PJM Generation Adequacy Analysis:

Technical Methods

Capacity Adequacy Planning Department

PJM Interconnection, L.L.C.

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Introduction

Reliability requirements for a bulk power system are typically separated into two distinct, but related, functional areas: Adequacy and Security. As defined by NERC, adequacy refers to "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[1] Security, as defined by NERC, refers to "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[1] A well planned and adequate power system will lead to a secure system in day to day operations.

Generation adequacy, or the sufficiency of generation supply to meet expected demand, is one of the fundamental components of electric system adequacy assessment. This paper examines the analytical methods and models that PJM uses to assess the generation adequacy of the region. These techniques are based on sound, proven engineering theory and the physics of the bulk electric power grid. These methods, originally developed in the 1960s, have served PJM well over the ensuing decades in providing a safe and reliable electric system.

The generation adequacy standard PJM is obligated to meet is defined in Section 1 of the MAAC Reliability Principles and Standards[2], which states:

> "Sufficient megawatt generating capacity shall be installed to ensure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. Among the factors to be considered in the calculation of the probability are the characteristics of the loads, the probability of error in load forecast, the scheduled maintenance requirements for generating units, the forced outage rates of generating units, limited energy capacity, the effects of connections to other pools, and network transfer capabilities within the MAAC systems."

This "one day in ten year" loss-of-load expectation (LOLE) is the standard observed in most NERC regions and is the basis for determining PJM's required Installed Reserve Margin (IRM). The probabilistic nature of this standard requires that the tools used to determine the required IRM also be probabilistic. The tool developed and used by PJM for this purpose essentially uses a convolution of expected load distributions with expected capacity availability distributions to determine the loss-of-load probability (LOLP) of the PJM system.[3,4] The model includes all factors listed in the MAAC Section 1 criteria stated above. The specific statistical techniques used by the model include:

1 Probability Density Functions
2 Convolution Functions
3 Markov equations of a four-state model [7]
4 The Central Limit Theorem

5 Monte Carlo sampling
6 The First Order Statistic
7 Correlation and regression techniques and residuals
8 Testing for normality of probability distributions
9 Confidence interval determination.

In addition to determining the required PJM Installed Reserve Margin, PJM performs a number of other related analyses including evaluation of the reliability value of load management programs, capacity emergency transfer objective studies, winter weekly reserve target studies, and peak period planned maintenance assessments (see Citations 28, 29, 30). These planning study results are often directly applied in system operations. For example, the determination of the winter weekly reserve target is applied in the succeeding winter period by Operations to ensure that planned outages are coordinated to minimize system risk and maintain compliance with the MAAC Section 1 criteria.

The main section of this paper explains why and how PJM's modeling and analysis techniques are used to assess generation adequacy from a planning perspective. It also includes the results of benchmarking analysis performed to assess the consistency of our planning model with operational experience. The main section also underscores the integrated nature of planning and operations functions at PJM by outlining the direct impacts of each function on the other.

The main section of the paper is followed by a list of references which provide the conceptual basis for PJM adequacy tools and methods. Also included is a glossary which defines the terms and acronyms used throughout the paper. The Citations and References cited at the end of this paper provide the pertinent technical details and further explanations of the concepts and techniques presented in the main section. This paper itself is a summary of numerous reports and documents that describe the techniques in greater detail and are available at the PJM Interconnection Office.

Section 1

Reserve Requirement Analysis

The primary purpose of the Reserve Requirement Study is to determine the Installed Reserve Margin (IRM) required by PJM to meet the MAAC "1 in 10" LOLE standard. While the requirement is based on MAAC criteria, it is applied uniformly across the entire PJM region regardless of NERC reliability council boundaries. The Reserve Requirement Study is performed annually by Capacity Adequacy Department staff at PJM with extensive stakeholder review through the PJM Committee structure. The IRM ultimately recommended by the Committees and approved by the PJM Board is based on consideration of the analytical results and application of engineering judgment to reflect the influence of factors not explicitly considered in the analysis.

PRISM (Probabilistic Reliability Index Study Model) is the computer application used by PJM to calculate reliability indices to determine installed capacity reserve requirements. PRISM is a Web-based software tool that was recently developed based on the GEBGE model. GEBGE is a legacy FORTRAN program that had been used by PJM for adequacy studies since the mid 1960's.

The Reserve Requirement Study is based on a data model that has five principal components:

1) 52 weekly mean peak loads
2) 52 weekly standard deviations of the loads reflecting both forecasting error and weather variability
3) 52 weekly mean generating capacity values
4) 52 weekly available capacity distributions based on characteristics of the generators (forced outage rates, planned outage requirements, etc.)
5) A deterministic Capacity Benefit Margin (CBM) value between PJM and the external regions

The external regions included in the model (collectively referred to as the "world") include ECAR, SERC, NPCC, MAIN, SPP, and MAPP. Studies can be performed on a single area (PJM only) basis or on a two-area basis (PJM and adjacent regions). The determination of reserve requirements is done on a two-area basis to recognize the reliability value of interconnection with external regions. The data model for both the load and capacity representations is based on physical, geographic location.

The Reserve Requirement Study also produces the Forecast Pool Requirement (FPR) which is the IRM converted to units of unforced capacity. Unforced capacity (UCAP) represents the expected megawatt output of a unit that is, on average, not experiencing a forced outage. UCAP is used to assign capacity obligations and to measure compliance with those obligations. UCAP is also the units on which the PJM capacity markets are based.

The Reserve Requirement Study assesses the adequacy needs of the pool for each of the next five years. Results are primarily influenced by the characteristics of the generating units, variability of load, expected amount of new generation, load forecast error, and available capacity assistance from adjacent regions. The IRM is officially approved on a one year-ahead basis. Once approved, the IRM is held constant for the duration of a full planning period (June 1 through May 31 of the following year).

Two Area Model

The Reserve Requirement Study models two separate areas: Area 1 is the study region (PJM) and Area 2 is the electrically significant region connected to PJM (the "world"). As a result, the bulk electric power grid of most of the Eastern Interconnection is modeled. Geographically, this area includes most of the U.S. and Canada between the Atlantic Ocean and the Rocky Mountains. The bulk electric power grid generally includes all elements connected to the 138 kV and higher voltage level system.

The Reserve Study model includes three primary components: load, capacity, and the transmission link that connects PJM with the world area. The value of the simultaneous capability of the transmission link, under peak load conditions, is known as the Capacity Benefit Margin (CBM).[13, 14] The load and capacity models are probabilistically based, whereas the transmission link is represented by a single, expected value. As detailed in the Capacity Benefit Margin section of this paper, the determination of the expected transmission link is based on a probabilistic weighting of results from a series of power flow simulations.[15] A geographical representation of the Reserve Requirement Study model is shown in Diagram 1. A conceptual representation showing the three primary modeling components is depicted in Diagram 2.

Diagram 1

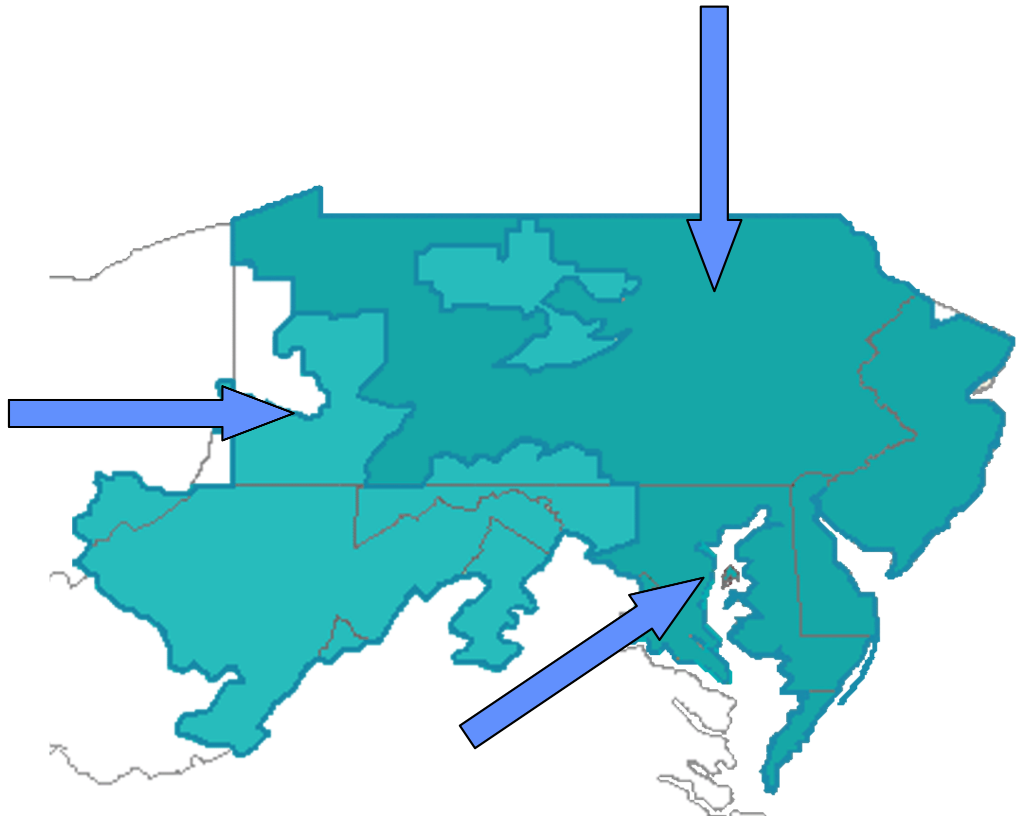
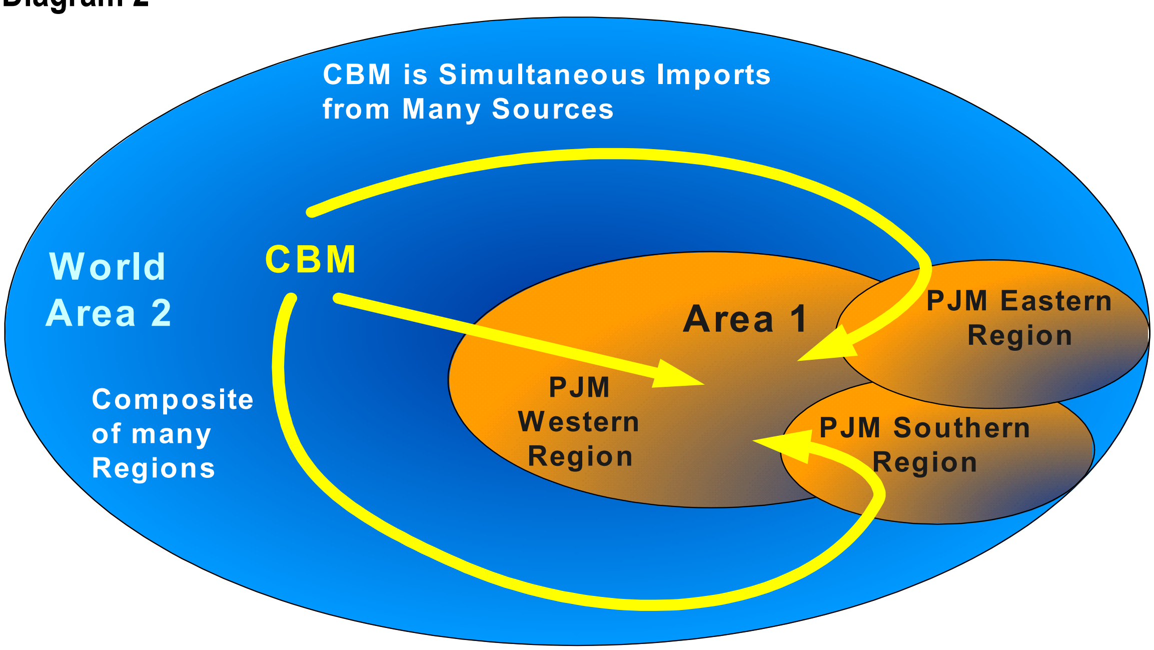


Diagram 2



PJM Region

Data for the PJM Region model is supplied by stakeholders (primarily Generators and the Electric Distribution Companies) and is also collected from PJM data systems. Stakeholder data is thoroughly reviewed by PJM staff to ensure accuracy. Three cases are currently developed for the Reserve Requirement Study to represent the three possible PJM configurations:

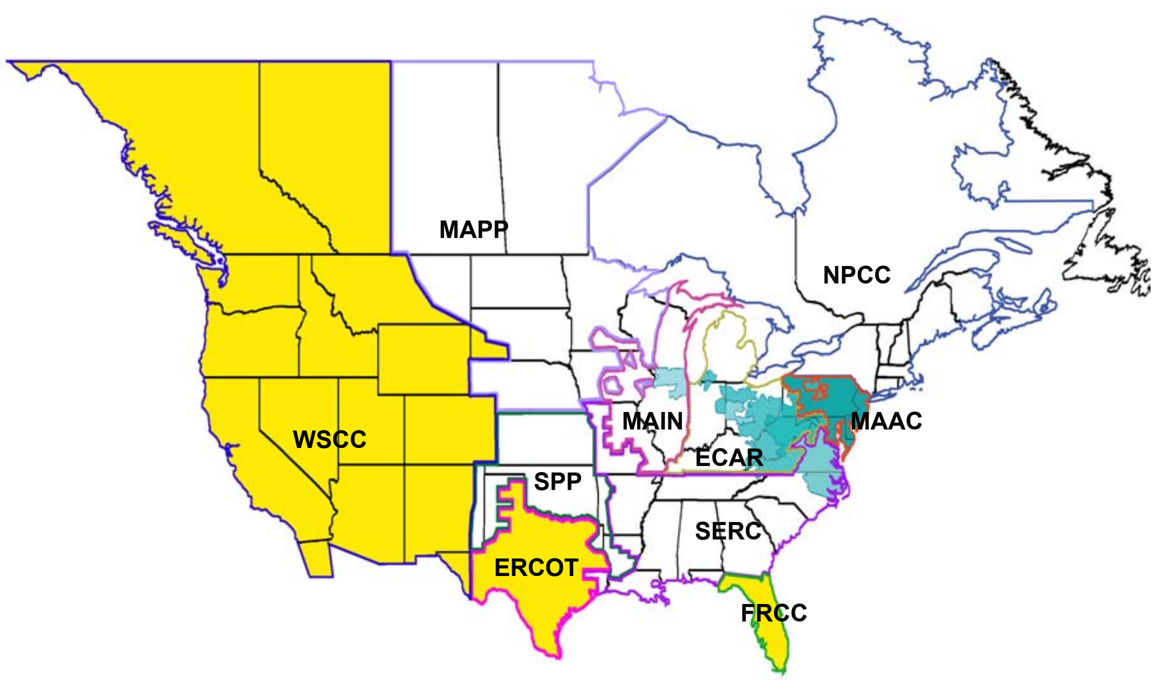
1) the MAAC region only
2) the MAAC region plus Allegheny Power
3) the MAAC region plus Allegheny Power, Commonwealth Edison, AEP, Dayton Power & Light and Dominion Virginia Power

These regions comprise the green/bluish-green area depicted in Diagram 3.

World Region (Eastern Interconnection minus PJM, ERCOT, and FRCC)

The world region is the area electrically interconnected to the PJM region. Diagram 3 shows this as the area in white. Regions in Texas, Florida, and west of the Rocky Mountains are not strongly interconnected to PJM and therefore are not modeled in the study. Diagram 3 shows the areas not modeled in the study in yellow.

Diagram 3



Single Transmission Tie (CBM = 3500 MW)

The model includes a single, bi-directional transmission tie between the two study regions. This tie represents the transmission system's ability to deliver capacity resources into PJM under peak demand periods. Power flow studies using Monte Carlo generator outage techniques[15] indicate that this value is 3500 MW. The 3500 MW emergency import capability is defined to be the Capacity Benefit Margin and is reserved for adequacy purposes and is therefore not available for firm transmission service under non-emergency conditions. Preserving this CBM for reliability purposes effectively reduces the calculated IRM by two to three percentage points. This collective benefit is shared pro-rata by all load serving entities in the PJM region.

Recent studies [22, 23] of the expanded PJM region indicate that PJM's emergency import capability (EIC) now exceeds 3500 MW. Statistical studies [17, 18, 19, 20], however, indicate that the vast majority of the reliability benefit of interconnection is supplied by the first 3500 MW of import capability. For this reason, CBM has been effectively capped at 3500 MW. Reserving import capability in excess of 3500 MW provides a minimal amount of additional benefit. Any EIC in excess of 3500 MW is therefore not reserved for reliability purposes and can be used to increase the amount of firm Available Transmission Capability available to the marketplace.

PRISM - Probabilistic Reliability Index Study Model

The models and analytical techniques used for generation assessment are based on numerous technical papers [5, 6, 11, 12] and on the physical nature of how generating machines, peak demand period loads and the transmission system interact in the delivery of energy across the bulk power grid. PJM has successfully used these techniques for more than 35 years in determining pool wide reserve requirements.

The PRISM (Probabilistic Reliability Index Study Model) tool uses SAS [24] software as an analytic engine and Oracle [25] as a database to enhance the PJM staff's abilities to assess adequacy requirements. The tool's focus is on creating a probabilistic generation model and load model and convolving the two to determine the probability of load exceeding available capacity. The generation and load models are based on the latest available information which offers the best predictor of future adequacy requirements.

PRISM analyses a weekly distribution of the expected peak loads and a distribution of the expected available capacity level in each study area. Each weekly load distribution is modeled to be normal (i.e. Gaussian). These distributions are based on the load data for the previous five years and the five year average generator availability statistics respectively. These two distributions are then convolved as depicted in Diagram 4. Two weeks are depicted in this diagram: one pertaining to a high demand peak week and the other to a low demand, non-summer week.

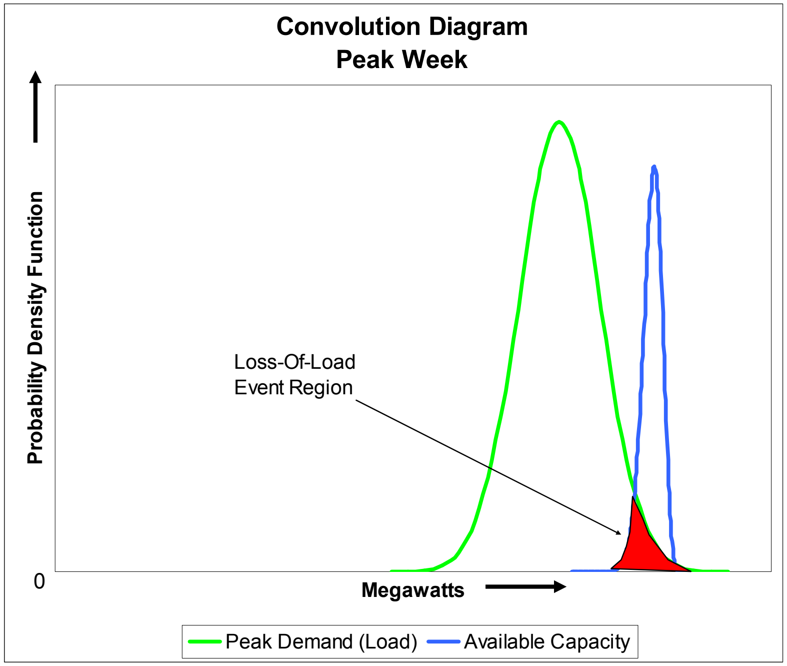
As depicted in Diagram 4, if load exceeds available capacity (the green line is to the right of the blue line), demand is unable to be served and a loss of load event occurs. The probability of a loss of load event occurring in that particular week is simply the area under the curves and shaded in red on the diagrams. The loss of load probability is therefore a joint probability calculation – the load level must be at a certain

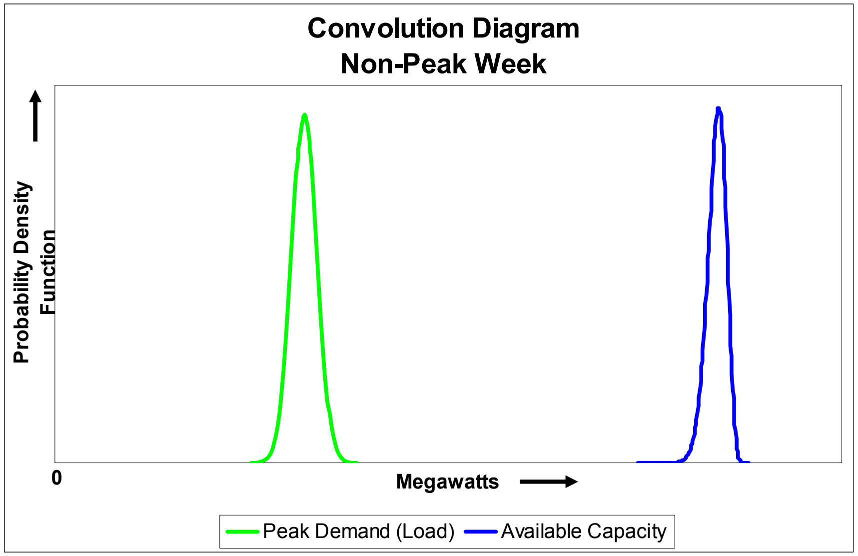
MW value coincidently with the available capacity level being below that same MW value. It is important to note that this model assumes independence between the load distribution and the capacity distribution.

Diagram 4 clearly shows that the loss of load probability (LOLP) is much greater on a peak week than on a non-peak week. This is due primarily to the load distribution, which has a higher mean and higher standard deviation during the peak week. This increases the potential for overlap (or red shaded area) between the two curves. Note the standard deviation of the capacity distribution is relatively small. This is due to the large number of units within PJM. With over 700 units, the possible range of system unit average unavailability decreases significantly and clusters around the mean. **This tight standard deviation on the capacity distribution applies to both peak and non-peak weeks and serves to reduce the loss of load probability.**

PRISM performs the convolution calculation for each week of the year and for each area of the model. The weekly LOLPs are then summed to determine the seasonal LOLPs, which are summed to produce the annual LOLP. The annual LOLP is the value that must meet the MAAC standard of a “1 in 10” loss of load expectation.

Diagram 4





The details of the model development are described below.

Load Model

The general shape of the load distribution is based on metered control area loads over a five year period. Hourly loads from each year are normalized based on the respective annual peaks to remove the effects of load growth. Basing the shape on five years of history is judged to be the appropriate period that both balances having a sufficient number of data points to reduce volatility and ensuring the model reflects recent load characteristics.

The load model used in the Reserve Requirement Study is "magnitude-ordered". This means that the weekly load data is not considered in chronological order but is ordered instead within each season of each year from the highest to the lowest. The loads are then averaged across the five year period based on this magnitude ordering (i.e. the highest weekly loads are combined across the years, the second highest weekly loads are combined and so forth through 52 weeks). The 25 points collected for each week (the 5 weekday peaks from each of the 5 years) then define the mean and standard deviation of the load distribution for that particular week. This "magnitude-ordered" approach results in an annual load profile that benchmarks very well with actual load experience. A load model approach that simply combined loads across years based on "calendar-ordering" (i.e. the first week of each June combined, the second week of each June combined, etc.) would tend to flatten out the load shape and result in an anomalous load profile that does not resemble any annual profile observed in operations.

Diagram 5 shows the distribution of daily peaks occurring on the five weekdays of a particular week. This normal distribution is characterized by its mean and standard deviation and is assumed to be identical for each of the five weekdays within a particular week. [26] PRISM develops 52 of these distributions, one associated with each week of the planning period. The value of the most probable weekly peak is determined from this curve based on use of the First Order Statistic. The First Order Statistic [27] empirically predicts the expected highest observation within a sample of a fixed size, where the population mean and standard deviation are known. For the most probable peak (MPP) calculations, the population is defined by the weekly load distribution and the sample size is five (one for each weekday of the week). From the First Order Statistic table [27], this sample size yields a First Order statistic of 1.16295 and is inputted into the formula below:

$$MPP = \mu + 1.16295\sigma$$

This formula states that, if 5 data points are randomly sampled from the distribution on Diagram 5, the expected value of the highest of the 5 data points (corresponding to the weekly peak) would be 1.16295 standard deviations above the distribution mean. The expected weekly peaks (or most probable peaks (MPPs)) across an entire planning period are plotted on the y axis in Diagram 6 (red line).

Another input to the load model is the historical load growth rate and the monthly peak demand forecast. The load shape is adjusted to essentially replace the historical load growth reflected in the metered loads with the current forecasted load growth for the future study period. Historical load growth is removed by normalizing loads based on the respective annual peaks. This adjustment ensures that the resulting load model is a more accurate predictor of future adequacy requirements.

The load model also recognizes the increased forecast uncertainty associated with longer planning horizons. This is accomplished through application of a unified increase in error for each week based on the length of the planning horizon under study. The increase in error is referred to as the Forecast Error Factor (FEF) [31]. The FEF adjustment is made each week according to the formula:

$$MPP = \mu + 1.16295\sigma_{\text{Total}} \ ,$$

where:

$$\sigma_{\text{Total}} = \sqrt{\sigma^2 + FEF^2} \ .$$

Thus the FEF adjustment has the effect of increasing the weekly load distribution standard deviations associated with planning periods further out in the future. The Reserve Requirement Study load models typically use an FEF of 0.5% error in the first planning period and increase this value by 0.5% for each succeeding planning period of the study. [17, 18, 19, 21, 31] The maximum FEF value is a 3% error and occurs six years forward in time.

The distribution of daily peaks within a week is assumed to be normal. [10] Analysis of historical daily peaks for each week of the year supports this assumption. [26] Historical data for sixty percent of the weeks are strictly normally distributed. Those weeks that are not strictly normally distributed have distributions that are bell shaped but exhibit some skewness. In particular the summer (peak) weeks show some negative skewness (i.e. the median daily peak is greater than the mean daily peak).

Using a normal distribution to represent these weeks is a conservative assumption, since it aligns the mean and median daily peaks and shifts the distribution to the right increasing the likelihood of exceeding the available capacity. Please refer to the Citations, primarily numbers 10 and 26, for a detailed description of the data and statistical testing and verification performed to demonstrate that a normal distribution for each week's daily peaks is appropriate.

Diagram 5

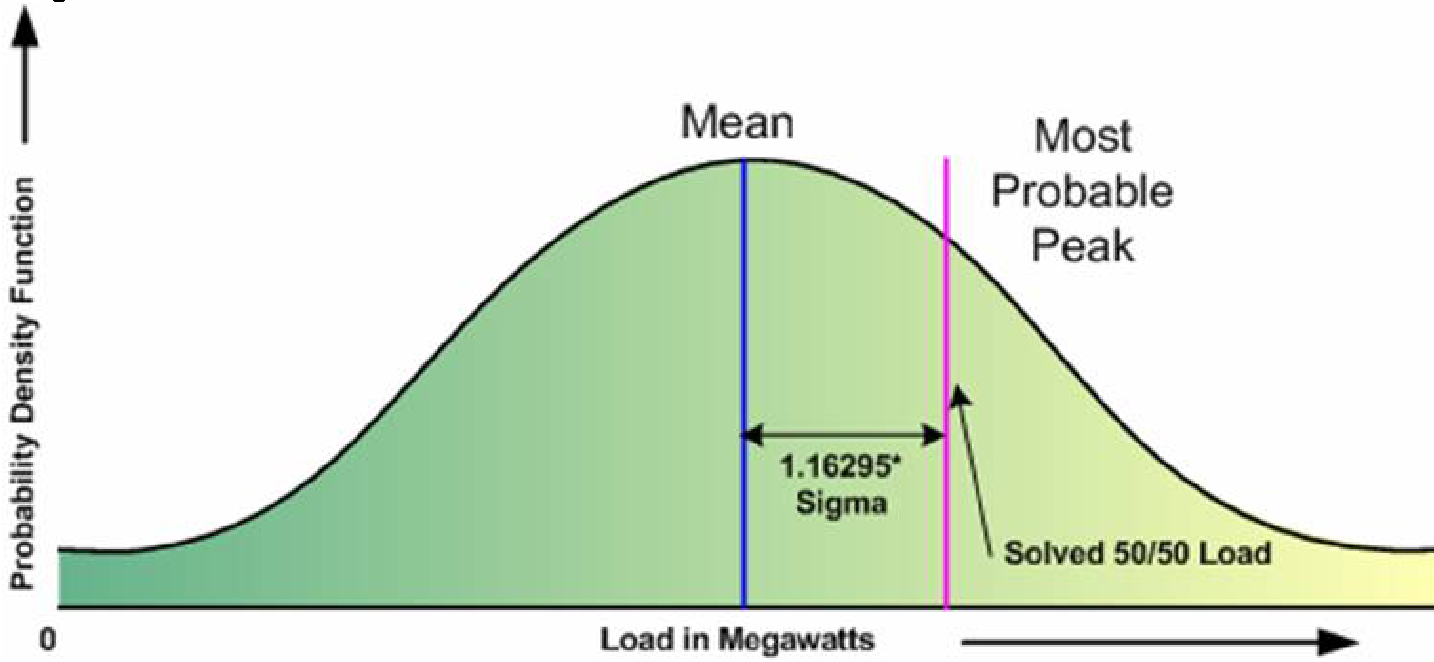


Diagram 7 emphasizes the point that each weekly load point on the annual load shape does not represent a single value, but is itself the most probable peak drawn from an entire distribution of possible peaks. A load distribution similar to the one depicted in Diagram 5 is associated with each weekly peak plotted in Diagram 6. This approach ensures that every possible load level, not just the expected or average load level, is considered in our adequacy analysis.

Diagram 6 – Load Shape

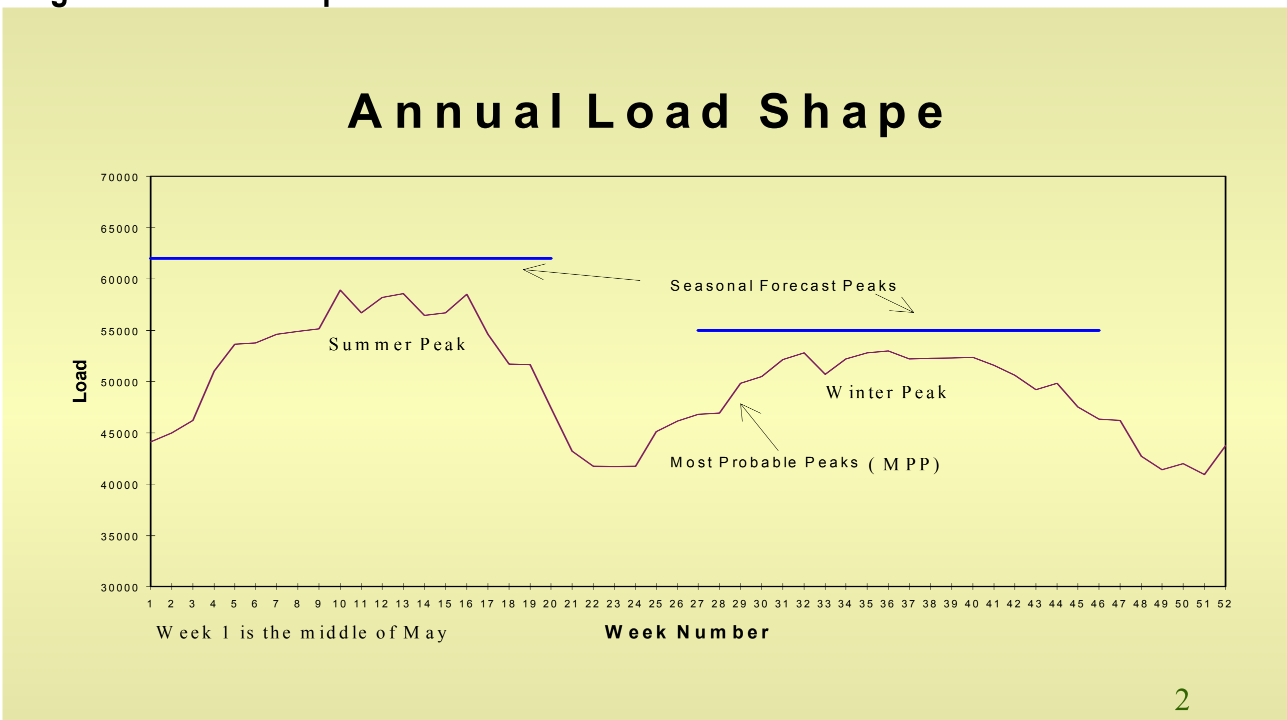
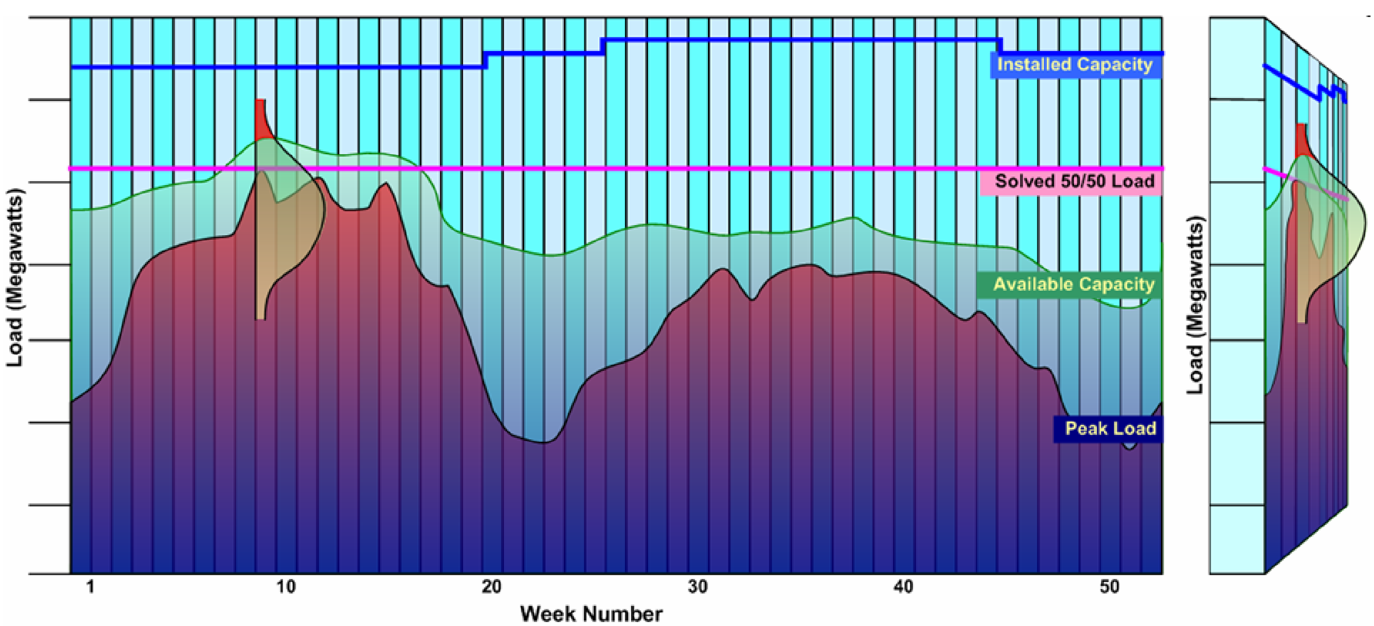


Diagram 7 – Load Shape combined with Weekly Load Distribution



The Green line represents the Available capacity. The tail of the weekly load distribution shown above the green line represents a loss-of-load event. Picture this diagram in 3 dimensions with the bell shape load extending up out of the page as shown in the image to the right.

Capacity Model

The PRISM capacity model explicitly models each generating unit in each area. The following input data is required for each unit:

1. Name
2. Location
3. Summer and Winter Capacity Ratings
4. Effective Equivalent Demand Forced Outage Rate (EEFORd)
5. Two State Variance
6. Planned Maintenance Requirements

The EEFORd statistic [7, 8, 32] is effectively the forced outage rate of the unit (which is an all-hours performance measure) adjusted to reflect the availability of the unit only over the hours during which it is "in demand" or required to produce energy. The two-state variance statistic [31, 32] is a single value which captures the effect of up to twelve partial outage states of the unit. The maintenance data specify the number of weeks per year required for planned maintenance. The calendar scheduling of that maintenance is optimized by PRISM by coordinating it with the maintenance requirements of all other units in that study area. These input statistics are fully developed in the Citations and References to this paper, primarily in Citation numbers 31 and 32.

The volume of data required to develop a capacity model for a 700 unit PJM region and a world area of over 4500 units is significant. Data warehousing technologies and SAS software [24, 25] have been developed to expedite the storage and extraction of this data. These new tools have dramatically reduced the amount of staff time required to produce the capacity models and allow sensitivity analyses to be performed in a much more efficient manner.

Generation statistics are generally based on the most recent five years of historical performance. This time period is consistent with that used for load model development and effectively balances the need for data timeliness with relative stability across years. Data reporting generally comports with Generation Availability Data Systems (GADS) standards. GADS [33] standards are established by NERC. Members submit the details of generating unit outage events through the Web-based eGADS tool [33]. PJM staff performs checks on these data and uses the Generator Outage Report Program (GORP) to produce all the statistics used in the capacity model development. The PJM Generator Unavailability Subcommittee (GUS), a stakeholder body of experts in generator performance analysis, advises PJM staff on the definitions and use of the performance statistics.

NERC compiles class average performance data for various generators based on type, fuel supply and megawatt size [34]. PJM uses this class average data for the world units and future units in the PRISM model. An in-house application makes the necessary calculations to produce the statistics needed for

EEFORd, variance, and the planned outage factor used to estimate planned maintenance. New generating units roll actual performance data into their historical base as it becomes available. NERC updates the class average generator data on an annual basis.

To develop the weekly capacity distributions, PRISM first addresses the need for planned maintenance outages. Each generating unit is assigned an expected number of weeks per year to be out on a planned outage event. PRISM considers the maintenance requirements of all units in a particular area and determines for each week which units, if any, will be on a scheduled planned outage. The general goal is to schedule planned outage events in periods, such as the spring or fall, where the risk of a loss-of-load event is small. If the planned outage requirements of all units can not be accommodated in the non-peak periods, then PRISM may schedule units for maintenance during the peak periods. PRISM also allows the user to manually enter a planned outage schedule for all units if a known pattern is required for analysis. Manually specifying a planned outage pattern is typically how actual events seen in operations are modeled. Each week in the model has its own planned outages scheduled unit by unit.

An examination of operations experience [21, 35] indicates that, on average, for the MAAC region PJM has one large generating unit out over the summer peak period due to any one of several reasons (extended forced outage, Nuclear Regulatory Commission-ordered shutdown, ramp up/ramp down time, etc.). To reflect this typical level of generator unavailability over the summer period, a large generating unit is manually scheduled out over the peak period in the Reserve Requirement Study. This adjustment is a conservative assumption that results in a higher reserve requirement of about one to two percentage points. Further discussion of this topic is provided in Section 2.

Capacity Benefit Margin

The determination of the transmission system's ability to import energy from outside the PJM Control Area under peak demand periods is based on power flow analysis of the bulk electric power grid. The models are developed based on cases from the NERC Multi-area Modeling Working Group (MMWG). Each year, the MMWG produces up to nine planning models useful for analyzing power flows anywhere in the Eastern Interconnection. The nine models capture a range of operating conditions such as summer, winter, fall and spring peak periods, shoulder periods and minimum load periods. The objective of the models is to form the basis for assessment under all operating conditions. The models are developed through a collaborative process involving extensive stakeholder input and review.

PJM has a defined analytical process, the Emergency Import Capability Study (EICS) [15], that outlines the various assumptions and techniques used to determine the Capacity Benefit Margin (CBM). This study examines peak summer conditions and assesses the transmission system's ability to supply energy to the borders of the PJM Control Area simultaneously from all interconnected regions. All systems within the Eastern Interconnection are assumed to be under peak loading conditions.

In the power flow based EICS, the selection of generating unit forced outages is performed using a Monte Carlo selection routine. The forced outage rate for each unit is given as the EEFORd, with this statistic indicating a unit's random availability. This statistic is used to influence a random selection of generating unit outages for assessment of the transmission grid under peak load conditions. By employing a Monte

Carlo technique to select generator outage patterns, the power flow analysis has moved toward a probabilistic approach for a large contributing aspect of the determination of transmission capability. The selection of units to be forced out plays a key role in the final determination of the emergency import capability. The current peak load emergency import capability reserved as CBM is 3500 MW. [13]

PRISM Solution Algorithm

The reliability program's capacity model uses each generating unit's capacity, forced outage rate, and planned maintenance requirements to develop a cumulative capacity outage probability table for each week of the planning period. Planned maintenance scheduling can be specified by the user or performed by the program.

Outage statistics of generating units are maintained for twelve outage states [33] (from unit "full on" to unit "full out"). PRISM cannot model these partial outages explicitly. The solution is the modified two-state variance representation for partial outages.[32] This two-state variance is used by PRISM to modify both the unit capacity and the effective forced outage rate to provide a statistically accurate representation of the 12 basic partial outage states. PRISM models a unit either full on or full off, but with the modified capacity and EEFORd the effect of the partial outages are captured. The result is a significantly better representation of the true availabilities of the generating units.

After scheduling planned outages, PRISM calculates a cumulative probability table for every week of the year based on the units in service and not on maintenance. The program then calculates the system LOLE at a given load level. PRISM calculates, on a weekly basis, the probability of every possible load level (represented by 21 intervals describing the area under a normal distribution for that interval) occurring simultaneously with every possible generation availability level (from the cumulative probability table). Any combination of load and capacity which results in the load level exceeding the generation available level contributes to the probability of a negative capacity margin (loss-of-load). In a two-area calculation, the probability that the other area will have an excess capacity margin, within the value of the tie size, is then subtracted from the first area's probability of loss of load.

The probability of zero margin or less is summed for each of the 21 intervals and then multiplied by 5 (5 weekdays per week) to give the loss-of-load expectation for that particular week. [3, 5, 6, 11, 12, 31] (Based on previous study findings, the loss of load probability over weekends and holidays is assumed to be zero.) The individual weekly LOLE's are then summed over the entire year to determine the annual LOLE. The annual PJM LOLE is currently required to be no worse than one day in ten years as mandated by MAAC. The reliability program reaches its solution by adjusting the load distribution, as opposed to attempting to outage generating capacity, until the annual LOLE is equal to one day in ten years.

A brief numerical example of the calculations is shown in the following illustration. The loss of load calculations shown in red corresponds to the red loss-of-load region shown in the above convolution diagram (Diagram 4). This example is a two-area solution that assumes the two areas will share reserves but that neither region will invoke load shedding to assist the other. This reflects the practice that PJM actually observes in operations.

ILLUSRATION OF TWO AREA Loss-Of-Load-Probability(LOLP) METHOD (NO LOSS OF LOAD SHARING)

Area A: 50 MW (5 - 10 MW units with 20% Equivalent Demand Forced Outage Rate(EFORd) each); 30 MW load; 20 MW reserve
Area B: 60 MW (6 - 10 MW units with 20% Equivalent Demand Forced Outage Rate(EFORd) each); 40 MW load; 20 MW reserve

	Area A					
A outage, MW	0	10	20	30	40	50
A probability	0.32768000	0.40960000	0.20480000	0.05120000	0.00640000	0.00032000
Help available	20	10	0	0	0	0
Help needed	0	0	0	10	20	30

Area B

B outage MW	**B Proability**	**Help Available**	**Help needed**						
0	0.26214400	20	0	0.08589935	0.10737418	0.05368709	0.01342177	0.00167772	0.00008389
10	0.39321600	10	0	0.12884902	0.16106127	0.08053064	0.02013266	0.00251658	0.00012583
20	0.24576000	0	0	0.08053064	0.10066330	0.05033165	0.01258291	0.00157286	0.00007864
30	0.08192000	0	10	0.02684355	0.03355443	0.01677722	0.00419430	0.00052429	0.00002621
40	0.01536000	0	20	0.00503316	0.00629146	0.00314573	0.00078643	0.00009830	0.00000492
50	0.00153600	0	30	0.00050332	0.00062915	0.00031457	0.00007864	0.00000983	0.00000049
60	0.00006400	0	40	0.00002097	0.00002621	0.00001311	0.00000328	0.00000041	0.00000002
							0.05120000	0.00640000	0.00032000

	Key		
1	No help needed; no loss of load	Probablity:	0.84892713
2	A gets help from B; loss of load avoided in A	Probablity:	0.03523215
3	A does not get help from B; loss of load only in A	Probablity:	0.01696072
4	B gets help from A; loss of load avoided in B	Probablity:	0.06543114
5	B does not get help from A; loss of load only in B	Probablity:	0.02772173
6	Loss of load in A & B	Probablity:	0.00572713
		TOTAL:	**1.00000000**

LOLP in A = Prob (3) + Prob. (6) =	0.02268785
LOLP in B = Prob (5) + Prob. (6) =	0.03344886
LOLP in System = Prob (3) + Prob. (5) + Prob. (6)	0.05040957

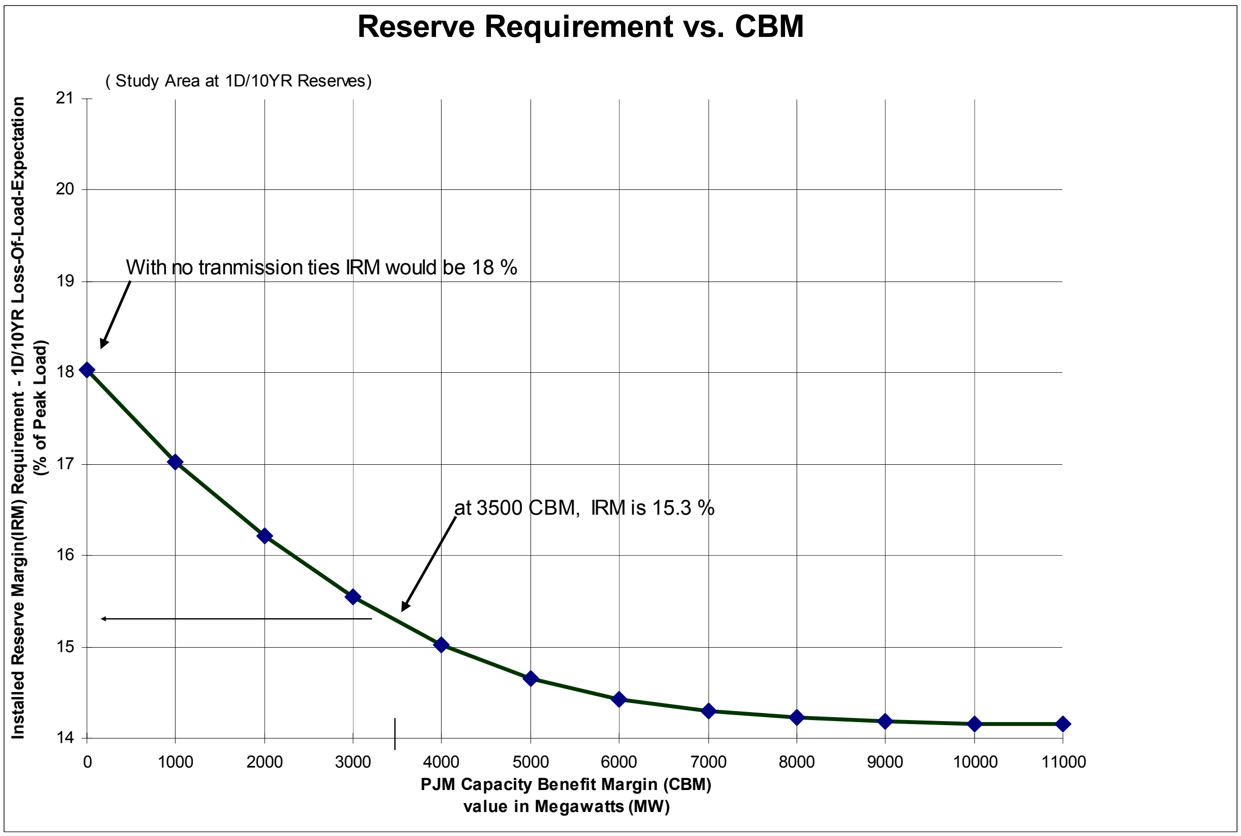
0.05792000	A	Zero Tie Size , LOLP in A
0.03523215	**B (2)**	Help from B for A
0.02268785	A-B	LOLP in A with Tie

The example calculations above display the techniques used to convolve the load model needs with the generator units' availability. This exhaustive technique, known as enumerated states, [36, 37, 38, 39, 40] produces the loss of load expectation (LOLE) at a given reserve level. If that LOLE is a value other than one day in ten years, PRISM shifts the annual load shape, in aggregate up or down, performs the distribution convolution again, determines the new LOLE and continues with this iterative technique until the desired LOLE is obtained. Once an LOLE of one day in ten years is obtained, the ratio of the PJM area's installed generation to its annual peak is the calculated Installed Reserve Margin (IRM).

PRISM does not use Monte Carlo sampling because, through the use of probabilistic distributions, the calculations consider every possible load and capacity state. The program does not produce any confidence interval associated with the results because the results represent the exact loss of load expectation (based on the study assumptions), not a statistically estimated parameter. Monte Carlo techniques necessarily provide an expected result with a certain confidence level because an infinite number of simulations would be required to produce the exact result with 100% confidence.

As seen in the above calculations the advantage of being tied to neighboring systems is that they can lend assistance during times of need when an individual area needs to avoid a loss-of-load event. Critical factors in these calculations are the amount of MW assistance that are needed, the ability of the other area to have excess to help (largely driven by load diversity between PJM and the world area) and finally the ability of the transmission system, via the Capacity Benefit Margin, to deliver the excess from the other area.

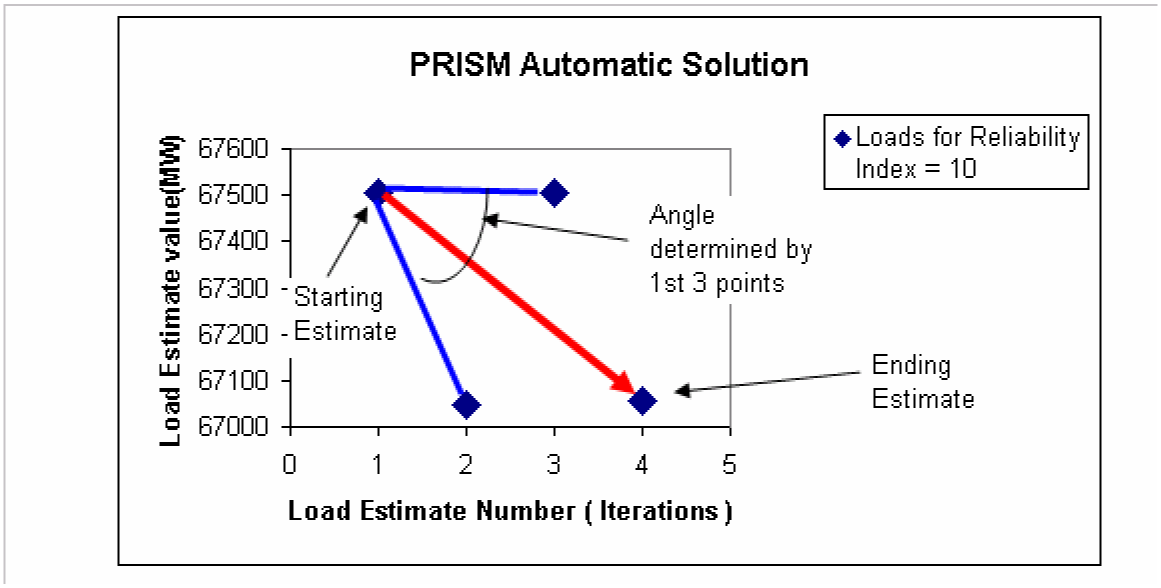
Diagram 8



The benefit of interconnection is depicted in Diagram 8. This diagram plots the PJM Installed Reserve Margin (IRM) against the Capacity Benefit Margin (CBM). As CBM increases, the potential amount of external capacity assistance increases and hence the PJM reserve requirement is reduced. As illustrated in the graph, the reliability benefit from increasing CBM reaches a saturation point around 6000 MW. At an import level of 6000 MW, the need for and availability of assistance from external regions are exhausted. The steepest portion of the curve is in the 0 MW to 3000 MW range and represents the most valuable portion of the CBM. Based on this graph and other considerations, the CBM value is fixed at 3500 MW.

A unique feature of PRISM is that a given reliability index can be set, say 1 event every 25 years, and the program will determine the solved load that meets this reliability index. PRISM does this by using an initial guess, similar to the way Newton-Raphson solutions work, and then doing a four part iteration to determine a next guess at the required load. [31] For a two-area study, PRISM uses a four part process. The initial estimate is used first, then Area 2 load is held constant while Area 1 load is varied, and then Area 1 load is held constant while Area 2 load is varied. Based on the results of the first three steps, the fourth step sets a new load for both Area 1 and Area 2. These loads are selected based on the slope of the blue lines depicted in Diagram 9. The solution process ends when either the maximum number of iterations is exceeded or the loads yield a reliability index within a specified tolerance of the desired index. This automatic solution allows PRISM to determine the required reserve margin based on a user-defined reliability index (i.e. one day in ten years).

Diagram 9



Example calculations of the automatic solution process:

RUN NO. 1 ------------------

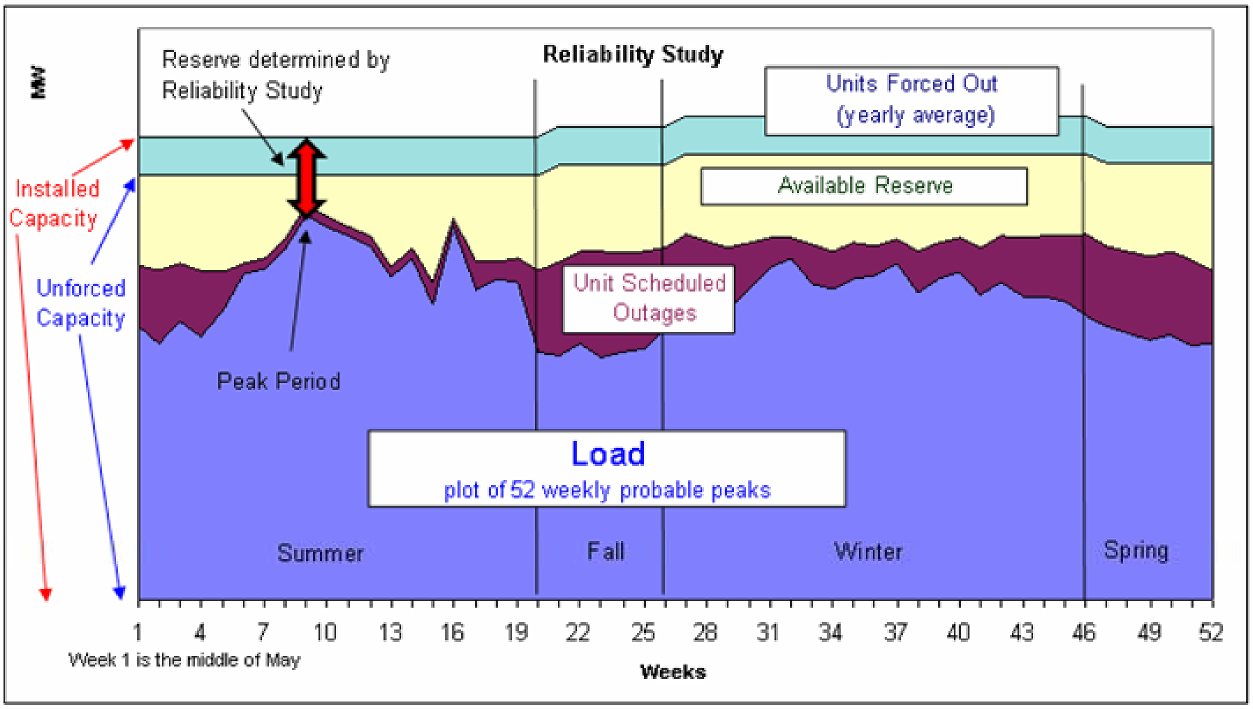
Area1 Load		Area1 RI	Area2 Load	Area2 RI-	
Part1	67504.00	8.01085	285178.00	9.59950	RI = Reliability Index (years/day)
Part2	67048.85	10.0380	285178.00	10.0089	
Part3	67504.00	8.19631	284823.62	10.1528	
Part4	67056.34	9.99760	285179.28	9.99989	

RUN NO. 2 -------------------

Area1 Load		Area1 RI	Area2 Load	Area2 RI-
Part1	67056.34	9.99760	285179.28	9.99989
Part2	67055.84	9.99791	285179.28	9.99990
Part3	67056.34	9.99760	285179.19	9.99989
Part4	67056.34	9.99760	285179.28	9.99989

Diagram 10 graphically depicts the results of the final iteration of a one day in ten year case from PRISM. The blue area represents the weekly peak demand levels, the maroon area represents the capacity on a planned outage and the light green area represents the capacity forced out. The vertical red arrow represents the installed reserves over the annual peak required to meet the desired reliability index.

Diagram 10 – Annual Load and Capacity Profile



ALM Factor Calculation

Active Load Management (ALM) [16, 41] refers to several different types of demand side programs that are implemented by PJM as one of the final steps before a loss of load event is initiated. Some examples of ALM are radio controlled activation of residential air conditioners and water heaters and contractual agreements with commercial and industrial customers to cut load upon notification. ALM does not include load curtailment achieved by promoting more efficient lighting and motors. These and other similar measures are referred to as Passive Load Management. ALM also does not include economic demand-side management programs which are voluntary, are not subject to PJM operational control, and therefore receive no capacity credit.

The reliability value of Active Load Management for Installed Capacity Accounting purposes is determined by calculating an ALM Factor using PRISM. This calculation is performed in units of load carrying capability (LCC). [9, 31] LCC refers to the amount of load, expressed in megawatts that a given resource can serve at a reliability index of one day in ten years. In this analysis, the aggregate pool ALM amount is represented as a hypothetical generating unit with a zero forced outage rate and zero planned outage events. The LCC of the aggregate ALM amount is the difference between the solved load from the base case without the “ALM generator” and the solved load from the case with the “ALM generator”:

ALM LCC = Load served with ALM – Load served without ALM

The ratio of the ALM LCC to the total amount of ALM in the pool is the ALM Factor. This factor typically ranges from about 0.95 to 0.99. This number means that every 100 MW of ALM effectively reduces the load requiring reserves in PJM by 95 to 99 MW. This ALM Factor is then used in the capacity obligation setting process to reduce the obligations of those entities with ALM customers.

Two other tests are performed related to the assessment of ALM programs. The first is to verify that the full reliability value of ALM is realized in the summer period. This test justifies the granting of full year capacity credit to ALM programs that may cover only the summer period. The second test is to verify that the full reliability value of ALM is realized in ten or fewer interruptions per year. Ten interruptions is the current requirement for granting ALM capacity credit. Recent tests indicate that the reliability value of ALM saturates in the range of four to seven interruptions, well below the ten interruption requirement. [19, 21, 31] A detailed discussion of these ALM tests is included in the Citations and References, primarily citation numbers 17, 21, 31, and 41.

Committee Review and Approval

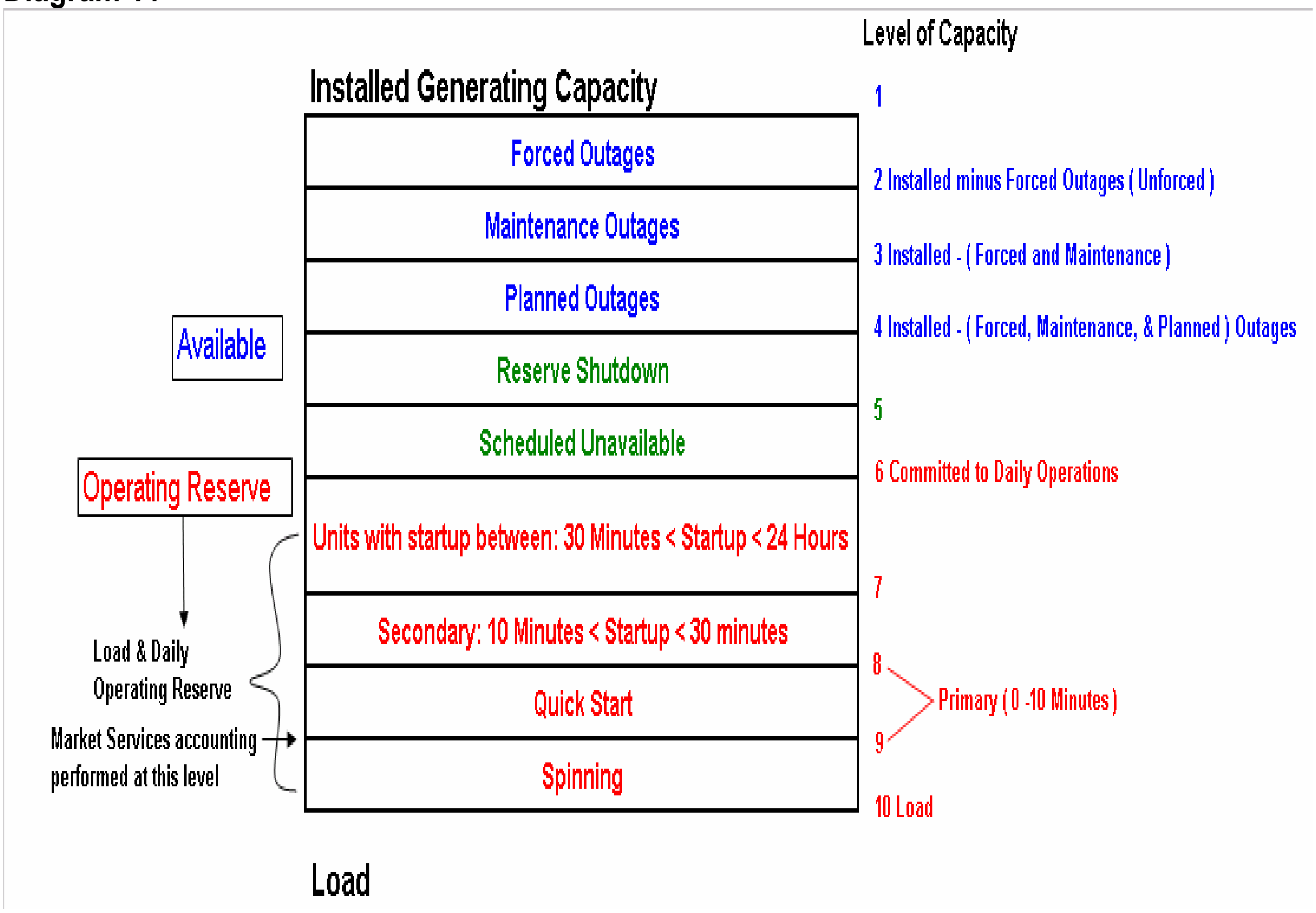
The ultimate authority over the determination of the approved Installed Reserve Margin and ALM Factor rests with the PJM Board of Managers. A supporting stakeholder committee structure is in place to advise and make recommendations to the PJM Board as necessary. Technical subcommittees, the Generator Unavailability Subcommittee and the Load Analysis Subcommittee, and PJM Staff , provide data input and begin initial review of the study results. All technical reports are passed up to the Members Planning Committee. The Planning Committee then forwards its recommendation to the Reliability Committee (RC). At the RC level, a formal vote is taken on the Installed Reserve Margin and ALM Factor and that recommendation is submitted to the PJM Board for final consideration.

Section 2

Benchmarking of Study Results with Operations

Diagram 11 shows how the same piece of generating equipment can have various values and requirements associated with it. Typically the planning processes used to measure a given unit's ability to deliver under peak load conditions are the areas shown in blue. The summer net dependable rating of a unit is the PJM Installed Capacity listed as level 1. This is the level for all adequacy analysis performed by PRISM. The PJM capacity market metric is the unforced capacity level indicated as level 2. The levels shown in red, levels 6 -9, are the typical levels at which operations measures compliance for security assessments. In all cases, each level is a measurement that is needed to assess different bulk system grid requirements. This diagram highlights the point that, while adequacy assessments and security assessments may be performed using different metrics, both consider the reliability values of generators. These values are, in fact, equal under both assessments when measured on a similar basis.

Diagram 11



All modeling techniques and assumptions for the Reserve Requirement Study are reviewed with stakeholders. Typically, the first draft of the modeling assumptions and workplan for the annual study is distributed for feedback starting in November for a study that begins to be performed in January. One of the typical modeling issues to address is how to match expected operational experience with the probabilistic adequacy assessments. The PJM staff takes a lead on this by interfacing with the PJM operational staff and developing technical solutions and options for correlating operational events seen on the bulk power grid with the modeling methods used in the PJM System Planning Division.

The frequency of large PJM generating unit outages for the MAAC region over the summer period was investigated from 1996-2000 and the results are tabulated in Diagram 12. [21, 33, 35] (Analysis for the summers of 2001, 2002 and 2003 is currently being performed). Large units were defined to be those with summer ratings greater than 600 MW. GADS outage events for the ten highest load days for the five year period were extracted and the number of large units out for any reason other than forced was tabulated:

Diagram 12

Year	Number of Large PJM Units Out
1996	3
1997	0
1998	1
1999	0
2000	2

The numbers in the table represent the greatest number of large generating units out on any of the ten highest load days. This number is conservative in the sense that it does not capture the possibility that an even greater number of large units could have been out on any of the other summer days. Based on these results, the standard modeling practice in the Reserve Requirement Study is to schedule one large generating unit out over the summer period for the model that comprises the MAAC region. For a study model twice the size of the MAAC region, as stated as case 3 on page 6, two large units are scheduled out over the summer period.

The proper modeling of generation units requires that any new unit falling under PJM's control area comply with submitting applicable data. This includes reporting using the eGADS web based system and transmittal of telemetry data to the PJM control center. PJM staff is working closely with the market integration companies to ensure that the proper data is obtained and verified in a timely manner.

Summer Maintenance Assessment

One of the activities of the PJM System Planning Division staff is reviewing and summarizing actual dispatcher logs of daily activities over the past year. Of particular interest are the planned outages over the peak summer period. The maintenance outage events of the summer period are reviewed to assess if any market participants are subject to penalty charges. The last several peak period maintenance assessments have indicated 100% compliance and resulted in no penalties for any PJM member. [33, 35]

Benchmarking of Frequency of Voltage Reduction Events

Findings show that PJM has implemented 11 voltage reductions over the last 13 years (1990 - 2002 inclusive). [21, 35] Of these 11, two were for test purposes and occurred at 9 PM and 3 AM. Five of the 11 were due to local transmission problems. That leaves the following four events due to a true system-wide capacity deficiency:

1/19/94 5% Voltage Reduction and Manual Load Dump
5/20/96 5% Voltage Reduction
5/8/00 5% Voltage Reduction
8/9/01 5% Voltage Reduction

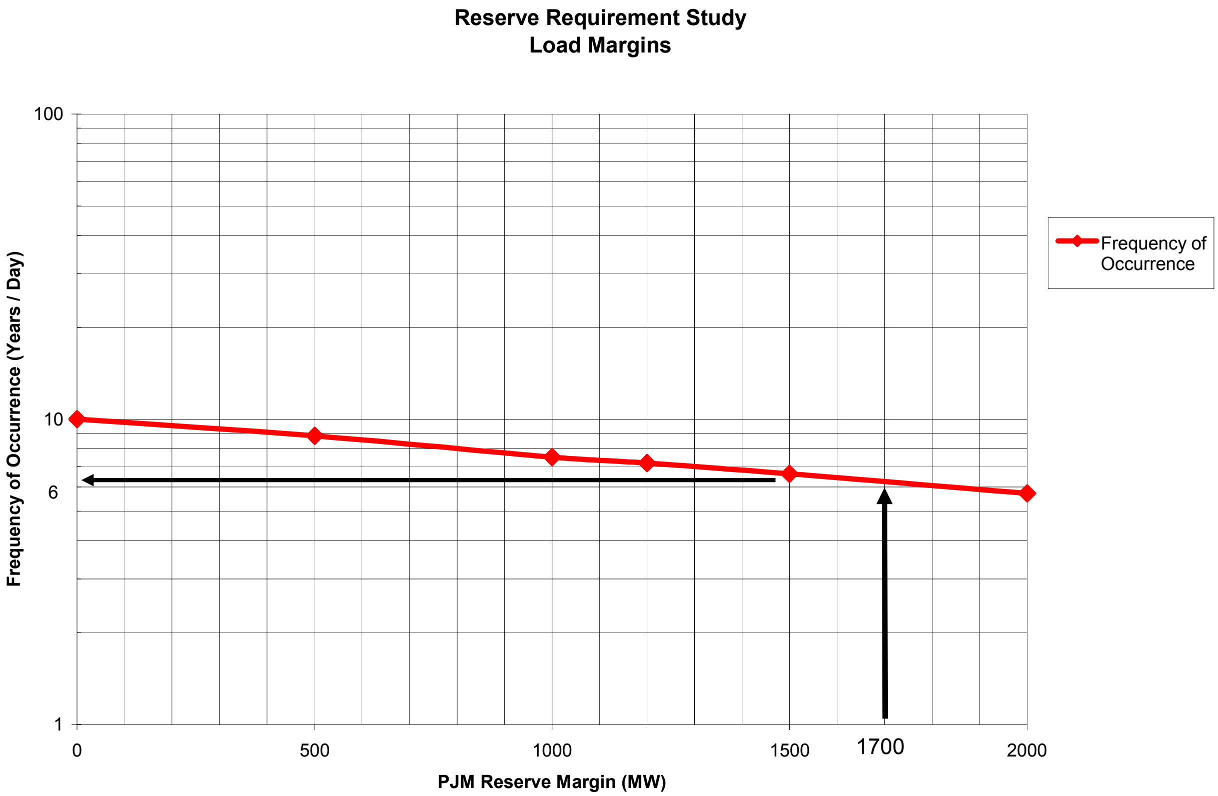
The January 1994 event was due to extraordinary weather conditions which led to a series of common cause failures stemming from fuel unavailability. The risk of common cause failures is not captured in the PRISM model, but work has begun to include this risk in future adequacy studies. That leaves 3 voltage reduction events in 13 years that PRISM would be expected to "predict".

The "1 in 10" criterion refers to the likelihood of having a 0 or negative reserve margin where:

reserve margin = available capacity – load

Voltage reductions are implemented at positive reserve margins. They are called at the operator's discretion following issuance of a primary reserve alert. A primary reserve alert is generally issued at a reserve margin of about 1700 MW. Voltage reductions are generally implemented when reserve margins drop to between 1200 MW and 1700 MW.

Diagram 13



PRISM analysis was performed to assess how often the adequacy model predicts the occurrence of a primary reserve alert, assuming these events occur at a reserve margin of 1700 MW. Diagram 13 depicts the likelihood of reserve margins ranging from 0 MW to 2000 MW. This diagram indicates the frequency with which a given reserve margin should occur (frequency is on the y axis and is expressed in years per occurrence). The y axis uses a logarithmic scale. The graph indicates that a reserve margin of 1700 MW should occur about once every six years (or twice in 12 years). Three primary reserve alerts (or four including January 1994) have been issued by Operations in the 13 year period from 1990 through 2002. The occurrence of operational events compared to the PRISM results are therefore well within the bounds of sampling error and indicate that PRISM does benchmark well with operating experience.

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Glossary

AEP

American Electric Power, a company and control area within ECAR.

Active Load Management (ALM)

Active Load Management applies to interruptible customers whose load can be interrupted at the request of the PJM OI. Such a request is considered an emergency action and is implemented prior to a voltage reduction.

ALM Factor

Ratio of ALM aggregate Load Carrying Capability (LCC) to total amount of ALM in PJM. The ALM LCC is determined by modeling ALM in the PJM reliability program. The ALM Factor is reviewed and changed, if necessary, each planning period by the Reliability Committee and PJM Board for use in determining the capacity credit for ALM.

APS

Allegheny Power System, a control area within ECAR that was the first portion of expansion of the PJM footprint and markets. Adjacent to the western portion of the MAAC region.

Available Transfer Capability (ATC)

The amount of energy above “base case” conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM Control Area under specified system conditions. ATC is the First Contingency Incremental Transfer Capability reduced by applicable margins.

Bulk Power Electric Supply System

All generating facilities, bulk power reactive facilities, and high voltage transmission, substation and switching facilities. Also included are the underlying lower voltage facilities that affect the capability and reliability of the generating and high voltage facilities in the PJM Control Area.

Capacity

Ability to deliver both firm energy to load located electrically within the Interconnection and firm energy to the border of the PJM Control Area for receipt by others.

CBM

Capacity Benefit Margin, expressed in megawatts, is a single value that represents the simultaneous imports into PJM that can occur during peak PJM system conditions. The capabilities of all transmission facilities that interconnect to the PJM Control Area with neighboring regions are evaluated to determine this single value.

Capacity Emergency Transfer Objective (CETO)

The import capability required by a subarea of PJM to satisfy the MAAC "1 in 10" adequacy requirement. This value is compared to the Capacity Emergency Transfer Limit (CETL) which represents the subarea's actual import capability as determined from power flow studies. The subarea satisfies the criteria if its CETL is equal to or exceeds its CETO. CETO/CETL analysis is typically part of the Deliverability demonstration.

ComEd

Commonwealth Edison is a control area within the Mid-America Interconnected Network. The Commonwealth Edison control area is in the state of Illinois principally centered around the Chicago metro area.

Control Area

An electric power system or combination of electric power systems bounded by interconnection metering and telemetry. A common generation control scheme is applied in order to:

- match the power output of the generators within the electric power system(s) plus the energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council of NERC;
- maintain power flows on Transmission Facilities within appropriate limits to preserve reliability; and
- provide sufficient generating Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Demand

See Load

ECAR

East Central Area Reliability Coordination Agreement. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the ECAR Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Ohio, Michigan, Indiana, Kentucky, West Virginia, Virginia, Tennessee, Pennsylvania, and Maryland.

Eastern Interconnection

The bulk power systems in the eastern portion of North America. The area of operation of these systems is bounded on the east by the Atlantic Ocean, bounded on the west by the Rocky Mountains, bounded on the south by the Gulf of Mexico and Texas, and includes the Canadian provinces of Quebec, Ontario, Manitoba and Saskatchewan. This is one of the three major interconnections within NERC.

EEFORd

Effective Equivalent Demand Forced Outage Rate. The forced outage rate used for reliability and reserve margin calculations. For each generating unit, this outage rate is the sum of the EFORd plus ¼ of the equivalent maintenance outage factor.

EFORd

Equivalent Demand Forced Outage Rate. The portion of time a unit is in demand, but is unavailable due to a forced outage.

eGADS

Web based Generator Availability Data Systems. Data is collected for both event and performance data in order to track projection of generating units' unavailability as required for PJM adequacy and capacity market calculations. This is based on the NERC GADS data reporting requirements, which in turn are based on IEEE Standard 762.

EICS

Emergency Import Capability Studies. A series of power flow studies that assess the capabilities of all PJM transmission facilities connected to neighboring regions under peak load conditions to determine the simultaneous import capability.

EMOF

Equivalent Maintenance Outage Factor. For each generating unit modeled, the portion of time a unit is unavailable due to maintenance outages.

ERCOT

Electric Reliability Council of Texas. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the ERCOT Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the state of Texas and is one of the three major interconnections within NERC.

FEF

Forecast Error Factor. A value that can be entered in the reliability program PRISM per planning period that indicates the percent increase of uncertainty in the forecasted peak loads. The FEF generally increases 0.5% per year as the planning horizon is lengthened.

FERC

The Federal Energy Regulatory Commission.

FOR

Generating Unit Forced Outage Rate. A statistic based on eGADS event data that indicates the likelihood a unit is unavailable due to forced outage events over the total time considered. There is no attempt to separate out forced outage events when there is no demand for the unit to operate.

Forecast Peak Load

Expected peak demand based on weather normalized load techniques. The forecast peak load is an hourly integrated total, in megawatts, indicating the load value given or higher has a 50 % probability of actually occurring.

Forecast Pool Requirement (FPR)

The amount, stated in percent, equal to one hundred plus the percent reserve margin for the PJM Control Area required pursuant to the Reliability Assurance Agreement (RAA), as approved by the Reliability Committee pursuant to Schedule 4 of the RAA. Expressed in units of "unforced capacity".

FRCC

Florida Reliability Coordinating Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the FRCC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the state of Florida.

GEBGE

See PRISM

Generating Availability Data System (GADS)

A computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Outage Rate Program (GORP)

A computer program maintained by the PJM Generator Unavailability Subcommittee that uses GADS data to calculate outage rates and other statistics.

Generator Forced/Unplanned Outage

An immediate reduction in output, capacity, or complete removal from service of a generating unit by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility. A reduction in output or removal from service of a generating unit in response to changes in or to affect market conditions does not constitute a Generator Forced Outage.

Generator Maintenance Outage

The scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility approved by the PJM OI.

Generator Planned Outage

The scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the PJM OI.

Generator Unavailability Subcommittee (GUS)

A PJM subcommittee, reporting to the Planning Committee, that is responsible for computing outage rates and other statistics needed by the Reliability Committee for calculating capacity obligations.

Good Utility Practice

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include practices, methods, or acts generally accepted in the region.

IRM

Installed Reserve Margin. The percent of aggregate generating unit capability above the forecasted peak load that is required for adherence to meet a given adequacy level. Expressed in units of installed capacity.

Load

Integrated hourly energy used either located electrically within the PJM Control Area or delivered to the border of the PJM Control Area for receipt by others. Loads are reported and verified to the tenth of a megawatt (0.1 MW).

Load & Capacity Subcommittee (L&CS)

A PJM subcommittee, reporting to the Planning Committee that assists PJM staff in performing the annual Reserve Requirement Study and maintains the reliability analysis documentation.

Load Analysis Subcommittee (LAS)

A PJM subcommittee, reporting to the Planning Committee that supplies the PJM peak and seasonal load forecasts.

LCC

Load Carrying Capability, typically expressed in megawatts. The amount of load that a given resource or resources can serve at a predetermined adequacy standard (typically one day in ten year).

LOLE

Generation System Adequacy is determined as Loss of Load Expectation (LOLE) and is expressed as days per year. This is a measure of how often, on average, the available capacity is expected to fall short of the demand. LOLE is a statistical measure of the frequency of failure and does not quantify the magnitude or duration of failure. The use of LOLE to assess Generation Adequacy is an internationally accepted practice

LOLP

Loss of Load Probability, which is the probability that the system cannot supply the load peak during a given interval of time, has been used interchangeably with LOLE within PJM. LOLE would be the more accurate term if expressed as days per year. LOLP is more properly reserved for the dimensionless probability values. LOLP must have a value between 0 and 1.0.

MAAC

The Mid-Atlantic Area Council, a reliability council under §202 of the Federal Power Act, established pursuant to the MAAC Agreement dated August 1994 or any successor.

A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAAC Region through coordinated operations and planning of generation and transmission facilities. The MAAC Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, and Virginia.

MAIN

Mid-America Interconnected Network. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAIN Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Illinois, Wisconsin, Missouri, and Michigan.

MAPP

Mid-Continent Area Power Pool. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAPP Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Wisconsin, Minnesota, Iowa, North Dakota, South Dakota, Nebraska, Montana and Canadian provinces of Saskatchewan and Manitoba.

MMWG

Multi-area Modeling Working Group. The NERC MMWG includes direct representation from the NERC Regions in the Eastern Interconnection, as well as a working group power flow and dynamics coordinator(s), a liaison representative of the NERC staff, and corresponding representatives from the ERCOT and WSCC Regions. The group is charged with the responsibility for developing and maintaining a library of power flow and dynamics base cases for the benefit of NERC members for use by the Regions and their member systems in planning and evaluating future systems and current operating conditions.

MPP

The Most Probable Peak Load is used in the PJM reliability program PRISM. This is the expected weekly peak load corresponding to the 50/50 load forecast based on a sample of 5 weekday peaks.

NERC

The North American Electric Reliability Council, a reliability council responsible for the oversight of regional reliability councils established to ensure the reliability and stability of the regions.

NPCC

Northeast Power Coordinating Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the NPCC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of New York, Main, Vermont, New Hampshire, Connecticut, Rode Island, Massachusetts, Canadian provinces of Ontario, Quebec, Nova Scotia, New Brunswick, and Prince Edward Island.

PC

Planning Committee. A technical committee that is charged with oversight of technical issues in configuration, analysis, planning and operation of the bulk electric power grid in the PJM Control Area. There are technical subcommittees that report to this Committee including: Relay Subcommittee, Load Analysis Subcommittee, Generator Unavailable Subcommittee, Load and Capacity Subcommittee, and Transmission and Substation Design Subcommittee

pcGAR

Personal computer based Generator Availability Report. The pcGAR is a database of all NERC generator data and provides reporting statistics on generators operating in North America. This data and application is distributed by NERC annually, with interested parties paying a set fee for this service.

Peak Load

See Forecast Peak Load

Peak Season

Peak Season is defined to be those weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week begins on a Monday and ends on the following Sunday, except for the week containing the 36th Wednesday, which ends on the following Friday.

PJM ISO

PJM Independent System Operator

PJM Open Access Same-Time Information System (PJM OASIS)

The electronic communication system for the collection and dissemination of information about Transmission Services in the PJM Control Area established and operated by the PJM OI in accordance with FERC standards and requirements.

Planning Period

The twelve months beginning June 1 and extending through May 31 of the following year, provided as changing conditions may require, the Reliability Committee may recommend other Planning Periods to the PJM Board of Managers.

PRISM

Probabilistic Reliability Index Study Model. PRISM is the PJM planning reliability program. PRISM replaced GEBGE which was a FORTAN language program. The models are based on statistical measures for both the load model and the generating unit model. This is a computer application developed by PJM that is a practical application of probability theory and is used in the planning process to evaluate the generation adequacy of the bulk electric power system.

Power Flow

Models and studies that determine the power flowing through transmission facilities based on various load and generating unit conditions. Typically, an iterative Newton-Raphson solution technique is used to determine the network flows in the transmission facilities based on Kirchhoff's and Ohm's laws which govern solution convergence.

R.I.

Reliability Index. The reliability index is a value that is used to assess the bulk electric power system's future occurrence for a loss-of-load event. A RI value of 10 indicates that there will be, on average, a loss of load event every ten years.

RAA (Reliability Assurance Agreement)

One of four agreements that define authorities, responsibilities and obligations of participants and the PJM OI. This agreement also defines the role of the RAA Reliability Committee. The agreement is amended from time to time, establishing obligation standards and procedures for maintaining reliable operation of the PJM Control Area. The other principal PJM agreements are the Operating Agreement, the PJM Transmission Tariff, and the Transmission Owners Agreement.

RAA-RC

Reliability Assurance Agreement Reliability Committee

R-Study

PJM Reserve Requirement Study, which is performed annually. The primary result of the study is a single calculated percentage, the R factor, that represents the amount above peak load that must be maintained to meet the MAAC adequacy criteria. The MAAC adequacy criteria is based on a probabilistic requirement of experiencing a loss-of-load event, on average, once every ten years.

SERC

Southeastern Electric Reliability Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the SERC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Arkansas, Kentucky, Louisiana, Missouri, Texas, and West Virginia.

SPP

Southwest Power Pool. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the SPP Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Kansas, Oklahoma, Texas, Arkansas, Louisiana, and New Mexico.

Weather Normalized Loads

A load adjustment technique approved by the Load Analysis Subcommittee to compensate load data for weather conditions. The adjustment changes the load values to those associated with a 50 / 50 probability of occurrence. (i.e. the load value given or higher has a 50 % probability of actually occurring). This technique is typically associated with forecasting peak load values.

World

Refers to the area electrically connected to the PJM Control Area. Could include ECAR, NPCC and SERC or most of the Eastern Interconnection depending on the study requirements.