7 Impact of Proposed New Generation and Transmission Projects

The impact to the IESO-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 IESO web site www.ieso.ca under the "Services – Connection Assessments" web page.

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