2007

PJM Reserve Requirement Study

PJM Capacity Obligation Parameters for the 10-year Planning Horizon from June 1st 2007 through May 31st 2017

Reserve Requirement Assumptions Working Group (RRAWG)
Planning Committee (PC)

August 15, 2007

This page intentionally left blank

2007 PJM Reserve Requirement Study

Table of Contents Page

Part 1 – Results and Recommendations

PJM RRS Executive Summary

- The Reserve Requirement Study (RRS), conducted each year by PJM, establishes the reliability parameters that support a generation Loss of Load Expectation (LOLE) of once, on average, every 10 years for the PJM RTO.

- Consistent with the requirements of ReliabilityFirst Corporation (RFC) Standard BAL-502-RFC-01 - Resource Planning Reserve Requirements, the 2007 RRS provides a ten-year resource adequacy projection for the planning horizon that begins June 1, 2007 and extends through May 31st, 2017.

- This Study satisfies all NERC / RFC Adequacy Standard BAL-502-RFC-01 - Resource Planning Reserve Requirements for all entities that are in the PJM Planned Reserve-Sharing Group (PRSG).

- The purpose of the RRS is to determine the Forecast Pool Requirement (FPR) and the Demand Resource (DR) Factor by calculating the Installed Reserve Margin (IRM) for future planning periods. (The DR Factor was formerly known as the Active Load Management (ALM) Factor.) In accordance with the Reliability Pricing Model (RPM) auction schedule, results from this study will establish the IRM and associated parameters for the 2010/11 and 2011/12 planning periods only.

- The results of the 2007 RRS are summarized below: **The RRAWG and PJM Staff recommend the values shown in bold in the following chart.**

RRS Year	Delivery Year Period	Calculated IRM	**Recommended IRM**	Avg. EFORd	**Recommended FPR**	**Recommended DR Factor**
2007	2010 / 2011	15.5%	**15.5%**	6.21%	**1.0833**	**0.955**
2007	2011 / 2012	15.5%	**15.5%**	6.21%	**1.0833**	**0.955**

Note: Avg. EFORd does not include Outside Management Control events beginning in 2006.

- The IRM, FPR and DR Factor values recommended above require review, endorsement and approval by the following succession of groups:
  - Planning Committee (PC)
  - Markets and Reliability Committee (MRC)
  - PJM Members Committee (MC)
  - PJM Board of Managers

- The Capacity Model in the study is based on five historical years of generator performance (2002-2006).

- The Load Model is based on nine historical years of hourly loads (1996-2004). The load model consists of 52 weekly mean and standard deviation values. For the 2007 RRS, the Load Model basis was changed from a 7-year period to a 9-year period. Using a longer time period will increase consistency between annual studies.

- For the 2007 RRS, there is a net increase of 5,508 MW of generation within the PJM RTO, reflecting approximately 7,172 MW of new generation and approximately 1,664 MW of retired generation. This is over the ten year time period of the study.

- PJM's PRISM program is the primary reliability modeling tool used in the RRS. PRISM utilizes a two-area LOLP modeling approach consisting of: Area 1: the PJM RTO and Area 2: the outside World.

- The PJM RTO includes the PJM Mid-Atlantic Region, APS (Allegheny Power System), AEP (American Electric Power), ComEd (Commonwealth Edison), Dayton (Dayton Power and Light), DLCO (Duquesne Power and Light) and Dom (Dominion Virginia Power).

- The Outside World (or "World") area consists of several adjacent NERC (North American Electric Reliability Corporation) regions including: NPCC (Northeast Power Coordinating Council), MRO (Midwest Reliability Organization), and the non-PJM portions of SERC (South Eastern Reliability Corporation) and the RFC (Reliability *First* Corporation).

- Modeling of the "World" region assumes a Capacity Benefit Margin (CBM) of 3,500 MW to PJM.

- The PRISM-driven reliability model calculated an IRM for 2010 / 2011 of 15.5%. This represents a 0.8% increase from last year's calculated value of 14.7% IRM for 2009/2010.

- **The increase of 0.8% in the IRM from last year's study is due to two factors: a slight increase in the PJM average forced outage rate and, more importantly, a decrease in PJM/World load diversity**. Decreased PJM/World load diversity results in less capacity emergency assistance being available to PJM from external areas. In this year's model, both PJM and the World peaked in the same week. As discussed in the Key Observations section and detailed in Appendix K, over the last nine years PJM and World peaks are more likely than not to occur during the same week.

- **Based on these study results, the RRAWG and PJM Staff recommend endorsement of a 15.5% IRM for both the 2010/2011 and 2011/2012 planning periods. The purpose of the IRM is to send a stable, long-term price signal to the capacity market. Significant adjustments to the IRM should only be made after a clear trend has been identified. Since this is the first study in many years that indicates an increase in the IRM, the RRAWG and PJM Staff believe that the IRM adjustment should be modest unless and until a clear trend over multiple studies is established.**

- Compared to the 2006 RRS model, the 2007 RSS five-year average Effective Equivalent Demand Forced Outage Rate (EEFORd) increased by 0.14% to 6.80%.

- For the calculated Forecast Pool Requirement, the pool wide average EFORd value does not include outage events considered outside management control. eGADS users began to enter outage events of this type in January, 2006. Determining the Forecast Pool Requirement in this manner is consistent with the way that generator unforced capacity (UCAP) values are determined in the PJM capacity market.

- The **winter weekly reserve target** for the 2007/ 2008 winter period **is recommended to be 28%**. This is the same value that was approved for the 2006/2007 winter period. The analysis supporting this recommendation is detailed on pages 32-33 of this report.

- Historical RRS values:

Table 1

Historical RRS Parameters

RRS Year	Delivery Year	Calculated IRM	**Approved IRM**	Avg. EFORd	FPR	DR Factor
2000	2000/2001	18.3%	19.5%	9.8%	1.0784	0.987
2001	2001/2002	17.4%	19.0%	9.5%	1.0767	0.965
2002	2002/2003	19.0%	19.0%	8.4%	1.0897	0.966
2003	2003/2004	16.4%	17.0%	6.4%	1.0950	0.950
2004	2004/2005	14.9%	16.0%	5.9%	1.0912	0.953
2005	2005/2006	14.5%	15.0%	6.5%	1.0749	0.946
2005	2006/2007	14.7%	15.0%	6.1%	1.0795	0.954
2006	2007/2008	14.6%	15.0%	6.2%	1.0790	0.957
2006	2008/2009	14.6%	15.0%	6.1%	1.0796	0.958
2006	2009/2010	14.7%	15.0%	6.1%	1.0795	0.957

Introduction

- **Purpose**

  The annual PJM Reserve Requirement Study (RRS) calculates the reserve margin that is required to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabiltyFirst Corporation (RFC) Standard RFC–RES-001. This study is conducted each year in accordance with the process outlined in PJM Manual 20 (M-20), ***PJM Reserve Requirements***. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to serve customer load with sufficient reserve for reliable service.

  The results of the RRS provide key inputs to the Reliability Pricing Model (RPM). These parameters include the Installed Reserve Margin (IRM), pool wide average Equivalent Demand Forced Outage Rate (EFORd), Forecast Pool Requirement (FPR) and Demand Resource (DR) Factor. These values are used in the RPM auctions and are specifically used to determine the Variable Resource Requirement (VRR) curve for the RTO. The DR Factor is used to determine the UCAP value of the two PJM load management products: Demand Resources (DR) that can be offered into the RPM auctions and Interruptible Load for Reliability (ILR) that is nominated and certified prior to the delivery year. Please refer to PJM's RPM Manual for further details. These parameters are also coordinated with Capacity Emergency Transfer Objective (CETO) analysis.

  The results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process, pursuant to Schedule 6 of the PJM Operating Agreement, for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

- **Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR)**

  The IRM and FPR are important values calculated in the RRS as they satisfy compliance requirements for ReliabiltyFirst Corporation (RFC) and they are used in the RPM market. See Report Sections: Compliance with ReliabilityFirst Corporation, Market Related Assessments, and Appendix C for further details.

  The timetable for calculating and approving these values is based on the RPM marketplace requirements.

- **DR Factor (formerly ALM Factor)**

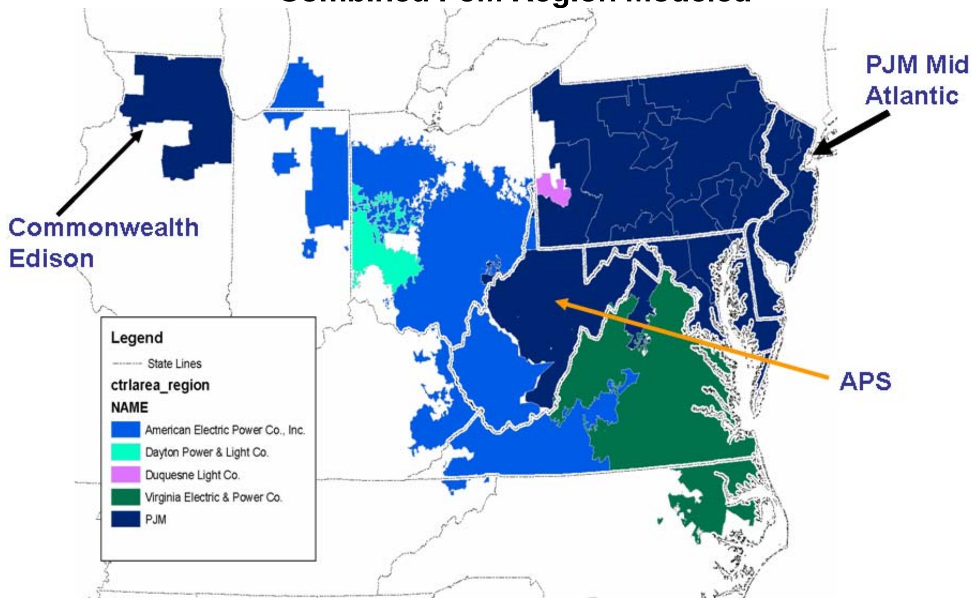
  The DR Factor is used under the RPM to determine the UCAP value of load management products. See Report Section: Market Related Assessments for further details. This Factor must be based on the final IRM and FPR values approved by the PJM Board of Managers. If an IRM other than the recommended value of 15.5% is approved by the PJM Board, the FPR and DR Factor would need to be re-calculated.

  The timetable for calculating and approving this value is based on the RPM marketplace requirements.

- **Regional Modeling**

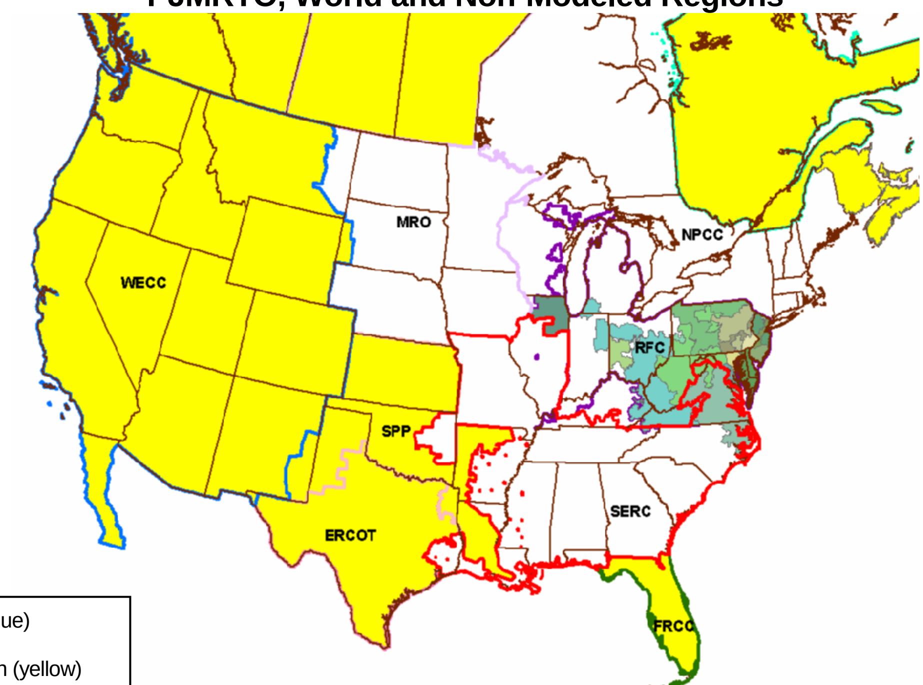
  The study examines the combined PJM footprint area (Figure 1) that consists of the PJM Mid-Atlantic Region plus APS (Allegheny Power System), ComEd (Commonwealth Edison), AEP (American Electric Power), Dayton (Dayton Power and Light), DLCO (Duquesne Light) and DomVP (Dominion Virginia Power).

Figure 1
Combined PJM Region Modeled



Areas adjacent to the PJM Region are referred to as the "World" (Figure 2) and consist of the non-PJM portion of RFC and the Southeastern Electric Reliability Council (SERC), much of the Northeast Power Coordinating Council (NPCC) territory and the Midwest Reliability Organization (MRO-USA). Areas outside of PJM and the World are not modeled in this study. However, sensitivities are periodically run to assess if all the appropriate areas are included in the World model.

Figure 2
PJMRTO, World and Non-Modeled Regions



PJM RTO (green / blue)
World (white)
Non-Modeled Region (yellow)

Summary of RRS Results

- **Ten-Year RRS Results**

Table 2 below shows a ten-year forward projection from the study for informational purposes. The two years for which the parameters must be finalized are highlighted in yellow.

Table 2
Ten-Year Reserve Requirements Summary

	Calculated IRM				Forecast Reserve			Assumed IRM	
	A	B	C	D	E	F	G	H	I
Delivery Year	% IRM PJM RTO	% IRM Outside World	Average PJM EEFORd %	Average Weekly Maintenance %	% Forecast Reserve PJM RTO	% Forecast Reserve Outside World	PJM Reliability Index (single area)	Assumed % IRM PJM RTO	PJM Reliability Index (single area)
2007	15.6%	14.7%	6.9%	5.7%	23.5%	20.4%	149	15.0%	5
2008	15.5%	14.7%	6.8%	5.6%	22.4%	19.9%	92	15.0%	6
2009	15.4%	14.7%	6.8%	5.7%	21.0%	19.6%	53	15.0%	6
2010	15.5%	14.7%	6.8%	5.7%	19.9%	19.1%	34	15.0%	6
2011	15.5%	14.7%	6.8%	5.7%	18.8%	18.6%	22	15.0%	6
2012	15.5%	14.7%	6.8%	5.8%	17.5%	17.5%	14	15.0%	6
2013	15.4%	14.7%	6.8%	5.8%	16.3%	16.8%	9	15.0%	6
2014	15.4%	14.7%	6.8%	5.8%	14.6%	15.9%	5	15.0%	6
2015	15.4%	14.7%	6.8%	5.8%	12.9%	15.4%	3	15.0%	6
2016	15.4%	14.7%	6.8%	5.8%	11.8%	15.1%	2	15.0%	6
10-year Average	**15.5%**	**14.7%**	**6.8%**	**5.7%**	**17.9%**	**17.8%**	**38**	**15.0%**	**6**

- **Calculated IRM Section** (PRISM Run # 3048)
    - PJM Reliability Index is in years/day
    - Results reflect “calculated” (un-rounded) reserve requirements for the PJM RTO (column A) and the Outside World (column B) resulting from application of the PRISM and Week Peak Frequency modeling tools.
    - Calculated IRM results are determined using a 3,500 MW Capacity Benefit Margin (CBM).
    - The capacity model used for this study includes external PJM capacity purchases and sales.
    - 2,500 MW of unit deratings were modeled to reflect generator performance impacts during extreme hot and humid summer conditions.
    - The Average Forced Outage Rates (EEFORd) (column C) is a pool average effective equivalent demand forced outage rate for all units in the PJM RTO model (about 1,100 units). These are not the forced outage rates to be used in the RAA Obligation formula and are based on a 5 year period.
    - The average weekly maintenance (column D) is the percentage of the average annual total capacity in the model out on weekly planned maintenance.

- **Forecasted Reserves Section** (PRISM Run # 3050)
    - The PJM RTO forecast reserves (column E) are used to derive the PJM reliability index (column G).
    - The PJM forecast reserves for the next ten years are above the calculated requirement. Reserves include about 7,172 MW of new generation projects identified through the Regional Transmission Expansion Plan (RTEP). All modeled generation projects have a commercial probability assigned to them and are included in the EIA-411 data submission. The commercial probability has a value between 0.15 and 1.0. A project receives a value of 1.0 (100%) when it becomes commercially available. The commercial probabilities are listed in Table 9 on page 24.

- The reserves also reflect about 1,664 MW of announced generator retirements.
- It is important to note that the RTEP is dynamic and that the actual PJM reserve levels may differ significantly from those forecasted today. Another factor contributing to future reserve margin uncertainty is PJM's rule which allows units to retire with as little as 90 days notice.
- Reserves (column E and column F) are expressed as percent of restricted peak load.
- PJM Reliability Index (column G) is expressed in years per day (the inverse of the days per year LOLE). This column indicates reliability when all external ties are cut into PJM. This parameter represents "zero import capability" or the PJM single area case. The Reliability Index (RI) for the Forecast Reserve (column G) represents the expected number of years before a loss of load event will occur.
- The forecast reserves include all known purchase and sales, per the EIA-411 Schedule 4.

o **Assumed IRM Section** (PRISM run # 2854)

- Column H values are used to determine the Column I values. This assumes, per the study assumptions, an approved reserve requirement for information purposes only.
- The Final IRM for the PJM RTO (column H) is an assumed value. This is intended for information in the stakeholder review and endorsement and ultimately, PJM Board approval.
- The RI for the Assumed IRM (column I) represents the frequency of loss of load occurrences if the PJM RTO were not part of the Eastern Interconnection. Compared to the RI for the Calculated IRM, the Assumed IRM RI has lower indices giving a sense of the value of PJM being strongly interconnected. In other words, if PJM were not interconnected it could experience loss of load events twice as often.

Key Observations

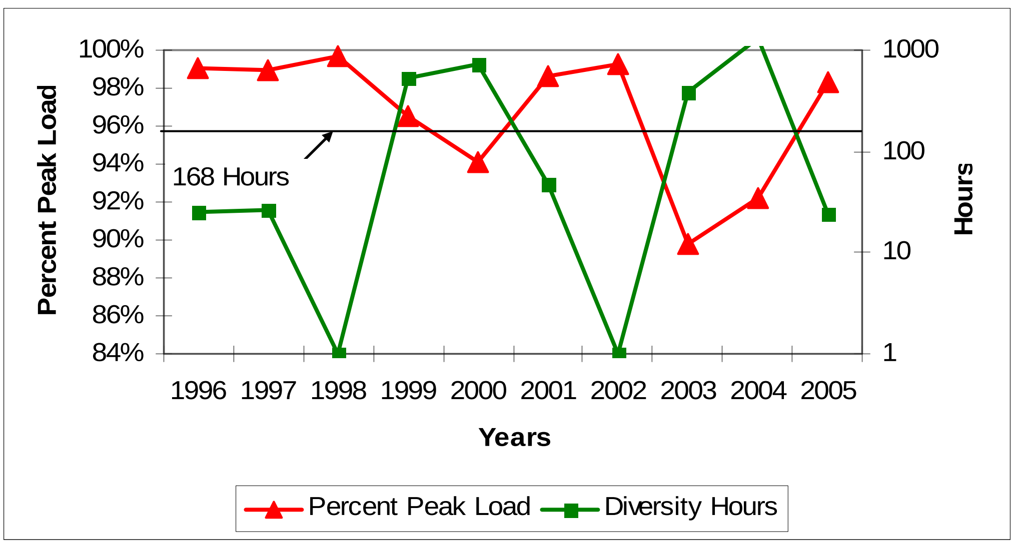
- **General Trends and Observations**

    - Generation performance characteristics, such as unit availability, have appeared to stabilize. For example, the pool wide average forced outage rate used in the study is only 0.14% above that seen last year. The generation model is the single most significant modeling parameter in the determination of the IRM.

    - Load model diversity continues to have a significant impact on IRM results. Diversity is the timing of when the World area peaks compared to when the PJM RTO area peaks. In the 2006 RRS, there was diversity or separation of when the two areas peaked. The greater the diversity, the more capacity assistance the World can give at the time when PJM needs it and, therefore, the lower the PJM IRM. Diversity is a modeling characteristic that PJM has little or no control over. For this reason, engineering judgment should be applied in determining the correct level of reserves. Figure 3 below shows that typically PJM and the World peak during the same week, i.e. there is little diversity. Zero diversity occurs in the figure below when the red line is at 100% and the green line is at hour 1. The left vertical axis shows the World peak (as a percentage of its annual peak) coincident with the PJM peak for each of the last ten years. The right vertical axis (logarithmic scale) shows the number of hours between the PJM and the World respective peaks. If the hours are at or below 168 (7days X 24 Hrs), the PJM and World peaks occurred during the same week. Figure 3 shows that six of the last ten years have had little or no PJM/World load diversity. See also Appendix K.

Figure 3

Diversity between PJMRTO and World



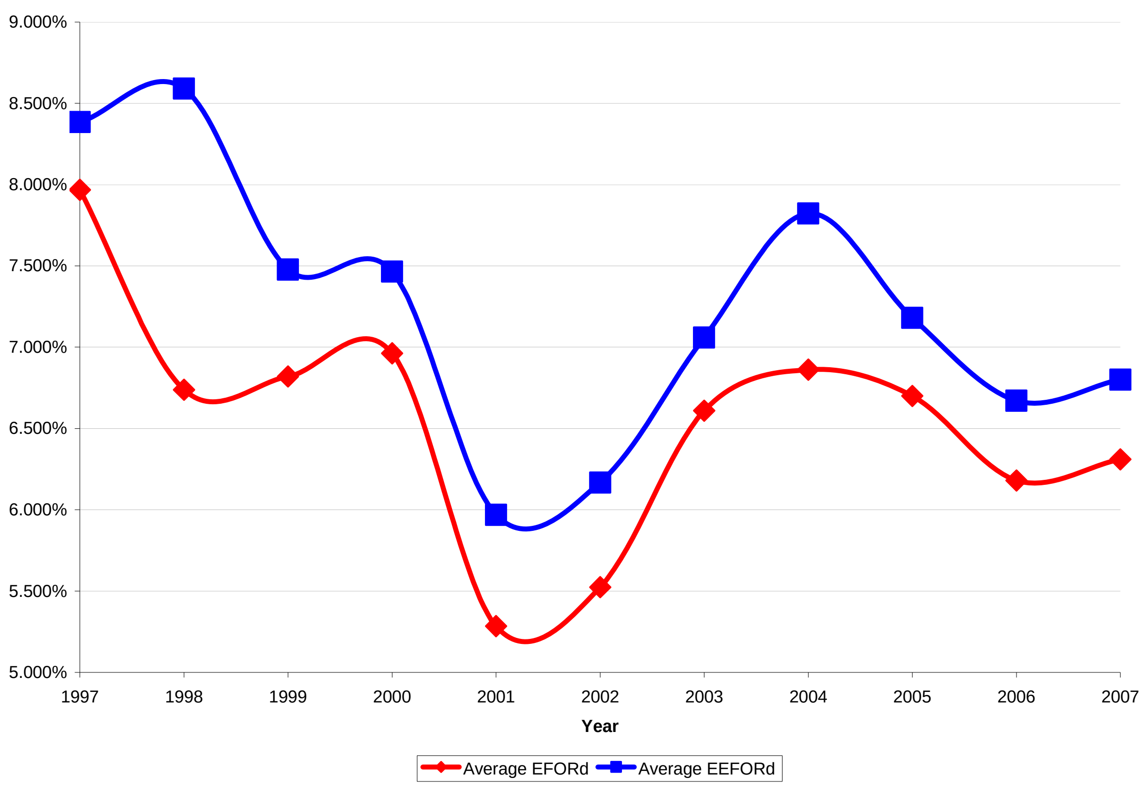
    - Changes in load model characteristics are having a significant impact on certain study results. The combination of stabilized generation performance characteristics and normal variations in load model characteristics has necessitated further analysis by PJM Staff. PJM Staff instituted a review process to assess the hourly loads used in the model. This will improve the consistency of the studies from year to year and among the various studies (RRS, CETO, and Interregional). Recent observations indicate that study areas with a relatively small reserve margin and good unit performance are particularly sensitive to small load model characteristic changes. PJM is investigating the possible use of a new load model in capacity adequacy studies. This new load model would be based on the model used in the recently developed PJM load forecasting process. PJM staff will review with the RRAWG the results of this investigation as it progresses.

- o Numerous sensitivity cases were performed and the results are shown in Appendix B. These sensitivity results are an important input in developing a recommendation for the IRM and FPR. Considering long-term trends and not focusing exclusively on individual study results is important when developing an IRM recommendation.

- o The trend in the RSS capacity model performance is shown in Figure 4. The change in EFORd and EEFORd is relatively small from study to study.

Figure 4

PJMRTO Capacity Forced Outage Rate Variation



- o The winter ratings for many units were significantly reduced. Winter ratings have no effect on the IRM calculation but may impact CETO values for some Load Deliverability Areas.

Recommendations

- **Installed Reserve Margin (IRM)** — Based on the study results and the additional considerations mentioned above, PJM recommends endorsement of an IRM value of 15.5% for the 2010 / 2011 delivery year and 15.5% for the 2011 / 2012 delivery year. The Reserve Requirement Assumptions Working Group reviewed these study results and unanimously endorsed the PJM recommendation.

- **Forecast Pool Requirement (FPR)** — The approved IRM is converted to the FPR for use in determining capacity obligations. The FPR is defined by the following equation:

FPR = (1 + IRM) * (1 – PJM Avg. EFORd)

Note: PJM Avg. EFORd does not include Outside Management Control events beginning in 2006.

An IRM of 15.5%, with a PJM average EFORd of 6.21%, would yield the following FPRs:

2010 / 2011 Delivery Year	**FPR = (1.155) * (1 – 0.0621) = 1.0833**
2011 / 2012 Delivery Year	**FPR = (1.155) * (1 – 0.0621) = 1.0833**

- **Demand Resource Factor (DR Factor)** — The DR Factor is based on the approved IRM. The values shown below assume an approved IRM of 15.5%. The DR Factor is a measure of the reliability value of demand resources. The load carrying capability of these resources is divided by the total amount of DR to yield the factor.

2010 / 2011 Delivery Year	**DR Factor = 2049 / 2146 = 0.955**
2011 / 2012 Delivery Year	**DR Factor = 2050 / 2146 = 0.955**

- **Winter Weekly Reserve Target** — The recommended 2007 / 2008 Winter weekly reserve target is **28%**. This recommendation is discussed on pages 32 – 33 of this report.

Part 2 – Modeling and Analysis

Load Forecasting

- **PJM Load Forecast – January 2007**

  The most recent PJM Load Forecast is used in the 2007 RRS. The forecast is contained in the PJM Load Forecast Report – January 2007 which is available on the PJM web site at: http://www.pjm.com/documents/reports.html. Please see PJM Manual 19 (Load Data Systems) for the methods and techniques used in the load forecasting process. Manual 19 is available at: http://www.pjm.com/contributions/pjm-manuals/manuals.html.

- **Monthly forecasted Unrestricted Peak demand, Demand Resources and Interruptible Load for Reliability.**

  The monthly loads used in the RRS are based on the forecasted monthly unrestricted peak loads. The forecasted monthly peak loads are shown in Table 3.

  While the PJM forecasted loads are from the PJM Load Forecast Report - January 2007, the World loads are derived from NERC's Electric Supply and Demand (ES&D) data and coordination with neighboring regions' staffs. This year NERC's ES&D had for the first time the ReliabilityFirst Corporation (RFC), Midwest Reliability Organization (MRO), Southeast Reliability Council (SERC), and Southwest Power Pool (SPP) defined differently than previous region boundaries. This was the first year of the RFC with no historic data available. PJM Staff restated the current data into the previous zone definitions (ECAR, MAIN, etc). This restatement of region boundaries will continue to be used in future studies until the historic hourly loads are accumulated for the required RRS time period.

  The forecasted load reductions available from identified demand resources are shown in Table 3. The forecasted load reductions available from demand resources are applied to the forecasted monthly unrestricted peak loads to obtain the forecasted monthly restricted peak loads. The IRM is the amount of capacity above the restricted peak load required for a loss of load occurrence once, on average, every 10 years.

Table 3

Load Forecast for 2010 / 2011 and 2011 / 2012 Delivery Years

		PJMRTO			WORLD		
Delivery Year	**Month**	**Unrestricted Load**	**Load Management**	**Restricted Loads**	**Unrestricted Load**	**Load Management**	**Restricted Loads**
2010 / 2011	January	118330	1499	116831	349563	9898	339665
	February	114261	1499	112762	331822	9898	321924
	March	105180	1499	103681	309857	9898	299959
	April	99163	1499	97664	279488	9898	269590
	May	111942	1499	110443	324858	9898	314960
	June	134687	2146	132541	380246	9826	370420
	July	144082	2146	141936	408574	9826	398748
	August	136838	2146	134692	405586	9826	395760
	September	123102	2146	120956	363260	9826	353434
	October	98348	1499	96849	299552	9898	289654
	November	103045	1499	101546	305055	9898	295157
	December	115401	1499	113902	330357	9898	320459
2011 / 2012	January	119703	1499	118204	355597	9835	345762
	February	115837	1499	114338	337531	9835	327696
	March	106003	1499	104504	315401	9835	305566
	April	100469	1499	98970	284069	9835	274234
	May	113855	1499	112356	330084	9835	320249
	June	137009	2146	134863	386276	9763	376513
	July	146404	2146	144258	415159	9763	405396
	August	139179	2146	137033	412028	9763	402265
	September	124440	2146	122294	369450	9763	359687
	October	99643	1499	98144	304227	9835	294392
	November	104499	1499	103000	309977	9835	300142
	December	117035	1499	115536	335882	9835	326047

- **Forecast Error Factor (FEF).**
  The forecast error factor represents the increased uncertainty associated with forecasts covering a longer time horizon. Historically, the RRS had used a FEF beginning with 0.5 % for the first forecast year and increasing by 0.5 % for each successive delivery year. The FEF was limited to a maximum value of 3%. With the recent implementation of the RPM capacity market, the forecast error factor used in the RRS has been changed to 1.0% for all future delivery years. This is due to the ability for the market to acquire additional resources in auctions close to the delivery year. This mitigates the uncertainty of the load forecast as RPM mimics a one-year-ahead forecast. See Appendix F and the Modeling and Analysis Section for further discussion of how the FEF is used in the determination of the Expected Weekly Maximum (EWM).

- **21 point Standard Normal weekly distribution.**
  PRISM's load model is a weekly load model. PRISM computes the daily LOLE using weekly distributions. The RRS uses a standard normal distribution as the appropriate forecast weekly distribution. This distribution is based on 5 peak weekdays. The standard normal distribution is represented using 21 points with the values shown below

Table 4

Normal Distribution Values

Sigma	Probability
4.2	0.000033
3.78	0.000145
3.36	0.000638
2.94	0.002351
2.52	0.007273
2.1	0.01894
1.68	0.0414
1.26	0.07608
0.84	0.11749
0.42	0.15248
0	0.16634
-0.42	0.15248
-0.84	0.11749
-1.26	0.07608
-1.68	0.0414
-2.1	0.01894
-2.52	0.007273
-2.94	0.002351
-3.36	0.000638
-3.78	0.000145
-4.2	0.000033

Figure 5

Normal Distribution Graph

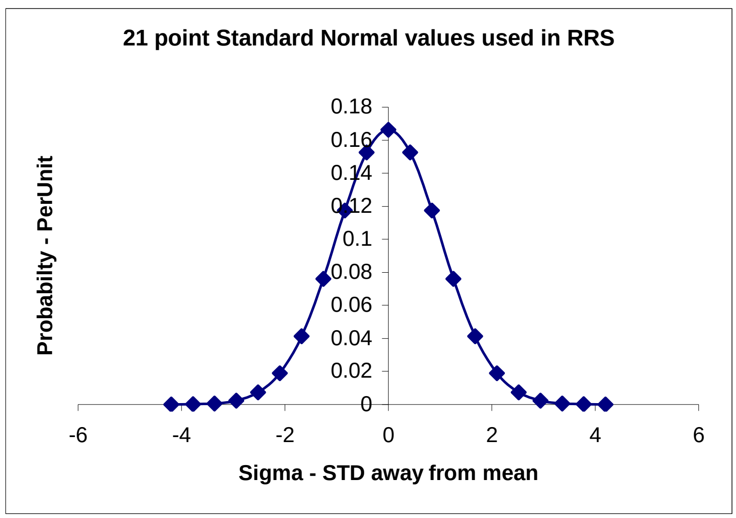


Figure 6 graphically shows how the distribution in Figure 5 is overlaid onto the weekly EWM to determine the LOLE for each week. This uses an order statistic of 5 which represents the 5 daily weekday peaks. See Appendix F for further discussion of how the order statistic, when n= 5, is used in the determination of the EWM and how the 21 points are used to determine the daily LOLE.

- **Week Peak Frequency (WKPKFQ) Parameters.**
  Forecasted weekly unrestricted peaks are obtained from the forecasted monthly unrestricted peaks. These forecasted weekly unrestricted peaks are applied to a weekly peak model which is developed using the Week Peak Frequency (WKPKFQ) application. WKPKFQ currently uses historical data to obtain a weekly peak mean and standard deviation for each week of the study period. Then each year of the historical data is magnitude ordered (highest to lowest) and averaged across years to replicate actual load experience. The weekly restricted peak and the WKPKFQ mean and standard deviation are used to develop weekly standard normal distributions for each week of the study period. The definition of the load model, per the input

parameters necessary to submit a WKPKFQ run, define the modeling region and basis for all adequacy studies. WKPKFQ required input parameters include:

- Historic time period of the model.
- Sub-zones or geographic regions that define the model.
- Forecast report to use.
- Start and end year of the forecast study period.
- 5 or 7 days to use in the load model. All RRS studies use a 5 day model, excluding weekends.
- Holidays to exclude from hourly data. These include Labor Day, Independence Day, Memorial Day, Good Friday, New Year's Day, Thanksgiving, Black Friday, and Christmas Day.

Table 5 shows the results of the PJMRTO WKPKFQ run used in this study.

Table 5

PJMRTO Load Model Parameters

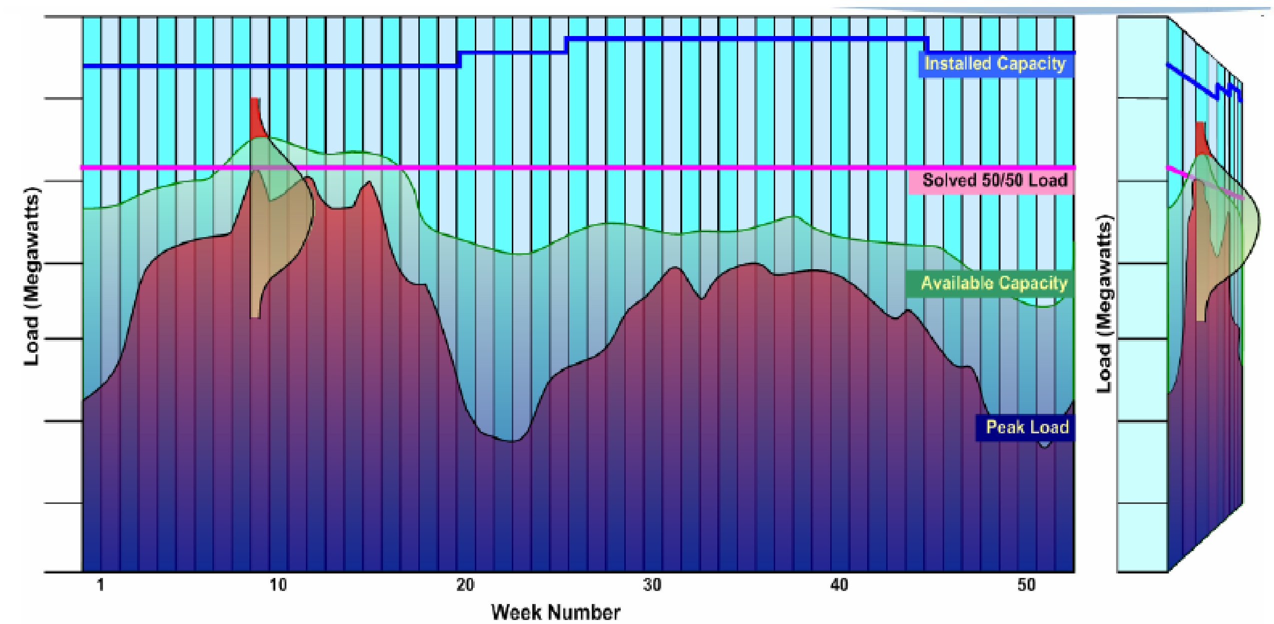
Week Number	Mean	Standard Deviation
1	0.68169	0.03819
2	0.69869	0.04255
3	0.7253	0.048
4	0.76395	0.07369
5	0.83014	0.06741
6	0.87808	0.0573
7	0.92363	0.06711
8	0.87494	0.06634
9	0.89852	0.07555
10	1	0.07047
11	0.93108	0.07357
12	0.89212	0.06988
13	0.97137	0.06452
14	0.86023	0.0914
15	0.85606	0.05917
16	0.83519	0.04338
17	0.78228	0.06714
18	0.80722	0.06142
19	0.73822	0.06109
20	0.67648	0.02023
21	0.70666	0.03166
22	0.68615	0.03201
23	0.68015	0.02927
24	0.69623	0.03102
25	0.71375	0.03663

Week Number	Mean	Standard Deviation
26	0.72659	0.05108
27	0.73944	0.02797
28	0.75038	0.03236
29	0.75273	0.04395
30	0.78168	0.05032
31	0.80234	0.05586
32	0.8043	0.0535
33	0.78916	0.05138
34	0.82718	0.06361
35	0.81217	0.05091
36	0.84827	0.05879
37	0.81818	0.05889
38	0.79734	0.05072
39	0.78901	0.05718
40	0.77101	0.05052
41	0.77015	0.04162
42	0.76019	0.04405
43	0.77687	0.04712
44	0.73342	0.04367
45	0.72299	0.03594
46	0.70584	0.04002
47	0.68422	0.0344
48	0.67166	0.02977
49	0.69893	0.04663
50	0.67234	0.02044
51	0.68474	0.02401
52	0.74085	0.10528

Parameter	**Value**
Title	PJM07RST
Description	PJM RTO 2007 R-Study 9 Year Plots Model {1996-2004} LAS Year: 2007 Growth Start Year: 2007 Growth End
Year Range	1996 - 2004
Growth Factor	0.011213824
Growth Start Year	2007/2008
Growth End Year	2016/2017
Report Select	1
Zones	AE,BGE,DPL,JCPL,METED,PN,PECO,PEPCO,PL,PS,RECO,UGI,AEP,APS,COMED,DAY,DQE,VEPO
Exclude Weekends	Y
Exclude Holidays	Y
Excluded Holidays	1 ,2,3,4,5,6,7,8

Figure 6 shows how the load parameters are coordinated to calculate values for a loss of load event, and the associated probability for these values (a higher value is less likely to occur). See Appendix F for further discussion of how the daily LOLE is determined. The Peak Load line is statistically adjusted until the 1-day-in-10-years criterion is met. 52 weekly LOLEs are summed to get the annual LOLE. In Figure 6, the beginning of Week 1 corresponds to May 15th.

Figure 6
52-week PJMRTO Load Profile



Generation Forecasting

- **GADS Data and eGADS Procedures.**

  The principal modeling parameters in the RRS are those that define the generator unit characteristics. All generation units' performance characteristics are derived from PJM's eGADS web based system. For detailed information on PJM Generation Availability Data System (GADS), see Manual M23 posted on the PJM site at: http://www.pjm.com/contributions/pjm-manuals/pdf/m23.pdf . The eGADS system is based on the IEEE Standard 762-2006. IEEE Standard 762 – 2006 is available by going to the IEEE web site (http://www.ieee.org/portal/site) => Standards => Buy Standards => Type 762 in the search window.

  The PJM Reliability Assurance Agreement (RAA), Schedule 4 and Schedule 5 are related to the concepts used in generation forecasting. The RAA dated September 29, 2006, is available at: http://www.pjm.com/documents/downloads/agreements/raa.pdf . However, a revised RAA per the recent RPM implementation was submitted for FERC approval June 19, 2007. Implementation of this revision is pending FERC approval.

  Appendix B, Sensitivity run number 13 indicates that a 1% change in the pool wide EEFORd will cause a change of 1.26% in the IRM. This indicates a direct, positive correlation between unit performance and the solved IRM.

- **GADS Data and PJM Fleet Class Average Values**

  For units with missing or insufficient GADS (Generating Availability Data System) data, PJM utilizes "class average" data developed from PJM's RTO fleet-based historical unit performance statistics. This was a change from the use of NERC based "class averages" in previous studies. Such "class averaging" is therefore used for future units, neighboring system units, and for those PJM units with less than 5 years of GADS events. Recent improvements to PJM's fleet-based statistics include:
  - the ability to check on specifics of underlying data,
  - the ability to verify specifics of statistical calculations and
  - identification of necessary data that is independent of outside resources.

With recent market integration activities, the PJMRTO Region has significantly increased its number of generating units. This increase has mitigated the need for assistance from the world region and improved the reliability of PJM on a stand-alone basis. See Figure 9 or Sensitivity runs #16 and # 23 (Appendix B) regarding single area related assessments. Less than one half of the units in PJM continue to use class average data for at least part of their five-year history. It's important to note that modeling of PJM class average data in the study for these new units may not reflect their actual performance.

The process of combining the GADS data with "class average data" is called blending. The term blending is used when a given generating unit does not have actual reported outage events for the full five-year period being evaluated. The five-year period is used to calculate the various statistics (EFORd, EEFORd, EMOF Two State Variance, POF) used in the study model.

- Equivalent Demand Forced Outage Rate, EFORd
- Effective Equivalent Demand Forced Outage Rate, EEFORd
- Equivalent Maintenance Outage Factor, EMOF
- Planned Outage Factor, POF

The actual generator unit outage events are blended with the class average values according to the generator class category for that unit. For example, a unit that has three years worth of its own reported outage history will have two years worth of class average values used in blending. The statistics, based on the actual reported outage history, will be weighted by a factor of 3/5 and the class average statistics will be weighted by a factor of 2/5. The values are added together to get a statistical value for each unit that represents the entire five-year time period.

The class average categories are from NERC's Brochure, with the values determined from PJM's fleet of units. A five-year period is used for the statistics, with 74 unique generator class keys. The five-year period is based on the data available in the NERC Brochure or in PJM's eGADS, using the latest time period. A generator class category is given for each unit type, primary fuel and size of unit. The numbers of units for each category give an indication of how many units the average values are based on. The unit years value allows for an indication of how many units were part of the total five-year reporting period. The class average statistical values used in the reserve requirement study for the blending process are shown in Table 6. These values are available via the web based application discussed in the next section.

In addition, a comparison of the values from the previous study is shown in Table 7. The previous study used NERC-based class average values. The NERC class averages are based on data from about 6000 units located in North America. This comparison shows no abnormalities in moving to a set of class average values based on the PJM fleet of units.

- **Generating unit owner review of detailed model**

  The generation owner representatives are solicited to provide review and submit changes to the preliminary generation unit model. This activity is performed via PJM's web site at: http://www.pjm.com/Rstudy/rStudyServlet. Access to this web site requires an ID and password, as the detailed data is considered confidential. The administration for access to this site is provided by PJM's Capacity Adequacy Planning Staff. This review typically occurs in late winter, with member representatives needing to participate via teleconference and web conference when the review efforts begin.

  Close to 100% of the units modeled were reviewed by generation owners for this study.

  This review by the generation owners provides valuable feedback and increases confidence that the model parameters are the best possible for use in the RRS. This review improves the data integrity of the most significant modeling parameters in the RRS.

- **Forced Outage Rates: EFORd and EEFORd**

  All forced outages are based on eGADS reported events.

  - **Effective Equivalent Forced Outage Rate on Demand (EEFORd)** – This forced outage rate is used for reliability and reserve margin calculations. There are traditionally three categories for GADS reported events: forced outage (FO), maintenance outage (MO) and planned outage (PO). The PRISM program can only model two categories (FO and PO). The EEFORd statistic is a solution for modeling all GADS events. A portion of the MO outages is placed within the FO category, while the other portion is placed with the PO category. In this way, all reported GADS events are modeled. The statistic used for MO is the equivalent maintenance outage factor (EMOF). For a more complete discussion of these equations see Manual 22 at : (http://www.pjm.com/contributions/pjm-manuals/pdf/m22.pdf) The equation for the EEFORd is as follows:

Equation 1

$$EEFORd = EFORd + (1/4 * EMOF)$$

- **Equivalent Forced Outage Rate on Demand (EFORd)** – This forced outage rate is used in reliability and reserve margin calculations. See Manual M-22 and RAA Schedule 4 and Schedule 5 for more specific information for defining and using this statistic. The EFORd forms the basis for the EEFORd and is the statistic used to calculate the unforced capacity (UCAP) value of generators used in the marketplace. UCAP is used in the Reliability Pricing Model (RPM). However, the EFORd values used in the RRS are different from those used in the marketplace. This is due to the fact that a five year period is used for the values modeled in the RRS and a one year period is the basis for determining the UCAP value of generators in the capacity market. For the 2007 RRS, the 5 year period is defined in the study assumptions as calendar years 2002-2006.

Table 6

PJMRTO Fleet Class Average Generation Performance Statistics

Generator Class Key

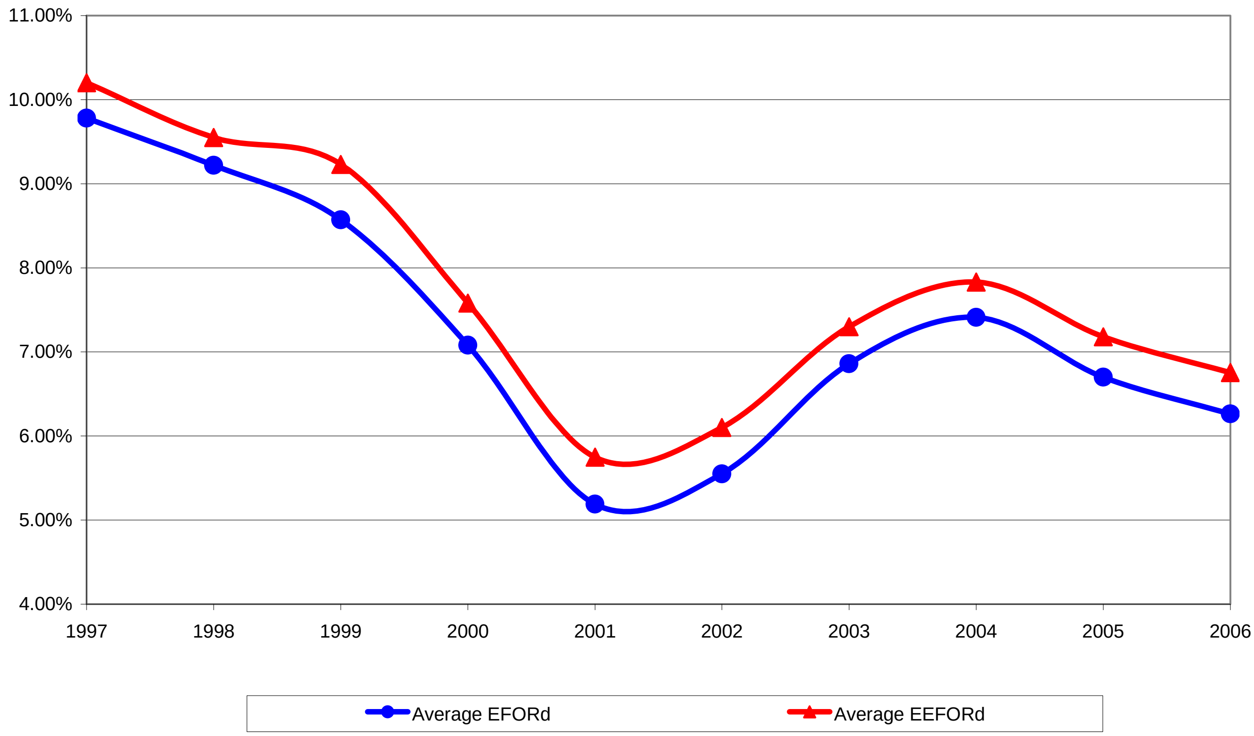
Start Date	End Date	Unit Type & Primary Fuel Category		Gen Class Key	# of Units	Unit Years	Average capacity Megawatts	POF Weeks per Year	EFORd	EEFORd	EMOF	Two State variance Megawatts
1/1/2001	12/31/2005	FOSSIL All Fuel Types	All Sizes	1	1478	6454	293	7	6.41%	7.10%	2.75%	3954
1/1/2001	12/31/2005	FOSSIL All Fuel Types	001-099	2	356	1419	58	5	6.98%	7.58%	2.39%	236
1/1/2001	12/31/2005	FOSSIL All Fuel Types	100-199	3	396	1740	138	6	6.34%	7.13%	3.15%	2582
1/1/2001	12/31/2005	FOSSIL All Fuel Types	200-299	4	169	771	232	7	5.89%	6.57%	2.73%	3223
1/1/2001	12/31/2005	FOSSIL All Fuel Types	300-399	5	134	595	344	8	5.88%	6.69%	3.22%	4263
1/1/2001	12/31/2005	FOSSIL All Fuel Types	400-599	6	254	1115	501	8	6.80%	7.48%	2.70%	6593
1/1/2001	12/31/2005	FOSSIL All Fuel Types	600-799	7	120	576	699	8	6.91%	7.45%	2.16%	9464
1/1/2001	12/31/2005	FOSSIL All Fuel Types	800-999	8	36	174	828	8	3.99%	4.62%	2.52%	6738
1/1/2001	12/31/2005	FOSSIL All Fuel Types	1000 Plus	9	13	65	1218	9	9.24%	9.94%	2.79%	29973
1/1/2001	12/31/2005	FOSSIL Coal Primary	All Sizes	10	898	4107	320	6	6.47%	7.08%	2.44%	4214
1/1/2002	12/31/2006	FOSSIL Coal Primary	001-099	11	191	843	102	3	9.39%	10.12%	2.68%	1611
1/1/2002	12/31/2006	FOSSIL Coal Primary	100-199	12	191	843	102	3	9.39%	10.12%	2.68%	1611
1/1/2002	12/31/2006	FOSSIL Coal Primary	200-299	13	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Coal Primary	300-399	14	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Coal Primary	400-599	15	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Coal Primary	600-799	16	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Coal Primary	800-999	17	18	90	850	4	6.36%	6.76%	1.64%	62325
1/1/2002	12/31/2006	FOSSIL Coal Primary	1000 Plus	18	18	90	850	4	6.36%	6.76%	1.64%	62325
1/1/2001	12/31/2005	FOSSIL Oil Primary	All Sizes	19	144	491	281	9	7.65%	8.51%	3.44%	4397
1/1/2002	12/31/2006	FOSSIL Oil Primary	001-099	20	191	843	102	3	9.39%	10.12%	2.68%	1611
1/1/2002	12/31/2006	FOSSIL Oil Primary	100-199	21	191	843	102	3	9.39%	10.12%	2.68%	1611
1/1/2002	12/31/2006	FOSSIL Oil Primary	200-299	22	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Oil Primary	300-399	23	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Oil Primary	400-599	24	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Oil Primary	600-799	25	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Oil Primary	800-999	26	18	90	850	4	6.36%	6.76%	1.64%	62325
1/1/2001	12/31/2005	FOSSIL Gas Primary	All Sizes	28	452	1707	222	6	6.49%	7.34%	3.38%	3354
1/1/2002	12/31/2006	FOSSIL Gas Primary	001-099	29	191	843	102	3	9.39%	10.12%	2.68%	1611
1/1/2002	12/31/2006	FOSSIL Gas Primary	100-199	30	191	843	102	3	9.39%	10.12%	2.68%	1611
1/1/2002	12/31/2006	FOSSIL Gas Primary	200-299	31	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Gas Primary	300-399	32	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Gas Primary	400-599	33	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Gas Primary	600-799	34	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Gas Primary	800-999	35	18	90	850	4	6.36%	6.76%	1.64%	62325
1/1/2001	12/31/2005	FOSSIL Lignite Primary	All Sizes	37	20	93	545	5	6.29%	6.79%	1.99%	6512
1/1/2002	12/31/2006	NUCLEAR All Types	All Sizes	38	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR All Types	400-799	39	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR All Types	800-999	40	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR All Types	1000 Plus	41	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR PWR	All Sizes	42	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR PWR	400-799	43	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR PWR	800-999	44	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR PWR	1000 Plus	45	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR BWR	All Sizes	46	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR BWR	400-799	47	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR BWR	800-999	48	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR BWR	1000 Plus	49	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2002	12/31/2006	NUCLEAR CANDU	All Sizes	50	32	155	1052	3	2.26%	2.48%	0.86%	23323
1/1/2001	12/31/2005	JET ENGINE	All Sizes	51	365	1538	39	2	9.41%	10.16%	2.00%	139
1/1/2002	12/31/2006	JET ENGINE	001-019	52	148	719	14	0	10.68%	11.09%	1.54%	20
1/1/2002	12/31/2006	JET ENGINE	20 Plus	53	172	748	42	2	9.72%	10.55%	2.96%	148
1/1/2001	12/31/2005	GAS TURBINE	All Sizes	54	1016	4012	55	3	10.26%	10.73%	1.88%	290
1/1/2002	12/31/2006	GAS TURBINE	001-019	55	148	719	14	0	10.68%	11.09%	1.54%	20
1/1/2002	12/31/2006	GAS TURBINE	020-049	56	172	748	42	2	9.72%	10.55%	2.96%	148
1/1/2002	12/31/2006	GAS TURBINE	50 Plus	57	214	830	84	1	7.68%	8.23%	2.21%	878
1/1/2002	12/31/2006	COMBINED CYCLE	All Sizes	58	70	350	169	2	5.65%	6.18%	2.03%	4090
1/1/2001	12/31/2005	HYDRO	All Sizes	59	1010	4378	65	7	3.89%	4.36%	1.86%	176
1/1/2002	12/31/2006	HYDRO	001-029	60	149	574	9	2	3.46%	3.70%	0.57%	13
1/1/2002	12/31/2006	HYDRO	30 Plus	61	149	574	9	2	3.46%	3.70%	0.57%	13
1/1/2002	12/31/2006	PUMPED STORAGE	All Sizes	62	24	110	134	3	2.14%	2.46%	1.10%	1991
1/1/2001	12/31/2005	MULTIBOILER/MULTI-TURBINE	All Sizes	63	46	184	139	4	8.03%	8.63%	2.41%	1524
1/1/2002	12/31/2006	DIESEL	All Sizes	65	107	405	3	0	12.06%	12.50%	1.74%	4
1/1/2001	12/31/2005	FOSSIL Oil/Gas Primary	All Sizes	66	550	2178	235	7	6.32%	7.17%	0.07%	3675
1/1/2002	12/31/2006	FOSSIL Oil/Gas Primary	001-099	67	191	843	102	3	9.39%	10.12%	2.68%	1611
1/1/2002	12/31/2006	FOSSIL Oil/Gas Primary	100-199	68	191	843	102	3	9.39%	10.12%	2.68%	1611
1/1/2002	12/31/2006	FOSSIL Oil/Gas Primary	200-299	69	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Oil/Gas Primary	300-399	70	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Oil/Gas Primary	400-599	71	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Oil/Gas Primary	600-799	72	113	511	500	4	8.65%	9.53%	3.41%	19975
1/1/2002	12/31/2006	FOSSIL Oil/Gas Primary	800-999	73	18	90	850	4	6.36%	6.76%	1.64%	62325
1/1/2002	12/31/2006	Wind	All sizes	74	1	60	5	0	0.00%	0.00%	0.00%	0

Table 7
Comparison of Class Average Values- 2006 RRS vs. 2007 RRS

Unit Type & Primary Fuel Category	Gen Class Key	Units Change	Unit Year Change	POF Change	EFORd Change	EEFORd Change	EMOF Change	Variance Change
FOSSIL All Fuel Types All Sizes	1	18	4994	0	0.18%	0.18%	0.00%	73
FOSSIL All Fuel Types 001-099	2	13	1076	0	0.69%	0.69%	0.00%	20
FOSSIL All Fuel Types 100-199	3	-1	1343	-1	0.29%	0.29%	0.00%	44
FOSSIL All Fuel Types 200-299	4	4	606	0	0.06%	0.06%	0.00%	17
FOSSIL All Fuel Types 300-399	5	0	461	0	-0.38%	-0.37%	0.00%	-190
FOSSIL All Fuel Types 400-599	6	4	865	0	0.14%	0.13%	0.00%	125
FOSSIL All Fuel Types 600-799	7	-2	454	0	-0.13%	-0.13%	0.00%	-195
FOSSIL All Fuel Types 800-999	8	0	138	0	-0.17%	-0.17%	0.00%	-257
FOSSIL All Fuel Types 1000 Plus	9	0	52	0	-0.41%	-0.41%	0.00%	-1933
FOSSIL Coal Primary All Sizes	10	3	3212	-1	0.22%	0.22%	0.00%	100
FOSSIL Coal Primary 001-099	11	35	687	-3	3.34%	3.47%	0.28%	1349
FOSSIL Coal Primary 100-199	12	-53	599	-3	3.49%	3.48%	-0.28%	-897
FOSSIL Coal Primary 200-299	13	-4	394	-2	3.00%	3.25%	0.91%	16845
FOSSIL Coal Primary 300-399	14	30	428	-3	2.08%	2.36%	1.02%	15544
FOSSIL Coal Primary 400-599	15	-50	348	-3	1.57%	1.90%	1.22%	13120
FOSSIL Coal Primary 600-799	16	18	416	-4	1.85%	2.29%	1.65%	10929
FOSSIL Coal Primary 800-999	17	-7	65	-5	2.07%	2.03%	-0.14%	55321
FOSSIL Coal Primary 1000 Plus	18	6	78	-5	-3.38%	-3.47%	-0.33%	30118
FOSSIL Oil Primary All Sizes	19	0	347	1	0.06%	0.06%	0.00%	25
FOSSIL Oil Primary 001-099	20	146	798	-2	-1.62%	-1.45%	0.45%	1355
FOSSIL Oil Primary 100-199	21	157	809	-7	2.44%	2.29%	-0.82%	-1018
FOSSIL Oil Primary 200-299	22	104	502	-5	0.40%	0.71%	1.12%	16030
FOSSIL Oil Primary 300-399	23	97	495	-7	2.54%	2.19%	-1.51%	15105
FOSSIL Oil Primary 400-599	24	92	490	-3	3.45%	3.18%	-1.20%	14597
FOSSIL Oil Primary 600-799	25	103	501	-7	-0.36%	-0.13%	0.80%	7419
FOSSIL Oil Primary 800-999	26	10	82	-3	4.40%	3.71%	-2.71%	57803
FOSSIL Gas Primary All Sizes	28	9	1264	-1	0.59%	0.59%	0.00%	165
FOSSIL Gas Primary 001-099	29	52	704	0	3.02%	3.14%	0.22%	1414
FOSSIL Gas Primary 100-199	30	60	712	-4	3.07%	2.93%	-0.80%	-998
FOSSIL Gas Primary 200-299	31	72	470	-4	3.37%	3.32%	-0.30%	16841
FOSSIL Gas Primary 300-399	32	72	470	-5	3.06%	2.82%	-1.08%	15650
FOSSIL Gas Primary 400-599	33	45	443	-5	2.70%	2.61%	-0.45%	14120
FOSSIL Gas Primary 600-799	34	100	498	-9	0.61%	0.13%	-2.05%	5781
FOSSIL Gas Primary 800-999	35	8	80	-5	0.77%	0.12%	-2.55%	52728
FOSSIL Lignite Primary All Sizes	37	-3	70	-1	-0.27%	-0.27%	0.00%	-264
NUCLEAR All Types All Sizes	38	-76	47	-4	-2.04%	-2.12%	-0.36%	-7338
NUCLEAR All Types 400-799	39	15	138	-7	-4.33%	-4.48%	-0.62%	-6191
NUCLEAR All Types 800-999	40	-10	113	-4	-2.24%	-2.26%	-0.12%	-6390
NUCLEAR All Types 1000 Plus	41	-17	106	-3	-1.21%	-1.32%	-0.45%	-7268
NUCLEAR PWR All Sizes	42	-30	93	-4	-1.54%	-1.57%	-0.14%	-6086
NUCLEAR PWR 400-799	43	24	147	-4	0.94%	0.92%	-0.11%	1653
NUCLEAR PWR 800-999	44	10	133	-4	-2.41%	-2.40%	0.00%	-6640
NUCLEAR PWR 1000 Plus	45	0	123	-3	-1.66%	-1.71%	-0.23%	-8542
NUCLEAR BWR All Sizes	46	1	124	-2	-0.72%	-0.92%	-0.83%	-4682
NUCLEAR BWR 400-799	47	29	152	-2	-1.78%	-2.10%	-1.29%	-3294
NUCLEAR BWR 800-999	48	20	143	-2	-1.07%	-1.22%	-0.62%	-4023
NUCLEAR BWR 1000 Plus	49	16	139	-2	-0.36%	-0.59%	-0.93%	-4980
NUCLEAR CANDU All Sizes	50	18	141	-9	-9.21%	-9.29%	-0.36%	-18970
JET ENGINE All Sizes	51	3	1176	-1	0.52%	0.52%	-1.39%	7
JET ENGINE 001-019	52	96	667	-2	-11.12%	-11.22%	-0.50%	-43
JET ENGINE 20 Plus	53	-138	438	-1	1.75%	1.79%	-0.18%	0
GAS TURBINE All Sizes	54	45	3041	0	0.11%	0.11%	0.00%	3
GAS TURBINE 001-019	55	-48	523	-2	-9.37%	-9.49%	-0.57%	-22
GAS TURBINE 020-049	56	-45	531	0	-1.60%	-1.15%	1.45%	73
GAS TURBINE 50 Plus	57	-344	272	-3	-0.52%	-0.45%	0.27%	292
COMBINED CYCLE All Sizes	58	-77	203	-3	0.14%	-0.23%	-1.56%	1715
HYDRO All Sizes	59	-8	3360	0	0.33%	0.33%	0.00%	13
HYDRO 001-029	60	-314	111	-4	-1.09%	-1.42%	-1.71%	7
HYDRO 30 Plus	61	-406	19	-6	0.56%	0.41%	-1.01%	-318
PUMPED STORAGE All Sizes	62	-81	5	-4	-2.50%	-2.55%	-0.37%	963
MULTIBOILER/MULTI-TURBINE All Sizes	63	-3	135	0	0.86%	0.86%	0.00%	139
DIESEL All Sizes	65	-4	294	-1	-1.99%	-2.19%	-0.84%	2
FOSSIL Oil/Gas Primary All Sizes	66	0	1628	0	0.00%	0.00%	-3.33%	0
FOSSIL Oil/Gas Primary 001-099	67	7	659	0	1.64%	1.77%	0.27%	1388
FOSSIL Oil/Gas Primary 100-199	68	36	688	-5	2.95%	2.81%	-0.81%	320
FOSSIL Oil/Gas Primary 200-299	69	67	465	-4	2.93%	2.94%	-0.05%	16577
FOSSIL Oil/Gas Primary 300-399	70	59	457	-6	2.89%	2.61%	-1.22%	11861
FOSSIL Oil/Gas Primary 400-599	71	36	434	-5	2.82%	2.70%	-0.58%	5320
FOSSIL Oil/Gas Primary 600-799	72	91	489	-8	0.17%	0.03%	-0.69%	-25110
FOSSIL Oil/Gas Primary 800-999	73	7	79	-4	2.37%	1.70%	-2.62%	31373
Wind All sizes	74	1	60	0	0.00%	0.00%	0.00%	0

Figure 7 shows the historical EFORd and EEFORd trends. The values in Figure 7 are annual values, indicating annual changes in unit performance. The values used are for units in that year that have a full 12 months of GADS data, as reported through PJM's eGADS web-based system.

Figure 7
Historical Trends for GADS-based EFORd and EEFORd



PJM Staff coordinates the statistical parameters used in the RRS with those available on the PJM web site's resource reports and information. However, the detailed data needed for the RRS may not apply to other reporting parameters and requirements. PJM's resource reports are available at: http://www.pjm.com/planning/res-adequacy/resource-reports.html. This web site and PJM Manual 22 contain the details concerning proper rules and calculation procedures of the statistical values used in the RPM marketplace for all units including: Mature Units, Mothballed Units, and Combined Cycle Conversion of Existing CT units.

- **Generating Unit Modeling Issues**

  The generating unit characteristics indicate the probability of a unit's availability, either at its full rating or when derated, to serve load. Typically, it is advantageous to model individual units, as opposed to combining units within a given plant. The probability of being unavailable is a cumulative calculation with the multiplication done by each unit modeled. For example, if two 50 MW units, each with a 10% EFORd, are modeled as a single 100 MW unit with a 10% EFORd, the plant would have a **10 percent** chance of providing zero capacity to serve load. Alternatively, if these two 50-MW units were modeled individually, that same plant would have only a **1 percent** chance of providing zero capacity to serve load. Therefore, modeling the two units individually captures the true reliability value of the plant.

  The model has a limitation of rounding to the nearest tens of megawatts. For example, any units of size 0-4 MWs will round to zero; units of size 5-14 MWs round to ten, etc. This limitation should be kept in mind so that the model's aggregate rounded summer rating megawatt value is similar to the unit's actual aggregate value.

- **Fleet-based Performance by Primary Fuel Category**

  The PJM RTO fleet of units is summarized, by primary fuel, in Table 8. This summary is based on the individual detailed unit model (i.e. small units have not been combined in groups of 10 MW). This summary does reflect the process of blending discussed above. This summary also uses the actual summer net dependable rating (SND) of all units, as opposed to using the rounded value discussed above. Most of the values in this report are based on the rounded capacity values. The outage rate for wind units reflects the PJM stakeholder process modeling, not actual outage event data.

Table 8

Fleet-based Unit Performance by Primary Fuel Category

2010 / 2011 Delivery Year	# of Units	Actual Capacity MW's	% Total MWs	Forced Outage Rates %	Ambient Temperature Derating
Coal	257	69480	40.84%	8.27%	628
Nuclear	32	30994	18.22%	2.45%	0
Gas	632	49468	29.07%	7.41%	1368
Hydro	96	2338	1.37%	3.26%	182
Oil/Gas	94	10056	5.91%	9.82%	256
Pumped	24	5225	3.07%	2.45%	66
Diesel	42	411	0.24%	11.59%	0
Wind	128	874	0.51%	0.00%	0
"All Fuel Types"	25	776	0.46%	8.27%	0
Multiboiler	1	521	0.31%	13.47%	0
PJM RTO Total	***1331***	***170143***	***100.00%***	6.78%	2500

- **Modeling of Generating Units' Ambient Deratings**

  Per the approved rules in place for Operations, Planning and Markets, a unit can operate at less than its SND rating and not incur a GADS outage event. As discussed above all units in the model are based on eGADS submitted data. The ambient derate modeling assumption and the eGADS data allow all observed outages to be modeled as seen by PJM Operations Staff.

  Derating of generating units affected by hot and humid summer conditions is captured by this evaluation. This modeling practice is intended to capture the increased risk due to limited output from certain generators caused by more extreme than expected ambient weather conditions.

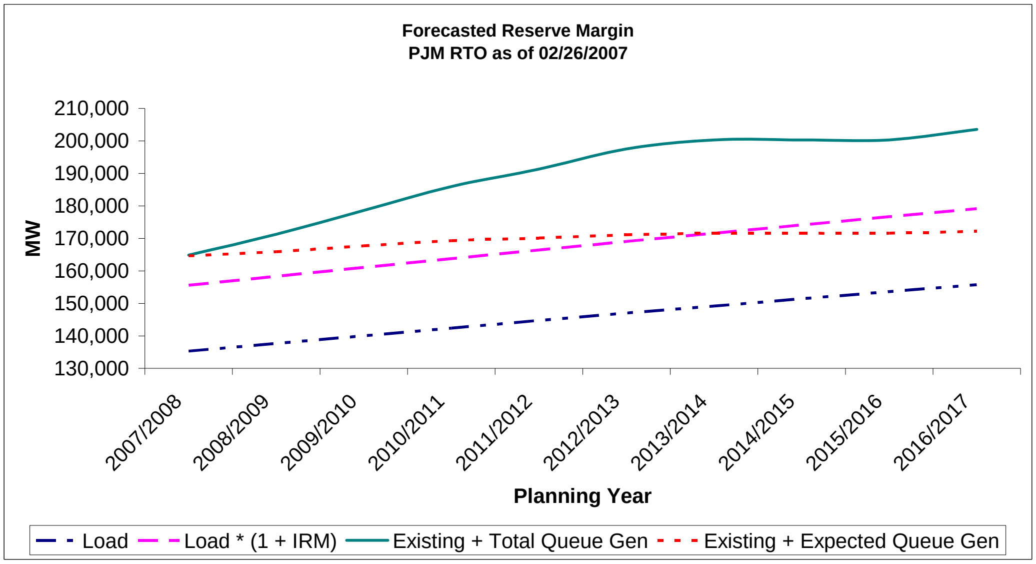
  Per the RRS assumptions, 2,500 MW was derated in the peak summer period to model this risk. This derating is consistent with that modeled by the NYSRC (see report dated January 5, 2007 at: http://www.nysrc.org/pdf/Reports/2007_08IRMReportFinal011707.pdf.) in performing its adequacy assessment. This modeling assumption was developed through close coordination with the PJM Operations Staff. Operations Staff recommended a derating in the range of 2000 MW to 2500 MW be in place for the RRS. The derating, implemented in the RRS model by scheduling planned maintenance of PJM units in the summer operating period, increased the reserve requirement 1.6%. The particular units scheduled to be out in the study have average characteristics for the given classification of units affected and the outages span the full length of the high-risk summer period. PJM will continue to assess, on an on-going basis, the impact of these ambient weather conditions on generator output. See the Operations Related Assessment Section of this report for further details.

- **Generation Interconnection Forecast**

The following Forecast Reserve Margin Graph, available at: http://www.pjm.com/planning/res-adequacy/resource-reports.html, is the basis for the forecast values. This graph was posted in February 2007 and is updated monthly. Concerning the values shown in figure 8 please note: the forecast restricted peak load value, the expected interconnection additions, and announced retirements are different in the RRS due to the use of updated values and the capacity values are different due to the RRS model including Reliability Must Run (RMR) units.

The commercial probabilities listed in Table 9 represent the likelihood a project, given its current interconnection queue status, becomes commercially available to serve load within the PJM RTO. These probabilities are derived by assessing actual queue project installations of historic queues since 1999. As the project moves through different stages of development the probability associated with it increases accordingly. These values have been judged to be the most appropriate estimates for planning purposes.

Figure 8
Forecast Reserve Margin Graph- February 2007



PJM RTO - 02/26/2007

	A	B	C	D	E	F	G	H	I
Planning Year	Forecasted Summer Peak Net Internal Demand	Forecasted Peak Net Internal Demand + Reserve Requirement	Existing Installed Capacity as of 02/26/2007	Total Interconnection Queue Generation by June 1st	Expected Interconnection Generation Additions by June 1st	Announced Retirements	Existing + Total Interconnection Queue Generation	Existing + Expected New Generation Additions	Summer Peak Forecasted Reserve Margin %
2007/2008	135,288	155,581	164,914	313	76	385	164,842	164,605	21.7
2008/2009	137,669	158,319	164,914	7,530	2,390	1,085	171,287	165,910	20.5
2009/2010	140,037	161,043	164,914	7,298	1,797	0	178,585	167,707	19.8
2010/2011	142,409	163,770	164,914	7,343	1,585	0	185,928	169,292	18.9
2011/2012	144,731	166,441	164,914	5,362	820	0	191,290	170,112	17.5
2012/2013	147,014	169,066	164,914	6,244	996	0	197,534	171,107	16.4
2013/2014	149,193	171,572	164,914	2,790	463	0	200,324	171,570	15.0
2014/2015	151,408	174,119	164,914	0	0	0	200,324	171,570	13.3
2015/2016	153,617	176,660	164,914	0	0	0	200,324	171,570	11.7
2016/2017	155777	179,144	164,914	3,234	647	0	203,558	172,217	10.6

Column A: PJM Total Demand - Active Load Management. Forecast is calculated as a diversified sum of zonal forecasts.
Column B: Column A multiplied by the Reserve Requirement of 1.15
Column C: Installed Capacity as of 2/26/2007. This number represents "iron-in-the-ground" inside of the PJM electrical territory. This number excludes external sales/purchases and does not necessarily represent generation controlled by PJM.
Column D: Represents the Queue Generation from June 1st of the first year listed to May 31st of the second year listed.
Column E: Queue Generation * Commercial Probability (by project status)
Column F: Announced Future Generator Retirements
Column G: Existing Installed Capacity + Total Queue Generation - Announced Retirements
Column H: Existing Installed Capacity + Expected Queue Generation - Announced Retirements
Column I: [Column H/Column A] - 1

*Each planning year row represents a snapshot of the system as of the first day of the planning year (June 1st)

Table 9
Commercial Probabilities for Expected Interconnection Generation Additions

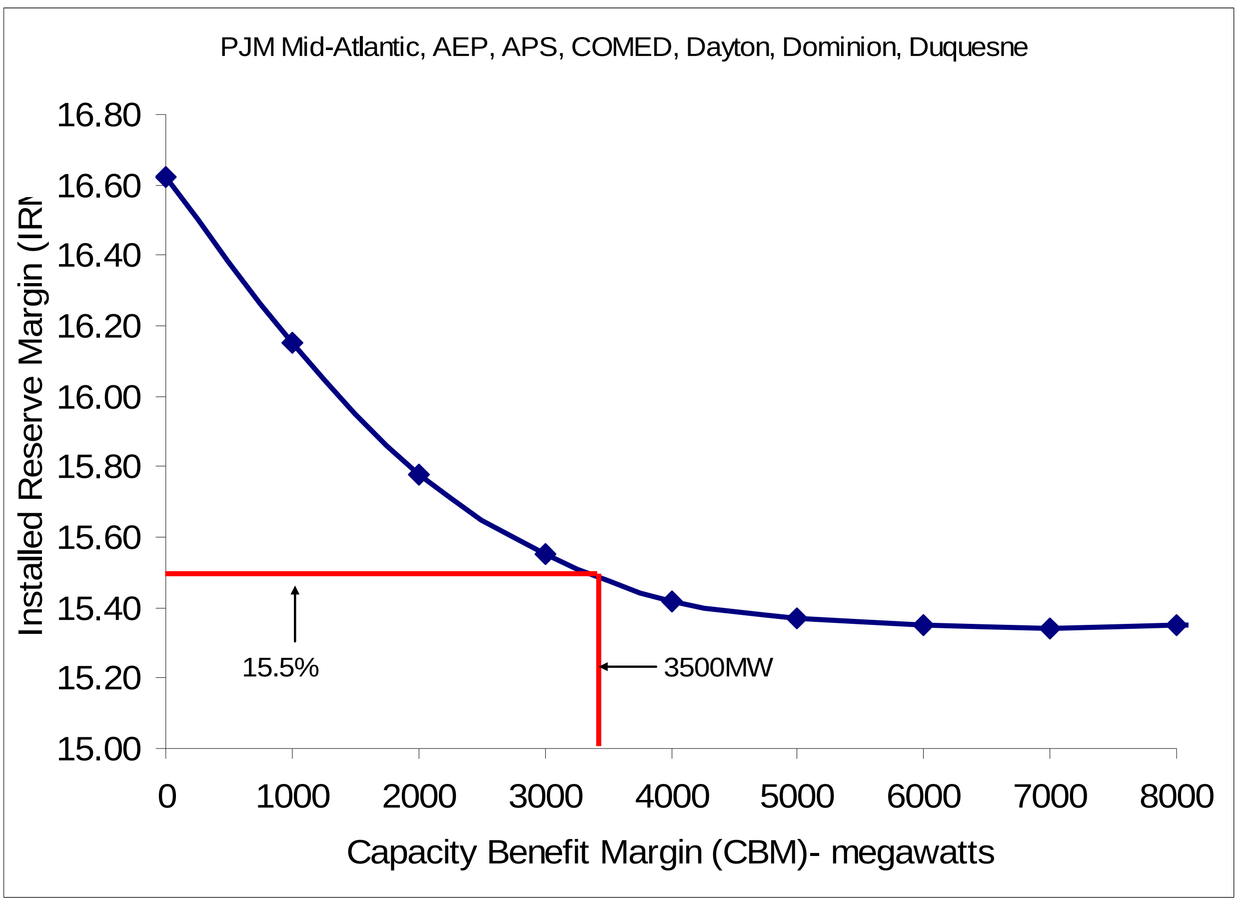
Status	Commercial Probability
In the Queue, No studies performed (Active)	15%
All of the above, plus a feasibility study completed (Active)	20%
All of the above, plus an impact study completed (Active)	30%
All of the above, plus a facilities study completed (Active)	50%
All of the above, ISA executed (UC)	75%
Successful completion (IS, ISP, IS-NC)	100%

Transmission System Considerations

- **PJM Transmission Planning (TP) Evaluation of Import Capability**
  The PJM TP Staff previously conducted an Expected Import Capability Study (EICS) to evaluate the emergency import limits of the PJM RTO under summer peak conditions. That study showed that at least 7,500 MW could be imported into the PJMRTO. This limit is evaluated annually to assess whether the CBM value should be changed. This evaluation, along with the below Capacity Benefit Margin discussion, yielded a RRS assumption of 3,500 MW. Although PJM can import more than the 3,500 MW, the additional import capability is reflected in ATC through the OASIS postings and not reserved as CBM. This allows the additional import capability to be used in the marketplace. This is seen as a just consideration, as the reliability benefit of CBM saturates near the 3,500 MW limit. The shape of the curve in Figure 9 has been consistent for many previous studies.

- **Capacity Benefit Margin (CBM)**
  The CBM was varied between 0 MW and 8,000 MW. The relationship of IRM with CBM is graphically depicted in Figure 9. A decrease in the CBM from 3,500 MW to 0 MW increases the pool's reserve requirement by about 1.2%. This value is influenced primarily by the degree of load diversity between PJM and the World region and the World reserve level.

Figure 9
Relationship of IRM and CBM



- **Transmission Projects**
  The PJM RTEPP is coordinated with the transmission model used in Adequacy studies, including the RRS. The process to review transmission projects is performed by the Transmission Expansion Advisory Committee (TEAC) as frequently as on a monthly basis. Recent evaluation included the new Neptune Cable

and the Linden VFT (Variable Frequency Transformer) Projects. Both were found to have virtually no impact on the IRM. While these projects may affect the number of resources available to satisfy the IRM, they do not affect the IRM itself, which is a measure of the resources required to satisfy reliability criteria. All internal transmission projects presently approved as part of the RTEP will not affect the PJM IRM. However, these projects may affect the CETO and/or CETL values for Load Deliverability Areas.

- **Capacity Benefit of Ties (CBOT)**
  The CBOT is the difference between the RRS run with a 3,500 MW CBM and the RRS run with a 0 MW CBM. This is sensitivity run number 23 (Appendix B). The capacity benefit of ties is 1.18% of the PJM forecasted load or about 1,600 MW. The CBOT is directly affected by the PJM/World diversity in the model (more diversity results in a higher CBOT) and the reserve level modeled in the World area.

Modeling and Analysis Considerations

- **Generating Unit Additions / Retirements**

  The generation modeling was coordinated with an estimate of each project's commercial probability. Projects that are expected to be completed are shown in the forecast reserve margin figure (figure 8). See the Summary of RRS results section for further information. This graph is updated monthly and available on the PJM web site. The new feature of this was modeling units measured with a commercial probability. This factor was applied to all planned unit changes, adjusting the rating, as seen in the generation interconnection process queues. This was a change from only modeling units with a signed ISA, at their full capacity rating. The graph used is shown in the summary of RRS results section of this report. Table 10 gives a summary of the generator additions and retirements as modeled in the 10 year RRS model.

Table 10

New and Retiring Generation within PJMRTO

Next 120 Months (2007-2016)

	Total Additions (MW)	Retirements (MW)	Total
AE	178	-447	-269
AEP	1163	0	1163
APS	2095	0	2095
BGE	328	0	328
COMED	711	0	711
DAY	-1092	0	-1092
DOM	853	0	853
DPL	189	0	189
DLCO	0	-101	-101
JCPL	221	0	221
ME	14	0	14
PECO	202	0	202
PEPCO	192	0	192
PLGRP	1557	-280	1277
PN	154	0	154
PS	406	-836	-430
Grand Total	7172	-1664	5508

Note: Values frozen as of April 2007. DLCO has no known retirements at time of report publication.

- **DR Factor (formerly ALM Factor)**

  For the 2010 / 2011 delivery year, the 0.955 DR Factor is similar to the 0.957 calculated last year. The DR Factor for the 2011/ 2012 delivery year is also 0.955. The DR Factor is an analytically derived measure of the reliability benefit of interruptible load and indicates that every 1 MW of DR is worth 0.955 MW of peak load reduction.

  On an annual basis, PJM verifies that the amount of load management in the RTO does not exceed the level at which the reliability value of load management saturates. The saturation point in this year's study was 10.0% of the RTO's unrestricted forecasted peak. The current level of load management in the RTO (1.3% of the forecasted peak) is well below the saturation level. Table 11 shows the results of determining the saturation point for DR or the maximum amount of DR that adheres to the 10 interruption limit.

Table 11

CURTAIL Results - Maximum amount of Load Management

PRISM Run Number	Delivery Year	Number of Load Management interruptions	Reliability Benefit LOLE
2813	2010	1	2.037
2813	2010	2	1.347
2813	2010	3	0.815
2813	2010	4	0.473
2813	2010	5	0.292
2813	2010	6	0.214
2813	2010	7	0.186
2813	2010	8	0.178
2813	2010	9	0.176
2813	2010	10	0.175
2813	2010	11	0.175
2813	2010	12	0.175
2813	2010	13	0.175
2813	2010	14	0.175
2813	2010	15	0.175

DR = 14408 MW 10% RTO Load

- **Load Management Credit**

  The load management credit is the resource value applied to LSE Demand Resource/Interruptible Load for Reliability programs delegated to PJM for dispatch. The initiation is considered an emergency action under PJM request and is implemented prior to a voltage reduction. However, the initiation is not considered a loss-of-load event.

  For all PJM reserve levels, the 52-week and the summer-only load management factor are the same. This finding justifies the granting of full-year credit for summer-only load management. The present requirement of reserving ten load management interruptions for PJM's use for full credit was also verified. These analysis results are shown in Table 12.

Table 12

CURTAIL Results – Saturation point of Load Management

PRISM Run Number	Delivery Year	Number of Load Management interruptions	Reliability Benefit LOLE
2988	2010	1	0.161
2988	2010	2	0.149
2988	2010	3	0.148
2988	2010	4	0.148
2988	2010	5	0.148
2988	2010	6	0.148
2988	2010	7	0.148
2988	2010	8	0.148
2988	2010	9	0.148
2988	2010	10	0.148

- **World Modeling**

This data is publicly available through the NERC Electric and Supply Database. This is a NERC compilation of all the EIA-411 data submissions. The NERC Reliability Assessment Subcommittee (RAS) 2006 Long-Term Reliability Assessment report, dated October 2006, shows low reserve levels for some neighboring regions. PJM Staff contacted staff in these regions and obtained updated data. The low reserve levels were corrected by the PJM Staff upon coordinating with other regions' staff.

It's important to note there are risks involved with using public data and judgment must be used in interpreting the results of the study and their sensitivity to these public data inputs. The study assumptions state to use the lower of the forecasted reserves compared to the required reserves, resulting in the accuracy of public data possibly impacting PJMRTO's reserve requirement. If required, assistance from neighboring systems should be available.

Figure 10

PJM and Outside World Regions – Summer Capacity Outlook

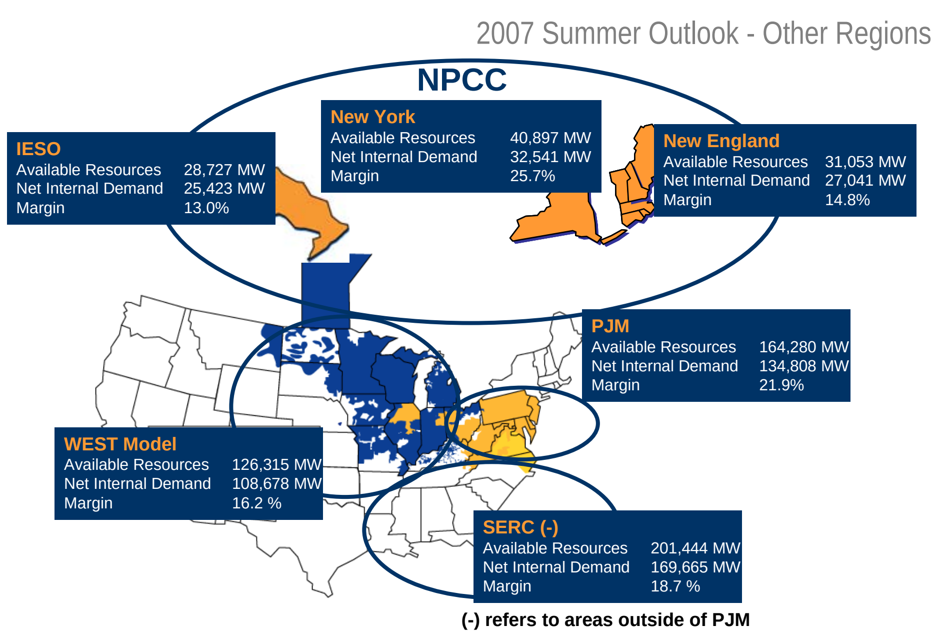


Figure 10 depicts the summer outlook for capacity within each of the "Outside World" regions that are adjacent to PJM. This data is also shown in tabular form in Table 13.

Table 13

PJM and Outside World – Summer Capacity Outlook

Region	**RTO**	Available Resources MW	Net Internal Demand MW	Calculated Margin
NPCC	**NYISO**	40,897	32,541	25.7%
NPCC	**ISO-NE**	31,053	27,041	14.8%
NPCC	**IESO**	28,727	25,423	13.0%
RFC	**PJM**	164,280	134,808	21.9%
RFC / MRO	**West Model**	126,315	108,678	16.2%
SERC	**SERC**	201,444	169,665	18.7%

IESO = Independent Electricity System Operator (Ontario)

- **Expected Weekly Maximum (EWM) and LOLE Comparisons**

The expected weekly maximum value is the peak demand used by the program to calculate the loss of load expectation (LOLE). Both the weekly EWM and LOLE are important values to track in assessing the study results. From observing these values over several historic studies, it can be seen that most models have 99.9% of the risk in a few weeks of the summer period. These weeks have the highest EWM values. Please refer to Appendix F for clarification and specifics of how the EWM is used and the resulting weekly LOLE. The EWM value is calculated per the following equation:

Equation 2

$$EWM_X = \mu_X + 1.16295 * \sqrt{\sigma_X^2 + FEF^2}$$

Where:

μ_X = Weekly Mean,

1.16295 = A Constant, the Order Statistic when n=5

σ_X^2 = Weekly variance

FEF = Forecast Error Factor, for given delivery Year

x ranges from 1 to 52

From those weekly calculations, in Figure 11, the following pattern can be seen for the PJMRTO and World regions. We see that for both the 2006 RRS and the 2007 RRS that the PJM RTO peaks in the same week, week 10. Also the 2007 shape is very "peaky" having one strong peak week. The World area's peak changed from week 10 to week 11, with the second highest week in week 13. This indicates that the 2007 model has little diversity.

Figure 11

Expected Weekly Maximum Comparison- 2006 RRS vs. 2007 RRS

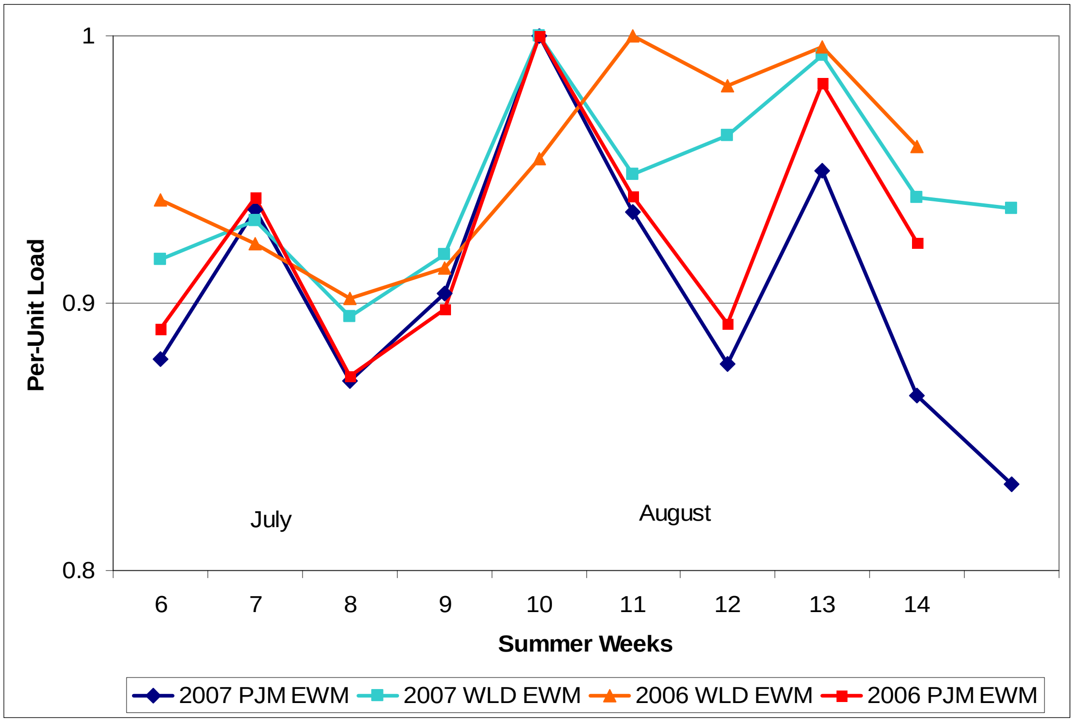
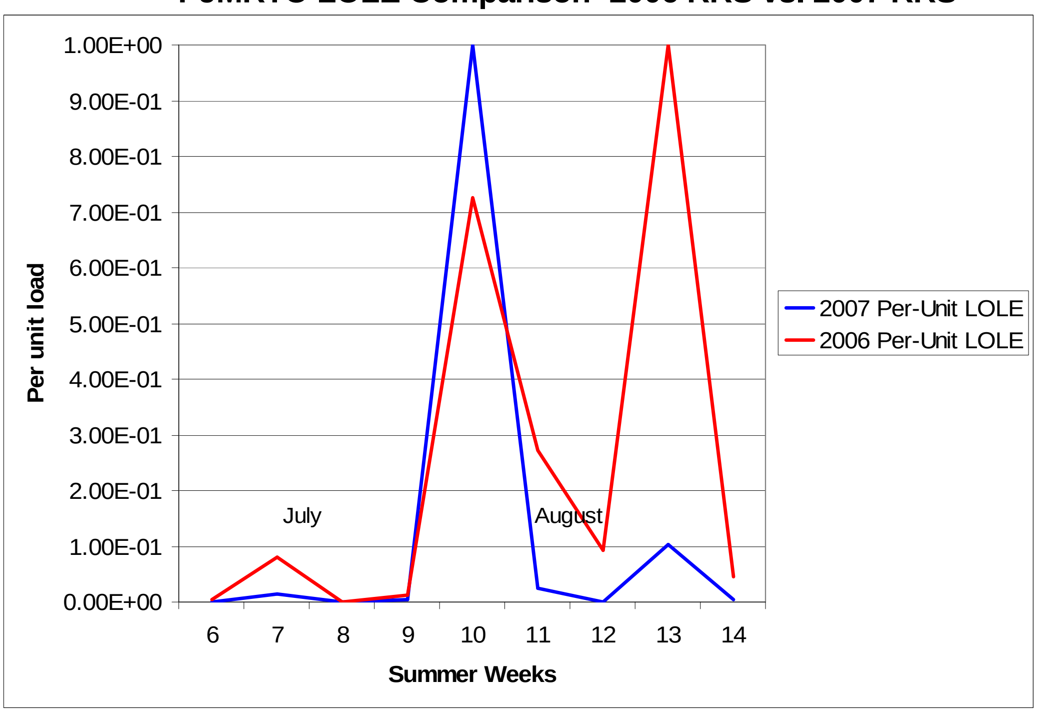


Figure 12 compares the LOLE patterns for PJMRTO. For the 2007 RRS the LOLE is peaky, with most of the risk occurring in week 10. This is a result of the diversity with the World and the EWM load shape. From these two graphs it is apparent that the diversity between the PJMRTO and the World can impact the results.

Figure 12

PJMRTO LOLE Comparison- 2006 RRS vs. 2007 RRS



Operations Related Assessments

- **Impact of Ambient Conditions**

In coordination and discussion with PJM Operations Staff, the impact of ambient conditions on unit performance was identified as an issue in the RRS model. The observations of the Operations Staff were important in this assessment. The assessment looked at PJM's Operations experience with the full PJM RTO footprint. Currently this experience includes only two peak summer periods. As such, the Operations Staff could not fully comment on the market integration zones (AEP, APS, ComEd, Dayton, DLCO, and DomVP) due to limited experience. However, they did have a clear indication for how units in the Mid-Atlantic Region were impacted by extreme ambient conditions (i.e. very hot and very humid conditions).

The PJM Planning Staff evaluated operations data for all units and for all hours judged to be extreme ambient conditions. The data was collected on an hourly basis for individual units. The goal was to determine the relationship of Temperature Humidity Index (THI) on the output of the PJM fleet of units. To date we only have two summer peak periods to analyze. More periods are needed to draw conclusions. PJM Staff is continually collecting the data so that when a large enough population of data becomes available, further review and consideration can be made by the RRAWG and PC. To date, the following analysis has been performed:

- For several types of units the impact on unit performance could be seen. Table 14 and Figure 13 are representative of the several unit categories seen to be impacted.
- The data shown in Table 14 show the correlation parameters for Combustion Turbine units, in the 20 MW to 49 MW size range.
- The R^2 value of 0.9133 indicates that 91% of the variation in the output can be attributed to changes in ambient conditions. This is a reflection of the physical capabilities of these machines.
- The other categories of units with strong correlation factors include: coal units greater than 800 MW, Small Fossil, Hydro, Pump Storage Units, Nuclear, Gas, Oil/gas, and Diesel. Again this is based on only a few data points so the conclusion of a strong correlation is preliminary. However, these results were discussed with the PJM Operations Staff and the results were consistent with their experience.

Table 14

Linear Regression Fit of Unit Output to Ambient Conditions

Combustion Turbine 20 – 49 MW

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	144.0988	144.0988	94.81	<.0001
Error	9	13.6795	1.51994		
Corrected Total	10	157.7783			

Root MSE	1.23286	**R-Square**	0.9133
Dependent Mean	12.4105	**Adj R-Sq**	0.9037
Coeff Var	9.934		

Variable	Label	Parameter Estimate	Standard Error	t Value	Pr > | t|
Intercept	Intercep	-80.29784	9.52869	-8.43	<.0001
Temperature Humidity Index	THI	1.14455	0.11755	9.74	<.0001

Figure 13

Extreme Ambient Conditions impact on Unit Output

Combustion Turbine 20 – 49 MW

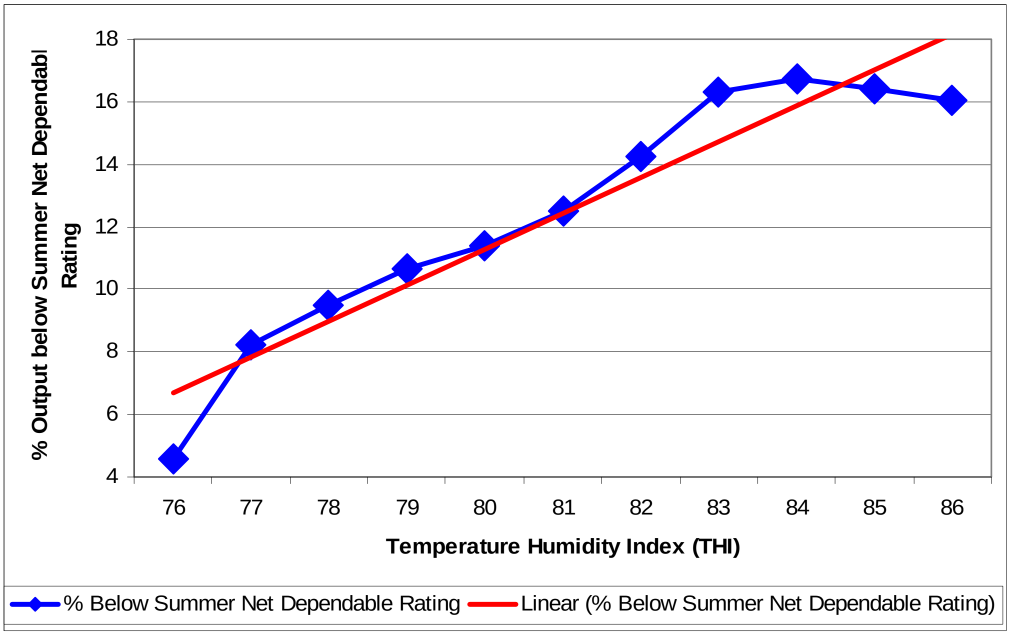
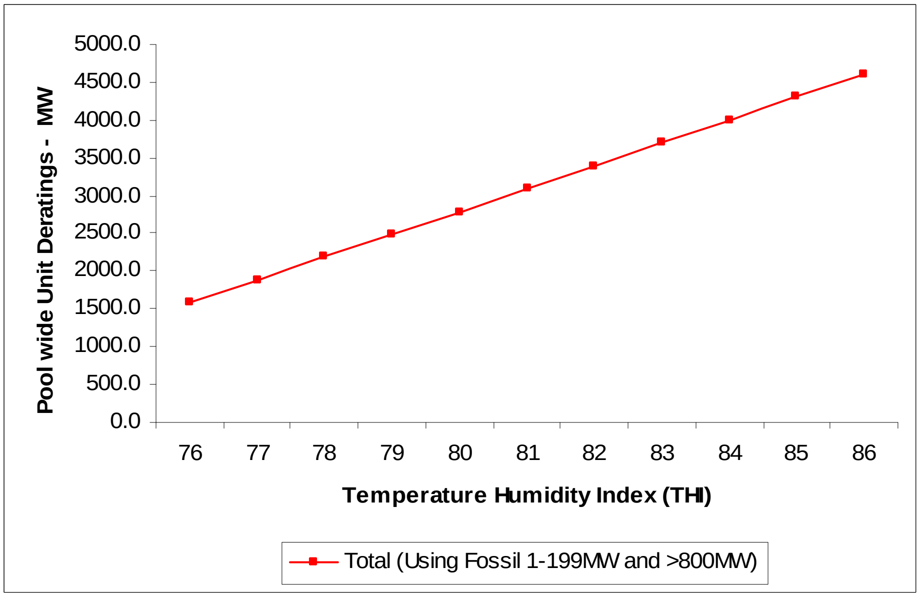


Table 15 displays groups of unit types in the PJM Mid-Atlantic region (only) that have a strong correlation between output and ambient conditions and their associated deratings for outages due to ambient conditions. Further analysis was done to assess possible impacts to the full PJM RTO and is shown in Figure 14. The expected summer peak THI in the Mid-Atlantic is 83.8. Extreme conditions begin at a THI of about 89. The horizontal axis in Figure 14 shows the number of degrees above the 83.8 expected peak THI. The Figure indicates that the RRS should model the higher value, 2500 MW, in the range of values suggested by the Operations Staff.

Figure 14

MW Deratings across PJMRTO



Note: Amount of deratings can be due to several causes, such as spinning reserves for regulation.

Table 15

Unit Output Deratings by Fuel Type- PJM Mid-Atlantic Region

PJM MA	MW	Output MW	Difference(MW)	MW to Derate
	52418	49261	3156	**2500**

	Num. of Units	Rated MW	Percent of Total MW	Output MW	Percent of MW Output	Percent of Difference	MW to Derate
Coal	64	13568	25.9%	13019	26.4%	**18.2%**	**455**
Nuclear	13	13248	25.3%	12978	26.3%	**8.6%**	**214**
Gas	91	11054	21.1%	10511	21.3%	**17.2%**	**430**
Hydro	17	1323	2.5%	1099	2.2%	**7.1%**	**177**
Oil/Gas	162	12444	23.7%	10986	22.3%	**46.2%**	**1155**
Pumped	3	400	0.8%	327	0.7%	**2.3%**	**58**
Diesel	13	101	0.2%	89	0.2%	**0.4%**	**10**
						100.0%	**2499**

- **Winter Weekly Reserve Target Analysis**

PJM Staff and the RRAWG recommend **28%** as the minimum winter reserve target to be applied to the PJMRTO for the upcoming 2007/08 winter period. This value is the same as that recommended in last year's study. The 28% target is based on unit summer ratings and is expressed as a percentage of the forecasted weekly peak load. With this recommendation, the PJM Operations Department would coordinate generator maintenance scheduling over the winter period to seek to preserve a 28% margin after units on planned and maintenance outages are removed. This margin is a guide to be used by PJM Operations and is not an absolute requirement.

Figure 15 shows a comparison of last year's load model to that used in the 2007 Reserve Requirement Study. The two load models have similar characteristics and averages, with the 2007/08 model indicating a lower expected weekly maximum over the entire winter period compared to last year's model. The PJM load model is the single most important driver of the calculated winter weekly reserve target. With that recognition, we would expect a slightly lower reserve target value for the 2007 Reserve Requirement Study compared to the 2006 Reserve Requirement Study.

Table 16 shows the results of the MARS analysis indicating an average weekly reserve over the winter period of 26.8%. The PJM Staff believes that maintaining a minimum 28% reserve target for the 2007/08 13-week winter operating period ensures that the actual winter loss of load risk is consistent with that modeled in the 2007 PJM Reserve Requirement Study.

Planning Committee endorsement of the recommended 28% winter weekly reserve target will be requested at the July 18, 2007 meeting. The recommendation on this item will be forwarded to the Operating Committee and the PJM Operations Staff responsible for generating unit planned maintenance scheduling.

Figure 15

Winter Weekly Load Shape – 2006 RRS vs. 2007 RRS

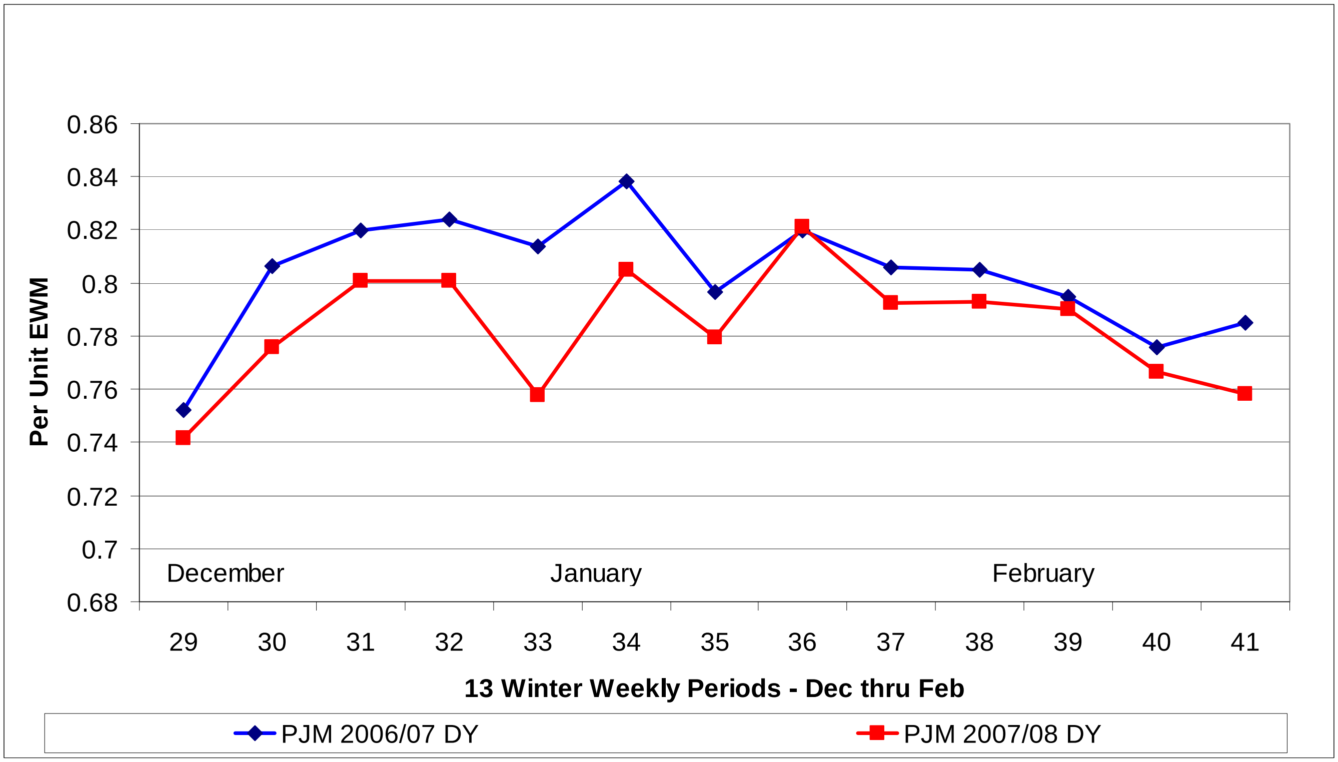


Table 16

Winter Weekly Reserve Target

Month	Calendar Week	% Weekly Reserves level for 1D/10 YR	LOLE (3rd Margin State)
December	49	19.97	3.6787E-04
	50	19.74	2.9760E-04
	51	22.99	0
	52	32.45	0
January	1	26.77	0
	2	21.64	3.0173E-04
	3	28.71	0
	4	31.50	0
	5	41.34	0
February	6	20.02	4.2987E-04
	7	27.58	0
	8	32.90	0
	9	22.17	0
Average Weekly Reserves		**26.8**	

- **Control Zone Load Shedding Protocol**

The PJM RTO is operated such that the seven various control zones within the PJM footprint conform to PJM Manual 13, Emergency Operations, http://www.pjm.com/contributions/pjm-manuals/pdf/m13.pdf (See page 39 and Attachment E). The seven control zones within the PJMRTO are Mid-Atlantic (MA), AEP, APS, Dayton, Dom, DLCO, and ComEd. Other related references include PJM Manual 37, Reliability Coordination (http://www.pjm.com/contributions/pjm-manuals/pdf/m37.pdf) and PJM Manual 03, Transmission Operations Section 5 (http://www.pjm.com/contributions/pjm-manuals/pdf/m03.pdf). This sensitivity examines those emergency operation procedures. The RRS assumes mutual load shedding across the PJMRTO, but our operation practices typically do not shed firm load in one control zone to help another control zone. This analysis verifies that we are at a one in ten LOLE given these operating practices. This analysis uses a two area model, invoking load management resources for the control zone of interest while not invoking load management for the neighboring PJM zones. Note this is a conservative assumption, consistent with the above references, but the PJM dispatcher determines the course of action to be followed to insure the Security of the PJM RTO. The reserves of Area 2 are increased to reflect the import capability of the outside PJM RTO region. The tie size is varied to determine the amount needed for the study area to be at a LOLE of 1D/10Yrs. The resulting tie size is then provided to the PJM Transmission Planning (TP) Department to verify if, under non-coincident conditions, the neighboring regions can supply at least the resulting tie size value. Table 17 shows the study's results for this analysis. PJM Transmission Planning staff verified that all seven PJM RTO control zones can import the tie size amount indicated.

Table 17

Load Shedding Protocol Analysis

Control Zone		Reserves	Capacity	Calculated Load	**Tie Size Result**	PRISM #	RI
AEP	Area1	31.20%	34570	26349	**1**	2905	218.7372
	Area2	16.34%	132370	113779			
MA	Area1	9.82%	67850	61783	**6275**	2918	9.9974
	Area2	25.19%	99090	79152			
APS	Area1	18.48%	10120	8542	**1092**	2923	10.0287
	Area2	18.96%	156820	131826			
Dayton	Area1	-2.02%	3550	3623	**1100**	2904	10.0031
	Area2	19.53%	163390	136694			
Dom	Area1	12.69%	21760	19310	**1340**	2909	10.0866
	Area2	19.52%	145180	121469			
DLCO	Area1	7.71%	3140	2915	**1200**	2900	10.0166
	Area2	19.24%	163800	137370			
ComEd	Area1	7.45%	25950	24151	**2900**	2928	10.0334
	Area2	21.12%	140990	116405			

Market Related Assessments

- **RPM Market**
  The Reliability Pricing Model (RPM) is the capacity market implemented by PJM on June 1, 2007. The RRS calculates or is coordinated with the following values required in the RPM Marketplace: IRM, FPR, DR Factor and CETO values.

  PJM's web based application, eRPM, is used to perform capacity transactions in the market place. The planning parameters derived from the RRS that are used in RPM are available at: http://www.pjm.com/markets/rpm/operations.html.

- **IRM and FPR**

  The Installed Reserve Margin (IRM) is a percentage which represents the amount of installed capacity required above the forecast restricted 50/50 peak load demand. It is the buffer above expected peak load required to meet the reliability criterion. The IRM is a key input used to determine Load Serving Entity (LSE) capacity obligations. Calculation of the IRM is necessary to the determination of the FPR.

  The FPR is a multiplier that converts load values into capacity obligation. The FPR has two necessary inputs to determine its value: the IRM and the PJMRTO pool-wide EFORd (equivalent demand forced outage rate). The FPR is defined by the following equation:

Equation 3

$$\text{FPR} = (1 + \text{Approved IRM}) * (1 - \text{PJM Avg. EFORd})$$

  The IRM and the FPR therefore represent identical levels of reserves expressed in different units. The IRM is expressed in units of installed capacity (or ICAP) whereas the FPR is expressed in units of unforced capacity (or UCAP). Unforced capacity is defined in the RAA to be the megawatt (MW) level of a generating unit's capability after removing the effect of forced outage events.

  The capacity obligation associated with a particular PJM zone is the product of that zone's adjusted planning period peak and the FPR. The obligation is expressed in units of unforced capacity.

  PJM's objectives are to establish an IRM that preserves reliability while not imposing an undue cost on load to pay for unnecessary generation reserves. PJM has used judgment in past recommendations for establishing an FPR due to some of the uncertainties associated with the current unforced capacity structure. (Appendix E).

  With RPM now in place, PJM will continue to review the RRS assumptions and consider appropriate changes to address the reduction in uncertainty.

- **DR Factor (formerly ALM Factor)**

  The Demand Resource Load Factor (DR Factor) refers to interruptible capacity resources and the capability to reduce metered load. Further reference of DR Factor (also called Active Load Management (ALM) in previous references) can be found in PJM Manual 19 (M-19), ***Load Data Systems***. Since Demand Resource (DR) is end-use customer load which can be interrupted at the request of PJM, the DR Factor is used per the RPM marketplace rules, please refer to RPM manual for further details. The DR Factor is an analytically derived value that can not have a value greater than one. To derive the value of all demand resources, the load carrying capability (LCC) is determined by performing Probabilistic Reliability Index Study Model (PRISM) calculations. The ratio of the load carrying capability to the total amount yields the DR Factor.

- **Coordination with Capacity Emergency Transfer Objective (CETO)**

  CETO studies are coordinated with the RRS. Typically the RRS provides the annual updates in the database and models, with the CETO tagged to correspond to a given RRS. The CETO and RRS are needed to be coordinated due to the marketplace requirements and to assure that the RRS assumption that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load is valid. By passing the load deliverability test this assumption is validated. See Appendix H for details on the Load Deliverability tests and refer to the RPM web site cited above for further details.

- **OASIS postings**

  The value of CBM is directly used in the various transmission path calculations for Available Transfer Capability (ATC). See the discussion in the Transmission Forecasting section and the use of 3500 MW used in the OASIS ATC postings.

Part 3 – Appendices

Appendix A
Base Case Modeling Assumptions for 2007 PJM RRS

Parameter	2006 Study Modeling Assumptions	Recommended 2007 Study Modeling Assumptions 11/29/06 letter to PC Approved at 12/6/06 PC mtg.	Basis for Recommended Assumptions	Possible Impact on IRM
Load Forecast				
Unrestricted Peak Load	145, 951 MW – 8/02/2006 @ 17:00	TBD	Forecasted Load growth per 2007 PJM Load Forecast Report, using 50/50 normalized peak.	
Weekly Load Model Shape Hourly loads	1997- 2003 Load Shape 7 Year	1996 - 2004 Load Shape 9 Year	LAS recommendation for 7 – 10 year period for Load Shape. After evaluating 2006 data, analysis indicates longer time period for load shape, used throughout all studies best insures consistency of representation for this analysis.	
Forecast Error Facto (FEF)	Forecast Error held at 1 % for all delivery years.	Forecast Error held at 1 % for all delivery years.	Consistent with consensus gained through PJM stakeholder process.	
Monthly Load forecast shape	Consistent with 2006 PJM load forecast Report and 2005 NERC ES&D report (World area).	Consistent with 2007 PJM load forecast Report and 2006 NERC ES&D report (World area).	Updated data …	
Daily Load forecast shape	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Consistent with consensus gained through PJM stakeholder process	
Capacity Forecast				
Generating Unit Capacities	Coordinated with eCapacity and EIA-411 submission.	Coordinated with eCapacity, eRPM databases, and EIA-411 submission.	New RPM Market structure required coordination to new database Schema. Consistency with other PJM reporting and systems.	
New Units	Generation Interconnection Queues with signed ISA requirement. https://www.pjm.com/planning/project-queues/queue-gen-active.jsp.	Generation Interconnection Queues coordinated with February version of forecast reserve margin graph which uses commercial probability. See http://www.pjm.com/planning/res-adequacy/resource-reports.html.	Change from signed ISA requirement to using commercial probability for proposed projects.	
Wind Resources	Derived from hourly wind data and through PJM stakeholder process. Units can use a capacity factor of 20% or actual performance once historic data is available.	Derived from hourly wind data and through PJM stakeholder process. Units can use a capacity factor of 20% or actual performance once historic data is available.	Based on limited collection of hourly wind data. 20% capacity factor based on PJM stakeholder process.	

Parameter	2006 Study Modeling Assumptions	Recommended 2007 Study Modeling Assumptions 11/29/06 letter to PC Approved at 12/6/06 PC mtg.	Basis for Recommended Assumptions	Possible Impact on IRM
Firm Purchases and Sales	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJMRTO capacity. External Sales reduce the PJMRTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in eCapacity transactions.	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJMRTO capacity. External Sales reduce the PJMRTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in eRPM auctions.	Match EIA-411 submission and eRPM auctions.	
Retirements	Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/project-queues/gen-retire.html.	Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/project-queues/gen-retire.html. Consistent with forecast reserve margin graph.	Updated data available on PJM's web site, but model data frozen in Spring 2007.	
Unit Operational Factors				
Forced and Partial Outage Rates	5-year (2001-05) GADS data. (Those units with less than five years data will use class average representative data.)	5-year (2002-06) GADS data. (Those units with less than five years data will use class average representative data.)	Most recent 5-year period. Use PJMRTO unit fleet to form class average values.	
Planned Outages	Based on eGADS data, History of Planned Outage Factor for units.	Based on eGADS data, History of Planned Outage Factor for units.	Updated schedules.	
Summer Planned Outage Maintenance	In review of recent Summer periods, no Planned outages have occurred. But 2500 MW of planned outages are in the model to reflect operations experience due to extreme ambient conditions.	In review of recent Summer periods, no Planned outages have occurred. But 2500 MW of planned outages are in the model to reflect operations experience due to extreme ambient conditions.	Review of historic 2005 and 2006 unit operational data.	
Gas Turbines, Fossil, Hydro Nuclear Ambient Derate	Ambient Derate includes several categories of unit. Based on review of operations data, Summer 2005. 2500 MW out on planned outage over summer peak	Ambient Derate includes several categories of unit. Based on review by Operations Staff and review of operations data, Summer 2005 and 2006. 2500 MW out on planned outage over summer peak.	Operational history and Operations Staff experience indicates unit derate during extreme ambient conditions. More years of operational experience under full PJMRTO footprint are needed.	
Class Average Statistics	NERC Class Average Values. 74 categories based on unit type, size and primary fuel.	PJMRTO fleet Class Average values. 74 categories based on unit type, size and primary fuel.	PJMRTO values have a sufficient population of data for most of the categories. The values are more consistent with planning experience.	
Generation Owner Review	Web Application to review and sign-off of capacity model. Performed by Generation Owner representatives.	Web Application to review and sign-off of capacity model. Performed by Generation Owner representatives.	Annual review to insure data integrity of principal modeling parameters.	

Parameter	2006 Study Modeling Assumptions	Recommended 2007 Study Modeling Assumptions 11/29/06 letter to PC Approved at 12/6/06 PC mtg.	Basis for Recommended Assumptions	Possible Impact on IRM
Load Management - Demand Resource (DR) and Interruptible load for Reliability (ILR)				
Demand Resources	PJMRTO Active Load Management was modeled per the February 2006 PJM Load Forecast Report. The amount modeled was 2061 MW.	PJMRTO load management was modeled per the June release of values. The amount modeled was 2146 MW.	Model latest load management data.	
Emergency Operating Procedures	IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions.	IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions.	Consistent reporting across historic values.	
Transmission System				
Interface Limits	The Capacity Benefit Margin (CBM) is input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3500 MW.	The Capacity Benefit Margin (CBM) is input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3500 MW.	Shape of the curve showing relationship of IRM to CBM. Figure 7.	
New Transmission Capability	Consistent with PJM's RTEPP overseen by TEAC.	Consistent with PJM's RTEPP overseen by TEAC.	Consistent with PJM's RTEPP overseen by TEAC.	
Modeling Systems				
Modeling Tools	PRISM Version 3.0	PRISM Version 3.0	Per recommendation by PJM Staff. Latest available version.	
Modeling Tools	WeekPeakFreq (WKPKFQ) Version 3.0	WKPKFQ Version 3.0	Per recommendation by PJM Staff. Latest available version.	
Modeling Tools	Applications for Reliability Calculations (ARC) Version 3.0	ARC Version 3.0	Per recommendation by PJM Staff. Latest available version.	
Modeling Tools	Multi-Area Reliability Simulation (MARS) Version 2.84	Multi-Area Reliability Simulation (MARS) Version 2.84	Per recommendation by PJM Staff and General Electric Staff. Latest available version.	
Outside World Area Models	Updated models for ECAR, MAIN, MRO-USA, NPCC (Ont, NY, NE), SERC (TVA, Entergy, Southern, VACAR) and SPP.	1st year for new NERC region boundary reporting. Updated models for RFC, MRO-USA, NPCC (Ont, NY, NE), SERC (TVA, Entergy, Southern, VACAR) adjusted to fit into the old NERC region boundary definitions.	Updated per publicly available data and by coordination with other region's planning staff.	

Appendix B
Description and Explanation of 2007 Study Sensitivity Cases

Case No.	Description and Explanation	Change in 2006 Base Case IRM (%)
1	**Load model update – Weekly shape**	**Increase by 2.27 % ***
	Impact of the new load model characteristics on IRM. These modeling characteristics are from the Weekly Peak distributions, or 52 mean and standard deviation values. The current load model replaces the load model in the previous Study.	
2	**Load model update – Monthly Forecast shape**	**Decrease by 1.06 % ***
	Impact of the updated load forecast report on IRM. The current monthly forecast load model values replace the monthly load model values in the previous Study.	
3	**Load model update – Both weekly and monthly shape**	**Increase by 1.36 % ***
	Impact of the updated load forecast report and the new weekly parameters combined on IRM. The current load model replaces the load model in the previous Study.	
4	**PJM Capacity Model update**	**Increase by 0.05 % ***
	Impact of capacity model characteristics on IRM. The current capacity model replaces the capacity model in the previous Study.	
5	**PJMRTO and World Capacity Model update**	**Increase by 0.24 % ***
	Impact of the World region capacity model characteristics on IRM. The current capacity model replaces the capacity model in the previous Study. The world reserves in the 2006 study were held at their forecast value.	
6	**Insert 2007 diversity into 2006 model**	**Increase by 1.26% ***
	Two area model changing the world models weekly value to match those in the 2007 model. Week 11 and week 10 values were swapped. This increased the 2006 RRS official IRM results by 1.26 %. This case is done by inserting the new load model diversity into the previous RRS base case.	
*** Sensitivity Numbers 1 through 6 assess the change in the 2006 RRS using the new 2007 RRS model. These sensitivities assess the impact of individual modeling characteristics that drive the change seen in the final 2007 RRS results.**		

Case No.	Description and Explanation	Change in 2007 Base Case IRM (%)
7	**No Load Forecast Uncertainty (LFU)**	**Decrease by 4.5 %**
	This scenario represents "perfect vision" for forecast peak loads, assuming that the forecast peak loads for PJMRTO and the Outside World areas have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather and, to a smaller degree, economic uncertainties on IRM requirements. The weekly STD = 0.00001 , removing any value for the forecast error factor, and for the standard normal distribution values setting the 10 points above the 50/50 point value to 0.000001.	
8	**Insert 2006 diversity into 2007 model**	**Decrease by 0.87 %**
	Diversity refers to the timing of when the PJMRTO and surrounding World model peak. If the two areas peak at the same week, then there is little or no diversity. A Peak Load Ordered Time Series (PLOTS) is used which, for a season, orders the weeks by magnitude. By averaging the historic time period daily peaks it is determined when the peak of the season occurs. The PRISM model has 52 weekly peaks, with the monthly shape derived by the 2007 PJM Load Forecast and the 2006 ES&D monthly demands. Changes in the diversity are consequence of the time period specified in the study assumptions. The time period for the 2007 Study was 9 years, 1996-2004. By changing the world model weekly value to match those in the 2006 model, week 11 and week 10 values were swapped.	
9	**Load shedding by control area**	**Pass. See Table 17**
	This series of sensitivities assess the 7 control areas protocol to not shed load to support the other control regions in the PJMRTO footprint. This is a two area study that models the control area of interest in Area1 and the rest of the PJMRTO in Area2. From the IRM Study, the CBOT is added to Area2 thus incorporating all help from surrounding regions. The reserves in the study areas are modeled at the lesser of the forecast reserves or the reserve requirement. Iterative runs are made to determine the Tie size required for a loss of load event once, on average, every 10 years. Transmission Planning Staff then verifies that the Tie size values can be imported into this region.	
10	**Poor performing units**	**Decrease by 0.56 %**
	Units identified as poor performers, substantially above the class average values, are removed from the case. Units with an EEFORd greater than or equal to 25% were removed. The intention of this sensitivity case is to demonstrate the impact of replacing traditional central generation facilities with newer better performing units. Eliminating the poor performing units from the study results in a lower IRM because the associated forced outage rates associated are higher than the average system forced outage rates. This sensitivity case can be used to assess impacts of older units. The average pool EFORd was 5.89 %, and the average pool EEFORd was 6.36%.	
11	**High Ambient Temperature Unit Derating**	**Decrease by 1.6 %**
	Assessment of performance of PJMRTO units on high ambient temperature conditions indicated that some units can not produce their summer net dependable rating on these days. This derated ability is per PJM's Operations rules and is not considered a GADS derated outage event. This assessment assumes that all units are not affected by high ambient temperature conditions and that they can produce their full summer net dependable rating. Currently PJM Staff is assessing the impacts of high ambient temperature conditions on unit performance compiling data and experience in operating the full PJMRTO. Once enough data and operating experience has	

	been logged, this modeling assumption will be re-evaluated. This sensitivity removes the 2500 MW on planned outage for the peak summer period (weeks 6-15)	
12	**Use the EFORd Statistic for all units' Forced outage rate, replacing the EEFORd for all units in the model.**	**Decrease by 0.8%**
	This case replaces for all units, the EEFORd statistic with the EFORd statistic. The EEFORd equals the EFORd plus ¼ of the EMOF. This sensitivity case assumes that all units operate at their stated summer net dependable rating or are off line. The Equivalent Maintenance Outage Factor (EMOF) is a measure of the derated outage states that all units experience. For this sensitivity, there are no derated outage states, where a unit would operate say at 90% of the summer net dependable rating. Although we know that all units do operate at various levels of their stated rating, this is a measure of impacts of the derated outage states typically experienced by most units.	
13	**Impact of change in EEFORd to IRM : F-Factor**	**Increase by 1.26 %**
	There is a direct correlation to the forced outage rate of the PJMRTO units to the PJM IRM. This sensitivity changes the forced outage rate statistic used in the Study, the Effective Equivalent Demand Forced outage rate (EEFORd) by 1 % and observes the change in the IRM.	
14	**Include Unit Ambient Derate to World Region**	**Increase by 0.04 %**
	Include a similar percentage (to that modeled in the PJMRTO area) of planned outages as an ambient derating for world region. Two area solution.	
15	**Adjusted the seasonal factors to adjust units' ratings to reflect expected winter ratings**	**No Change-0.00 %**
	In this years model the units' winter rating were significantly reduced. Our model matches eCapacity data submissions and that submitted for the EIA-411 report. The average winter factors used for this sensitivity was 1.05602 or an increase of 5.62% due to colder ambient temperatures. This value for the winter capacity was what was used in the 2006 RRS. No change was observed in the IRM using the higher winter y factors.	
16	**Figure 9, Various values of Capacity Benefit Margins**	**See Figure 9**
	Figure 9 shows the impact to IRM as you increase the value of Capacity Benefit Margin (CBM). CBM is a measure of transfer assistance available from the modeled outside neighboring region. From this graph one can tell what value our interconnected ties have on the calculated IRM, and where the value of CBM saturates or become constant. From this graph, previous assessments have chosen the CBM value to use in the study as 3500 MWs as there is a small benefit for reduction of IRM compared to a larger benefit of OASIS ATC postings. The results are shown in Figure 9	
17	**Figure 9, for 7 Control zones within the PJMRTO**	**See Figure 9**
	Various Figures are determined to show the impact to IRM as you increase the value of Capacity Benefit Margin (CBM) for each of the 7 control areas that make up the PJMRTO. The 7 control zones are Mid-Atlantic, AEP, APS, ComEd, Dayton, DLCO, and Dom. Area1 for these runs is the control area of interest. Area2 is the rest of	

the PJMRTO plus the neighboring world regions. The units experiencing deratings due to high ambient conditions are modeled in Area 2(the exception is the MA zone has ~ 1100 MW modeled in Area1).
The results of this analysis are 7 graphs similar to Figure 9.

18	**Forecast Reserves of External Control Area**	**Decrease by 1.38 %**

We model the world at forecast reserves, keeping the PJMRTO at its 1D/10 YR requirement. The neighboring control areas forecast reserves are greater than what was assumed in the base case. Making more external capacity available for reserve sharing will reduce the IRM. The higher external control area IRMs in this case are simulated by decreasing the base case load.

19	**Neighbor Region Topology**	**Increase by 0.95 %**

Assessment of the most appropriate neighboring region to use as the World model is made. Both increasing the size of the world region and reducing the size is made to determine the impacts of the surrounding region best to model.

In the 2005 Study, we reduced the world model seeing no impact to the PJMRTO IRM when the SPP region was not part of the model.
In the 2007 Study model, we reduced the world model, deleting the regions not directly electrically connected to PJMRTO. These included SERC subregions Entergy, Southern and NPCC subregion New England. We saw an impact to the PJMRTO IRM thus validating the need to keep these regions in the model.

20	**Unit Planned Maintenance Scheduling – Levelized risk**	**No change**

The levelized risk option schedules maintenance by the load carrying capability (LCC) of each unit rather than the actual installed capacity. The load carrying capability is a function of unit size, forced outage rate and slope of the reliability verse reserve characteristic.

$$LCC = M \times LOG_{10}\left(\frac{X}{(1-EEFORd)+(EEFORd * X)}\right)$$

where

X is antilog_{10} Unit (Capability/ Slope)
M is slope of change in reserve in MW for a change in reliability level by a factor of 10
LCC is Load Carrying Capability
EEFORd is forced outage rate of the unit, Effective Equivalent Demand Forced Outage Rate

This approach recognizes the increased risk when smaller units are taken out for maintenance as opposed to the risk when larger units are taken out for maintenance. Total capacity on maintenance is the same in each case. Once the load carrying capabilities have been calculated, maintenance is scheduled the same as levelized reserve.

The levelized reserve maintenance option is simpler and with less maintenance being scheduled, there has been no significant difference between the two maintenance scheduling options over many studies.

21	**One Area Model for whole region (PJMRTO plus World) -2500 MW out on PO**	**Decrease by 1.4 %**

This sensitivity models the entire modeling region, PJMRTO and the surrounding world as one area. This assumes no seams issues, no transmission constraints, and a single unit commitment dispatch for the large region. This region is the closest modeling representation we have for the Eastern Interconnection. A decrease in IRM is expected due to the larger population of units that are in the single area. A total of 2500 MW were scheduled out on Planned maintenance to model the reduction in capacity due to ambient conditions.

22	**Maximize Imports over Tie**	**NA**
	We changed the model to solve to a high RI (1d/200 yrs) and increased the World reserves to 200 %. The value of solved load was used to compare to the single area solved load. The difference is the LCC or expected value of the 3500 MW tie size. The expected value of flows over the tie size was less than the CBM. The value determined was 3126 MW, indicating that the full value of the tie size is not typically used.	
23	**Single Area PJMRTO Model**	**Increase 1.18**
	This models only the PJMRTO in a single area case. The solution is for a reliability Index (RI) of 10, or once every 10 years. When compared to the official case results, this represents the value of the interconnected ties, or capacity benefit of Ties (CBOT). The difference between the base run and this sensitivity in the solved loads is 1496 MW. This value represents the value of the 3500 CBM.	
24	**PJMRTO at cleared RPM auction**	**RI = 28.2567**
	Two area run. Model the reserves per the most recent RPM auction. The peak load is the restricted peak load for the diversified PJMRTO peak. The Capacity is what was bid and cleared in the most recent RPM market. The cleared capacity in the 2007 / 2008 Delivery Year market yielded a reserve of 19.2%.	
25	**PJM and World at forecast reserves** (PRISM # 2996 **)**	**RI = 67.0701**
	Two area model keeping both PJM and the World areas at their respective forecast reserves. Because both PJM and the World are forecasted to be above their required 1D/10 YR reserves, PJM will be at a higher Reliability Index. PJM will have an expected outage once every 67 years at these forecasted values.	
26	**One Area Model for whole region (PJMRTO plus World)-9250 MW out on PO**	**See Below**
	This sensitivity models the entire region, PJMRTO and the surrounding world as one area. This assumes no seams issues, no transmission constraints, and a single unit commitment dispatch for the large region. This region is the closest modeling representation we have for the Eastern Interconnection. A total of 9250 MW were scheduled out on Planned maintenance to model the reduction in capacity due to ambient conditions. An increase of 0.5% IRM is observed compared to sensitivity number 20.	
27	**Increase in Forecast Error Factor**	**Increase by 0.39 %**
	This sensitivity changes the forecast error factor used in the study. The Forecast Error Factor (FEF) is increased to 2% compared to the 1% used in the base case. The change in IRM is observed for 2010/2011 delivery year. Refer to Appendix L for further details.	
28	**Reliability Level at 15% IRM**	**RI=9.0213**
	This sensitivity computes the reliability for PJMRTO at various levels of Installed Reserve Margin (IRM). The surrounding region- World is solved to meet its reliability level of 1 day in 10 while PJMRTO is solved at a 15% installed reserve. Refer to Appendix M for further details.	
29	**PJMRTO at 15% IRM and World at Forecast Reserves (19.1% for 2010 / 2011)**	**RI=13.9**
	This sensitivity computes the RI for PJMRTO (IRM =15%) with the world set at its forecast reserves of 19.1% for the 2010 /2011 delivery year. Two area model with 3500 MW CBM and 2500 MW ambient derating for PJMRTO.	

30	**Load Model period impact on IRM**	**See below**
	This sensitivity computes the IRM for PJMRTO using a 7 year (1998 - 2004) and 8 year (1997 -2004) load model (WKPKFQ). These were two separate runs to show the impact of the load model period used in the base case study. The LAS recommended using a load model period of 7 to 10 years. The 7 year load model gave a lower IRM, by 0.66 %. The 8 year load model gave a lower IRM, by 0.06 %.	
31	**Interchange Areas –Area1(World) and Area2(PJMRTO)**	**No Change**
	This sensitivity interchanges the Areas for the World model and PJMRTO model. Historically, using the GEBGE algorithms, a difference in the IRM results would be seen when swapping the area models. PRISM uses updated algorithms to improve on this GEBGE behavior. This sensitivity for the 2010 / 2011delivery year yielded the same IRM results as the base case run.	
32	**PJMRTO IRM Vs. World Reserves**	**See Below**
	This sensitivity uses a two area study to graph the IRM of the PJM RTO as a function of World Reserves. World Reserves were varied from the calculated requirement (1 day in 10) to the forecasted reserves. The runs are made by solving the World for a fixed load (corresponding to a installed reserve level) and PJM RTO is solved to its criteria. As the reserves of the world increase, the IRM requirement for PJM RTO decreases. The IRM for the RTO saturates at a value little above 14%.	
33	**PJMRTO RI Vs. World Reserves**	**See Below**
	This sensitivity uses a two area study to graph the RI (days/ year) of the PJM RTO as a function of World Reserves. World Reserves were varied from the calculated requirement (1 day in 10) to the forecasted reserves. The runs are made by solving the World for a fixed load (corresponding to a installed reserve level) and PJM RTO is held to a constant reserve level. As the world reserves increase from its criterion value to its forecasted value the PJM RTO RI increases. Sensitivity number 29 shows the RI of the PJMRTO (at 15% installed reserves) with the world reserves at forecast.	

Appendix C
Resource Planning Reserve Requirements
PJM's compliance with Standard BAL-502-RFC-01

A. Introduction

1. Title: Resource Planning Reserve Requirements

2. Number: BAL-502-RFC-01

3. Purpose:

To establish requirements for a minimum level of resource adequacy to reliably serve all load in the ReliabilityFirst (RFC) corporate region.

4. Applicability

These requirements are applicable to all Load Serving Entities (LSEs) and Planned Reserve-Sharing Groups (PRSGs) within ReliabilityFirst. PRSGs may be a single LSE, or group of LSEs (for example, participants in an RTO or ISO) that contractually commit to use its shared resources to meet the reliability obligation to serve the load of the PRSG as a whole, in accordance with applicable regulatory requirements. An LSE may choose to delegate specific requirements as defined herein to the PRSG in which it participates.

5. Effective Date:

April 1, 2006 to permit a reasonable transition and implementation for the 2007 and 2008 Planning Years

B. Requirements

R1. The Loss of Load Expectation (LOLE) for any load in RFC due to resource inadequacy shall not exceed one occurrence in ten years. This requirement applies to all PRSGs within RFC.

R2. Each LSE

R2.1 shall be a member of a PRSG for determining its resource planning reserve requirements. Membership in PRSGs must recognize interconnected system arrangements and are subject to verification by RFC.

R2.2 shall report to RFC within 90 days of the effective date of BAL-502-RFC-01 which PRSG is responsible for determining its resource planning reserve requirements. In addition, if a LSE changes the PRSG that is responsible for determining its resource planning reserve requirements, the LSE shall notify RFC at least 90 days prior to the proposed change or 180 days prior to the planning period under review, whichever is greater.

R3. Resource Planning Reserve Requirement analyses performed by each PRSG shall:

R3.1. be performed or verified annually

R3.2. express resource planning reserve requirements as a percentage of the 50:50 probability forecast peak load (Reserve Margin).

R3.3. determine a resource planning reserve requirement for each of the PRSG members for the upcoming planning year as defined by the PRSG.

R3.4. be performed or verified for the nine subsequent planning years to provide information for long-term resource planning without establishing specific resource planning reserve requirements

R3.5. model a "loss-of-load event" as system conditions before taking emergency actions (e.g. unplanned voltage reductions or public appeals) but including system conditions subsequent to taking planned contractual actions (e.g. direct control load management).

R3.6. consider the availability of all generating units within the PRSG committed to meet the adequacy of Group load. At a minimum, the calculations must consider the following characteristics of the generating unit population:

R3.6.1. Historic generating unit performance and any projected changes

R3.6.2. Generating unit seasonal ratings

R3.6.3. The population of units deemed "typical" for compiling the history to determine generating performance statistics for new units

R3.6.4. Projected planned generator outages and maintenance schedules

R3.6.5. Fuel limitations, wind or hydro energy limitations or other reasons for limited dispatchability of generators

R3.6.6. Common mode outages that effect resource adequacy

R3.6.7. Availability of Resources with Environmental or Regulatory Restrictions

R3.7. consider the characteristics of other resources within the PRSG committed to meet the adequacy of Group load. At a minimum, the calculations must consider the following:

R3.7.1. Limitations such as notice, buy-through provisions, duration, or frequency

R3.7.2. How it is dispatched

R3.7.3. Physical characteristics such as weather, cold load pickup, etc.

R3.8. consider the characteristics of load, such as the following:

R3.8.1. Load diversity

R3.8.2. Seasonal load variation

R3.8.3. Load variability due to weather, regional economic forecasts, etc.

R3.8.4. Load forecast uncertainty

R3.8.5. Contractual arrangements concerning load shedding agreements among PRSG members

R3.9. shall base the LOLE calculation on a methodology employing the sum of the daily loss of load probabilities.

R3.10. consider the benefit of interconnections to other entities outside the PRSG recognizing transmission limitations and the likelihood of capacity resources being available to the PRSG when needed.

R3.11 documentation of the consideration for each of the items in R3.1 through R3.10 must be provided.

R4. Each PRSG shall document that it has an agreement to enforce the requirement of R3.3 on its LSE members.

R5. Each LSE shall secure the resources needed to meet the resource planning reserve requirement established by a PRSG for the upcoming planning year.

R6. The consideration of any resources within the PRSG not committed to serving the capacity needs of the Group that are included as resources in the calculation of required reserve levels or accepted as resources used to meet requirements must be specifically justified and documented.

(NERC: Resource Planning Reserve Requirements BAL-502-RFC-01)

R1 – Section1, letter dated April 19, 2006.
R2.1 – NA, see Section 13
R2.2 – NA, see Section 13
R3 - Section 1
R3.1 – Section 1, Section 4, Page 17
R3.2 -Section 1, page 1 and Table 1
R3.3 – Section 1
R3.4 – Section 2 and Section 3. The current assessment is for a ten year period.
R3.5 – Section 4, page 13. We measure compliance at the restricted load level. (Unrestricted Load – ALM = Restricted Load)
R3.6 – Section 4 pages 13, 19-20, Section 5 pages 14-15, Section 6, Section 7
R3.6.1 - Section 4, Section 6
R3.6.2 – Section 4 page 13, Section 7
R3.6.3 – Section 2 Attachment 3, Section 3 Attachment 3
R3.6.4 - Section 2 Attachment 3, Section 3 Attachment 3
R3.6.5 – Section 6, Section 7 page 13
R3.6.6 - Section 10, Section 11
R3.6.7 – Section 6, Section 7 Appendix A page 11, Section 2 attachment 2, Section 3 Attachment 2
R3.7 - Section 2, Section 3, Section 8 page 49
R3.71 – Section 2, Section 3, Section 6, Section 7
R3.7.2 - Section 2, Section 3, Section 6, Section 7
R3.7.3 - Section 2, Section 3, Section 6, Section 7
R3.8 - Section 9, Section 4 page 10, Section 5
R3.8.1 - Section 9, Section 12 page 28
R3.8.2 - Section 9
R3.8.4 - Section 9
R.3.8.5 - Section 9
R3.9 - Section 4 page 8, Section 5
R3.10 - Section 1 Figure 1, Section 2, Section 3, Section 4 page 15 and 17, Section 5
R3.11 - Section 8
R4 - Section 8, Whole document
R5 - NA, done through PJM's eRPM process.
R6 - Section 2 Attachment 2 and 3, Section 3 Attachment 2 and 3

Description of Compliance documentation Sections

Section 1 – 2006 Reserve requirement Study results

Section 2 – 2006 Reserve requirement Study assumptions

Section 3 – 2007 Reserve requirement Study assumptions

Section 4 – Manual 20, PJM Reserve Requirements

Section 5 – PJM Generation Adequacy Analysis, Technical Methods

Section 6 – Manual 23, eGADS user manual

Section 7 – Manual 21, Rules and procedures for determination of generating capability

Section 8 - Docket Nos EL05-148 and ER05-1410, Sept 29, 2006. Attachment A PJM RAA (Reliability Assurance Agreement) Revisions

Section 9 – Manual 19, Load data systems

Section 10 – Winter Weekly Reserve Target

Section 11 – Adequacy of Natural Gas infrastructure to serve electric power generating sector (confidential)

Section 12 – PJM Load Forecast report, January 2007

Section 13 – List of PJM LSEs that informed us that PJM will be their PRSG.

Appendix D
Reserve Requirement Assumption Working Group (RRAWG)

RRAWG Main Deliverables and Schedule

There are 3 primary deliverables of the RRAWG.

1. The assumptions letter for the upcoming RRS
   This has historically been completed in December. RPM requirements move the start of this effort up to October.

2. The IRM, FPR, Demand Resource Factor (DR Factor) Analysis Report
   This has historically been completed in April, but RPM requirements might move the completion date to July.

3. The Winter Weekly Reserve Target in the Report
   This has historically been completed in June or July, for the upcoming winter period. The RPM requirements will have this as part of the July report.

Appendix E
Engineering Judgments used in the Reserve Requirement Study

Purpose: Following is a list of "engineering judgment" items that should be considered when approving the Forecast Pool Requirement (FPR) based on Installed Reserve Margin (IRM) Study results.

Items are ordered by impact to the study results, with Item #1 having the greatest impact.

ASSUMPTIONS THAT UNDERESTIMATE THE IRM

Item #	Description
1	**Independence of Unit Outage Events (no recognition of common cause failures)** Historically, this has been a valid assumption widely used throughout the industry. All production grade commercial applications used to perform probabilistic reliability indexes use this assumption. But changes in the make up of the industry, such as the current trend to build mostly units that rely on the shared gas transmission system, could invalidate this assumption for some units that do have a correlation for outages due to the shared gas transmission pipeline.
2	**Forecast Error Factor (FEF)** The Forecast Error Factor (FEF) has been used for many years with the knowledge and review of the Load Analysis Subcommittee. This factor typically has been set to 1/2% for the 1st planning period of the Study and increased by ½ % increments per planning period with a maximum value of 3%. As required by the RPM proposal, the 2005 IRM Study will model a 1% Forecast Error Factor for the 2006-07 planning period and for each of the three succeeding years. This change from our current practice of increasing the FEF as the planning horizon lengthens will reduce the calculated IRM for the second, third and fourth forecast years of the study.
3	**Assistance from World area when commercial incentives are changing** The value of the outside world's assistance is associated with two modeling characteristics: The first characteristic is PJM's need and the timing of Loss-of-Load events. The second characteristic is the ability of the World to supply assistance at this time of need. The assumption that the outside world adjacent to PJM will help PJM avoid Loss-of-Load events is based on historic operating experience. But changing Industry environments, based on profit incentives, in the future may reduce this non-commercial activity going forward. A related issue and potential to impact this assumption is that of external capacity having the correct reservations in the OASIS systems and its capability to be transferred from one region to the other.
4	**Modeling all External NERC Regions in a Single Area** PRISM is limited to a 2-area model: PJM and the World Area. Thus all external NERC regions are modeled in a single area. This approach assumes that all external NERC regions share loss-of-load events which, of course, are not the case. Furthermore, PRISM solves the World to collectively be at a "1 in 10" reliability level whereas, in practice, each external NERC Region is at "1 in 10" and hence the World is collectively at a level worse than "1 in 10". These two assumptions associated with the World area cause the program to overstate (probably slightly) the amount of benefit PJM derives from interconnection to external regions.

ASSUMPTIONS THAT OVERESTIMATE THE IRM

Item #	Description
1	**Units out on planned maintenance over Summer peak period** The moving of planned outage events to the summer peak period has been used in the modeling since 1992. This represents what has been seen in Operations over the Summer period and reflects PJM's experience for the size of the control region (about 1300 units) being modeled. Currently 2500 MWs is modeled out to reflect reduced unit output during high ambient conditions (Hot & Humid). However, we need operations data for the full PJMRTO footprint to verify and evaluate this assumption, going forward. Obtaining the Operations data for unit outage events for historic Summer peak periods is being performed by the PJM Staff.
2	**Holding World at 1d/10yr reserves rather than forecast reserves** The IRM Procedure calls for modeling the World at the lesser of "1 in 10" or forecast reserves. This practice is followed so that PJM does not depend on World "excess" reserves that may be committed to other regions. Any excess reserves, however, may be uncommitted and actually available to serve PJM under a capacity emergency. Thus this assumption may understate (slightly) the amount of assistance available to PJM from the World area. Historically, the world forecast reserves are higher than the 1d/10yr reserves.
3	**Normal load model rather than non-normal load model** The assumption of normally distributed daily peak loads has been used for many years in the PJM analysis. The objective is to capture all possible loads and their likelihood in the calculation of the loss-of-load expectation. The program historically has used a 21 point distribution, which was a fixed set of values for all weeks of the analysis. This program has a weekly load model that is magnitude ordered within a season, having a mean and standard deviation for each of the 52 weeks in the model. The 21 point distribution, assumed to be a normal distribution, is overlaid on top of the each week's mean and standard deviation in the calculation of loss of load expectation. This assumption may have higher risk due to the range of plus or minus 4.2 standard deviations used. This distribution was applied to all 52 weeks in the model. The program did not include a method to be able to have different weekly distributions. With only having the ability to apply one distribution to every week, the assumption of a normally distributed week was considered conservative and appropriate. Recent efforts by PJM Staff have re-visited this set of calculations. The PRISM application was modified to include new calculation techniques that have a different and unique distribution for each week of the model. The focus of the improvements was to add the capability to incorporate non-normal distributions, when applicable, in the load model. New methods to determine the weekly distributions for the study regions modeled in the PRISM studies are the focus of these efforts.

ASSUMPTIONS WITH AN UNDETERMINED IMPACT ON IRM

Item #	Description
1	**PJM and World regions load diversity** The value of the Capacity Benefit Margin (CBM) is associated with the timing of when the PJM load model peaks occur relative to the timing of when the World load model peaks occur. Diversity refers to the magnitude associated with the difference in this timing of the two study areas' weekly peaks. The Load Analysis Subcommittee (LAS) recommended using a 7 to 10 year period of hourly peak loads for determining the load model shape for each study area, to address the influence of diversity on the study results. The IRM Study expanded the historical basis for load models from five to nine years to reduce the volatility in PJM/World load diversity that has been observed in recent IRM Studies. The issue of diversity will impact the two area study results and is based on the historic hourly loads used. Because of the nature of using actual observed hourly values, to predict future load characteristics, diversity can either increase or decrease with little ability to influence this study model characteristic once the load model time period assumptions are chosen.
2	**Perfect correlation between 2 load models** The perfect correlation of the Study area load model shape with the neighboring world area load model has been used for years. This results in a direct correlation, point by point, of the Area 1(PJM) and Area 2 (World) 21 point distributions. This assumes that when Area 1 peaks, it only includes the likelihood of that same point on the Area 2 (World) load model. No correlation to other likelihoods of the Area 2 (World) load shape is included in the calculations. Including the probability of other points on the Area 2 (World) load shape, centered around the Area 1 (PJM) load model point, is being considered but the detailed design has not been done hence the impact on the calculated LOLE can not be determined yet.
3	**Use of class average values for Market Integration zones** In the reporting of individual unit outage events, the statistics used in the Adequacy studies use a 5 year reporting period. When a unit has reported outage events for a portion of this 5 year period, the class average statistics, applicable to this size and type of unit are used for the missing reporting time period of actual events. Also the class average statistics are used for all future units being modeled as no actual operating experience in available yet. The actual unit performance characteristics may be significantly different than the class average values. However, recent modeling is based on the PJMRTO fleet of units which may mitigate this difference.

Appendix F
PJM Generation Adequacy Technical Methods

This documentation attempts to provide a readable explanation of how the LOLE studies are performed. This 37 page document is available at the PJM web site. Navigate to www.pjm.com and type "Technical Methods" in the search box or go the following link. http://www.pjm.com/planning/res-adequacy/downloads/20040621-white-paper-sections12.pdf

This document discusses the following:

1. Criteria used in the LOLE Studies
2. Reserve Requirement Analysis
3. Two area-model
4. PJM and World Region
5. Single Transmission Tie
6. Probabilistic Reliability Index Study Model (PRISM)
7. Convolution solution technique
8. Load model
9. Capacity Model
10. Capacity Benefit Margin
11. PRISM solution algorithm
12. ALM Factor calculation (Now called DR Factor)
13. Committee review and approval
14. Benchmarking of study results with operations
15. Citations
16. References
17. Glossary

Appendix G
Modeling Parameters
Base Case: PRISM Results Summary – Run # 3048

Year	Area	Week Num	Install Cap	Install Pct	Avail Pct	Tie Size	RI
2007	1	10	166940	15.6324	13.9008	3500	10.0020
2007	2	10	457170	14.6787	14.6787	3500	9.9973
2008	1	10	168210	15.4873	13.7710	3500	9.9973
2008	2	10	465580	14.7225	14.7225	3500	10.0005
2009	1	10	169190	15.4066	13.7015	3500	10.0000
2009	2	10	472480	14.7271	14.7271	3500	9.9969
2010	1	10	170460	15.4513	13.7583	3500	10.0028
2010	2	10	478830	14.7202	14.7202	3500	9.9995
2011	1	10	171720	15.4679	13.7870	3500	10.0013
2011	2	10	484390	14.7146	14.7146	3500	9.9994
2012	1	10	172500	15.4730	13.7996	3500	9.9997
2012	2	10	489180	14.6889	14.6889	3500	9.9946
2013	1	10	173270	15.4259	13.7607	3500	10.0031
2013	2	10	495090	14.7161	14.7161	3500	10.0039
2014	1	10	173270	15.3905	13.7258	3500	10.0009
2014	2	10	499660	14.7318	14.7318	3500	10.0002
2015	1	10	173270	15.3652	13.7008	3500	9.9986
2015	2	10	505070	14.7351	14.7351	3500	10.0022
2016	1	10	173920	15.4229	13.7639	3500	9.9963
2016	2	10	512600	14.7218	14.7218	3500	10.0020

Base Case: System Parameters Report– Capacity model PRISM # 3048

Area	Year	Actual Capacity	Rounded Capacity	Actual Avg. Capacity	Syspar Rounded Avg. Capacity	Rounded Pool Values EEFORd	Rounded Pool Values EFORd	Actual Pool Values EEFORd	Actual Pool Values EFORd	Units
1	2007	166545	166940	142	142	0.0687	0.0638	0.0686	0.0636	1175
1	2008	167896	168210	134	135	0.0684	0.0634	0.0682	0.0633	1249
1	2009	168873	169190	130	131	0.0680	0.0631	0.0678	0.0629	1295
1	2010	170143	170460	129	129	0.0680	0.0631	0.0678	0.0629	1317
1	2011	171402	171720	129	129	0.0680	0.0631	0.0678	0.0629	1333
1	2012	172183	172500	129	129	0.0680	0.0631	0.0679	0.0630	1339
1	2013	172946	173270	129	129	0.0681	0.0632	0.0679	0.0630	1345
1	2014	172946	173270	129	129	0.0681	0.0632	0.0679	0.0630	1345
1	2015	172946	173270	129	129	0.0681	0.0632	0.0679	0.0630	1345
1	2016	173593	173920	129	129	0.0679	0.0630	0.0678	0.0629	1347
2	2007	453403	457170	104	105	0.0730	0.0671	0.0729	0.0670	4346
2	2008	461823	465580	105	106	0.0732	0.0673	0.0730	0.0671	4382
2	2009	468705	472480	106	107	0.0733	0.0674	0.0732	0.0673	4413
2	2010	475068	478830	107	108	0.0734	0.0675	0.0733	0.0674	4445
2	2011	480597	484390	108	108	0.0735	0.0676	0.0734	0.0674	4472
2	2012	485376	489180	108	109	0.0735	0.0676	0.0734	0.0675	4493
2	2013	491280	495090	109	110	0.0736	0.0677	0.0735	0.0676	4518
2	2014	495840	499660	109	110	0.0737	0.0678	0.0736	0.0677	4543
2	2015	501230	505070	110	111	0.0738	0.0679	0.0737	0.0677	4567
2	2016	508753	512600	111	111	0.0739	0.0680	0.0738	0.0678	4603

Capacity Model – Prism # 3048

2010 / 2011 Delivery Year	Total Area Capacity	
subzone	actual	rounded
PJM RTO		
AE	1354	1370
AEP	35768	35940
BGE	5295	5300
ComEd	26463	26500
Dayton	3518	3560
Dom VP	22169	22190
DPL	4543	4590
DLCO	3035	3040
JCPL	4141	4150
MetEd	4100	4140
APS	12027	11990
PECO	11691	11720
PEPCO	6348	6400
PLGRP	10796	10690
PS	11147	11140
PenElec	7748	7740
	170143	**170460**
WORLD		
ECAR Other	85058	85850
ENTERGY	34028	34260
MAIN Other	51492	51960
MAPP OTHER US	38201	38770
NEPOOL	32569	33000
NEW YORK	41966	42390
ONTARIO	32973	33050
QUEBEC	5534	5420
SOUTHERN	61270	61600
TVA	38453	38620
VACAR Other	53524	53910
	475068	**478830**

2011 / 2012 Delivery Year	Total Area Capacity	
subzone	actual	rounded
PJM RTO		
AE	1354	1370
AEP	35880	36050
BGE	5295	5300
ComEd	26638	26680
Dayton	3519	3560
Dom VP	22169	22190
DPL	4669	4720
DLCO	3035	3040
JCPL	4141	4150
MetEd	4100	4140
APS	12060	12020
PECO	11691	11720
PEPCO	6536	6590
PLGRP	11420	11310
PS	11147	11140
PenElec	7748	7740
	171402	**171720**
WORLD		
ECAR Other	85327	86120
ENTERGY	34647	34880
MAIN Other	51910	52370
MAPP OTHER US	38381	38960
NEPOOL	32561	32990
NEW YORK	41952	42380
ONTARIO	32201	32280
QUEBEC	5534	5420
SOUTHERN	62849	63180
TVA	39567	39740
VACAR Other	55668	56070
	480597	**484390**

Forecast Reserve Report – (Sensitivity # 25 of Appendix B)

Forecast Reserves				
Area	Delivery Year	Actual Capacity	Restricted Peak Load	Input Reserves
1	2007	166545	134815	23.54%
1	2008	167896	137196	22.38%
1	2009	168873	139564	21.00%
1	2010	170143	141936	19.87%
1	2011	171402	144258	18.82%
1	2012	172183	146541	17.50%
1	2013	172946	148720	16.29%
1	2014	172946	150935	14.58%
1	2015	172946	153144	12.93%
1	2016	173593	155304	11.78%
2	2007	453403	376706	20.36%
2	2008	461823	385334	19.85%
2	2009	468705	391959	19.58%
2	2010	475068	398748	19.14%
2	2011	480597	405396	18.55%
2	2012	485376	413191	17.47%
2	2013	491280	420688	16.78%
2	2014	495840	427928	15.87%
2	2015	501230	434229	15.43%
2	2016	508753	442202	15.05%

World Load Model Parameters

ARC WEEK	MEAN	STANDARD DEVIATION
1	0.74733	0.03436
2	0.76696	0.028478
3	0.77601	0.043282
4	0.81939	0.049445
5	0.8805	0.038321
6	0.89	0.045755
7	0.90162	0.04819
8	0.91542	0.037145
9	0.9308	0.045445
10	1	0.057662
11	0.96868	0.038058
12	0.94029	0.054477
13	0.9779	0.046746
14	0.92536	0.046753
15	0.92823	0.040406
16	0.89444	0.031746
17	0.86259	0.039275
18	0.84522	0.034189
19	0.79708	0.053032
20	0.72575	0.029294
21	0.76048	0.048056
22	0.72607	0.030353
23	0.71937	0.029969
24	0.73249	0.034146
25	0.74483	0.027715

ARC WEEK	MEAN	STANDARD DEVIATION
26	0.746663	0.037439
27	0.75772	0.025876
28	0.760204	0.028733
29	0.797098	0.036486
30	0.801487	0.04229
31	0.806136	0.052206
32	0.831282	0.046858
33	0.783788	0.0362
34	0.842964	0.067895
35	0.826568	0.045978
36	0.839505	0.046852
37	0.822304	0.043106
38	0.806488	0.044367
39	0.790351	0.050205
40	0.787307	0.04182
41	0.776701	0.03076
42	0.761864	0.038729
43	0.775352	0.042365
44	0.745025	0.032269
45	0.736091	0.030346
46	0.726233	0.023984
47	0.703708	0.023379
48	0.711082	0.026782
49	0.72266	0.028235
50	0.701247	0.022061
51	0.736751	0.038877
52	0.759568	0.059647

Parameter	Value
Title	WLD07RST
Description	World 2007 R-Study 9 Year Plots Model {1996-2004} LAS Year: 2007 Growth Start Year: 2007 Growth End Year: 2007 2016
Year Range	1996 - 2004
Growth Factor	0.015021109
Growth Start Year	2007/2008
Growth End Year	2016/2017
Report Select	1
Zones	MAPPOUS,NE,NY,ONT,ECARO,MAINO,ENT,SOCO,TVA,VAC
Exclude Weekends	Y
Exclude Holidays	Y
Excluded Holidays	1 ,2,3,4,5,6,7,8

Seasonal Factors to adjust units' ratings – Increase the non-Summer Unit ratings due to lower ambient temperatures

2007	Summer	Winter	Spring/Fall
PJM	1.00000	1.01930	1.00970
WORLD	1.00000	1.03400	1.01700

2008	Summer	Winter	Spring/Fall
PJM	1.00000	1.01960	1.00980
WORLD	1.00000	1.03340	1.01670

2009	Summer	Winter	Spring/Fall
PJM	1.00000	1.01940	1.00970
WORLD	1.00000	1.03290	1.01640

2010	Summer	Winter	Spring/Fall
PJM	1.00000	1.01920	1.00960
WORLD	1.00000	1.03250	1.01620

2011	Summer	Winter	Spring/Fall
PJM	1.00000	1.01920	1.00960
WORLD	1.00000	1.03210	1.01600

2012	Summer	Winter	Spring/Fall
PJM	1.00000	1.01910	1.00950
WORLD	1.00000	1.03180	1.01590

2013	Summer	Winter	Spring/Fall
PJM	1.00000	1.01900	1.00950
WORLD	1.00000	1.03130	1.01560

2014	Summer	Winter	Spring/Fall
PJM	1.00000	1.01900	1.00950
WORLD	1.00000	1.03100	1.01550

2015	Summer	Winter	Spring/Fall
PJM	1.00000	1.01900	1.00950
WORLD	1.00000	1.03060	1.01530

2016	Summer	Winter	Spring/Fall
PJM	1.00000	1.01890	1.00940
WORLD	1.00000	1.03010	1.01510

Monthly Loads – Unrestricted Peak, Load Management, and Restricted Peak

Unrestricted Peak Loads

2007	January	February	March	April	May	June	July	August	September	October	November	December
PJM	114178	110008	100438	94820	106185	127464	136961	130369	115435	94382	98806	111066
World	329853	313225	293151	264347	307724	360349	387207	383832	344888	283001	288284	311967

2008	January	February	March	April	May	June	July	August	September	October	November	December
PJM	115484	111129	102049	96207	107612	129734	139342	132304	118341	95848	99365	112270
World	337451	320547	299261	269850	314329	368226	395137	392392	351575	289176	295090	319253

2009	January	February	March	April	May	June	July	August	September	October	November	December
PJM	116884	112861	103715	97641	109202	132044	141710	134319	121206	97140	101539	113872
World	343454	326175	304308	274474	319652	374155	401733	398971	357137	294211	299913	324888

2010	January	February	March	April	May	June	July	August	September	October	November	December
PJM	118330	114261	105180	99163	111942	134687	144082	136838	123102	98348	103045	115401
World	349563	331822	309857	279488	324858	380246	408574	405586	363260	299552	305055	330357

2011	January	February	March	April	May	June	July	August	September	October	November	December
PJM	119703	115837	106003	100469	113855	137009	146404	139179	124440	99643	104499	117035
World	355597	337531	315401	284069	330084	386276	415159	412028	369450	304227	309977	335882

2012	January	February	March	April	May	June	July	August	September	October	November	December
PJM	120916	116876	107254	102232	115522	138327	148687	141361	125373	102288	105861	117973
World	362612	344105	321535	289395	336307	393676	423004	419465	376779	309214	315763	342577

2013	January	February	March	April	May	June	July	August	September	October	November	December
PJM	122031	117602	108732	103605	117083	139952	150866	143276	127601	103670	106523	118153
World	369820	351153	327587	294861	342766	401278	430602	427343	383355	314889	322049	350003

2014	January	February	March	April	May	June	July	August	September	October	November	December
PJM	123342	119107	109973	104885	118273	142678	153081	145161	130045	104952	107619	120272
World	376535	357442	333204	299922	348821	407789	437920	434898	389602	320401	327759	355859

2015	January	February	March	April	May	June	July	August	September	October	November	December
PJM	124664	120794	111750	106252	120833	144852	155290	147059	132850	106290	109688	121747
World	382346	362799	338268	304525	353730	413676	444273	441291	394956	325282	332470	361261

2016	January	February	March	April	May	June	July	August	September	October	November	December
PJM	126135	122366	112926	107424	122772	147606	157450	149578	134016	106704	111168	123488
World	389365	369425	344759	310415	360067	420621	452212	448919	402467	331493	338364	367511

Load Management - Demand Resources and Interruptible Loads for Reliability

2007	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	10573	10573	10573	10573	10573	10501	10501	10501	10501	10573	10573	10573

2008	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	9875	9875	9875	9875	9875	9803	9803	9803	9803	9875	9875	9875

2009	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	9846	9846	9846	9846	9846	9774	9774	9774	9774	9846	9846	9846

2010	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	9898	9898	9898	9898	9898	9826	9826	9826	9826	9898	9898	9898

2011	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	9835	9835	9835	9835	9835	9763	9763	9763	9763	9835	9835	9835

2012	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	9885	9885	9885	9885	9885	9813	9813	9813	9813	9885	9885	9885

2013	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	9986	9986	9986	9986	9986	9914	9914	9914	9914	9986	9986	9986

2014	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	10064	10064	10064	10064	10064	9992	9992	9992	9992	10064	10064	10064

2015	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	10116	10116	10116	10116	10116	10044	10044	10044	10044	10116	10116	10116

2016	January	February	March	April	May	June	July	August	September	October	November	December
PJM	1499	1499	1499	1499	1499	2146	2146	2146	2146	1499	1499	1499
World	10082	10082	10082	10082	10082	10010	10010	10010	10010	10082	10082	10082

Restricted Peak Loads – Unrestricted Peak minus Load Management

2007	January	February	March	April	May	June	July	August	September	October	November	December
PJM	112679	108509	98939	93321	104686	125318	134815	128223	113289	92883	97307	109567
World	319280	302652	282578	253774	297151	349848	376706	373331	334387	272428	277711	301394

2008	January	February	March	April	May	June	July	August	September	October	November	December
PJM	113985	109630	100550	94708	106113	127588	137196	130158	116195	94349	97866	110771
World	327576	310672	289386	259975	304454	358423	385334	382589	341772	279301	285215	309378

2009	January	February	March	April	May	June	July	August	September	October	November	December
PJM	115385	111362	102216	96142	107703	129898	139564	132173	119060	95641	100040	112373
World	333608	316329	294462	264628	309806	364381	391959	389197	347363	284365	290067	315042

2010	January	February	March	April	May	June	July	August	September	October	November	December
PJM	116831	112762	103681	97664	110443	132541	141936	134692	120956	96849	101546	113902
World	339665	321924	299959	269590	314960	370420	398748	395760	353434	289654	295157	320459

2011	January	February	March	April	May	June	July	August	September	October	November	December
PJM	118204	114338	104504	98970	112356	134863	144258	137033	122294	98144	103000	115536
World	345762	327696	305566	274234	320249	376513	405396	402265	359687	294392	300142	326047

2012	January	February	March	April	May	June	July	August	September	October	November	December
PJM	119417	115377	105755	100733	114023	136181	146541	139215	123227	100789	104362	116474
World	352727	334220	311650	279510	326422	383863	413191	409652	366966	299329	305878	332692

2013	January	February	March	April	May	June	July	August	September	October	November	December
PJM	120532	116103	107233	102106	115584	137806	148720	141130	125455	102171	105024	116654
World	359834	341167	317601	284875	332780	391364	420688	417429	373441	304903	312063	340017

2014	January	February	March	April	May	June	July	August	September	October	November	December
PJM	121843	117608	108474	103386	116774	140532	150935	143015	127899	103453	106120	118773
World	366471	347378	323140	289858	338757	397797	427928	424906	379610	310337	317695	345795

2015	January	February	March	April	May	June	July	August	September	October	November	December
PJM	123165	119295	110251	104753	119334	142706	153144	144913	130704	104791	108189	120248
World	372230	352683	328152	294409	343614	403632	434229	431247	384912	315166	322354	351145

2016	January	February	March	April	May	June	July	August	September	October	November	December
PJM	124636	120867	111427	105925	121273	145460	155304	147432	131870	105205	109669	121989
World	379283	359343	334677	300333	349985	410611	442202	438909	392457	321411	328282	357429

Appendix H
Load Deliverability Tests

Load Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver energy from generation facilities to wherever it is needed to ensure that the transmission system is adequate for delivery of energy to load. Local Deliverability Areas (LDAs) are sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combinations of zones.

PJM's Load Deliverability analysis is conducted to determine the emergency capacity import objective (what import capacity is required) and the emergency capacity limit (how much capacity is able to get in) involving a two-step test:

- **Capacity Emergency Transfer Objective (CETO)** – this test establishes the required emergency import capability within a defined area or an LDA for satisfying reliability criteria. The CETO verifies that there are no PJM intra-area transmission bottlenecks. CETO analysis determines a megawatt import value and is a measure of the assistance required to meet the reliability criteria for the subarea of study.

- **Capacity Emergency Transfer Limit (CETL)** – this test determines the maximum limit (in MWs) that a defined area or an LDA can import under capacity emergency conditions.

The CETO study increases the amount of capacity imported into the LDA, measuring the resulting reliability index (it ignores actual transmission characteristics). When the reliability index reaches 1-day-in-25-years, the associated import level is the calculated CETO. The 1-day-in-25-years index refers to the frequency with which the study area should shed load due to insufficient import capability only.

PJM Manual 14B, Titled "Generation and Transmission Interconnection Planning", Attachment E: PJM Deliverability Testing Methods, provides more detailed information. This Manual is posted on the PJM Web Site at: http://www.pjm.com/contributions/pjm-manuals/pdf/m14b.pdf.

Appendix I
Conduct of the RRS

- **Compliance with Reliability First Corporation (RFC) Criteria**
- **Loss Of Load Expectation (LOLE) and PJM Reliability Criteria**

The required reliability standard for resource adequacy is expressed as a Loss of Load Expectation (LOLE) for the entire PJMRTO Region. Loss of Load is defined as invoking emergency operations procedures beyond demand resources and interruptible load for reliability. LOLE is expressed in terms of days per year. PJM has adopted an LOLE planning criterion of 1-in-10 which is stated in the RFC Standard, BAL-502-RFC-01 effective April 1, 2006, criteria as:

> R1. The Loss of Load Expectation (LOLE) for any load in RFC due to resource inadequacy shall not exceed one occurrence in ten years.

This standard is based on a frequency metric and does not consider event duration or magnitude. For purposes of the RRS, the LOLE criterion for PJM can be expressed as 0.1 days per year.

This standard was recently adopted by the Regional Reliability Organization, ReliabilityFirst Corporation (RFC), and applies to all Planned Reserve Sharing Groups (PRSG) within its footprint. The PJMRTO qualifies as one of those PRSGs.

Each year, PJM performs a reliability study to determine the calculated IRM required by the PJMRTO to satisfy the "1 day in 10 years" LOLE standard. IRM is expressed as percent margin above forecasted annual restricted peak load. Study results are reviewed by the Planning Committee, Markets & Reliability Committee and Members Committee and a recommendation is forwarded to the PJM Board of Managers for final approval.

For further details of how this study provides compliance with RFC Standard, BAL-502-RFC-01, see Appendix C.

- **Modeling Tools**

PJM's PRISM program is the primary modeling tool used for conducting the resource adequacy studies. PRISM is classified as a "two-area" model that simulates the PJMRTO and areas adjacent to PJM's footprint, called the "World". PRISM was in part descended and developed from an older two-area reliability model developed by General Electric (GE) called "GEBGE" (BGE referring to Baltimore Gas and Electric). The original GEBGE and its successor, PRISM, have been used by PJM since the 1960s.

PJM also has rights and access to a multiple area model, the GEMARS (Multi-Area Reliability Simulation) program, but uses this to enhance the analysis capabilities of PRISM. PJM uses the GEMARS program for developing case sensitivities, coordinating study models and results with neighboring regions, participating in interregional studies, and performing the winter weekly reserve target analysis.

The PRISM program is used to calculate the LOLE of up to two interconnected systems with a single transfer link. PRISM is used to calculate installed capacity reserve margin and the DR factor.

Other supporting programs and reports used in the RRS include:

- ARC — Applications for Reliability Calculations. This web based application coordinates all databases and applications used to calculate generation Adequacy. All programs and reports are launched by this PJM Intranet application.
- WeekPeakFreq — Produces the load model(s) used by PRISM. Once the required input parameters are given, this application produces 52 weekly mean and standard deviations for the defined study model. Input parameters include, historic time period, geographic region subzones, forecast start year, forecast end year, forecast report to use, 5 or 7 day model, holidays to exclude. (See Appendix G)

- CURTAIL — Evaluates the reliability benefit of load management, which includes Demand Resources (DR) and interruptible load for reliability (ILR). PJM's Load Management is subject to a limit on the maximum number of interruptions allowed per year. Currently the limit is 10.
- SYSPAR – A report that summarizes the models' capacity characteristics. (See Appendix G)
- Forecast Reserves – A report that summarizes the model load, capacity and resulting reserves. (See Appendix G)
- Capacity Check – A report that summarizes in some detail the capacity model. (See Appendix G)

One of the key objectives in conducting the RRS is to develop the Base Case (or Baseline) scenario, as this case is used in determining the IRM and FPR. The various assumptions that are used to derive the Base Case are presented in Appendix A. The Sensitivity cases, which start with the Base Case, are listed in Appendix B. The Base Case, Sensitivities, and Engineering Judgment (see Appendix E) are all necessary to make a recommendation for the IRM, FPR and DR Factor.

- **Development and Approval Process**

PJM has the overall responsibility of establishing and maintaining the Adequacy and Security of electricity supply within the PJMRTO. The Operating Agreement (OA) and Reliability Assurance Agreement (RAA) lay down the specific rules and guidelines for determining the required amount of generating capacity.

PJM Staff performs a study each spring to calculate the IRM. This study is initially reviewed by the Reserve Requirement Assumptions Working Group (RRAWG). The study uses a probabilistic model that recognizes, among other factors, historical load variability, load forecast error, scheduled maintenance requirements for generating units, forced outage rates of generating units and the capacity benefit of interconnection ties with other regions. Study results are reviewed through the PJM Committee structure and the PJM Members Committee forwards its recommendation on the IRM to the PJM Board of Managers. The PJM Board of Managers is ultimately responsible for approving the PJM IRM.

Resource adequacy planning begins at least three years in advance of the applicable planning period. Early in the timeline, resource owners submit their capacity plans including expected outages for the capability period. During this time, PJM Staff provides load forecasts to determine peak load demand. PJM also determines the calculated reserve requirement for the PJM RTO based on industry guidelines and standards for reliability, as established by the North America Electric Reliability Council (NERC) and ReliabilityFirst Corporation (RFC).

In accordance with the PJM Reliability Assurance Agreement (RAA), the assumptions and study activities are primarily developed by the PJM Reserve Requirements Assumptions Working Group (RRAWG) and endorsed by the PJM Planning Committee (PC). The principal duties and timetable of the RRAWG are shown in Appendix D.

As per the terms of the RAA, the IRM, FPR and DR Factor values are forwarded in succession to the PJM Markets and Reliability Committee (MRC) and the PJM Members Committee (MC) for approval by the membership at-large. The MC-recommended reliability parameters are then sent to the PJM Board of Managers for their consideration and decision.

For the 2010 delivery year, the PJM Board of Managers approval is required by October 19, 2007. In turn, the PJM Board of Managers makes an informational filing to the Federal Energy Regulatory Commission (FERC) for ultimate approval. These approved parameters are then implemented by PJM for the specified delivery year.

The Study results and recommendations from PJM management and the Members Committee will be forwarded to the PJM Board of Managers. The PJM Board of Managers will review, for approval, an FPR and corresponding DR factor for the 2010 / 2011 delivery year by October 19, 2007. (The RPM process requires that the IRM for a delivery year be approved by the PJM Board of Managers by February 1 three years prior to the delivery year.) The 2011/2012 parameters will be submitted for approval at the same time, with an approval date requirement of February 1, 2008.

Appendix J
Historical Study Results

Table 18 provides a comparison of Study results dating back to 1998. The reliability benefits of market integration are clearly demonstrated when comparing system requirements for the PJM Classic footprint (before market integration) with more recent studies that take advantage of full market integration. Other notes and observations include:

- The July 1998 IRM Study reflects the ten-year averaging used by PJM during that period.
- The April 1999 IRM Study reflects the five-year averaging used by PJM.
- All subsequent IRM studies use single planning period values.
- Two RRS evaluations were developed for the 2003 planning year; one with partial market integration and an updated version with full market integration.

Table 18

Comparison of PJM Reserve Requirement Studies (RRS)

Month / Year Study Performed	Delivery Year	Calculated PJM RTO IRM	Calculated World IRM	Avg. Forced Outage Rate	Avg. Weekly Maintenance	**Approved IRM**	DR Factor
Before Market Integration: *PJM Mid-Atlantic*							
Jul-98	2000/2001	18.3%	16.1%	9.9%	7.0%	**19.5%**	0.987
Apr-99	2001/2002	17.4%	15.2%	9.8%	7.3%	**19.0%**	0.965
Apr-00	2002/2003	19.0%	15.2%	8.9%	7.6%	**19.0%**	0.966
Apr-01	2003/2004	17.2%	14.7%	8.0%	8.3%	**19.0%**	0.948
Partial Market Integration: *PJM Mid-Atlantic + RECO + APS*							
May-02	2003/2004	16.4%	16.8%	7.2%	8.1%	**17.0%**	0.950
May-03	2004/2005	15.3%	15.5%	6.6%	9.3%	**16.0%**	0.952
Full Market Integration: *PJM Mid-Atlantic + RECO + APS + ComEd + Dayton + Dominion + Duquesne*							
Jul-03	2004/2005	14.9%	15.4%	7.1%	11.0%	**16.0%**	0.953
Jul-04	2005/2006	14.5%	14.7%	7.2%	9.0%	**15.0%**	0.946
Apr-05	2006/2007	14.7%	15.7%	6.8%	8.0%	**15.0%**	0.954
Apr-06	2007/2008	14.6%	14.1%	6.7%	6.1%	**15.0%**	0.957
Apr-06	2008/2009	14.6%	14.1%	6.7%	6.1%	**15.0%**	0.958
Apr-06	2009/2010	14.7%	14.2%	6.7%	6.1%	**15.0%**	0.957
Jul-07	2010/2011	15.5%	14.7%	6.8%	5.7%	**15.5%**	0.955
Jul-07	2011/2012	15.5%	14.7%	6.8%	5.7%	**15.5%**	0.955

Note that the July 2007 values are not yet approved.

Appendix K
Historical Diversity

Table 19

Diversity between PJM and World

World					PJM					
Yearly Unrestricted Peak	Hour Ending	actual_date	PJM Unrestricted load @ time of World Peak	% of Yearly Peak	Yearly Unrestricted Peak	Hour Ending	actual_date	World Unrestricted load @ time of PJM peak	% of Yearly Peak	Time difference between peaks (Diversity)
292882	16	6-Aug-96	105150	0.983	106949	17	7-Aug-96	290268	0.991	1 day, 1 hour
297911	15	14-Jul-97	112195	0.978	114691	17	15-Jul-97	295075	0.990	1 day, 2 hours
296894	16	21-Jul-98	114613	0.994	115306	17	21-Jul-98	295965	0.997	1 hour
306847	16	28-Jul-99	116195	0.951	122147	17	6-Jul-99	296212	0.965	22 days, 1 hour
322406	16	10-Jul-00	111041	0.969	114564	17	9-Aug-00	303407	0.941	30 days, 1 hour
336338	16	7-Aug-01	126913	0.966	131400	16	9-Aug-01	331680	0.986	2 days
328543	16	1-Aug-02	129697	0.995	130360	17	1-Aug-02	326173	0.993	1 hour
304956	15	5-Aug-03	101922	0.807	126332	17	21-Aug-03	273956	0.898	16 days, 2 hours
313626	16	3-Aug-04	119732	0.996	120235	17	9-Jun-04	289048	0.922	55 days, 1 hour
323601	16	25-Jul-05	128577	0.958	134219	16	26-Jul-05	318151	0.983	1 days
					145951	17	2-Aug-06			

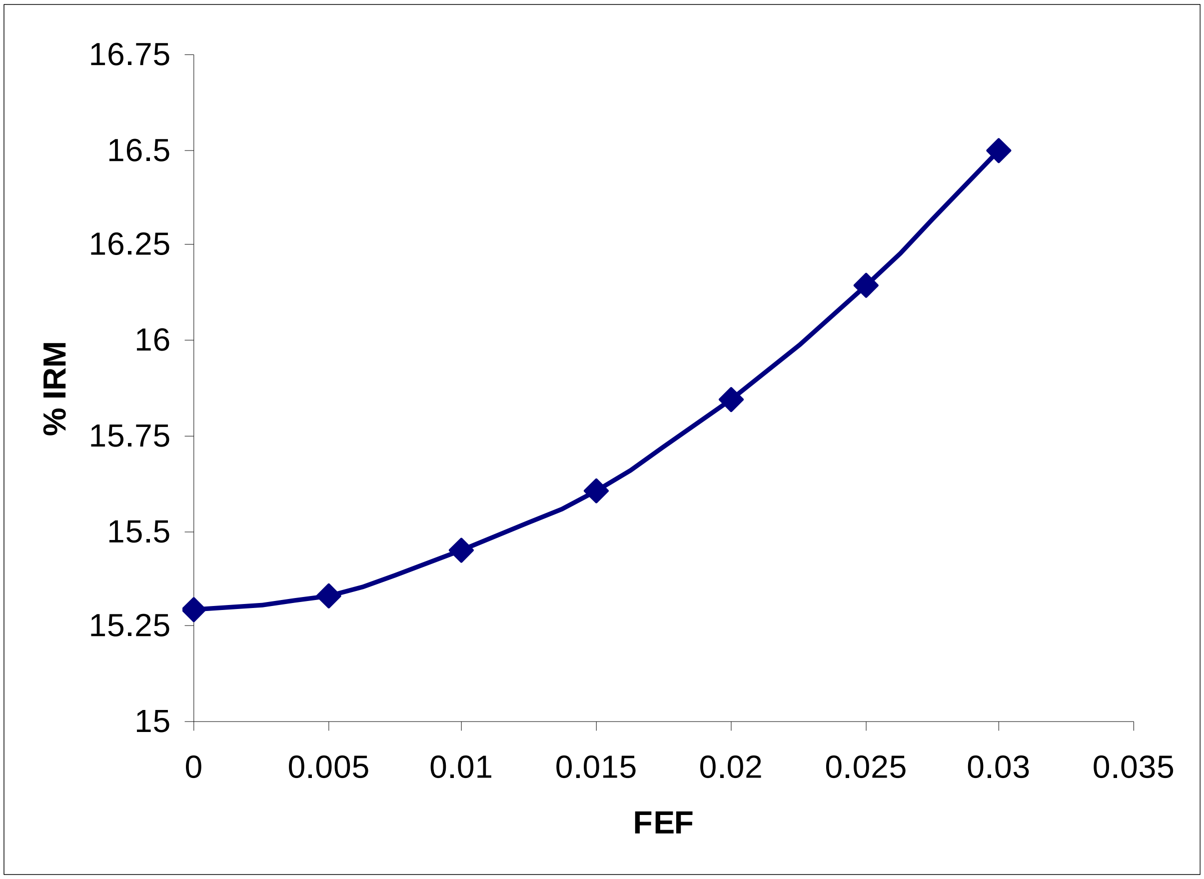
Note: World data is not yet available for 2006

The PJM yearly unrestricted values prior to 2002 use an estimated value for the Rockland Electric Company area. Similar to Table 19, the 2007 RRS model has little or no load diversity. Compared to the 2006 RRS, the increase in IRM seen in the 2007 RRS can be attributed primarily to the reduction in diversity. See sensitivity runs # 8 and # 6.

Appendix L
Forecast Error Factor

Figure 16

Forecast Error Factor (FEF) vs. Installed Reserve Margin (IRM)



Appendix M
Installed Reserve vs. RI

<u>Figure 17</u>
Installed Reserve Margin (IRM) vs. RI (Years/ Day)