



2009

PJM Reserve Requirement Study

11-year Planning Horizon: June 1st 2009 - May 31st 2020

Analysis Performed by PJM Staff

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Final Draft

Reviewed by Reserve Requirement Assumptions Working Group (RRAWG)

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2009 PJM Reserve Requirement Study (RRS)

Table of Contents	Page
Part I – Results and Recommendations	1
PJM RRS Executive Summary	2
Introduction.....	5
• Purpose	5
• Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR)	5
• DR Factor	5
• Regional Modeling	5
Summary of RRS Results	7
• Eleven-Year RRS Results	7
Key Observations.....	9
• General Trends and Observations.....	9
Recommendations	13
 Part II – Modeling and Analysis	 15
Load Forecasting	16
• PJM Load Forecast – January 2009 Load Report.....	16
• Monthly forecasted Unrestricted Peak demand, Demand Resources and Interruptible Load for Reliability	16
• Forecast Error Factor (FEF)	16
• 21 point Standard Normal Distribution, for daily peaks	17
• Week Peak Frequency (WKPKFQ) Parameters	17
• PRISM solved load and 50/50 peak load forecast	19
Generation Forecasting	21
• GADS, eGADS and PJM fleet Class Average Values.....	21
• Generating Unit Owner Review of Detailed Model.....	22
• Forced Outage Rates: EFORd and EEFORd.....	22
• Determination of EFORd Excluding Outside Management Control (OMC) Events	23
• Generating Unit Modeling Issues	27
• Fleet-based Performance by Primary Fuel Category	27
• Modeling of Generating Units’ Ambient Deratings	28
• Generation Interconnection Forecast.....	29
Transmission System Considerations.....	31
• PJM Transmission Planning (TP) Evaluation of Import Capability	31
• Capacity Benefit Margin (CBM).....	31
• Transmission Projects.....	31
• Capacity Benefit of Ties (CBOT).....	31

•	Coordination with Capacity Emergency Transfer Objective (CETO) .	32
•	OASIS postings.....	32
Modeling and Analysis Considerations.....		32
•	Generating Unit Additions / Retirements.....	32
•	DR Factor.....	33
•	Load Management (LM) Credit	34
•	DR Factor.....	35
•	World Modeling.....	35
•	Expected Weekly Maximum (EWM) , and LOLE Weekly Values.....	38
•	Standard BAL-502-RFC-02 clarification items.....	40
•	RPM Market	41
•	IRM and FPR	41
Operations Related Assessments.....		42
•	Winter Weekly Reserve Target Analysis.....	42
Reserve Requirement Assumptions Working Group (RRAWG) activities		44
1. Planning Committee requests to RRAWG		44
•	Sensitivity of the IRM to the number of historical years used in the development of the load model	44
•	Use of 21 points in the load distribution and the possible need for greater granularity.....	44
•	Use of a normal vs. non-normal load distribution	44
•	Examination of World reserve levels and deliverability of those reserves to PJM.....	44
•	Modeling of intra-World load diversity	44
•	Derating of summer capacity to account for extreme ambient weather conditions.....	44
•	Possible use of MARS as a complement to PRISM	45
•	Treatment of calculated vs. recommended IRM	45
2. RRAWG investigation issues.....		45
•	Identified in the May13th 2009 Study assumptions letter.....	45
•	FPR's reflection of 2,500 MW derate to maintain consistency with RPM and Operations.	45
•	Investigation of the 50/50 annual peak load value determination.....	45
•	Possible use of Non-Normal load distributions.....	45
•	Identified in the RRAWG parking lot items	46
•	Considerations used to move from the calculated IRM value to the endorsed IRM value.....	46
•	The modeling of all world regions into 1 area, implying helping each other first (prior to PJM)	46
•	MARS sensitivity runs for correlating with PRISM.....	46
•	Generator outages at critical peak demand periods.....	46
•	Assess World model to reflect intra hour PJM-World diversity.....	46
Glossary.....		47

Part III – Appendices	62
Appendix A Base Case Modeling Assumptions for 2009 PJM RRS.....	63
Appendix B Description and Explanation of 2009 Study Sensitivity Cases.....	67
Appendix C Resource Planning Reserve Requirements PJM’s compliance with Standard BAL-502-RFC-02.....	73
Appendix D Reserve Requirement Assumptions Working Group (RRAWG)	89
Appendix E Method for assessing time period to use for PLOTS load model.....	91
Appendix F ISO Reserve Requirement Comparison.....	92
Appendix G RRAWG Review of Study -- Transmittal Letter to PC.....	93
Appendix H “Engineering Judgment” Considerations used in the RRS	95

Tables

Table I - 1: Historical RRS Parameters	4
Table I - 2: Eleven - Year Reserve Requirement Study	7
Table II - 1: Load Forecast for 2013 / 2014 Delivery Years	16
Table II - 2: PJM RTO Load Model Parameters (PRISM # 4989)	18
Table II - 3: Intra-World load diversity	19
Table II - 4: PJM RTO Fleet Class Average Generation Performance Statistics (2004-2008)	24
Table II - 5: Comparison of Class Average Values - 2008 RRS vs. 2009 RRS	25
Table II - 6: PJM RTO Fleet-based Unit Performance by Primary Fuel Category	27
Table II - 7: Commercial Probabilities for Expected Interconnection Generation Additions	31
Table II - 8: New and Retiring Generation within PJM RTO	32
Table II - 9: CURTAIL Results - Maximum amount of Load Management	34
Table II - 10: CURTAIL Results - Saturation point of Load Management	34
Table II - 11: Weekly LOLE values	39
Table II - 12: Winter Weekly Reserve Target	43
Table F - 1: Comparison of reserve requirements on a coincident, unforced basis. MISO vs. PJM	92

Figures

Figure I - 1: Combined PJM Region Modeled	6
Figure I - 2: PJM RTO, World and Non-Modeled Regions	6
Figure I - 3: Historical Weighted-Average Forced Outage Rates (Five-Year Period)	9
Figure I - 4: World Reserve level, valid range to consider	10
Figure I - 5: Relation between the IRM and World Reserves	11
Figure I - 6: Relation between the IRM and the CBM	12
Figure II - 1: Historical Annual Weighted-Average Forced Outage Rates (Individual Annual values)	26
Figure II - 2: PJM RTO Capacity by Fuel Type	28
Figure II - 3: Forecast Reserve Margin Graph - September 2009	30
Figure II - 4: PJM and Outside World Regions - Summer Capacity Outlook	36

Figure II - 5: Previous NERC World Regions (Includes ECAR and MAIN)	37
Figure II - 6: Current NERC defined World Regions (Includes RFC)	37
Figure II - 7: Relation between IRM and CBM when World reserves are 19.9%	38
Figure II - 8: Installed Reserve Margin (IRM) vs. RI (Years/Day)	39
Figure II - 9: Winter Weekly Load Shape comparison – 2008, and 2009 RRS	43
Figure D - 1: Time Line for 2009 RRS	90
Equations	
Equation II - 1: Calculation of Effective Equivalent Demand Forced Outage Rate (EEFOR _d)	23
Equation II - 2: Calculation of Forecast Pool Requirement (FPR)	41

Part I – Results and Recommendations

PJM RRS Executive Summary

- The purpose of the Reserve Requirement Study (RRS) is to determine the Forecast Pool Requirement (FPR) and the Demand Resource (DR) Factor. This is accomplished primarily by calculating the Installed Reserve Margin (IRM) for future planning periods. In accordance with the Reliability Pricing Model (RPM) auction schedule, results from this study will re-establish the IRM, FPR and DR Factor for the 2012/2013 Delivery Year (DY) and establish the IRM, FPR and DR Factor for the 2013/14 Delivery Year.
- This Study satisfies all North America Electric Reliability Corporation (NERC) / ReliabilityFirst Corporation (RFC) Adequacy Standard BAL-502-RFC-02 Resource Planning Reserve Requirements. This Standard requires that the Planning Coordinator establish reliability parameters that support a generation Loss of Load Expectation (LOLE) of one occurrence in ten years.
- Based on results from this Study (including the Appendix B sensitivity analyses), **PJM Staff recommends a 15.4% IRM for the 2012/2013 Delivery Year and a 15.3% IRM for the 2013/2014 Delivery Year.**
- **The 0.9% decrease in the 2013/2014 IRM from last year's RRS (2012/2013) is primarily due to an enhancement made to the selection process for the Peak Load Ordered Time Series (PLOTS) load model period which results in increased load diversity between PJM and the World.** (See Figures I-4, I-5, Table II-3, and Appendix E.) This enhancement, which was endorsed by the PJM Planning Committee, establishes objective criteria to select the historical period that is used to develop the PJM and World load models. This new approach should result in a more stable calculated IRM going forward as it reduces the fluctuation in the tie benefit that has been observed in recent studies.
- The generating unit performance characteristics remained essentially unchanged from the 2008 study. (See Table II-5 on page 24 and Figure I-3 on page 8.)
- The results of the 2009 RRS are summarized below. **PJM Staff recommends** 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
2009	2012 / 2013	15.4%	15.4%	6.28%	1.0815	0.955
2009	2013 / 2014	15.3%	15.3%	6.30%	1.0804	0.957

Note: Avg. EFORD does not include Outside Management Control generator outage events.

* EFORD = Equivalent Demand Forced Outage Rate (See Part II, page 22)

- For the 2012/13 and 2013/14 Delivery Years, the resulting change in the FPR, which is used in the RPM process, is 0.0057 and 0.0068 respectively (from 1.0872 in last year's study to the table values above for the current study).
- **The winter weekly reserve target for the 2009/2010 winter period is recommended to be 25%.** This is compared to the 26% value that was approved for the 2008/2009 winter period. The analysis supporting this recommendation is detailed in the "Operations Related Assessments" section of this report.
- The IRM, FPR and DR factors recommended above are reviewed and considered for endorsement by the following succession of groups:
 - Reserve Requirement Assumptions Working Group (RRAWG)
 - Planning Committee (PC)
 - Markets and Reliability Committee (MRC)
 - PJM Members Committee (MC)
 - PJM Board of Managers (for final approval)

- PJM's Probabilistic Reliability Index Study Model (PRISM) program is the primary reliability modeling tool used in the RRS. PRISM utilizes a two-area Loss of Load Probability (LOLP) modeling approach consisting of: Area 1 - the PJM RTO and Area 2 - the neighboring World.
- In August 2009, American Transmission System Inc. (ATSI) announced its intention to join the PJM RTO, with a target integration date of June 2011. **ATSI load and generation, therefore, is modeled internal to PJM in this study. Sensitivity analysis was performed with ATSI load and generation outside PJM and the results indicate no significant impact on the IRM (see Appendix B, Case No. 22).**
- The PJM RTO includes the PJM Mid-Atlantic Region, Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (Dom), Duquesne Light Co. (DLCO) and American Transmission System Inc. (ATSI).
- The Outside World (or "World") area consists of the North American Electric Reliability Corporation (NERC) regions adjacent to PJM. These regions include the Northeast Power Coordinating Council (NPCC) and the non-PJM portions of the South Eastern Reliability Corporation (SERC) and the ReliabilityFirst Corporation (RFC). In addition, a case was run with the larger World area that has been modeled in previous studies. This larger World area includes most of the Eastern Interconnection. **Study results indicate that the PJM IRM is virtually unchanged if the larger World model is substituted for the smaller World model.**
- Modeling of the "World" region assumes a Capacity Benefit Margin (CBM) of 3,500 MW into PJM, which serves as a maximum limit on the amount of outside assistance. The CBM is set to 3,500 MW per Schedule 4 of the PJM Reliability Assurance Agreement. Figure I-6 shows the benefit of this interconnection for various values of CBM.
- For the 2009 RRS, there is a net increase of approximately 10,000 MW of generation within the PJM RTO, reflecting approximately 11,670 MW of new generation and approximately 1,670 MW of retired generation. This is over the eleven year time period of the study. The amount of forecast load management during peak periods was reduced from 4,395 MW to 3,456 MW. This reduction is due in part to a change in reporting implemented in the January 2009 PJM Load Forecast Report (see page 1, 4th bullet of the Load Forecast Report.). The amount of load management does not affect the calculation of the IRM.
- Compared to the 2008 RRS model, the 2009 RRS five-year average Effective Equivalent Demand Forced Outage Rate (EEFORd) increased by 0.05% to 7.32%.
- For the calculated FPR, the pool-wide average EFORD value excludes outage events considered outside management control. eGADS users began to enter outage events of this type in January, 2006. Determining the FPR in this manner is consistent with the way that generator unforced capacity (UCAP) values are determined in the PJM capacity market.
- Consistent with the requirements of ReliabilityFirst Corporation (RFC) Standard BAL-502-RFC-02 - Resource Planning Reserve Requirements, the 2009 RRS provides an eleven-year resource adequacy projection for the planning horizon that begins June 1, 2009 and extends through May 31, 2020.
- Historical RRS values:

Table I - 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
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
2008	2012/2013	16.2%	16.2%	6.44%	1.0872	0.950

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 ReliabilityFirst Corporation (RFC) Standard BAL-502-RFC-02. This study is conducted each year in accordance with the process outlined in PJM Manual 20 (M-20), *PJM Resource Adequacy Analysis*. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load with sufficient reserves.

The results of the RRS provide key inputs to the PJM 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 PJM Regional Transmission Organization (RTO). The DR Factor is used to determine the unforced capacity (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 (Refer to PJM's Manual 18 (dated 8/18/2009), pgs 28-34,82,93,104-106,108,113,137, for further details). These parameters are also coordinated with PJM's test for deliverability, the Capacity Emergency Transfer Objective (CETO).

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 ReliabilityFirst Corporation (RFC) and they are used in the RPM market. (See Report Sections: Modeling and Analysis Considerations and Appendix C for further details.)

The timetable for calculating and approving these values is shown in the May 13, 2009 study assumptions letter to the PC and Appendix D.

- **DR Factor**

The DR Factor is used under the RPM to determine the UCAP value of load management products. (For further details, refer to this Report's Section: Modeling and Analysis Considerations.) 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 values of 15.4% for 2012/2013 DY and 15.3% for 2013/2014 DY is approved by the PJM Board, the FPR and DR Factor would need to be re-calculated.

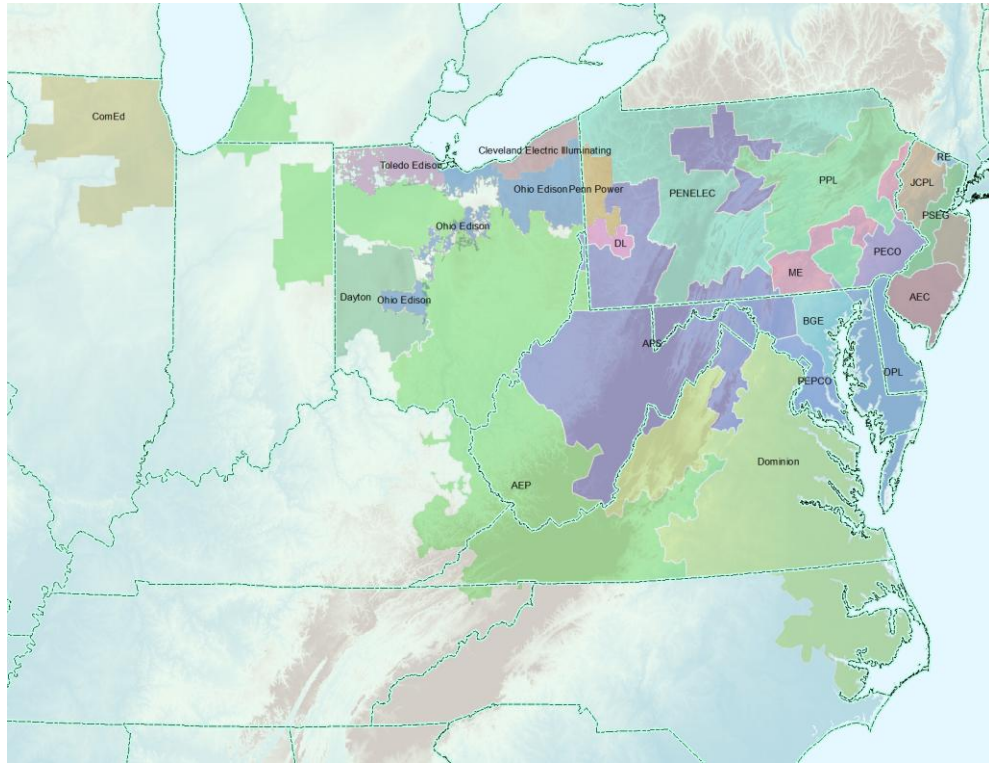
The timetable for calculating and approving the DR Factor is based on the RPM marketplace requirements.

- **Regional Modeling**

In August 2009, American Transmission System Inc. (ATSI) announced its intention to join the PJM RTO, with a target implementation date of June 2011. ATSI load and generation is modeled internal to PJM in this study.

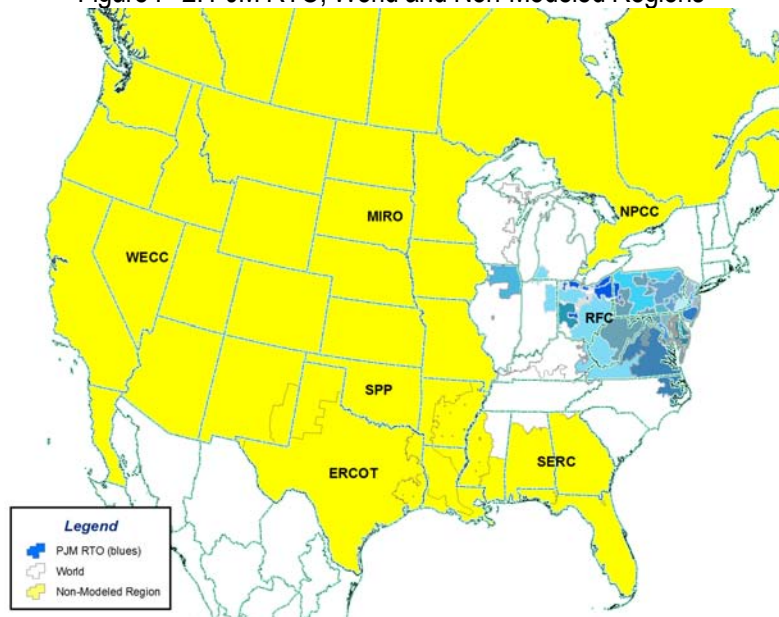
The study examines the combined PJM footprint area (Figure I-1) that consists of the PJM Mid-Atlantic Region plus Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (DOM), Duquesne Light Co. (DLCO) and American Transmission System Inc. (ATSI). The load and generation in the American Transmission System Inc. (ATSI) territory is assessed both inside and outside the PJM footprint.

Figure I - 1: Combined PJM Region Modeled



Areas adjacent to the PJM Region are referred to as the “World” (Figure I-2) and consist of the non-PJM portion of RFC, the Southeastern Electric Reliability Council (SERC) and the USA portion of the Northeast Power Coordinating Council (NPCC) territory. Areas outside of PJM and the World are not modeled in this study. Sensitivities were run to assess the larger World region, which added the Midwest Reliability Organization (MRO-US), Entergy, Southern, and Ontario regions, comparing it to the smaller World region.

Figure I - 2: PJM RTO, World and Non-Modeled Regions



Summary of RRS Results

- **Eleven-Year RRS Results**

Table I-2 below shows an eleven-year forward projection from the study for informational purposes. The Delivery Year for which the parameters must be finalized is highlighted in yellow. These results do not reflect any previous modeling or approved values.

Table I - 2: Eleven-Year Reserve Requirement Study

Delivery Year	Calculated IRM				Forecast Reserve					Assumed IRM	
	A	B	C	D	E	F	G	H	I	J	K
	% IRM PJM RTO	% IRM Outside World	Average PJM EEFORd %	Average Weekly Maintenance %	Capacity	Restricted Load	% Forecast Reserve PJM RTO	% Forecast Unrestricted Reserve PJM RTO	Neighboring World region assumed reserves %	Assumed % IRM PJM RTO	PJM Reliability Index (single area) Years/Day
2009	15.5%	16.2%	7.4%	6.1%	182,937	143,230	27.7%	24.5%	16.2%	15.5%	5.2
2010	15.5%	16.1%	7.4%	6.0%	184,742	145,821	26.7%	24.1%	16.1%	15.5%	5.3
2011	15.4%	16.1%	7.3%	6.0%	186,531	149,725	24.6%	21.8%	16.1%	15.4%	5.3
2012	15.4%	16.1%	7.3%	6.0%	188,697	154,349	22.3%	19.6%	16.1%	15.4%	5.4
2013	15.3%	16.0%	7.3%	6.0%	191,317	157,300	21.6%	19.0%	16.0%	15.3%	5.4
2014	15.3%	15.9%	7.3%	6.1%	191,593	159,484	20.1%	17.6%	15.9%	15.3%	5.3
2015	15.2%	15.9%	7.3%	6.1%	191,856	161,535	18.8%	16.3%	15.9%	15.3%	5.3
2016	15.4%	15.9%	7.3%	6.1%	192,550	163,457	17.8%	15.4%	15.9%	15.3%	5.1
2017	15.4%	15.9%	7.3%	6.1%	192,550	165,447	16.4%	14.0%	15.9%	15.3%	5.2
2018	15.4%	15.8%	7.3%	6.1%	192,550	167,362	15.1%	12.7%	15.8%	15.3%	5.2
2019	15.2%	15.7%	7.3%	6.0%	193,696	169,290	14.4%	12.1%	15.7%	15.3%	5.5
11-year Average	15.3%	16.0%	7.3%	6.0%	189,911	157,909	20.5%	17.9%	16.0%	15.3%	5.3

- **Calculated IRM Columns (PRISM Run # 4989)**

- Calculated IRM, columns A and B are at an LOLE criterion of 1 day in 10 years.
- The PJM Reliability Index (RI) is expressed as years per day
- Results reflect “calculated” (to the nearest decimal) 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 Effective Equivalent Demand Forced outage rate (EEFORd) (column C) is a pool-wide average effective equivalent demand forced outage rate for all units in the PJM RTO model (about 1,200 units). These are not the forced outage rates to be used in the RAA Obligation formula and are based on a five-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.
- Column A is based on the PRISM solved load, not the January 2009 load forecast values. See page 18 for further details.

- **Forecasted Reserves Columns**

- The PJM forecast reserves for the next nine years are above the calculated requirement. Reserves include about 11,670 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 0.12 and 1.0. A project thereby receives a

value of 1.0 (100%) when it becomes commercially available. These commercial probabilities are listed in Table II - 7.

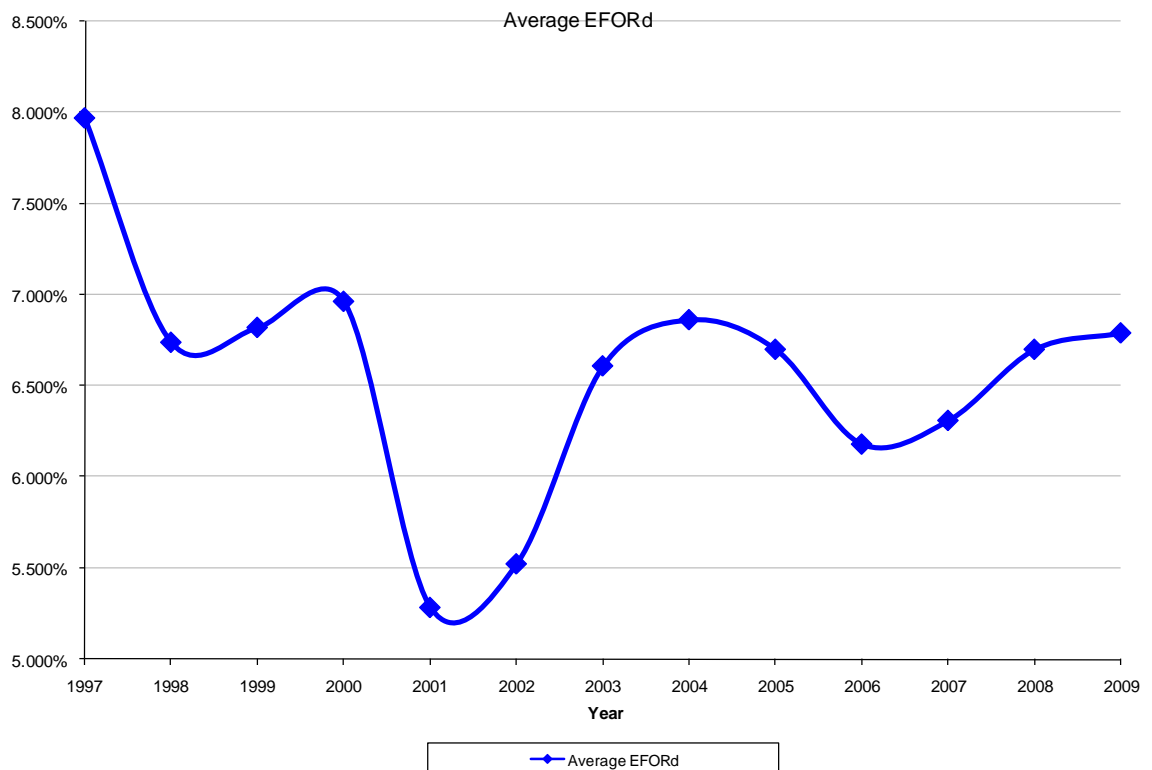
- The reserves also reflect about 1,670 MW of announced generator retirements.
 - The RTEP is dynamic and actual PJM reserve levels may differ significantly from those forecasted today. Another factor contributing to future reserve margin uncertainty is PJM's rule which allows units to retire with as little as 90 days notice.
 - Reserves (column G) are expressed as percent of restricted peak load. Restricted peak load is total internal demand less load management (DR and ILR).
 - PJM Reliability Index (RI) (column K) is expressed in years per day (the inverse of the days per year LOLE). This column indicates reliability when all external ties into PJM are cut. This parameter represents "zero import capability" or the PJM single area case.
 - The forecast reserves include all known purchase and sales, per the EIA-411 Schedule 4.
 - Forecast reserves for the neighboring World region (column I) are expressed as total internal demand less some load management (DR and ILR). The valid range of World reserves is shown in Figure I – 4, from 15.2% to 19.9 %. Work continues to estimate World DR & ILR actions at the time of the PJM RTO need for assistance. Currently no reliable data source has been established to estimate this value of World DR & ILR. Engineering judgment was used to establish the World reserves at the level that yields an RI equal to an LOLE of 1 day in 10 years for the World.
- **Assumed IRM Columns** (PRISM run # 5091)
- Column J values are used to determine the Column K values. This assumes, per the study assumptions and RRAWG review, an approved reserve requirement for information purposes only.
 - The Final IRM for the PJM RTO (column J) is an assumed value. This is intended for information in the stakeholder review, endorsement and ultimately, PJM Board approval.
 - The RI for the Assumed IRM (column K) 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, roughly twice as often, as measured by invoking a voltage reduction in the emergency operation procedures.
-

Key Observations

- **General Trends and Observations**

- Generation performance characteristics, such as average unit forced outages, appear to be little changed compared to the 2008 study. Rolling the 2008 GADS data into the model and rolling the 2003 data out appears to yield a nearly identical model. (This model also includes the ATSI units.) For example, the pool-wide average forced outage rate used in the study is 0.05% greater than that used last year. (The 2008 RRS had experienced an increase of 0.47% above the 2007 Study.) The generation model and the average forced outage rate is a significant parameter in the determination of the IRM.
- Numerous sensitivity cases were performed and the results are shown in Appendix B. These sensitivity results are an important input in validating the analysis and developing a recommendation on the IRM and FPR. Considering long-term trends without focusing exclusively on individual study results is important when developing an IRM recommendation. Long-term trends significant in the study include: the historic trend of forced outage rates, assistance from neighboring systems, and forecasted load model shapes and associated uncertainties.
- Pool wide average forced outage rate values (EFORds), in the various annual RRS capacity models, are shown in Figure I-3. The forced outage rates shown are for the five-year period used in a given study, showing the capacity weighted average value for the PJM fleet of units. Looking at the values in the 2003 Study onward, the values seem oscillatory with the latest three Study values increasing (**Note:** The values in Figure I-3 are not determined on the same basis as the EFORd value reported in the Tables on pages 2 and 3. The EFORd values below include Outside Management Control (OMC) events and are used in the RRS model. The EFORd value on pages 2 and 3 exclude OMC events and are used for the sole purpose of converting the IRM to the FPR.).

Figure I - 3: Historical Weighted-Average Forced Outage Rates (Five-Year Period)



- Compared to the 2008 RRS model, the winter ratings increased slightly (about 0.3%). Winter ratings have a small effect on the IRM calculation but may impact Capacity Emergency Transfer Objective (CETO) values for some Load Deliverability Areas (LDAs).
- Load diversity between PJM and World was impacted by two significant changes in this year's study. First, as documented in Appendix E, the number of years used in the hourly load model is now determined by an established process. Second, the world monthly peak forecast is now a coincident peak and no longer the sum of non-coincident peaks from individual sub-regions. This modeling change increased the load diversity between PJM and the World.
- The World reserves were assessed and modeled in a different manner than in previous studies, per the Study assumptions. This modeling change of World forecast reserves considered only those regions adjacent to the PJM RTO. The New York, New England and MISO regions have firm requirements, while the TVA and VACAR regions have soft targets. The soft targets chosen are consistent with the NERC values for these regions. Figure I - 4 summarizes the values used to determine a valid range for a World reserve level of 15.2 % to 19.9 %. The requirements used are shown in the IRM column. The diversity values shown are from an assessment of 13 years of historic data, using the average of the values seen over the summer season. See Table II – 3 for further details. In 7 of the 13 historic years, the diversity was lower than the average. Please reference Appendix H which tabulates the impact of many of the modeling assumptions. This new assumption, to use the average of the values seen over a consistent peak period (August), was judged to understate the IRM. Consideration for a choice of the appropriate World reserves level includes operational data and practices. Work is in process to establish a source for this data. Issues identified for further investigation include assessment of World loads at the time of the PJM RTO peaks, operational actions and levels at time of PJM RTO peak, and amount of OASIS reservations for forecast delivery years. A value of 16% was deemed the appropriate choice for World reserves after discussions with the RRAWG and applying engineering judgment. A World reserve level of 16% yields an RI equal to an LOLE of 1 day in 10 years for the collective World region.

Figure I - 4: World Reserve level, valid range to consider

	NCP 2009	IRM	Diversity	CP 2009	LM 2009	LM as % NCP	NCP- LM (NID)	CAP based on NID	CP- LM	Reserves as % of CP	Reserves as % of CP- LM
NY	33452	16.50%	0.9595	32097	2107	6.30%	31345	36517	29990		
NE	27875	10.15%	0.9595	26746	1914	6.87%	25961	28596	24832		
MISO	104039	15.40%	0.9595	99825	1700	1.63%	102339	118099	98125		
TVA	44651	15.00%	0.9595	42843	1738	3.89%	42913	49350	41105		
VACAR	64361	15.00%	0.9595	61754	2150	3.34%	62211	71543			
Dominion	18982				28	0.15%	18954				
VACAR Other	45379	15.00%	0.9595	43541	2122	4.68%	43257	49746	41419		
Total Composite Region =	255396			245052	9581	3.75%	245815	282308	235471	15.20%	19.89%

Data Sources

NY and NE - NPCC Reliability Assessment for Summer 2009 (published April 30, 2009 - pages 76-77)
 NPCC Summer 2009 Multi-Area Probabilistic Reliability Assessment (published April 30, 2009 - pages 28-29)

MISO - RFC 2009 Summer Assessment of Demand and Resources (published May 2009 - page 4)
 Using Old NERC Boundaries "MAIN Other" Plus "ECAR Other"(Includes FE)

TVA and VACAR - 2008 NERC ES&D Report, assuming zero load diversity between DomVP and rest of VACAR

NY, NE and MISO are modeled at their approved IRMs for 2009. TVA and VACAR are modeled at the NERC soft target IRM of 15%.

Dominion NCP and ALM is per the PJM Load Forecast Report, January 2009 (pages 32 and 46)

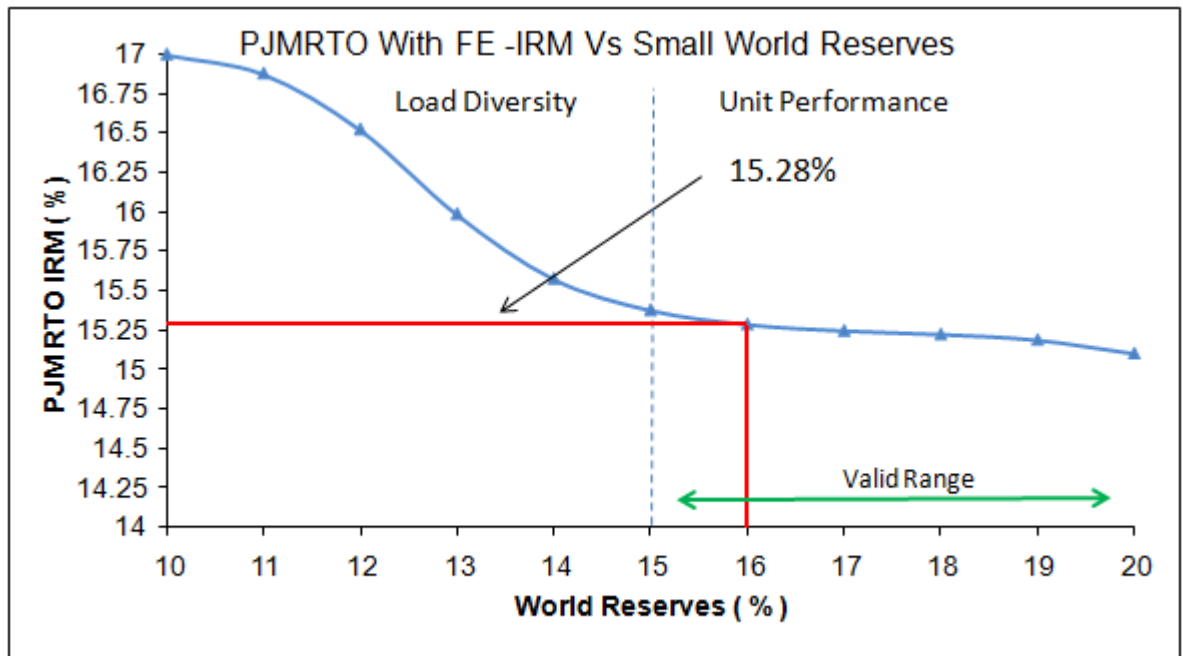
- The World reserves were modeled to reflect the established regional reserve requirements. If a requirement was not in place for a particular World sub region, the NERC target IRM of 15% was applied to that sub region. Figure I – 4 is a summary of the established valid range identified.

Figure I – 5 shows the impact of the World reserves on the PJM RTO IRM. This figure assumes a CBM value of 3,500 MW at all World reserve levels. The green horizontal line labeled “valid range” shows the range of World generation reserve levels depending on the amount of World load management assumed to be curtailed or to have voluntarily reduced consumption in response to economic incentives, at the time of a PJM capacity emergency. The lower end of the range would be the World reserve level if no World load management were implemented with all such customers consuming at their maximum rates and the higher end is the reserve level assuming all World load management is implemented or customers have voluntarily reduced their loads at the time of a PJM emergency. Figure I-5 indicates that PJM assistance from the World saturates at a World reserve level of about 16%. This indicates that the assistance is constrained by the CBM. The World “1 in 10” reserve level, as calculated by PRISM, is indicated by the vertical red line. The slope of this curve has more than one modeling characteristic affecting its shape. Please note that:

- The region from 10% -15% is also influenced by the load diversity. For many relatively low magnitude load states, the World can assist PJM for a limited amount of assistance due to the PJM need for help occurring at a time of lower World load.
- The region from 15% to 20% is also affected by the generator performance in the World area. The World region will serve its own needs before any assistance can be given to PJM. Thus with either better performing units or larger reserves, the World can provide more assistance. For larger assistance requests from PJM, the World assists in a more gradual manner partly due to the performance of its units. Note that the World assistance does increase gradually as its reserves increase, and at some very large reserve level the unit performance does not affect its ability to assist PJM.

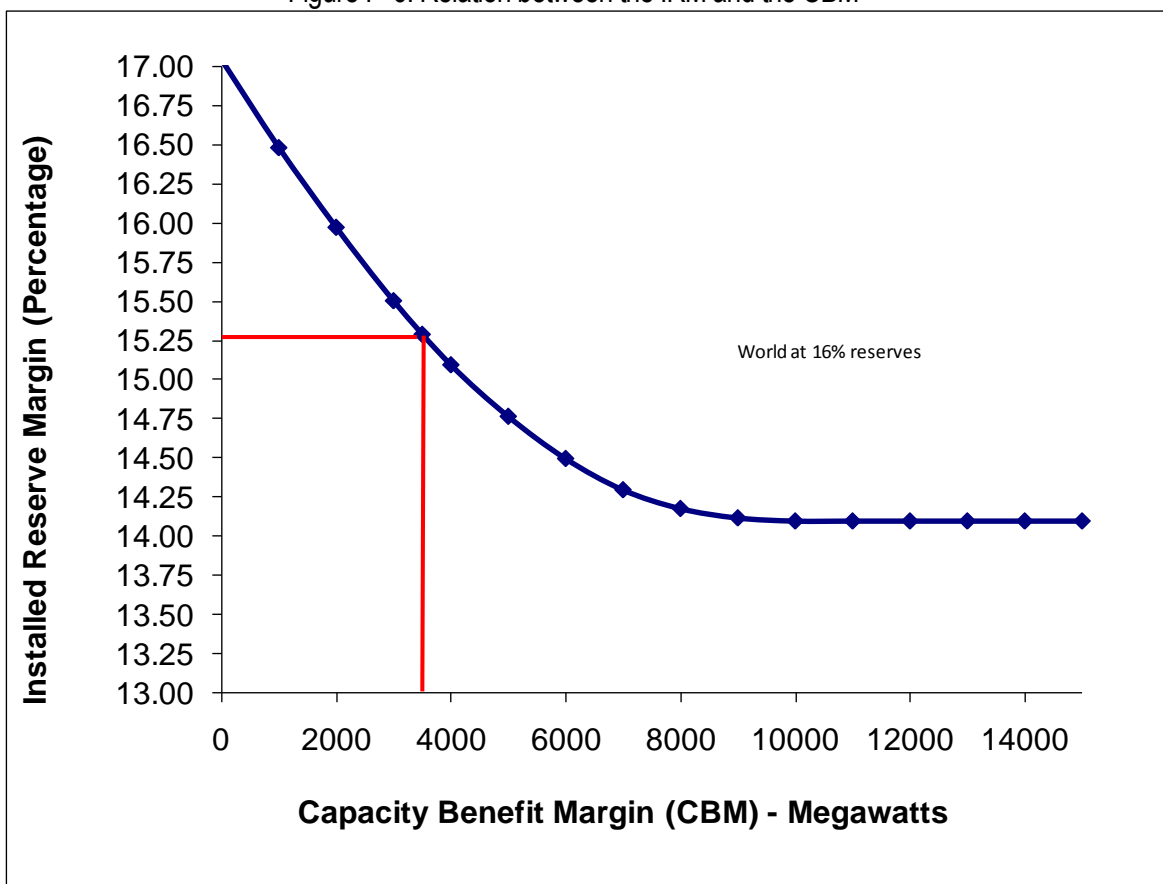
The PJM IRM at this “1 in 10” World reserve level is 15.28%. This is the basis for the recommended IRM of 15.3%.

Figure I - 5: Relation between the IRM and World Reserves



World reserves varied, PJM RTO solved for 1D 10 Yr - Mixed Mode Solution

Figure I - 6: Relation between the IRM and the CBM



- Figure I-6 shows how the PJM IRM varies as the CBM is increased. As indicated by the red line, the official CBM value of 3,500 MW results in a PJM IRM of 15.3%. Thus the PJM IRM is reduced by 1.7% due to the CBM (from 17% to 15.3%). Based on the forecasted load for 2013/2014, this 1.7% IRM reduction eliminates the need for about 2,800 MW of installed capacity (generation). This figure is consistent with Figure I – 5 in that both indicate that capacity assistance from the World is limited by CBM, not by World reserves (See Figure II-7 for a related assessment).
- This study used the load management value from the recent January 2009 PJM Load Forecast Report. The amount of load management does not affect the IRM or the FPR. It does have a small impact on the DR Factor and the Winter Weekly Reserve Target.
- When reserve requirements for the PJM RTO are compared to those of the MISO region, the PJM requirements are lower on a coincident peak, unforced basis. See Appendix F for further details.

Recommendations

- Installed Reserve Margin (IRM) — Based on the study results and the additional considerations mentioned above, PJM recommends endorsement of an IRM value of **15.4% and 15.3%** for the 2012/2013 and 2013/2014 Delivery Years, respectively. The Reserve Requirement Assumptions Working Group reviewed these study results.
Use of PRISM Peak Solution load for IRM
 - Load Forecast Distribution: The load forecast model is the distribution of the summer peak over a number of summer weather scenarios. The PJM Summer Peak forecast is the median (50/50) of this distribution. The IRM is applied to the official PJM Summer Peak forecast.
 - In PRISM, the IRM is expressed as a percent of the Expected Weekly Maximum (EWM) of the peak week of the summer. The EWM of the peak week of the summer also represents the 50/50 peak on the peak day of the summer.¹ Therefore, the IRM produced is consistent with the 50/50 Summer Peak forecast.
- Forecast Pool Requirement (FPR) — The approved IRM is converted to the FPR for use in determining capacity obligations. The FPR expresses the reserve requirement in unforced capacity terms. The FPR is defined by the following equation:

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

Note: PJM Avg. EFORd does not include Outside Management Control generator outage events.

Based on the recommended IRM values, the resulting FPRs would therefore be:

2012 / 2013 Delivery Year	FPR = (1.154) * (1 - 0.0628) = 1.0815
2013 / 2014 Delivery Year	FPR = (1.153) * (1 - 0.0630) = 1.0804

- Demand Resource Factor (DR Factor) — The DR Factor is based on the approved IRM. The values shown below assume approved IRMs of 15.4% and 15.3% for the 2012/13 and 2013/12 Delivery Years, respectively. 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.

2012 / 2013 Delivery Year	DR Factor = 3300 / 3456 = 0.955
2013 / 2014 Delivery Year	DR Factor = 3307 / 3456 = 0.957

- Winter Weekly Reserve Target — **The recommended 2009 / 2010 winter weekly reserve target is 25%.** This recommendation is discussed on pages 39 – 40 of this report.

¹ Two RRAWG members disagree that the expected weekly maximum of the week with the highest daily mean represents the summer 50/50 peak. Within the PRISM probabilistic load model, there is risk (probability) of the summer peak occurring in some other week.

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Part II – Modeling and Analysis

Load Forecasting

- **PJM Load Forecast – January 2009 Load Report**

The forecast contained in the January 2009 PJM Load Forecast is used in the 2009 RRS. The load report is available on the PJM web site at: <http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx>

The methods and techniques used in the load forecasting process are documented in Manual 19 (Load Forecasting and Analysis) which is available at the same web site.

- **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.

World loads are derived from NERC's Electric Supply and Demand (ES&D) 2008 data and coordination with neighboring regions' staffs. The 2009 RRS models the PJM RTO region by including the ATSI zone and removing it from the World region. This modeled PJM RTO region is different than that shown in the January 2009 PJM Load Forecast Report.

The 2008 NERC ES&D has the ReliabilityFirst Corporation (RFC), Midwest Reliability Organization (MRO), Southeast Reliability Council (SERC), and Southwest Power Pool (SPP) boundaries defined differently than the historic region boundaries.

This was the third year of the RFC with only two years of 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 (10 years).

The forecasted load reductions available from identified 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 occurring, on average, once every 10 years. Table II -1 values are shown in per-unit, based on the annual peak.

Table II - 1: Load Forecast for 2013 / 2014 Delivery Years

Delivery Year	Month	PJMRTO (with ATSI)	WORLD (Without ATSI)
		Unrestricted Loads	Unrestricted Loads
2013 / 2014	January	0.825630	0.826902
	February	0.798353	0.812645
	March	0.732850	0.747883
	April	0.691987	0.697692
	May	0.782266	0.801828
	June	0.926765	0.917919
	July	1.000000	0.959775
	August	0.958844	1.000000
	September	0.847185	0.871837
	October	0.696198	0.745715
	November	0.718150	0.748678
	December	0.799311	0.825247

- **Forecast Error Factor (FEF)**

The Forecast Error Factor (FEF) 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 is limited to a maximum value of 3%.

With the recent implementation of the RPM capacity market, the FEF 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 PJM Manual 20 and the “PJM Generation Adequacy Analysis – Technical methods” (at <http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx>) and the Modeling and Analysis Section for further discussion of how the FEF is used in the determination of the Expected Weekly Maximum (EWM). Sensitivity number 8, shown in Appendix B, shows results of sensitivity analysis performed to indicate how changes in the FEF affect the IRM.

- **21 point Standard Normal Distribution, for daily peaks**

PRISM’s load model is a daily peak load model, aggregated by week (1-52). PRISM computes the daily LOLE using these weekly aggregated distributions. The RRS uses a standard normal distribution as the appropriate forecast daily distribution. This distribution is based on five peak weekdays. The standard normal distribution is represented using 21 points, using an appropriate amount of sigma away from the mean to capture the significant values in the evaluated margin states. The modeling used is based on work by C.J. Baldwin, as presented in the Westinghouse Engineer journal titled “Probability Calculation of Generation Reserves”, dated March 1969. See PJM Manual 20, pages 19-23 for further details.

The 2009 RRS evaluated several other distribution shapes (truncated normal distributions) as alternatives to the standard normal distribution. The evaluations compared the ability of various distributions to accurately match the anticipated distribution of future peak loads, and particularly extreme outcomes, based on historical peak loads and also modeling of extreme peak loads based on weather data. The RRAWG evaluated the work performed to date, and determined further work is necessary to make a recommendation based on these alternative distribution shapes.

This model uses an order statistic of sample size five which represents the five daily weekday peaks.

- **Week Peak Frequency (WKPKFQ) Parameters**

Forecasted weekly unrestricted peaks, based on daily peaks, are obtained from the forecasted monthly unrestricted peaks. The WKPKFQ distributions, adjusted by the monthly unrestricted peak forecasts, are consistent with the monthly Load Forecast shape. The WKPKFQ application’s primary input is hourly data, determining the daily peak’s mean and standard deviation for each week. Each week within each year of historical data is magnitude ordered (highest to lowest) and those weeks are averaged across years to replicate extreme peak load experience. The annual restricted peak and the adjusted WKPKFQ mean and standard deviation are used to develop daily peak 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.
- Vintage of Load forecast report (year of report).
- 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 include: Labor Day, Independence Day, Memorial Day, Good Friday, New Year’s Day, Thanksgiving, the Friday after Thanksgiving, and Christmas Day.

The Peak Load Ordered Time Series (PLOTS) load model is the result of performing the WKPKFQ calculations. Table II-2 shows these results of PJM RTO WKPKFQ run 1747 used in this study. Further technical details of the WKPKFQ load model process are in the paper title “Reinventing a Legacy System with SAS®, the Web, and OLAP reporting” available at:

<http://www.nesug.org/proceedings/nesug07/ap/ap10.pdf> and the appendix and presentation at <http://www.nesug.org/proceedings/nesug07/toc.pdf> .

The PRISM load model is based on assessment of daily peaks, aggregating appropriate statistical quantities, by week. These aggregated statistical quantities are not derived for weekly distributions, but are daily distributions analyzed on a weekly basis. All PRISM calculations are done on a daily peak basis.

Table II - 2: PJM RTO Load Model Parameters (PRISM # 4989)

Week Number	Mean	Standard Deviation
1	0.685736	0.038762
2	0.666524	0.038323
3	0.731619	0.061027
4	0.789031	0.062505
5	0.810060	0.073029
6	0.873321	0.058456
7	0.884169	0.081846
8	0.868078	0.05185
9	0.881162	0.070029
10	1.000000	0.06681
11	0.924593	0.07146
12	0.963102	0.070774
13	0.930105	0.05167
14	0.863692	0.077777
15	0.840408	0.057282
16	0.823731	0.041986
17	0.750137	0.069543
18	0.767132	0.062137
19	0.713081	0.046027
20	0.663242	0.019741
21	0.70522	0.034167
22	0.669962	0.028958
23	0.676753	0.02914
24	0.688246	0.028704
25	0.695167	0.031729

Week Number	Mean	Standard Deviation
26	0.71562	0.056655
27	0.708681	0.03629
28	0.735446	0.034433
29	0.737778	0.042999
30	0.784422	0.041782
31	0.788544	0.055267
32	0.805552	0.057034
33	0.758031	0.058765
34	0.800103	0.050992
35	0.778704	0.058095
36	0.832082	0.056982
37	0.809592	0.065903
38	0.769479	0.050578
39	0.774567	0.050003
40	0.755135	0.049695
41	0.756374	0.038072
42	0.74867	0.040507
43	0.764666	0.042118
44	0.722664	0.039601
45	0.723145	0.032017
46	0.687186	0.038487
47	0.670278	0.031188
48	0.658601	0.030493
49	0.683351	0.040980
50	0.65862	0.02059
51	0.669892	0.02348
52	0.716776	0.097982

Parameter	Value
Title	2009 RRS Base Case- Area 1: PJM RTO with ATSI
Description	RTO with ATSI {AE, BGE, DPL, JCPL, METED, PN, PECO, PEPCO, PL, PS, RECO, UGI, AEP, APS, COMED, DAY, DQE, VEPO, CE, TE, PP, OE} Start year 97 for 10 years, 2009 Load Forecast, 2009 Start Year, 2019 End Year
Year Range	1997 - 2006
Growth Factor	0.012819311
Growth Start Year	2009/2010
Growth End Year	2019/2020
Report Select	1
Zones	AE*1,BGE*1,DPL*1,JCPL*1,METED*1,PN*1,PECO*1,PEPCO*1,PL*1,PS*1,RECO*1,UGI*1,AEP*1,APS*1,CEI*1,COMED*1,DAY*1,DQE*1,OE*1,PP*1,TE*1,VEPO*1
Exclude Weekends	Y
Exclude Holidays	Y
Excluded Holidays	1 ,2,3,4,5,6,7,8

The calculation methods determine how the Table II-2 load parameter values are used to calculate values for a loss of load event, and the associated probability for these. See “PJM Generation Adequacy Analysis: Technical Methods”, dated October 2003 for further discussion of how the daily LOLE is determined, at <http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx>. 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. The beginning of Week 1 corresponds to May 15th.

PJM-World diversity reflects the timing of when the World area peaks compared to when the PJM RTO area peaks. 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, due to the impact of diversity.

The PJM-World diversity received much investigation and analysis for the 2009 RRS, with the Planning Committee requesting several specifics to be investigated and reported on. Please see that summary in the section “Planning Committee requests to RRAWG”. A comprehensive method to evaluate and choose load models, with diversity as one of the considerations, was developed, approved by the Planning Committee and implemented for this Study. See Appendix E showing the details of this new process and the technical methods established for this assessment. The investigation of diversity and choice of the study load models is now an assessment to be done at the start of the study, before any LOLE analysis work is started. Load model diversity can have a significant impact on IRM results, and with this new assessment method in place changes in the annual study results should be reduced.

One of the aspects uncovered in the investigation of appropriate diversity was a method to forecast the coincident peak of the composite World region, based on historic hourly data. The sub regions of the

composite World regions were analyzed, several different ways, ultimately determining that the composite World region typically peaks in August. All the non-coincident peak forecasts for each of the world sub-regions show a peak in July.

In the investigation of diversity, the hourly load data was again used to show the monthly shape on an annual basis. This investigation led to discussions with the RRAWG and a decision to calculate an average monthly shape, using years that had an August peak. This insured consistency between the timing of the monthly peaks and the annual peak of the composite World region.

When examining seasonal diversity, an average of all historic years was used. In 7 of the 13 historic years, the diversity was lower than the average. Please reference Appendix H which tabulates the impact of many of the modeling assumptions. This new assumption, to use the average of the values seen over a consistent peak period (August), was judged to understate the IRM. MISO performs a similar diversity assessment, choosing to model the minimum of the historic diversity values. This approach was considered and discussed with the RRAWG, but determined to be too conservative when put in the broad context of all the modeling assumptions used in the RRS. A balance of all the modeling inputs is desired and using an average value for this specific aspect seemed to accomplish this. Table II – 3 summarizes the underlying historic data that led to a modeling choice of the values highlighted in yellow.

Table II - 3: Intra-World load diversity

SEASON*	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	diversity range	13 year avg
Winter*	3.96%	6.56%	3.71%	5.10%	10.15%	5.53%	7.67%	11.25%	6.51%	5.65%	6.76%	10.82%	4.98%	1995 - 2006	6.97%
Summer	3.74%	4.08%	3.31%	2.01%	4.64%	4.46%	2.78%	2.88%	8.50%	5.22%	4.19%	2.74%	4.04%	1995 - 2007	4.05%
Spring	4.37%	3.44%	5.66%	4.57%	5.18%	3.48%	6.03%	11.12%	14.05%	4.41%	6.66%	1.19%	4.21%	1995 - 2007	5.72%
Fall	5.52%	3.38%	1.42%	3.79%	4.51%	4.54%	5.17%	3.42%	8.94%	4.73%	5.42%	5.43%	4.12%	1995 - 2007	4.65%

MONTH NUMBER	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	diversity range	Average Diversity Using Aug Peak Years Only
1	85.28%	87.72%	88.52%	78.45%	85.78%	92.95%	82.79%	77.23%	85.90%	89.04%	81.86%	69.22%	76.68%	1995 - 2007	82.69%
2	86.61%	94.54%	80.88%	78.90%	79.20%	84.87%	76.20%	76.06%	82.79%	83.99%	73.56%	70.84%	80.82%	1995 - 2007	81.26%
3	76.93%	85.81%	73.13%	80.97%	77.20%	74.18%	74.37%	73.43%	74.89%	77.65%	72.65%	67.40%	70.56%	1995 - 2007	74.79%
4	70.10%	73.57%	71.77%	68.41%	67.82%	71.33%	68.91%	73.04%	72.09%	73.14%	64.08%	61.40%	64.68%	1995 - 2007	69.77%
5	74.21%	88.86%	72.63%	83.94%	73.37%	86.53%	73.71%	75.37%	71.11%	85.45%	68.98%	82.15%	78.28%	1995 - 2007	80.18%
6	89.24%	91.56%	98.03%	97.86%	95.64%	93.26%	89.12%	91.95%	94.48%	95.76%	91.14%	85.70%	92.51%	1995 - 2007	91.79%
7	100%	98.01%	100%	100%	100%	94.20%	96.06%	98.47%	93.69%	98.64%	100%	97.07%	91.89%	1995 - 2007	96.00%
8	99.91%	100%	91.01%	95.96%	96.87%	100%	100%	100%	100%	100%	99.56%	100%	100%	1995 - 2007	100.00%
9	83.36%	92.54%	90.91%	86.71%	88.61%	98.73%	83.32%	92.00%	83.06%	88.94%	87.33%	72.01%	86.87%	1995 - 2007	87.18%
10	70.80%	73.31%	78.51%	73.19%	70.24%	79.60%	67.97%	80.01%	72.35%	74.87%	74.90%	68.05%	80.41%	1995 - 2007	74.57%
11	78.31%	80.58%	79.86%	72.60%	79.48%	83.93%	69.48%	71.37%	77.36%	79.27%	71.53%	67.86%	69.09%	1995 - 2007	74.87%
12	86.60%	90.90%	83.00%	79.91%	80.14%	91.20%	73.13%	79.78%	83.08%	89.92%	80.00%	75.36%	76.84%	1995 - 2007	82.52%

*January and February of each calendar year are rolled back to be considered with the December of the previous so that the winter can be considered as a whole.

*Diversity values for Winter 2007 only use one month of data, December 2007. This value should be disregarded.

*Average Diversity for Winter was recalculated to not include 2007.

- **PRISM solved load and 50/50 peak load forecast**

The debate over the correct peak load to use in the denominator when stating the IRM calculated in PRISM is essentially a debate over the definition of a “50/50” summer peak load. The IRM is applied to the “50/50” peak day load that is produced by the PJM load forecast model so it is critical that the PRISM “50/50” peak load be consistent with the load forecast model “50/50” peak day load.

The development of a “50/50” peak day load in the PJM load forecast model is detailed in the slides at the following link:

<http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/~/media/committees-groups/stakeholder-meetings/lfts/20090408/20090408-stakeholder-training-final.ashx>

The forecast model develops a distribution of summer peak loads based on historical weather. This is accomplished by simulating 481 weather scenarios (13 scenarios for each of 37 years of historical weather). Each of these 481 simulated “summers” will produce a single peak load (which can occur in any day during June, July or August). These 481 peak loads are then plotted from lowest to highest to produce a distribution

of summer peaks. The midpoint (or 241st point) of this distribution is defined to be the “50/50” peak day load. The key point is that only the load from the peak day of each simulated summer is represented in the distribution. Loads on the other 91 days of the summer are not part of the distribution. This definition of a “50/50” summer peak is consistent with standard industry practice.

The LOLE model considers loads across all weeks of the year. It must recognize that the 50/50 peak day load may also be exceeded on other days of the year. (For instance, in a very hot summer, all top 5 CP days may exceed the 50/50 peak day load forecast.) This is the reason that the solved load in PRISM could be other than a 50/50 load when viewed across the summer. There is a greater than 50% chance that any day over the summer (including the peak day) may exceed the 50/50 peak day load. This is also true for the PJM load forecast model.

To maintain consistency with the load forecast model definition of a “50/50” peak day load, the IRM calculated in PRISM must be expressed as a percentage of the Expected Weekly Maximum (EWM) of the peak week. The probability of peak load exceeding this EWM on the peak day (in the peak week) is 50%. Thus the EWM of the peak week is the “50/50” load associated with the peak day of the summer. The official load forecast, to which the IRM is applied, is also the “50/50” load associated with the peak day of the summer. Therefore, the denominator in the IRM calculation is consistent with the 50/50 peak day load forecast.²

20

² Two RRAWG members disagree that the expected weekly maximum of the week with the highest daily mean represents the summer 50/50 peak. Within the PRISM probabilistic load model, there is risk (probability) of the summer peak occurring in some other week.

Generation Forecasting

- **GADS, eGADS and PJM fleet Class Average Values**

The Generator Availability Data System (GADS) is a NERC-based program and database used for entering, storing, and reporting generating unit data concerning generator outages and unit performance. GADS data is used by PJM and other RTOs in characterizing and evaluating unit performance.

The PJM Generator Availability Data System (eGADS) is an Internet based application which supports the submission and processing of generator outage and performance data as required by PJM and the NERC reporting standards. 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/documents/~media/documents/manuals/m23.ashx>. 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 → Purchase 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 revised RAA per the recent approved rate schedule FERC No. 44, dated May 28, 2009 can be found at: <http://www.pjm.com/documents/agreements/pjm-agreements.aspx>.

For units with missing or insufficient GADS 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” that was used in previous studies. Such “class averaging” is therefore used for future units, neighboring system units, and for those PJM units with less than five 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
- identification of necessary data that is independent of outside resources

With recent market integration activities, the PJM RTO 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 I-6 or Sensitivity Run #20 (Appendix B) regarding single area related assessments.).

Less than thirty percent 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 any 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. Furthermore, this five-year period is used to calculate the various statistics, including (but not limited to):

- Equivalent Demand Forced Outage Rate (EFORd)
- Effective Equivalent Demand Forced Outage Rate (EEFORd)
- Equivalent Maintenance Outage Factor (EMOF)
- Planned Outage Factor (POF)
- Equivalent Demand Forced Outage Rate, excluding Outside Management Control (XEFORd)

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 72 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 II-4. These values are available via the web based application discussed in the next section.

In Appendix B, Sensitivity Run No. 15 indicates that a 1% change in the pool-wide EEFORd will cause a 1.45% change in the IRM – indicating a direct, positive correlation between unit performance and the solved IRM. The EEFORd rates have little impact on the Unforced Reserve Margin, or FPR. It is the FPR that is used in the RPM capacity market to calculate Reliability Requirements, which are expressed in unforced capacity terms.

A comparison of the values from the previous study is shown in Table II-5. The previous study used the PJM fleet of units' class average values. However, evaluation and assessment of the NERC class averages are performed each study. These NERC averages are based on data from approximately 6,000 units located in North America. This assessment shows contributors to the modest increased forced outage rates are caused by diesels, small fossil, small jet engine and small gas turbines, with the maintenance outage events decreasing, indicated in the EMOF column of this table. Planned outages remained constant, as indicated in the POF column of this table. For units other than large fossil, the derated outage states for units remained essentially unchanged, as indicated by small changes in the variance column, expressed in megawatts.

- **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: <https://esuite.pjm.com/Rstudy/>.

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 occurred in the spring, with member representatives needing to participate in a kick-off meeting via teleconference and web conference when the review efforts begin.

This review done by 20 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 Demand Forced Outage Rate (EEFORd)** – This forced outage rate, determined for demand periods, 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 the FO and PO categories. 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/documents/~media/documents/manuals/m22.ashx>). The equation for the EEFORd is as follows:

Equation II - 1: Calculation of Effective Equivalent Demand Forced Outage Rate (EEFOR_d)

$$\text{EEFORd} = \text{EFORd} + (1/4 * \text{EMOF})$$

- **Equivalent Demand Forced Outage Rate (EFORd)** – This forced outage rate, determined for demand periods, 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 the capacity parameter used in the PJM 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 2009 RRS, the five-year period is defined in the study assumptions as calendar years 2004-2008.

- **Determination of EFORd Excluding Outside Management Control (OMC) Events**

Beginning in January 2006, eGADS users were offered the option of identifying forced outages as Outside Management Control (OMC). This classification is intended to cover generator outages due to causes such as transmission system problems that force the unit offline even though it is physically available to run. The RRS model uses an EFORd that includes OMC events because a reliability study must account for all generator outages regardless of cause. A PJM average EFORd that excludes OMC events, however, is required to convert the IRM to an equivalent “unforced” reserve margin (or FPR).

The determination of the EFORd without OMC events is a two part process. The first part of the process is to calculate an EFORd value with OMC events in the GADS data. This is a capacity weighted pool-wide value. The actual pool values shown in this table are used as they are based on the actual Summer Net Dependable (SND) rating for each unit. However, most of the PRISM calculations use the rounded capacity, to the nearest 10 MW.

The second step is to assess the OMC events as reported in the GADS data. Different generating unit owners report OMC events based on valid, yet various interpretations of the OMC reporting guidelines. The PJM staff assesses and investigates OMC events to ensure that they are reported using consistent interpretation of the OMC reporting guidelines. This ensures EFORd, without OMC events, is properly calculated. That assessment evaluates and considers items including demand periods, impact to pool-wide use, trends reported in other publications including the PJM State of the Market Report, and discussions with generation owners.

The EFORd values used in the RRS are based on data from 2004–2008. OMC events, however, are reported for only the years 2006, 2007 and 2008. To estimate an EFORd value excluding OMC events for years 2004-2005, PJM determined the difference between the EFORd value with and without OMC events for 2006 through 2008 (0.47%) and effectively applied that same difference to the first two years. The five-year average EFORd excluding OMC events was therefore calculated to be the EFORd including OMC events from the base case model less 0.47% or:

2012 DY 5 year average EFORd excluding OMC events = 6.75 % - 0.47 % = 6.28 %
2013 DY 5 year average EFORd excluding OMC events = 6.77 % - 0.47 % = 6.30 %

The values of 6.28% and 6.30% are then used to convert the 15.4% and 15.3% IRMs to an FPR as shown in the Recommendations Section on page 12.

Table II - 4: PJM RTO Fleet Class Average Generation Performance Statistics (2004-2008)

Start Date	End Date	Unit Type & Primary Fuel Category	Gen Class Key	POF Weeks per Year	EFORd	EEFORd	EMOF	Variance Megawatts	XEFORd	Second Yr Maint
1/1/2002	12/31/2006	FOSSIL All Fuel Types All Sizes	1	7	6.67%	7.28%	2.44%	4038	6.67%	10
1/1/2002	12/31/2006	FOSSIL All Fuel Types 001-099	2	4	7.69%	8.22%	2.13%	263	7.69%	8
1/1/2002	12/31/2006	FOSSIL All Fuel Types 100-199	3	6	6.43%	7.16%	2.91%	2587	6.43%	10
1/1/2002	12/31/2006	FOSSIL All Fuel Types 200-299	4	7	6.97%	7.61%	2.57%	3522	6.97%	10
1/1/2002	12/31/2006	FOSSIL All Fuel Types 300-399	5	8	5.78%	6.42%	2.57%	4126	5.78%	12
1/1/2002	12/31/2006	FOSSIL All Fuel Types 400-599	6	8	6.67%	7.23%	2.25%	6402	6.67%	12
1/1/2002	12/31/2006	FOSSIL All Fuel Types 600-799	7	8	6.77%	7.29%	2.09%	9229	6.77%	12
1/1/2002	12/31/2006	FOSSIL All Fuel Types 800-999	8	8	3.38%	3.81%	1.70%	5605	3.38%	12
1/1/2002	12/31/2006	FOSSIL All Fuel Types 1000 Plus	9	9	8.82%	9.56%	2.96%	28390	8.82%	10
1/1/2002	12/31/2006	FOSSIL Coal Primary All Sizes	10	6	6.54%	7.14%	2.41%	4243	6.54%	10
1/1/2004	12/31/2008	FOSSIL Coal Primary 001-099	11	3	12.61%	13.31%	1.29%	1282	12.00%	9
1/1/2004	12/31/2008	FOSSIL Coal Primary 100-199	12	3	12.61%	13.31%	1.29%	1282	12.00%	10
1/1/2004	12/31/2008	FOSSIL Coal Primary 200-299	13	4	10.30%	11.15%	1.31%	20929	9.74%	10
1/1/2004	12/31/2008	FOSSIL Coal Primary 300-399	14	4	10.30%	11.15%	1.31%	20929	9.74%	11
1/1/2004	12/31/2008	FOSSIL Coal Primary 400-599	15	4	10.30%	11.15%	1.31%	20929	9.74%	11
1/1/2004	12/31/2008	FOSSIL Coal Primary 600-799	16	4	10.30%	11.15%	1.31%	20929	9.74%	11
1/1/2004	12/31/2008	FOSSIL Coal Primary 800-999	17	4	5.18%	5.56%	0.80%	60540	5.14%	10
1/1/2004	12/31/2008	FOSSIL Coal Primary 1000 Plus	18	4	5.18%	5.56%	0.80%	60540	5.14%	10
1/1/2002	12/31/2006	FOSSIL Oil Primary All Sizes	19	9	11.88%	12.56%	2.71%	6082	11.88%	11
1/1/2004	12/31/2008	FOSSIL Oil Primary 001-099	20	3	12.61%	13.31%	1.29%	1282	12.00%	8
1/1/2004	12/31/2008	FOSSIL Oil Primary 100-199	21	3	12.61%	13.31%	1.29%	1282	12.00%	10
1/1/2004	12/31/2008	FOSSIL Oil Primary 200-299	22	4	10.30%	11.15%	1.31%	20929	9.74%	11
1/1/2004	12/31/2008	FOSSIL Oil Primary 300-399	23	4	10.30%	11.15%	1.31%	20929	9.74%	12
1/1/2004	12/31/2008	FOSSIL Oil Primary 400-599	24	4	10.30%	11.15%	1.31%	20929	9.74%	13
1/1/2004	12/31/2008	FOSSIL Oil Primary 600-799	25	4	10.30%	11.15%	1.31%	20929	9.74%	14
1/1/2004	12/31/2008	FOSSIL Oil Primary 800-999	26	4	5.18%	5.56%	0.80%	60540	5.14%	14
1/1/2002	12/31/2006	FOSSIL Gas Primary All Sizes	28	6	6.28%	6.92%	2.54%	3332	6.28%	11
1/1/2004	12/31/2008	FOSSIL Gas Primary 001-099	29	3	12.61%	13.31%	1.29%	1282	12.00%	8
1/1/2004	12/31/2008	FOSSIL Gas Primary 100-199	30	3	12.61%	13.31%	1.29%	1282	12.00%	10
1/1/2004	12/31/2008	FOSSIL Gas Primary 200-299	31	4	10.30%	11.15%	1.31%	20929	9.74%	11
1/1/2004	12/31/2008	FOSSIL Gas Primary 300-399	32	4	10.30%	11.15%	1.31%	20929	9.74%	12
1/1/2004	12/31/2008	FOSSIL Gas Primary 400-599	33	4	10.30%	11.15%	1.31%	20929	9.74%	13
1/1/2004	12/31/2008	FOSSIL Gas Primary 600-799	34	4	10.30%	11.15%	1.31%	20929	9.74%	14
1/1/2004	12/31/2008	FOSSIL Gas Primary 800-999	35	4	5.18%	5.56%	0.80%	60540	5.14%	14
1/1/2002	12/31/2006	FOSSIL Lignite Primary All Sizes	37	6	5.58%	5.94%	1.42%	5791	5.58%	10
1/1/2004	12/31/2008	NUCLEAR All Types All Sizes	38	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR All Types 400-799	39	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR All Types 800-999	40	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR All Types 1000 Plus	41	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR PWR All Sizes	42	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR PWR 400-799	43	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR PWR 800-999	44	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR PWR 1000 Plus	45	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR BWR All Sizes	46	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR BWR 400-799	47	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR BWR 800-999	48	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR BWR 1000 Plus	49	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2004	12/31/2008	NUCLEAR CANDU All Sizes	50	3	1.93%	2.12%	0.38%	19368	1.89%	14
1/1/2002	12/31/2006	JET ENGINE All Sizes	51	2	8.04%	8.68%	2.54%	121	8.04%	4
1/1/2004	12/31/2008	JET ENGINE 001-019	52	1	15.78%	16.25%	0.94%	24	15.00%	3
1/1/2004	12/31/2008	JET ENGINE 20 Plus	53	2	12.95%	13.61%	1.08%	145	11.78%	4
1/1/2002	12/31/2006	GAS TURBINE All Sizes	54	3	8.21%	8.61%	1.60%	283	8.21%	3
1/1/2004	12/31/2008	GAS TURBINE 001-019	55	1	15.78%	16.25%	0.94%	24	15.00%	3
1/1/2004	12/31/2008	GAS TURBINE 020-049	56	2	12.95%	13.61%	1.08%	145	11.78%	3
1/1/2004	12/31/2008	GAS TURBINE 50 Plus	57	1	9.44%	9.96%	0.83%	938	7.60%	4
1/1/2004	12/31/2008	COMBINED CYCLE All Sizes	58	2	8.49%	8.91%	0.80%	3164	8.21%	12
1/1/2002	12/31/2006	HYDRO All Sizes	59	8	4.55%	5.04%	1.95%	178	4.55%	4
1/1/2004	12/31/2008	HYDRO 001-029	60	2	5.68%	6.11%	0.48%	7	5.27%	5
1/1/2004	12/31/2008	HYDRO 30 Plus	61	2	5.68%	6.11%	0.48%	7	5.27%	4
1/1/2004	12/31/2008	PUMPED STORAGE All Sizes	62	3	2.61%	2.96%	0.60%	1715	2.32%	6
1/1/2002	12/31/2006	MULTI-BOILER/MULTI-TURBINE All Sizes	63	3	8.85%	9.37%	2.07%	2969	8.85%	8
1/1/2004	12/31/2008	DIESEL All Sizes	65	0	14.09%	14.46%	0.51%	3	12.27%	2
1/1/2002	12/31/2006	FOSSIL Oil/Gas Primary All Sizes	66	7	7.56%	8.21%	2.58%	3824	7.56%	11
1/1/2004	12/31/2008	FOSSIL Oil/Gas Primary 001-099	67	3	12.61%	13.31%	1.29%	1282	12.00%	8
1/1/2004	12/31/2008	FOSSIL Oil/Gas Primary 100-199	68	3	12.61%	13.31%	1.29%	1282	12.00%	10
1/1/2004	12/31/2008	FOSSIL Oil/Gas Primary 200-299	69	4	10.30%	11.15%	1.31%	20929	9.74%	11
1/1/2004	12/31/2008	FOSSIL Oil/Gas Primary 300-399	70	4	10.30%	11.15%	1.31%	20929	9.74%	12
1/1/2004	12/31/2008	FOSSIL Oil/Gas Primary 400-599	71	4	10.30%	11.15%	1.31%	20929	9.74%	13
1/1/2004	12/31/2008	FOSSIL Oil/Gas Primary 600-799	72	4	10.30%	11.15%	1.31%	20929	9.74%	14
1/1/2004	12/31/2008	FOSSIL Oil/Gas Primary 800-999	73	4	5.18%	5.56%	0.80%	60540	5.14%	14
1/1/2004	12/31/2008	Wind All sizes	74	0	0.00%	0.00%	0.00%	0	0.00%	0
1/1/2004	12/31/2008	Solar All sizes	75	0	0.00%	0.00%	0.00%	0	0.00%	0

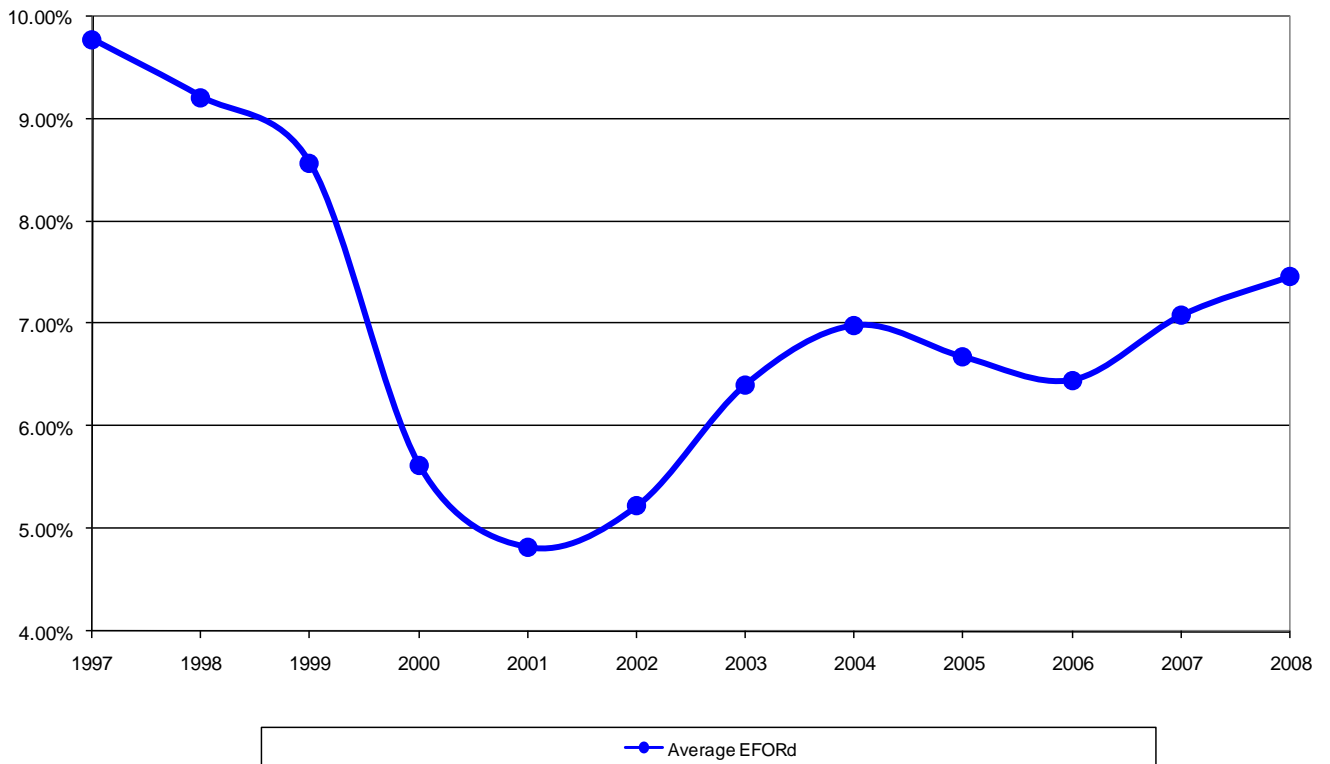
Variance is described in Manual 22, pages 12, 24-26.

Table II - 5: Comparison of Class Average Values - 2008 RRS vs. 2009 RRS

Unit Type & Primary Fuel Category	Gen Class	POF Change Weeks/Year	EFORd Change	EEFORd Change	XEFORd Change	EMOF Change	Variance
							Change
FOSSIL All Fuel Types All Sizes	1	0	0.26%	0.18%	0.73%	-0.31%	84
FOSSIL All Fuel Types 001-099	2	-1	0.71%	0.65%	1.18%	-0.26%	27
FOSSIL All Fuel Types 100-199	3	0	0.09%	0.03%	0.56%	-0.24%	5
FOSSIL All Fuel Types 200-299	4	0	1.08%	1.04%	1.55%	-0.16%	299
FOSSIL All Fuel Types 300-399	5	0	-0.10%	-0.26%	0.37%	-0.65%	-137
FOSSIL All Fuel Types 400-599	6	0	-0.13%	-0.24%	0.34%	-0.45%	-191
FOSSIL All Fuel Types 600-799	7	0	-0.14%	-0.16%	0.33%	-0.07%	-235
FOSSIL All Fuel Types 800-999	8	0	-0.61%	-0.82%	-0.14%	-0.82%	-1133
FOSSIL All Fuel Types 1000 Plus	9	0	-0.42%	-0.38%	0.05%	0.17%	-1583
FOSSIL Coal Primary All Sizes	10	0	0.07%	0.06%	0.26%	-0.03%	29
FOSSIL Coal Primary 001-099	11	1	1.02%	0.96%	0.84%	-1.77%	-5
FOSSIL Coal Primary 100-199	12	1	1.02%	0.96%	0.84%	-1.77%	-5
FOSSIL Coal Primary 200-299	13	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Coal Primary 300-399	14	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Coal Primary 400-599	15	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Coal Primary 600-799	16	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Coal Primary 800-999	17	0	0.10%	0.11%	0.09%	-0.68%	1937
FOSSIL Coal Primary 1000 Plus	18	0	0.10%	0.11%	0.09%	-0.68%	1937
FOSSIL Oil Primary All Sizes	19	0	4.23%	4.05%	4.44%	-0.73%	1685
FOSSIL Oil Primary 001-099	20	1	1.02%	0.96%	0.84%	-1.77%	-5
FOSSIL Oil Primary 100-199	21	1	1.02%	0.96%	0.84%	-1.77%	-5
FOSSIL Oil Primary 200-299	22	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Oil Primary 300-399	23	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Oil Primary 400-599	24	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Oil Primary 600-799	25	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Oil Primary 800-999	26	0	0.10%	0.11%	0.09%	-0.68%	1937
FOSSIL Gas Primary All Sizes	28	0	-0.21%	-0.42%	0.00%	-0.84%	-22
FOSSIL Gas Primary 001-099	29	1	1.02%	0.96%	0.84%	-1.77%	-5
FOSSIL Gas Primary 100-199	30	1	1.02%	0.96%	0.84%	-1.77%	-5
FOSSIL Gas Primary 200-299	31	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Gas Primary 300-399	32	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Gas Primary 400-599	33	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Gas Primary 600-799	34	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Gas Primary 800-999	35	0	0.10%	0.11%	0.09%	-0.68%	1937
FOSSIL Lignite Primary All Sizes	37	1	-0.71%	-0.85%	-0.51%	-0.58%	-721
NUCLEAR All Types All Sizes	38	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR All Types 400-799	39	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR All Types 800-999	40	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR All Types 1000 Plus	41	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR PWR All Sizes	42	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR PWR 400-799	43	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR PWR 800-999	44	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR PWR 1000 Plus	45	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR BWR All Sizes	46	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR BWR 400-799	47	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR BWR 800-999	48	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR BWR 1000 Plus	49	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
NUCLEAR CANDU All Sizes	50	0	-0.31%	-0.30%	-0.31%	-0.33%	-3079
JET ENGINE All Sizes	51	0	-1.37%	-1.48%	-0.61%	-0.45%	-18
JET ENGINE 001-019	52	0	2.45%	2.46%	2.12%	-0.91%	0
JET ENGINE 20 Plus	53	0	0.13%	0.11%	0.01%	-1.64%	-2
GAS TURBINE All Sizes	54	0	-2.05%	-2.12%	-1.35%	-0.28%	-7
GAS TURBINE 001-019	55	0	2.45%	2.46%	2.12%	-0.91%	0
GAS TURBINE 020-049	56	0	0.13%	0.11%	0.01%	-1.64%	-2
GAS TURBINE 50 Plus	57	-1	0.56%	0.53%	-0.29%	-1.41%	-21
COMBINED CYCLE All Sizes	58	0	-0.02%	-0.05%	0.02%	-1.04%	-367
HYDRO All Sizes	59	1	0.66%	0.68%	1.13%	0.09%	2
HYDRO 001-029	60	-1	-0.80%	-0.53%	-0.74%	-0.21%	-5
HYDRO 30 Plus	61	-1	-0.80%	-0.53%	-0.74%	-0.21%	-5
PUMPED STORAGE All Sizes	62	0	0.18%	0.22%	-0.03%	-0.62%	-54
MULTI-BOILER/MULTI-TURBINE All Sizes	63	-1	0.82%	0.74%	1.29%	-0.34%	1445
DIESEL All Sizes	65	0	2.59%	2.53%	2.20%	-1.24%	0
FOSSIL Oil/Gas Primary All Sizes	66	0	1.24%	1.04%	1.61%	-0.82%	398
FOSSIL Oil/Gas Primary 001-099	67	1	1.02%	0.96%	0.84%	-1.77%	-5
FOSSIL Oil/Gas Primary 100-199	68	1	1.02%	0.96%	0.84%	-1.77%	-5
FOSSIL Oil/Gas Primary 200-299	69	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Oil/Gas Primary 300-399	70	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Oil/Gas Primary 400-599	71	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Oil/Gas Primary 600-799	72	0	0.49%	0.50%	0.08%	-2.00%	984
FOSSIL Oil/Gas Primary 800-999	73	0	0.10%	0.11%	0.09%	-0.68%	1937
Wind All sizes	74	0	0.00%	0.00%	0.00%	0.00%	0

Figure II-1 shows the historical forced outage rate trends. The values in Figure II-1 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 web-based eGADS system.

Figure II - 1: Historical Annual Weighted-Average Forced Outage Rates (Individual Annual values)



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/resource-adequacy-planning/resource-reports-info.aspx>.

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.

Considering the annual data shown in Figure II-1 and the five year period data shown in Figure I-3, recent forced outage rates for the PJM RTO fleet of units are exhibiting a slight upward trend.

- **Generating Unit Modeling Issues**

The generating unit characteristics indicate the probability of a unit's availability to serve load, either at its full rating or when derated. 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 ranging from 0-4 MWs will round to zero; hence units sized from 5 MW to 14 MW will 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 II-6 for the 2013/ 2014 delivery year. This summary is based on the individual detailed unit model (i.e. where the smaller units have not been combined in groups of 10 MW). This summary reflects the "blending" process discussed above to determine the table values. 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.

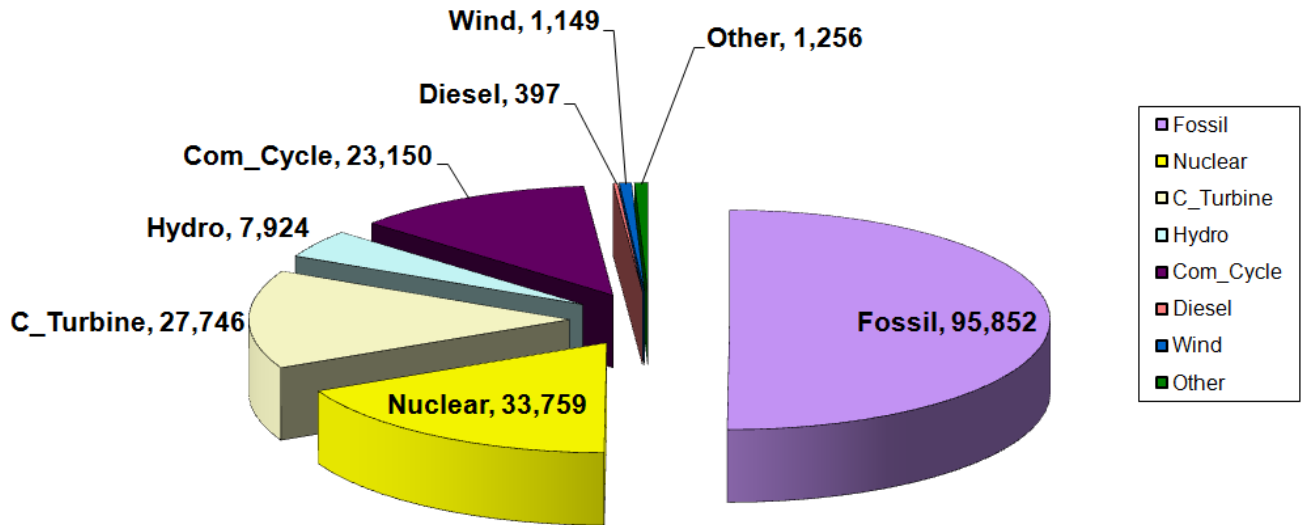
The outage rate for wind units, however, reflects the PJM stakeholder process modeling, not actual outage event data.

Table II - 6: PJM RTO Fleet-based Unit Performance by Primary Fuel Category

2013 / 2014 Delivery Year	# of Units	Actual Capacity MW	% Total MW	Forced Outage Rates %	Ambient Temperature Derating (MW)
Fossil	390	95,852	50.1%	9.09%	884
Nuclear	36	33,759	17.7%	2.23%	
C_Turbine	502	27,746	14.5%	10.82%	1368
Hydro	124	7,924	4.1%	2.83%	248
Com_Cycle	137	23,150	12.1%	4.89%	
Diesel	40	397	0.2%	11.40%	
Wind	148	1,149	0.6%	0.00%	
Other	38	1,256	0.7%	10.40%	
PJM RTO Total	1415	191,233	100.0%	7.32%	2500

Figure II-2 charts all PJM RTO capacity by fuel type for the 2013 / 2014 Delivery Year. Values are shown in megawatts.

Figure II - 2: PJM RTO Capacity by Fuel Type
Delivery Year 2013 / 2014 Capacity (MW)



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

Per the approved rules in place for PJM Operations, Planning and Markets, a unit can operate at less than its SND rating and still not incur a GADS outage event. All modeled units 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 also captures 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, "New York Control Area Installed Capacity Requirement for the Period May 2009 through April 2010 - Final Report" (see report dated December 5, 2008 at: <http://www.nysrc.org/pdf/Reports/2009%20IRM%20Report%20-%20Final%2012%2005%2008%20V1.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 2,000 MW to 2,500 MW, implemented in the RRS, based on experience from the Mid-Atlantic Region. The scheduling of planned maintenance of PJM RTO units in the summer operating period, increased the reserve requirement by 1.4%.

Specific units that are scheduled for maintenance outages were assigned, having 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 (The Operations Related Assessment Section of the 2008 RRS report includes further details. - <http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx>).

A sensitivity analysis was performed to assess the impact of these scheduled planned maintenance outages, in small amounts over many units. The current practice is to choose approximately 30 units for the 2,500 MW pool derating. This sensitivity case used 250 units with each unit assigned a 10 MW derating. The change in the results were negligible. The RRAWG reviewed this sensitivity and concluded that modeling the planned outages over many units did not warrant the extra resource requirements for this modeling refinement.

- **Generation Interconnection Forecast**

The Forecast Reserve Margin (Figure II-3) is the basis for the forecast values modeled in the RRS. This figure is based on values posted in September 2009 and is updated monthly on PJM's resource reports web page (<http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx>).

Concerning Figure II -3, it is important to note that 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, the capacity values are different due to the RRS model including external units, and modeling of the ATSI region.

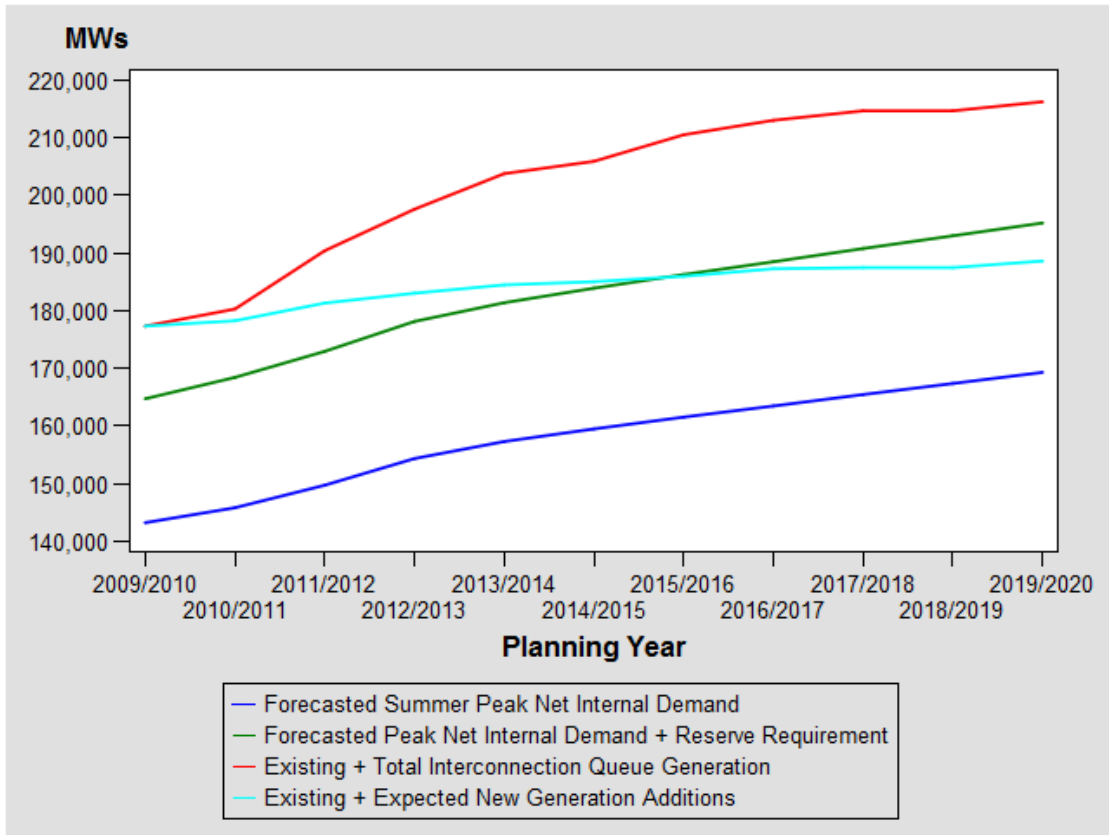
The commercial probabilities listed in Table II-7 represent the likelihood a project, given its current interconnection queue status, becomes commercially available to serve load within the PJM RTO. These probabilities are derived by assessing actual queue project installations of historic queues since 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 II-3 uses a consistent process with similar graphs posted monthly on the PJM web site at: <http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx> .

The formulation of Figure II-3 is a predefined data process that does not use the final SAS database tables used in the RRS. Differences in values in the graph and Table II - 8 and Table II-6 are in part due to the dynamic nature of the generation queue process which is the data source for this figure. In addition, the following items might impact differences seen in these three sets of summary values:

- The RRS model includes external capacity resources while Figure II-3 does not include these units.
- Figure II-3 is an input for developing the final generation values shown in Table II-8.
- Table II – 8 includes known changes per the posted September queues.
- To produce the Figure II-3 graph using the RRS SAS database schema would require significant effort by the PJM staff. This was deemed not necessary, although considered by the RRAWG, as the monthly graphs are what most members use and the three summaries give very similar results.

Figure II - 3: Forecast Reserve Margin Graph - September 2009



Planning Year	Column A: Forecasted Summer Peak Net Internal Demand	Column B: Forecasted Peak Net Internal Demand + Reserve Requirement	Column C: Existing Installed Capacity as of 09/17/2009	Column D: Total Interconnection Queue Generation by June 1st	Column E: Expected Interconnection Generation Additions by June 1st	Column F: Announced Retirements	Column G: Existing + Total Interconnection Queue Generation	Column H: Existing + Expected New Generation Additions	Column I: Summer Peak Forecasted Reserve Margin %
2009/2010	143,230	164,715	177,317	.	.	.	177,317	177,317	23.80
2010/2011	145,821	168,423	177,317	3,094	1,054	134	180,277	178,237	22.23
2011/2012	149,725	172,932	177,317	10,883	3,841	772	190,388	181,306	21.09
2012/2013	154,349	178,119	177,317	7,978	2,501	790	197,576	183,016	18.57
2013/2014	157,300	181,367	177,317	6,169	1,442	.	203,745	184,459	17.27
2014/2015	159,484	183,885	177,317	2,134	548	.	205,879	185,007	16.00
2015/2016	161,535	186,250	177,317	4,602	947	.	210,481	185,953	15.12
2016/2017	163,457	188,466	177,317	2,515	1,302	.	212,996	187,255	14.56
2017/2018	165,447	190,760	177,317	1,640	197	.	214,636	187,452	13.30
2018/2019	167,362	192,968	177,317	.	.	.	214,636	187,452	12.00
2019/2020	169,290	195,191	177,317	1,570	1,146	.	216,206	188,598	11.41

Column A: PJM Total Demand - Active Load Management. Forecast is calculated as a diversified sum of zonal forecasts. Values are from 2009 PJM Load Forecast Report, for the PJM RTO including ATSI.
 Column B: Column A multiplied by the Reserve Requirement of 1.15 for 2009/2010, 1.155 for 2010/2011-2011/2012, 1.154 for 2012/2013 and 1.153 2013/2014-2019/2020.
 Column C: Installed Capacity as of 09/17/2009 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: Snapshot of Interconnection Queue as of June 1st. Wind Queue Generation is rated at class average capacity factor.
 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

Note: These reserve margins are based on deliverable capacity located within PJM. The margins are NOT based on capacity committed through RPM. For RPM information, please refer to the following link <http://www.pjm.com/markets/rpm/operations.html>

Table II - 7: Commercial Probabilities for Expected Interconnection Generation Additions

Status	Commercial Probability
In the Queue, upto Feasibility Study Stage	12%
All of the above, plus an impact study completed (Active)	35%
All of the above, plus a facilities study completed (Active)	59%
All of the above, ISA executed (UC)	73%
Successful completion (IS, ISP, IS-NC)	100%

Based on an evaluation of historic generation queue information from 1999-2009

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 PJM RTO. Although the PJM RTO has the physical capability of importing more than the 3,500 MW CBM, the additional import capability is reflected in Available Transfer Capability (ATC) through the OASIS postings and not reserved as CBM. This allows for the additional import capability to be used in the marketplace.

The use of CBM (on an annual basis) in this study is consistent with the time period of the RFC criteria, and the Reliability Assurance Agreement, Schedule 4, sheet No. 29.

- **Capacity Benefit Margin (CBM)**

The CBM value of 3500 MW is specified in the PJM Reliability Assurance Agreement (RAA), Schedule 4, sheet No. 29. As a sensitivity case for this study, the CBM was varied between 0 MW and 15,000 MW. The relationship of IRM with CBM is graphically depicted in Figure I-6. A decrease in the CBM from 3,500 MW to 0 MW increases the pool's reserve requirement by about 1.76%. This value is influenced primarily by the degree of load diversity between PJM and the World region, with a minor role seen in the World reserve level.

- **Transmission Projects**

The PJM Regional Transmission Expansion Planning (RTEP) process is coordinated with the transmission model used in Adequacy studies, including the RRS. The process to review transmission projects is performed by the PJM Transmission Expansion Advisory Committee (TEAC). While evaluation of 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 (LDAs) (See PJM Manual 14 B, attachment C, pages 40-54 for further details.).

- **Capacity Benefit of Ties (CBOT)**

The CBOT is a measure of the reliability value that World interface ties bring into the PJM RTO. The CBOT is the difference between an RRS run with a 3,500 MW CBM and an RRS run with a zero (0) MW CBM. The CBOT was evaluated as Sensitivity Run # 16 (Appendix B). In this run, the CBOT result was 1.76% of the PJM forecasted load or roughly 2,830 MW of installed capacity. The CBOT is directly affected by the PJM/World load diversity in the model (more diversity results in a higher CBOT) and the availability of

assistance modeled in the World area. The PJM RTO benefits from firm capacity imports which are treated as internal capacity and are not part of the CBOT.

- **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 studies and the RRS need to be coordinated due to 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 PJM Manual 14 B, attachment C, pages 40-54 for details on the Load Deliverability tests and refer to the RPM website cited in the RPM section for specific analysis details and results (<http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx>).

- **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 3,500 MW used in the OASIS ATC postings.

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 II-3). The Summary of RRS results section includes further information.

Consistent with established Study modeling practice, the inclusion of planned generation was modeled based on commercial probabilities. A commercial probability factor was applied to all planned unit changes, adjusting the rating, as seen in the generation interconnection process queues. Table II-8 gives a summary of the generator additions and retirements as modeled in the 11 year RRS model.

Table II - 8: New and Retiring Generation within PJM RTO

Next 132 Months (2009-2019) – as of September 2009

Zone Name	Total Additions (MW)	Retirements (MW)	Total
AEC	429	0	429
AEP	1125	0	1125
Allegheny Energy (APS)	2535	0	2535
ATSI	0	0	0
BGE	626	0	626
ComEd	871	299	572
Dayton	26	0	26
DLCO	10	0	10
DomVP	2362	0	2362
DPL	74	179	-105
JCPL	496	0	496
ME	528	0	528
PECO	636	0	636
PEPCO	322	788	-466
PPL	935	0	935
PennElec	231	0	231
PSEG	466	355	111
UGI	0	44	-44
Grand Total	11,672	1,665	10,007

- **DR Factor**

For the 2013 / 2014 delivery year, the 0.957 DR Factor (PRISM # 5054) is similar to the 0.950 calculated last year. The DR Factor is an analytically derived measure of the reliability benefit of interruptible load and indicates that every 1 MW of DR is approximately worth 0.957 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 11.1% of the RTO's unrestricted forecasted peak.

The current level of load management in the RTO (2.1% of the forecasted peak) is well below the saturation level. Table II-9 shows the results of determining the saturation point for DR or the maximum amount of DR that adheres to the 10 interruption limit.

Table II - 9: CURTAIL Results - Maximum amount of Load Management

	PRISM Run Number	Delivery Year	Number of Load Management interruptions	Reliability Benefit LOLE
	5062	2013	1	2.588
	5062	2013	2	1.829
	5062	2013	3	1.184
	5062	2013	4	0.711
	5062	2013	5	0.423
	5062	2013	6	0.277
	5062	2013	7	0.216
	5062	2013	8	0.195
	5062	2013	9	0.189
Saturation when Benefit reaches 0.187	→ 5062	2013	10	0.187
	5062	2013	11	0.187
	5062	2013	12	0.187
	5062	2013	13	0.187
	5062	2013	14	0.187
	5062	2013	15	0.187
	5062	2013	16	0.187

DR = 11% of RTO Unrestricted Peak Load

- Load Management (LM) Credit**

The Load Management (LM) credit is the resource value applied to LSE Demand Resource/Interruptible Load for Reliability (ILR) 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. ILR has a limited duration, ending before the 2012 RPM market.

For all PJM reserve levels, the 52-week and the summer-only LM factor are the same. This finding justifies the granting of full-year credit for summer-only LM.

The present requirement of reserving ten LM interruptions for PJM's use for full credit was also verified. These analysis results are shown in Table II - 10.

Additional adhoc assessment work, using the General Electric's software, Multi Area Reliability Simulation (MARS), finds that the reliability benefit saturation point of LM is in the range of 4 to 12 interruptions. This assessment work has the advantage of using a more operations modeling approach, as ultimately the LM credit given is for use in operations. Moving this adhoc assessment work into the standard production process is an item to be considered by the RRAWG, once clear documentation and method details are presented to the WG.

Table II - 10: CURTAIL Results - Saturation point of Load Management

	PRISM Run Number	Delivery Year	Number of Load Management interruptions	Reliability Benefit LOLE
	5054	2013	1	0.2264
Saturation at 4 interruptions	5054	2013	2	0.1918
when Benefit	5054	2013	3	0.1872
reaches 0.1868	→ 5054	→ 2013	4	0.1868
	5054	2013	5	0.1868
	5054	2013	6	0.1868
	5054	2013	7	0.1868
	5054	2013	8	0.1868
	5054	2013	9	0.1868
	5054	2013	10	0.1868

- **DR 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 Forecasting and Analysis**, attachments A and B. 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 PJM Manual 18, dated 8/19/2009, (Pgs 28-34,82,93,104-106,108,113,137) for further details.

The DR Factor is an analytically derived value that cannot have a value greater than one. To derive the value of all demand resources, the load carrying capability (LCC) is determined by performing the PRISM calculations. The ratio of the load carrying capability to the total amount yields the DR Factor.

- **World Modeling**

This data is publicly available through the NERC Electric and Supply Database – and is a compilation of all the EIA-411 data submissions. This data is also reviewed by the PJM staff in the NERC Reliability Assessment Subcommittee (RAS) Long-Term Reliability Assessment report of October 2008. Per the May 13th study assumptions, approved at the May 20, 2009 PJM Planning Committee meeting, each of the individual regions was modeled at its required reserve requirement. Although both the larger previous world region modeled and the smaller adjacent region were assessed, the smaller region was shown to have similar characteristics and give identical LOLE results as the larger region. Therefore the world region immediately adjacent to the PJM RTO was deemed to be the most appropriate region to use in the study. Modeling the immediately adjacent region helps to address concerns for deliverability of outside world resources to the PJM RTO border.

There are risks involved with using public data and “engineering judgment” should be exercised in interpreting the results of the study and their sensitivity to these public data inputs. The PJM staff considered several options before moving to the new modeling of the regions at their required reserve levels. Only the New York, New England, and MISO (East and Central) regions have a firm target. For these regions, the latest reserve requirement was assumed for the delivery years of this study. For the TVA and VACAR sub regions of SERC, a reserve target of 15% was used; consistent with NERC’s modeling for assessment purposes. If required, assistance from neighboring systems should be available.

Figure II - 4: PJM and Outside World Regions - Summer Capacity Outlook

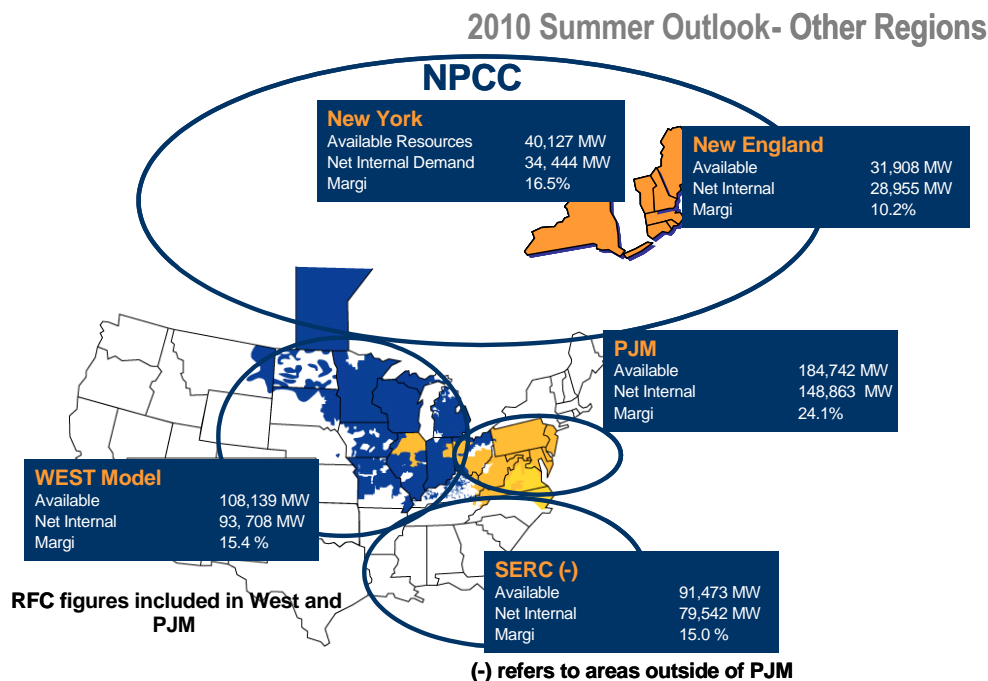


Figure II - 4 depicts the summer outlook for capacity within each of the "Outside World" regions that are adjacent to PJM. The West region includes the PJM zones: MAIN Other (The Gateway values are in this zone), and ECAR Other. The SERC minus region includes the World zones: TVA (Old), and VACAR Other. The assessment of the larger region included world sub regions MRO-US, SERC sub-regions Entergy (Old), and Southern, and the NPCC IESO control area (Ontario).

PJM's model requires a consistent set of detailed data, which is fundamentally based on the geographic area definition and hourly load data. In 2006 NERC regions changed these geographic area definitions, but without a mechanism to collect historical data for the new region boundaries. As such, the new geographic regions must be retrofitted back into the former geographic regions. Care is taken to not double count or discard data. All the data in the ES&D new boundary data is fit into the previous NERC regions.

Figure II - 5 depicts the previous regions (including the former ECAR, MAIN, and MAAC regions) while Figure II-6 depicts the current NERC boundaries. Until about 11 years worth of modeling data is collected, including hourly loads, for the new NERC boundaries, this translation effort is needed.

Figure II - 5: Previous NERC World Regions (Includes ECAR and MAIN)

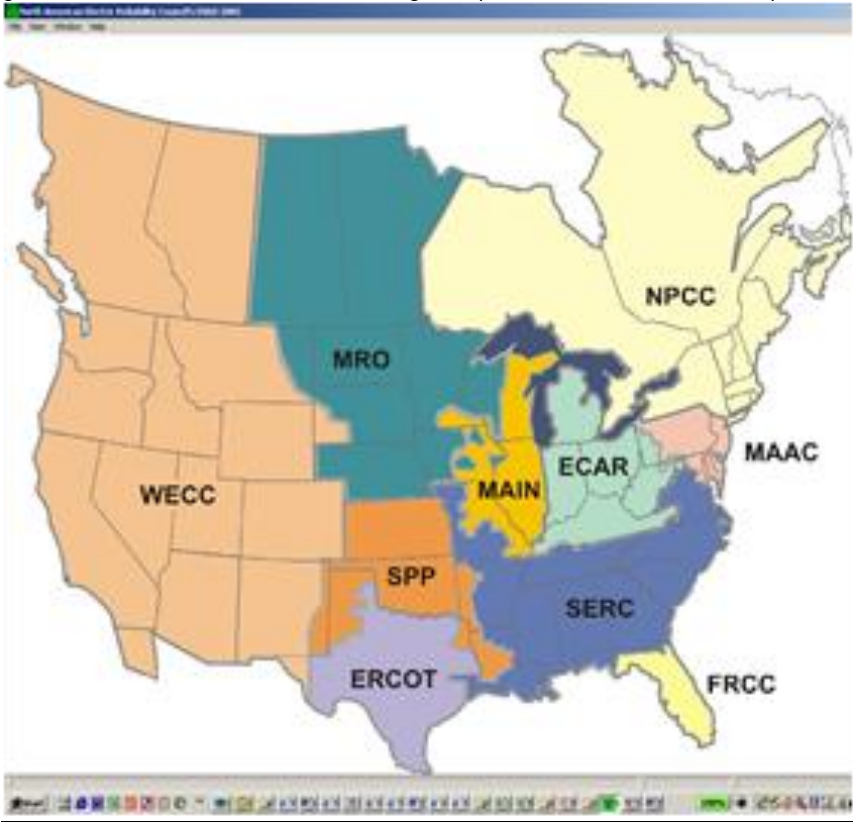


Figure II - 6: Current NERC defined World Regions (Includes RFC)

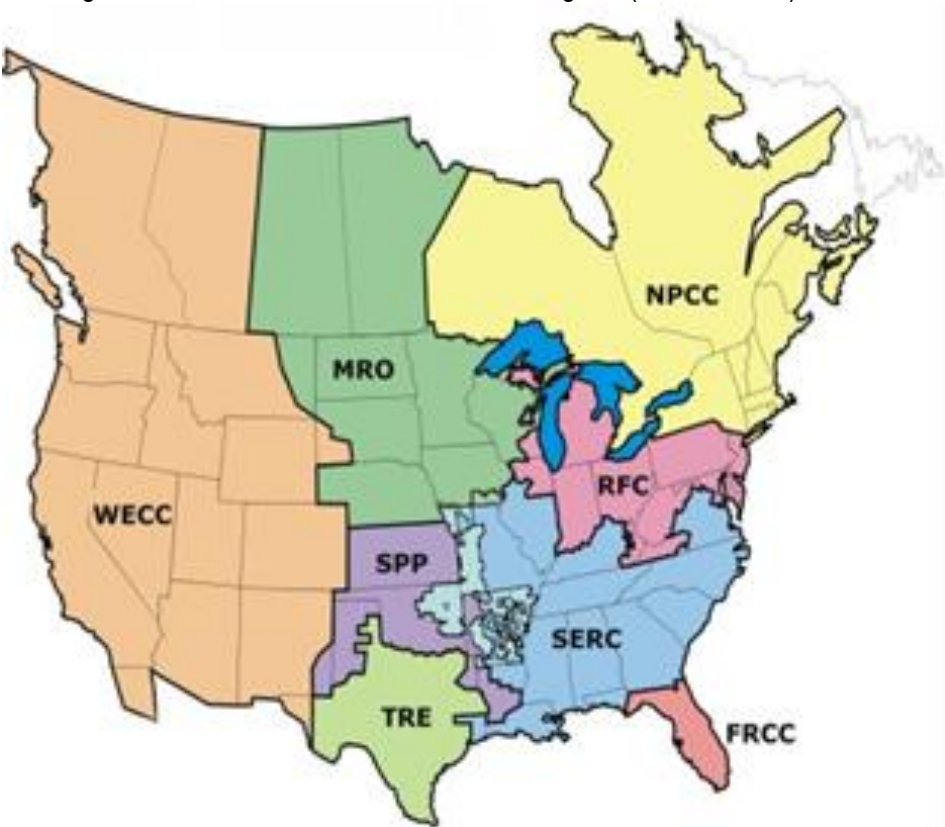


Figure II - 7: Relation between IRM and CBM when World reserves are 19.9%

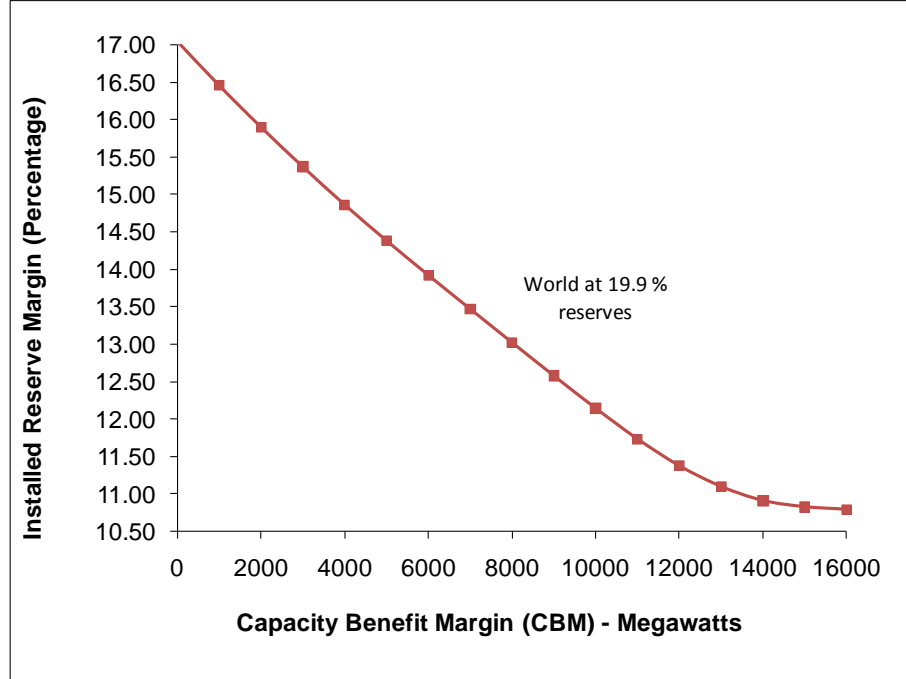


Figure I – 4 shows the valid range of the reserves to consider for the World region model. The maximum value is shown to be 19.89%. Figure II – 7 holds the World region at this maximum reserve value, varying the capacity benefit margin (CBM) up to 16,000 megawatts, in steps of 1,000 MW. This analysis is similar to what is shown in Figure I – 6 for the Base Case. Saturation of the value for CBM is at about 15,000 MW. This shows that having large reserve levels in the neighboring region, will increase the value of CBM yielding a higher Capacity Benefit Of Ties (CBOT) value, resulting in a lower PJM RTO IRM.

- **Expected Weekly Maximum (EWM) , and LOLE Weekly Values**

The Expected Weekly Maximum value (EWM) is the peak demand used by the PRISM program to calculate the loss of load expectation (LOLE). Both the 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 attain 99.9% of the risk within a few weeks of the summer period. It is these summer weeks that have the highest EWM values (Refer to “PJM Generation Adequacy Technical Methods” and PJM Manual 20 pages 19-23, for clarification and specifics of how the EWM is used and the resulting weekly LOLE).

From those weekly calculations, in Table II-11, the following pattern can be seen for the PJM RTO and World regions. For all weeks not shown, the weekly LOLE is zero (less than 10^{-11}). The pattern is different compared to the 2008 RRS, due to the modeling improvements that placed the World region peak in August. This indicates that the 2009 model has more diversity than the 2008 model.

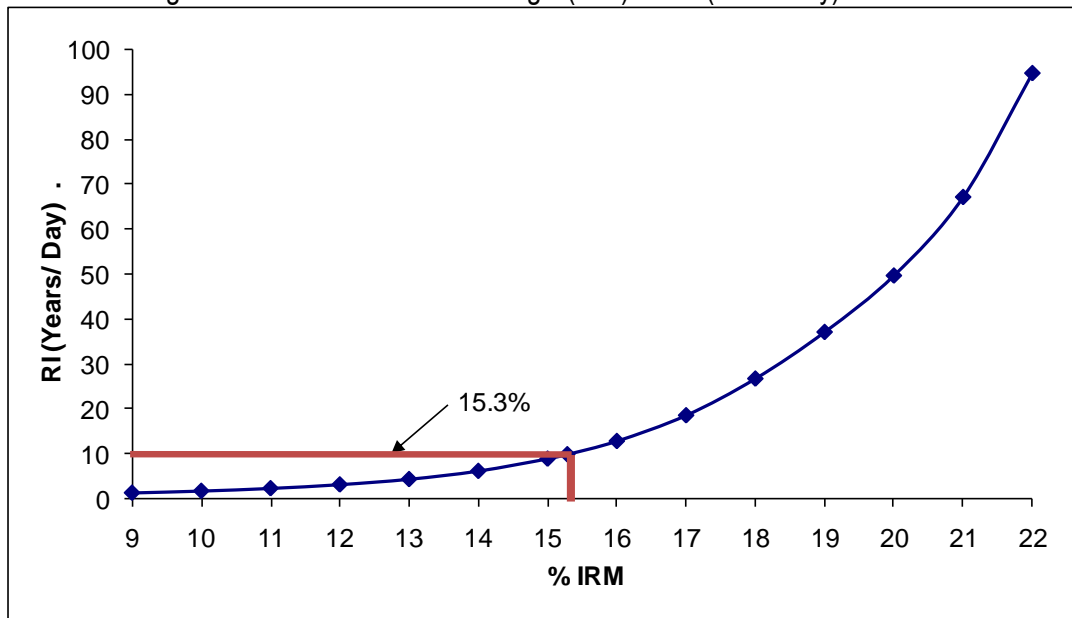
Table II - 11: Weekly LOLE values

	Run_Number	Year	Area	Area Week Number	weeklyLOLE
June	4989	2013	1	5	1.1794E-10
	4989	2013	1	6	1.3698E-06
	4989	2013	1	7	8.4771E-04
July	4989	2013	1	8	6.7265E-13
	4989	2013	1	9	1.3397E-05
	4989	2013	1	10	1.2952E-02
	4989	2013	1	11	5.0129E-04
	4989	2013	1	12	5.6664E-03
August	4989	2013	1	13	1.5664E-05
	4989	2013	1	14	4.3171E-06
	4989	2013	1	15	2.7771E-15
	4989	2013	2	5	1.7119E-15
	4989	2013	2	6	2.1630E-07
	4989	2013	2	7	1.6103E-04
	4989	2013	2	8	7.1699E-16
	4989	2013	2	9	3.1911E-06
	4989	2013	2	10	2.0085E-03
	4989	2013	2	11	1.9522E-04
	4989	2013	2	12	1.7458E-02
	4989	2013	2	13	1.6186E-04
	4989	2013	2	14	1.6092E-08
4989	2013	2	15	9.1090E-10	

Figure II-8 shows how the Reliability Index (RI) varies with installed reserve margin, for the PJM RTO area. The analysis is a two area study, manually varying the PJM RTO reserve levels while keeping the World at a 1 day in 10 years LOLE reserve level.

From this figure it is apparent that a reserve level of about 15.3% yields a loss of load event once every ten years. The relationship of the reserve level in the PJM RTO to the forecast expectation for outage events is shown in Figure II-8.

Figure II - 8: Installed Reserve Margin (IRM) vs. RI (Years/Day)



- **Standard BAL-502-RFC-02 clarification items**

To provide clarity concerning several items in the Standard BAL-502-RFC-02 requirement section R1 titled “The planning Coordinator shall perform and document a Resource Adequacy analysis annually”, the following is supplied:

R1.3.3.1 The criteria for including planned Transmission facilities: This is given in the RTEP assessments. The RTEP is overseen by the Transmission Expansion Advisory Committee (TEAC), a stakeholder group with the PJM committee structures. The Planning Committee also can establish and recommend appropriate criteria to be used for transmission facilities. See the Transmission System Considerations section for further details. The Criteria for inclusion of planned transmission facilities is given in the meeting minutes and presentations of the TEAC, PC, and the PJM manuals 14 A - E. The RRS is closely coordinated and integrated with these RTEP analyses, decisions by the PC and TEAC as all are part of the coordinated PJM Planning division efforts.

R1.4 Availability and Deliverability of fuel: An adhoc assessment, completed in July 2003, titled “Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector” addresses this topic. The Executive Summary of this report, pages v – xviii, provides the results of this assessment. This is a confidential report.

R1.4 Common Mode Outages that affect resource availability: The report, “Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector”, address this issue in part. In general, these types of outages are considered by discrete modeling, with most outages assumed to be independent events. The assumption of independent outage events applies to both the resource and load models and avoids any need for a matrix of covariance states. The solution techniques for including a covariance matrix are considered not practically possible. The Industry standard in the known solution methods is to make the assumption of independence for all outage events, treating any common mode outages by discrete modeling techniques. For example, for a “run of river” issue, more planned outages are modeled over the critical summer peak weeks due to several units using the same water source(same river). However, care should be used in drawing conclusions from the assumption for independence in the 21 point daily peak calculations. For example, there are steps involved in developing the load model parameters that do incorporate a correlation, particularly for the adjusted mean and standard deviations for each week. From a conceptual perspective this allows similar relationships, as those that exist in the development of the load forecast values, which allows the model to establish relationships between the weeks, such as magnitude ranking of weeks and the adjustment due to the load forecast monthly shape. The assumption of independence, understanding all the associated complexities, is implemented in the RRS modeling and calculation methods, which includes modeling of appropriate discrete common mode outage scenarios.

In addition, this report’s assessment of the Winter weekly reserve target is meant to address a common mode failure experienced in the Mid-Atlantic region, when several generating units experienced outages due to a region wide ice storm in the Winter of 1994.

R1.4 Environmental or regulatory restrictions of resource availability: In the Generation Forecasting section, it is discussed that the resource performance characteristics are primarily modeled per the PJM manuals, 21, 22, and 23. In the eGADS reporting, there is consideration and methods to account for both environmental and regulatory restrictions. The RRS modeling of resources uses performance statistics, directly from these reported events. Both discrete modeling techniques and sensitivity analysis is performed to gain insights about impacts concerning environmental or regulatory restrictions. In the modeling of resources this can reduce the rating for a given unit, impacted by this type of restriction. The RRS model is coordinated with the Capacity Injection Rights (CIR) for each unit, which can be affected by these restrictions.

R1.4 Any other demand response programs not included in the load forecast characteristics: All load modeled and its characteristics are part of R1.3.1, shown in Appendix C. There are no other load response programs in the RRS model.

R1.4 Market resources not committed to serving load: In general, all resources modeled have capacity injection rights, are part of the EIA-411 filing and coordinated with the RTEP Load deliverability tests, documented in PJM Manual 14 B, attachment C. In addition, coordination with the RPM capacity market modeling is performed. An example of this is allowing the modeling of Behind-The-Meter (BTM) units, per the modeling assumptions. See Appendix A for further details regarding BTM modeling (See Manual M19, page 19 ; Manual 14D, Appendix A).

R1.5 Transmission maintenance outage schedules: Discussed in the Transmission System Considerations section is the coordination with the RTEP process and procedures. This issue is specifically addressed in the load deliverability tests, as discussed in this section. The CETO analyze is closely coordinated with the RRS modeling and report, and is fundamental to addressing and verifying the assumption that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load.

- **RPM Market**

The Reliability Pricing Model (RPM) is the PJM's forward capacity market program that was implemented on June 1, 2007. The RPM requires the following input values derived from the RRS: IRM, FPR, DR Factor and CETO.

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-and-operations/rpm/rpm-auction-user-info.aspx>

- **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 PRISM model adjusts the load level until it finds the solution load that just meets the one day in ten years reliability standard. The IRM is calculated based on this solution load, for the peak day (which is also the peak week), using the installed capacity for that week in the numerator and this solution load in the denominator.

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 PJM RTO pool-wide EFORD (equivalent demand forced outage rate). The FPR is defined by the following equation:

Equation II - 2: Calculation of Forecast Pool Requirement (FPR)

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

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 an allocation of RTO resources procured in the RPM auction plus ILR forecast obligation (the ILR forecast ends at the 2012 market). 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.

With RPM now in place, PJM will continue to review the RRS assumptions and consider appropriate changes to address the reduction in uncertainty. However, a consistent level of the historic Engineering Judgment used, as documented in the RRAWG meetings, will continue. These historic engineering judgments are documented in Appendix H.

Operations Related Assessments

- **Winter Weekly Reserve Target Analysis**

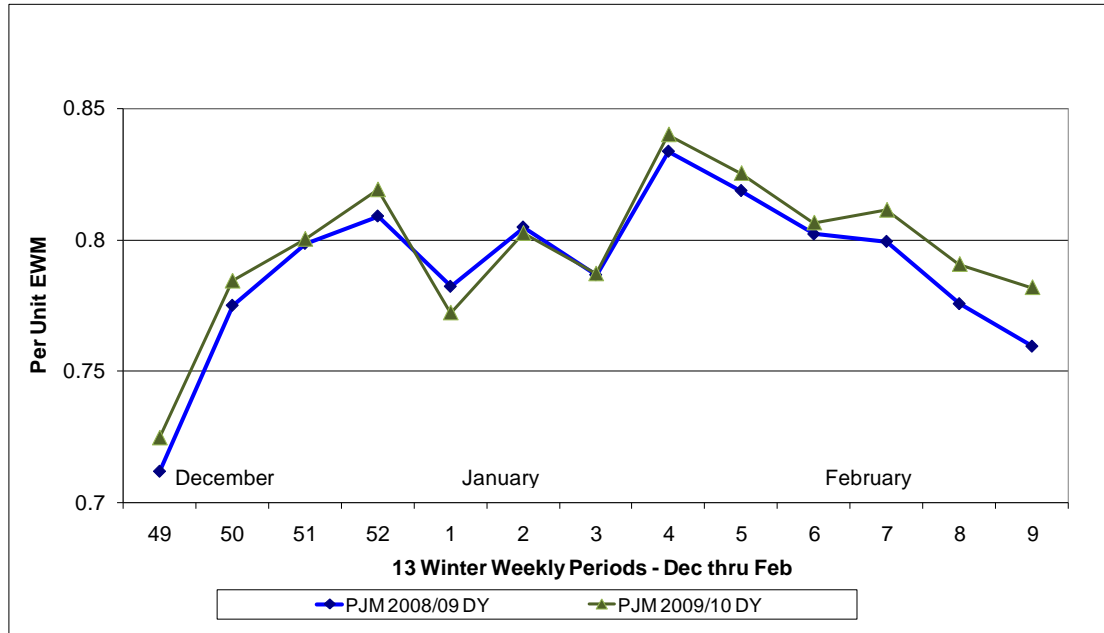
PJM Staff recommend 25% as the minimum winter reserve target to be applied to the PJM RTO for the upcoming 2009 / 2010 winter period. The recommended value is required to be an integer value, due to computer application requirements. This value represents a decrease from the current margin of 26%. The 25% target is based on unit summer ratings and is expressed as a percentage of the forecasted weekly peak load.

Table II-12 shows the results of the MARS analysis for the 2009 / 2010 winter period. The average reserve level over the 13 week winter period is 24.5%. This margin is lower than the 25.4% calculated in last year's study due to a slightly flatter PJM load shape over the winter period (see Figure II-9). A flatter load shape distributes the winter loss of load risk over a greater number of weeks and allows for a lower weekly average reserve margin. Based on this analysis, PJM Planning staff believes that maintaining a minimum 25 % reserve target for the 2009 / 2010 13-week winter operating period ensures that the actual winter loss of load risk is consistent with that modeled in the 2009 PJM RRS.

With this recommendation, the PJM Operations Department would coordinate generator maintenance scheduling over the winter period to seek to preserve a 25% 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.**

Endorsement of the 25% Winter Weekly Reserve Target from the PJM Planning Committee (PJM-PC) will be requested at the October 22, 2009 meeting. The recommendation on this item will be forwarded to the PJM Operating Committee (PJM -OC) and the PJM Operations Staff responsible for generating unit planned maintenance scheduling.

Figure II - 9: Winter Weekly Load Shape comparison - 2008 and 2009 RRS



In Figure II – 9, the 2008 / 09 DY shape is from the 2008 RRS while the 2009 / 2010 DY is from the 2009 RRS model.

Table II - 12: Winter Weekly Reserve Target

Month	Calendar Week	% Weekly Reserves level for 1D/10 YR	LOLE (3rd Margin State)
December	49	19.67	9.09E-05
	50	19.63	8.27E-05
	51	22.23	0.00E+00
	52	29.62	0.00E+00
January	1	24.37	0.00E+00
	2	19.70	1.12E-04
	3	26.71	0.00E+00
	4	28.06	0.00E+00
	5	32.75	0.00E+00
February	6	20.08	1.07E-04
	7	24.52	0.00E+00
	8	28.90	0.00E+00
	9	22.44	0.00E+00
Average Weekly Reserves		24.5	

There are six Emergency Operating Procedure (EOP) levels available to report LOLE: 1) Operating reserves, 2) Load Management resources, 3) 30 minute reserves, 4) Voltage reduction, 5) 10 minute reserves, and 6) Appeals for public curtailment. The reported LOLE values are before any Voltage reductions, but do include load management curtailments. Reported values are after implementation of a given EOP level, the 30 minute reserve level.

Reserve Requirement Assumptions Working Group (RRAWG) activities

1. Planning Committee requests to RRAWG

The following is a list of issues identified by the Planning Committee (PC) to be investigated by the Reserve Requirement Assumptions Working Group (RRAWG) for establishing the 2009 Reserve Requirement Study assumptions and assessment work. These issues came out of discussions at the September 2008 to December 2008 PC meetings. The status of the RRAWG's investigation efforts for each issue follows.

- **Sensitivity of the IRM to the number of historical years used in the development of the load model**

The study assumptions were changed to perform an assessment up front, requiring the RRAWG to make a recommendation to the PC at its July meeting. The PC approved this recommended modeling parameter at its July meeting. The model's sensitivity to this assumption results from the manner in which ordered weeks are assigned to calendar weeks and adjusted to match the monthly load forecast. The assignment and adjustment approach determines the relative timing of PJM and World peaks and, as a result, the PJM-World diversity. While the sensitivity of the IRM to the choice of load model period remains unchanged, the new method developed and shown in Appendix E (approved at the July PC meeting) mitigates the subjective nature for this modeling choice.

- **Use of 21 points in the load distribution and the possible need for greater granularity**

Assessment work indicates that this issue will be impacted by other proposed modeling changes, and should be addressed in 2010.

- **Use of a normal vs. non-normal load distribution**

For the 2009 RRS, several other distribution shapes (truncated normal distributions) were evaluated as alternatives to the standard normal ("bell-shaped") distribution. The evaluations compared the ability of various alternative distributions to accurately match the anticipated distribution of future peak loads, and especially extreme outcomes, based on historical peak loads and also modeling of extreme peak loads based on weather data. A decision was made to not use these alternative distribution shapes for the 2009 RRS. This was identified as important work going forward but was seen as at a preliminary stage needing more comprehensive assessments before a recommendation for a change can be made.

- **Examination of World reserve levels and deliverability of those reserves to PJM**

The study assumptions were changed to use MARS modeling to address this item. The world forecast reserve levels will be placed at levels established by neighboring ISOs or equivalent in the 2009 Study.

- **Modeling of intra-World load diversity**

This is part of the study assumption changes and is part of the 2009 RRS, per issue one, for the time period used in the load model. This investigation has identified an improvement for modeling the forecast coincident peak load for the World region. The improvement for modeling the forecast coincident peak load for the World region was made to the PC in July. The PC approved this modeling with the improved modeling for intra-World load diversity implemented in the 2009 RRS.

- **Derating of summer capacity to account for extreme ambient weather conditions**

Based on PJM Operations, the 2,500 MWs derate for the summer capacity is still valid. However, PJM is gaining a population of data for assessment based on having an adequate sample size population. It is anticipated that at least eight years of data is necessary to complete this assessment, with three years of data gathered to date. The target of needing eight years is from assessment of the operations data involved, combined with modeling experience and statistical assessment techniques used by the PJM staff.

- **Possible use of MARS as a complement to PRISM**

A Multi-Area Reliability Simulation (MARS) model was developed for Inter-regional study, and is planned to be used for adhoc assessment work. PJM is developing a MARS model to compare the individual 10 subzones of the world IRM requirements to the composite world IRM. The preliminary modeling was completed for the 2009 RRS but assessment work is pending, and was determined to be of interest to the RRAWG but not a priority to complete for the 2009 RRS.

- **Treatment of calculated vs. recommended IRM**

This continues to be a parking lot item for the RRAWG, with Appendix H documenting the specifics concerning this issue. The recommended values for the 2009 RRS are the Base Case calculated values.

The Reserve Requirement Assumptions Working Group (RRAWG), in cooperation with the PJM staff, has discussed these items over the past twelve months, performing assessment and investigation work into each identified issue. The above summary for each issue indicates the current results and direction for a complete investigation identified by the RRAWG.

To start this investigation, the PJM Staff developed a technical white paper describing the modeling issues that are involved in the modeling of the surrounding world region. This document is posted on the PJM web site at: <http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx>

Further details are shown in the posted items for several of the RRAWG meetings (March 2009 – September 2009). Please refer to Agenda item number 5 from the April 3rd, 2009 RRAWG meeting (<http://www.pjm.com/committees-and-groups/working-groups/rrawg.aspx#1>). The endorsed 2009 Reserve Requirement study assumptions were guided by the investigation into these issues.

2. RRAWG Investigation Issues

- **Identified in the May13th 2009 Study assumptions letter**

- **FPR's reflection of 2,500 MW derate to maintain consistency with RPM and Operations.**

- This investigation was delayed, noting that involvement with both Markets and Operations staff might be warranted to fully assess this issue. The focus are procedures in the non planning divisions that allow for unit outages and events (derating) that do not need to be recorded in the eGADS system.

- **Investigation of the 50/50 annual peak load value determination.**

- This investigation resulted in several presentations and technical assessment discussions at the WG meetings and in the RRAWG SharePoint site. Information and clarifying text was added to the 2009 RRS to address this (See page 12, 18-19). However a consensus was not achieved with a minority position proposed on this issue.

- **Possible use of Non-Normal load distributions.**

- Several truncated normal distributions were assessed, discussed, and considered for modeling in the 2009 RRS. However, the WG believes a more robust effort is required before recommending any changes. Work continues to bring 52 different distributions, into the PRISM model to perform analysis runs for the PJM RTO. The World model would probably continue to use the standard normal distribution. This is an on-going effort, targeted for assessment completion in 2010. Any recommendation for changes, and its implementation would follow.

- **Identified in the RRAWG parking lot items**

- **Considerations used to move from the calculated IRM value to the endorsed IRM value**

The 2009 RRS recommendation is the calculated base case values, indicating that previous uncertainties are being reduced. Assessment and evaluation of uncertainties related to the RPM Market to answer questions such as:

How do they affect reliability parameters?

How can identified uncertainties be mitigated in the process to determine the recommended reliability parameters?

- **The modeling of all world regions into 1 area, implying helping each other first (prior to PJM)**

This might require MARS modeling and assessments, which was identified on page 8 of the May 13th 2009 study assumptions. Once a comprehensive MARS model can be developed, evaluation of a method to assess this issue might assist incorporation of a new method into the established modeling practices. This effort has not begun.

- **MARS sensitivity runs for correlating with PRISM**

To improve the Load management credit evaluation, MARS was used to consider a more operation modeling approach. PJM staff needs to document the current phase of this effort so that the WG can review and evaluate.

- **Generator outages at critical peak demand periods**

The effort would assess unit availability at these periods, identifying and developing summaries for any patterns observed. The RRAWG would also review and comment on patterns seen for the ambient temperature durations seen in the 2008 and 2009 summer periods. This effort has not begun.

- **Assess World model to reflect intra hour PJM-World diversity**

Consider historic PJM RTO peak days and timing of World peaks, on those PJM peak days. Assess the historic hourly loads quantifying any observable patterns in the World peaks as they related to the PJM RTO peak. Develop summaries and any identified modeling changes for the RRAWG to review and consider. This effort has not begun.

Glossary

AEP

American Electric Power (AEP) is an Ohio-based company and control area within the RFC that was integrated into the PJM footprint on October 1, 2004. AEP is located in the middle of the PJM RTO region. (<http://www.aep.com/>)

Allegheny Energy

Allegheny Energy, previously called the Allegheny Power System (APS), is a Pennsylvania-based control area within RFC that was integrated into the PJM footprint on April 1, 2002. APS is adjacent to the western portion of the PJM Mid-Atlantic (PJMMA) region. (<http://www.alleghenyenergy.com/>)

American Transmission System Incorporated (ATSI)

American Transmission System Incorporated is a subsidiary of the FirstEnergy Corporation. The control areas within this system include four major companies; Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company and Pennsylvania Power Company. ATSI has Ohio and Pennsylvania-based control areas within RFC that has announced intentions to integrate into the PJM footprint on June 1, 2011. ATSI is adjacent to the western portion of the PJM Mid-Atlantic (PJMMA) region. (http://www.firstenergycorp.com/feconnect/American_Transmission_Systems_ATSI/index.html)

Available Transfer Capability (ATC)

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

BPS

The Bulk Power System (BPS) refers to all generating facilities, bulk power reactive facilities, and high voltage transmission, substation and switching facilities. The BPS also includes the underlying lower voltage facilities that affect the capability and reliability of the generating and high voltage facilities in the PJM Control Area. As defined by the Regional Reliability Organization, the BPS is the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

BRC

The PJM Board of Managers' Board Reliability Committee (BRC) is made up of PJM board members who conduct activities to review and assess reliability issues to bring to the full board of managers. The BRC is one of the groups that review the RRS report in the process to establish a FPR and DR Factor.

Capacity

The amount of electric power (measured in megawatts) that can be delivered to both firm energy to load located electrically within the PJM Interconnection and firm energy to the border of the PJM Control Area for receipt by others. Installed capacity and Unforced capacity are related measures of this quantity.

Capacity Benefit Margin (CBM)

Capacity Benefit Margin (CBM), expressed in megawatts, is the amount of import capability that is reserved for the emergency import of power to help meet LSE load demands during peak conditions and is excluded from all other firm uses.

Capacity Emergency Transfer Objective (CETO)

The import capability required by a sub area of PJM to satisfy the RFC's resource adequacy requirement of loss of load expectation. This assessment is done in a coordinated and consistent manner with the annual RRS, but is an independent evaluation. The CETO value is compared to the Capacity Emergency Transfer Limit (CETL) which represents the sub area's actual import capability as determined from power flow studies. The sub area satisfies the criteria if its CETL is equal to or exceeds its CETO. PJM's CETO/CETL analysis is typically part of the PJM's deliverability demonstration. See Manual 20, and Manual 14B, attachment C for details.

ComEd

Commonwealth Edison (ComEd) is an Illinois-based control area within the RFC that was integrated into the PJM footprint on May 1, 2004. ComEd is located on the western edge of the PJM RTO region.

(<http://www.exeloncorp.com/>)

Control Area (CA)

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

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

Dayton

Dayton Power and Light (Dayton), is an Ohio-based control area within RFC that was integrated into the PJM footprint on October 1, 2004. The Dayton control area is adjacent to the western portion of the AEP region.

(<http://www.waytogo.com/>)

Delivery Year (DY)

The Delivery Year (DY) is the twelve-month period beginning on June 1 and extending through May 31 of the following year. As changing conditions may warrant, the Planning Committee may recommend other Delivery Year periods to the PJM Board of Managers. In prior studies, the DY was formerly referred to as the "Planning Period".

Deliverability

Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver generation capacity from generation facilities to wherever it is needed to ensure, only, that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) Generation Deliverability; and (2) Load Deliverability.

Demand Resource (DR)

A resource with the capability to provide a reduction in demand. DRs are a component of PJM's Load Management (LM) program. The DR is bid into the RPM Base Residual Auction (BRA). See Load Management (LM) and ILR.

Demand Resource (DR) Factor

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

Demand

The rate at which electrical energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand is equal to load when integrated over a given period of time. See Load.

Diversity

Diversity is the difference of the sum of the individual maximum demands of the various subdivisions of a system, or part of a system, to the total connected load on the system, or part of the system, under consideration. The two regions modeled in the RRS are the PJM RTO and the surrounding World region. If the model has peak demand periods occurring at the same time, for both regions (PJM RTO and World), there is little or no diversity. The peak demand period values are determined as the Expected Weekly Maximum (EWM). A measure of diversity can be the amount of MWs that account for the difference between a Transmission Owner zone's forecasted peak load at the time of its own peak and the coincident peak load of PJM at the time of PJM peak.

DLCO

Duquesne Light Company (DLCO) is a Pennsylvania-based control area within the RFC that was integrated into the PJM footprint on January 1, 2005. The DLCO control area is adjacent to the western portion of the Allegheny Energy region. (<http://www.duquesnelight.com/>)

DomVP

Dominion Virginia Power (DomVP) is a Virginia-based control area within SERC that was integrated into the PJM RTO on May 1, 2005. The DomVP control area is adjacent to the southern portion of the Allegheny Energy region. (<http://www.dom.com/>)

Eastern Interconnection

The Eastern Interconnection refers to the bulk power systems in the eastern portion of North America. The area of operation of these systems is bounded on the east by the Atlantic Ocean, on the west by the Rocky Mountains, on the south by the Gulf of Mexico and Texas, and includes the Canadian provinces of Quebec, Ontario, Manitoba and Saskatchewan. The Eastern Interconnection is one of the three major interconnections within the NERC and includes the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), Southeast Reliability Corporation (SERC) and the Southwest Power Pool, Inc. (SPP).

EEFORd

The Effective Equivalent Demand Forced Outage Rate (EEFORd) is used for reliability and reserve margin calculations. For each generating unit, this outage rate is the sum of the EFORd plus $\frac{1}{4}$ of the equivalent maintenance outage factor.

EFORd

The Equivalent Demand Forced Outage Rate (EFORd) is the portion of time that a generating unit is in demand, but is unavailable due to a forced outage.

eGADS

eGADS is PJM's Web-based Generator Availability Data System where generation data is collected to track and project unit unavailability – as required for PJM adequacy and capacity market calculations. eGADS is based on the NERC GADS data reporting requirements, which in turn are based on IEEE Standard 762.

EICS

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

EMOF

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

EWM

The Expected Weekly Maximum (EWM) is the weekly peak load corresponding to the 50/50 load forecast, typically based on a sample of 5 weekday peaks. The EWM parameter is used in the PJM PRISM program. Also see Appendix F, reference eight, PJM Manual 20 pages 19-23.

FEF

The Forecast Error Factor (FEF) is a value that can be entered in the PRISM program per Delivery Year to indicate the percent increase of uncertainty within the forecasted peak loads. As the planning horizon is lengthened, the FEF generally increases 0.5% per year.

FERC

The Federal Energy Regulatory Commission (FERC) is the federal agency responsible with overseeing and regulating the wholesale electric market within the US. (<http://www.ferc.gov/>)

Forced Outage

Forced outages occur when a generating unit is forcibly removed from service, due to either: 1) availability of a generating unit, transmission line, or other facility for emergency reasons; or 2) a condition in which the equipment is unavailable.

Forced Outage Rate (FOR)

The Forced Outage Rate (FOR) is a statistical measurement as a percentage of unavailability for generating units and recorded in the GADS. FOR indicates the likelihood a unit is unavailable due to forced outage events over the total time considered. It is important to note that there is no attempt to separate out forced outage events when there is no demand for the unit to operate.

Forecast Peak Load

Expected peak demand (Load) representing an hourly integrated total in megawatts, measured over a given time interval (typically a day, month, season, or delivery year). This expected demand is a median demand value indicating there is a 50 % probability actual demand will be above or below the expected peak.

Forecast Pool Requirement (FPR)

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

GEBGE

GEBGE is a resource adequacy calculation program, used to calculate daily LOLE that was jointly developed in the 1960s/1970s by staff at General Electric (GE) and Baltimore Gas and Electric (BGE). The GEBGE program has since been largely superseded and replaced by PJM’s PRISM in the conduct and evaluation of IRM studies at PJM. (See PRISM.) GEBGE does however contain three support modules that are still used in PJM reliability evaluations: MEGAWATT, CAPMOD and CURTAIL.

Generating Availability Data System (GADS)

GADS is a NERC-based computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Outage Rate Program (GORP)

GORP is a computer program maintained by the PJM Planning staff that uses GADS data to calculate outage rates and other statistics.

Generator Forced/Unplanned Outage

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

Generator Maintenance Outage

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

Generator Planned Outage

A generator planned outage is the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair – with the approval of the PJM OI.

Good Utility Practice

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

ICAP

Installed capacity (ICAP) commonly refers to “iron in the ground” – or rated capacity of a generation unit prior to derating or other performance adjustments.

IESO

The Independent Electricity System Operator (IESO) is the nonprofit Regional Transmission Organization (RTO) responsible for managing Ontario's bulk electricity power system and operating the wholesale market. One of the five main control areas within the NPCC. (<http://www.ieso.ca/>)

ILR

Interruptible Load for Reliability (ILR) is a component of PJM's Load Management (LM) program. In the RPM program, just prior to the final incremental auction, load with verifiable existing interruptible capability may declare themselves an Interruptible Load for Reliability (ILR). This component will end for the 2012 delivery year RPM market place. See Load Management and Demand Resources.

Import Capability

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

IRM

The Installed Reserve Margin (IRM) is the percent of aggregate generating unit capability above the forecasted peak load that is required for adherence to meet a given adequacy level. IRM is expressed in units of installed capacity (ICAP). The PJM IRM is the level of installed reserves needed to meet the Reliability First Corporation criteria for a loss of load expectation (LOLE) of one day, on average, every 10 years

ISO-NE

The Independent System Operator of New England (ISO-NE) is an independent system operator (ISO) and not-for-profit corporation responsible for reliably operating New England's bulk electric power generation, transmission system and wholesale electricity markets. Created in 1997 and with headquarters in Holyoke, MA, the ISO-NE control extends throughout New England including Maine, New Hampshire, Vermont, Rhode Island, Massachusetts and Connecticut. (<http://www.iso-ne.com/>)

LDA

Locational Deliverability Areas (LDAs) are zones that comprise the PJM RTO as defined in the RAA schedule 10.1 and can be an individual zone, a combination of two or more zones, or a portion of a zone. There are currently 23 LDAs within the PJM footprint.

Load

Integrated hourly electrical demand, measured as generation net of interchange. Loads generally can be reported and verified to the tenth of a megawatt (0.1 MW) for this report.

Load Analysis Subcommittee (LAS)

A PJM subcommittee, reporting to the Planning Committee that provides input to PJM on load related issues.

Load Management (LM)

Load Management, previously referred to as Active Load Management (ALM), applies to interruptible customers whose load can be interrupted at the request of PJM. Such a request is considered an emergency action and is implemented prior to a voltage reduction. This includes both Demand Resources (DR) and Interruptible Load for Reliability (ILR).

LCC

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

LOLE

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

Let's consider the difference between probability and expectation. Mathematical expectation [E (x)] for a model is based on a given probability for each outcome. An equation for the calculation of expectation is:

$$E(x) = P_1X_1 + P_2X_2 + P_3X_3 + \dots + P_nX_n$$

$$E(x) = \sum_{i=1}^n P_iX_i$$

Where

P = probability of outcome

X = defined outcome (Example: on or off)

The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor. There is no implication that it is the most frequently occurring value or the most highly probable, in fact it might not even be possible. The expected value is not something that is "expected" in the ordinary sense but is actually the long term average as the number of terms (trials) increase to infinity.¹

For generation Adequacy the focus of these calculations, the LOLE, can be expressed in terms of probability as:

$$LOLE = \sum_{i=1}^{260} LOLE_i = \sum_{i=1}^{260} \sum_{j=1}^{21} LOLP_j$$

Where

$LOLE_i$ = Loss of Load Expectation for daily peak distribution

$LOLP_j$ = Loss of Load Probability for two state outcome, generation value is less than demand or not.

260 = Number of weekdays in a delivery year

Daily peak = The integrated hourly average peak, or Demand.

The LOLE_i for daily peak is calculated or convolved as:

$$LOLE_i = \sum_{j=1}^{21} LOLP_j = \sum_{j=1}^{21} PD_j(XD_j) * PG_j(XG_j)$$

Where

$PG(XG)$ = Probability of generation at 1st generation value(outcome) less than demand

$PD(XD)$ = Probability at given Demand value(outcome)

21 = Discrete Distribution values to assess all likely values of Demand

Demand = The integrated hourly average peak, or Daily peak.

¹ “Power System Reliability Evaluation”, Roy Billinton, 1970, Gordon and Breach, Science Publishers for further details on calculation methods.

LOLP

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

MARS

The General Electric Multi-Area Reliability Simulation (MARS) model is a probabilistic analysis program using sequential Monte Carlo simulation to analyze the resource adequacy for multiple areas. MARS is used by ISOs, RTOs, and other organizations to conduct multi-area reliability simulations.

MC

The PJM Members Committee (MC) reviews and decides upon all major changes and initiatives proposed by committees and user groups. The MC is the lead standing committee and reports to the PJM Board of Managers.

MIC

The PJM Market Implementation Committee (MIC) initiates and develops proposals to advance and promote competitive wholesale electricity markets in the PJM region for consideration by the Electricity Markets Committee. Along with the OC and the PC, the MIC reports to the MRC.

MISO

The Midwest Independent System Operator (MISO) is an independent, nonprofit regional transmission (RTO) organization that supports the constant availability of electricity in 15 U.S. states throughout the Midwestern U.S. and the Canadian province of Manitoba. The Midwest ISO was approved as the nation's first regional transmission organization (RTO) in 2001. The organization is headquartered in Carmel, Indiana with operations centers in Carmel and St. Paul, Minnesota. (<http://www.midwestiso.org/home>)

MRC

The PJM Markets and Reliability Committee (MRC) are responsible for ensuring the continuing viability and fairness of the PJM markets. The MRC also is responsible for ensuring reliable operation and planning of the PJM system. The MRC reports to the MC.

MRO

The Midwest Reliability Organization (MRO) is one of eight Regional Reliability Councils that comprise the North American Electric Reliability Council (NERC). The MRO is a voluntary association committed to safeguarding reliability of the electric power system in the north central region of North America. The MRO region is operated in the states of Wisconsin, Minnesota, Iowa, North Dakota, South Dakota, Nebraska, Montana and Canadian provinces of Saskatchewan and Manitoba. (<http://www.midwestreliability.org/>)

NERC

The North American Electric Reliability Corporation (NERC) is a super-regional electric reliability organization whose mission is to ensure the reliability of the bulk power system in North America. Headquartered in Princeton, NJ, NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada. (<http://www.nerc.com/>)

NPCC

The Northeast Power Coordinating Council (NPCC) is a regional electric reliability organization within NERC that is responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the Northeast region comprising parts or all of: New York, Maine, Vermont, New Hampshire, Connecticut, Rhode Island, Massachusetts, and the Canadian provinces of Ontario, Quebec, Nova Scotia, New Brunswick, and Prince Edward Island. (<http://www.npcc.org/>)

NYISO

The New York Independent System Operator (NYISO) operates New York State's bulk electricity grid, administers the state's wholesale electricity markets, and provides comprehensive reliability planning for the state's bulk electricity system. A not-for-profit corporation, the NYISO began operating in 1999. The NYISO is headquartered in Rensselaer, NY with an operation center in Albany, NY. (<http://www.nyiso.com/public/index.jsp>)

NYSRC

The New York State Reliability Council (NYSRC) a nonprofit, sub-regional electric reliability organization (ERO) within the NPCC. Working in conjunction with the NYISO, the NYSRC's mission is to promote and preserve the reliability of electric service on the New York Control Area (NYCA) by developing, maintaining and updating reliability rules which shall be complied with by the New York Independent System Operator (NYISO). (<http://www.nysrc.org/>)

OC

The PJM Operating Committee (OC) reviews system operations from season to season, identifying emerging demand, supply and operating issues. Along with the MIC and the PC, the OC reports to the MRC.

OI

The Office of the Interconnection (OI), typically referring to the PJM Operations staff.

OMC

Outside Management Control (OMC) events are a category of data events recorded in the eGADS data. This data category was implemented per the IEEE Standard 762 titled, "*IEEE Standard for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*", approved September 15, 2006, available in March

2007. PJM staff, consistent with NERC staff efforts, adopted this new reporting category, starting in January of 2006. Annex D of the IEEE Standard 762 gives examples for these event types including; Substation failure, transmission operation error, Acts of terrorism, Acts of nature such as tornadoes and ice storms, special environmental limitations, and labor strikes or disputes. See PJM Manual 23 - eGADS User Manual, Section 2.5 and 2.6 for further details (<http://www.pjm.com/documents/~media/documents/manuals/m23.ashx>).

PC

The PJM Planning Committee (PC) reviews and recommends planning and engineering strategies for the transmission system. Along with the MIC and the OC, the PC reports to the MRC. Technical subcommittees and working groups reporting to the PC include: Relay Subcommittee (RS), Load Analysis Subcommittee (LAS), Transmission and Substation Design Subcommittee (TSDS) and the Reserve Requirements Assumptions Working Group (RRAWG).

pcGAR

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

Peak Load

The Peak Load is the maximum hourly load over a given time interval, typically a day, month, season, or delivery year. See Forecast Peak Load.

Peak Load Ordered Time Series (PLOTS)

The Peak Load Ordered Time Series (PLOTS) load model is the result of the Week Peak Frequency application. This is one of the load model's input parameters. This is discussed in the load forecasting, Week Peak Frequency (WKPKFQ) parameters section of Part II – Modeling and analysis.

Peak Season

Peak Season is defined to be those weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week begins on a Monday and ends on the following Sunday, except for the week containing the 36th Wednesday, which ends on the following Friday. Please note that the load forecast report used in this study define peak season as June, July and August.

PJM-MA

The PJM Mid-Atlantic region (PJM-MA) of the PJM RTO, established pursuant to the PJM Reliability Assurance Agreements dated August 1994 or any successor. A control area of the PJM RTO responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the PJM Mid-Atlantic Region through coordinated operations and planning of generation and transmission facilities. The PJM Mid-Atlantic Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, and Virginia. The PJM-MA control area is the Eastern edge of the PJM RTO region.

PRISM

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

RI

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

ReliabilityFirst Corporation (RFC)

ReliabilityFirst is a not-for-profit super-regional electric reliability organization whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. Beginning operations on January 1, 2006, RFC is composed of the former Mid-Atlantic Areas Council (MAAC), East Central Area Reliability Coordination Agreement (ECAR) and parts of the Mid-America Interconnected Network (MAIN). RFC is one of the eight Regional Reliability Organizations under NERC in North America. RFC is headquartered in Canton, OH with another office in Lombard, IL. The RFC Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, Virginia, Illinois, Michigan, Wisconsin, Kentucky, West Virginia, Ohio, and Indiana. (<http://www.rfirst.org/>)

Reliability Assurance Agreement (RAA)

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

Reliability Pricing Model (RPM)

PJM's Reliability Pricing Model (RPM) is the forward capacity market in the PJM RTO Control Area. PJM Manual 18 outlines many aspects of this market place.

Reserve Requirement Study (RRS)

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

Reserve Requirement Assumptions Working Group (RRAWG)

Reporting to the PC, the RRAWG assists PJM staff in performing the annual Reserve Requirement Study (RRS) and maintains the reliability analysis documentation.

Restricted Peak Load

For the given forecast period, the restricted peak load equals the forecasted peak load minus anticipated load management.

RTEP

PJM's Regional Transmission Expansion Planning (RTEP) process identifies transmission enhancements to preserve regional transmission system reliability, the foundation for thriving competitive wholesale energy markets. PJM's FERC-approved, region-wide planning process provides an open, non-discriminatory framework to identify needed system enhancements.

SERC

The Southeastern Electric Reliability Council (SERC) is a regional electric reliability organization (ERO) within NERC that is responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems in all or portions of 16 central and southeastern states, including Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Arkansas, Kentucky, Louisiana, Missouri, Texas, and West Virginia. SERC is divided geographically into five diverse sub-regions that are identified as Central, Delta, Gateway, Southeastern and VACAR. SERC is headquartered in Charlotte, NC. (<http://www.serc1.org/Application/HomePageView.aspx>)

SPP

The Southwest Power Pool (SPP) is a regional transmission organization (RTO) responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the Southwest U.S. region, including all or parts of: Kansas, Oklahoma, Texas, Arkansas, Louisiana, and New Mexico. (<http://www.spp.org/>)

THI

The Temperature-Humidity Index (THI) reflects the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. The temperature-humidity index, THI, is defined as follows: $THI = T_d - (0.55 - 0.55RH) * (T_d - 58)$ where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.

SND

The Summer Net Dependable (SND) rating for a given generation unit is used in the summer period. All processes use the SND rating as the basis for evaluating a unit.

Unrestricted Peak Load

The unrestricted peak load is the metered load plus estimated impacts of Load Management.

Weather Normalized Loads

The weather-normalized loads are estimated seasonal peak assuming median peak day weather conditions. The weather-normalized loads are also referred to as 50 / 50 loads.

Zone / Control Zone

An area within the PJM Control Area, as set forth in PJM's Open Access Transmission Tariff (OATT) and the Reliability Assurance Agreement (RAA). Schedule 10 and 15 of the RAA provide information concerning the distinct zones that comprise the PJM Control Area.

Part III – Appendices

Parameter	2008 Study Modeling Assumptions	Recommended 2009 Study Modeling Assumptions 5/13/09 letter to PC Approved at 5/20/09 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 PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in eRPM auctions.	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO 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/generation-retirements.aspx . Consistent with forecast reserve margin graph.	Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/generation-retirements.aspx . Consistent with forecast reserve margin graph.	Updated data available on PJM's web site, but model data frozen in August 2009.	
Planned and Operating Treatment of Generation	All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements: 1.Firm Transmission service to the PJM border 2.Firm ATC reservation into PJM 3.Letter of non-recallability from the native control zone Assuming that these requirements are fully satisfied, the following comments apply: •Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World. •Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale. •Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area. •Active generation projects in the PJM interconnection queues will be modeled in the PJM RTO after applying a suitable commercial probability.	All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements: 1.Firm Transmission service to the PJM border 2.Firm ATC reservation into PJM 3.Letter of non-recallability from the native control zone Assuming that these requirements are fully satisfied, the following comments apply: •Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World. •Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale. •Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area. •Active generation projects in the PJM interconnection queues will be modeled in the PJM RTO after applying a suitable commercial probability.	Consistency with other PJM reporting and systems.	
Unit Operational Factors				
Forced and Partial Outage Rates	5-year (2003-07) GADS data. (Those units with less than five years data will use class average representative data.).	5-year (2004-08) GADS data. (Those units with less than five years data will use class average representative data.).	Most recent 5-year period. Use PJM RTO unit fleet to form class average values.	

Parameter	2008 Study Modeling Assumptions	Recommended 2009 Study Modeling Assumptions 5/13/09 letter to PC Approved at 5/20/09 PC mtg.	Basis for Recommended Assumptions	Possible Impact on IRM
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, 2006, 2007 and 2008 unit operational data for PJM RTO footprint.	
Gas Turbines, Fossil, Hydro Nuclear Ambient Derate	Ambient Derate includes several categories of unit. Based on review by Operations Staff and review of operations data, Summer 2005, 2006, and 2007. 2,500 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, 2006, and 2007. 2008 period assessment is pending. 2,500 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 PJM RTO footprint are needed.	
Class Average Statistics	PJM RTO fleet Class Average values. 71 categories based on unit type, size and primary fuel.	PJM RTO fleet Class Average values. 72 categories based on unit type, size and primary fuel.	PJM RTO values have a sufficient population of data for most of the categories. The values are more consistent with planning experience.	
Uncommitted Resources	Behind the meter generation (BTMG) modeling: Per the June 28, 2004 PC meeting, BTMG may be treated as either a capacity resource or may be used to reduce the 5 CP (coincident peak) load. The choice of the modeling method is left to the owner of the BTMG resource.	Behind the meter generation (BTMG) modeling: Per the June 28, 2004 PC meeting, BTMG may be treated as either a capacity resource or may be used to reduce the 5 CP (coincident peak) load. The choice of the modeling method is left to the owner of the BTMG resource.	Consistency with other PJM reporting and systems.	
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.	
Load Management - Demand Resource (DR) and Interruptible load for Reliability (ILR)				
Demand Resources	PJM RTO load management was modeled per the 2012/2013 RPM Base Residual Auction results. The amount modeled was 4,467 MW.	PJM RTO load management was modeled per the January 2009 PJM Load Forecast Report values. The amount modeled was 3,456 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 3,500 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 3,500 MW.	Reliability Assurance Agreement, Schedule 4, Capacity Benefit Margin definition. Validated by shape of the curve showing relationship of IRM to CBM. Figure I-6.	
New Transmission Capability	Consistent with PJM's RTEP overseen by TEAC.	Consistent with PJM's RTEP overseen by TEAC.	Consistent with PJM's RTEP overseen by TEAC.	

Parameter	2008 Study Modeling Assumptions	Recommended 2009 Study Modeling Assumptions 5/13/09 letter to PC Approved at 5/20/09 PC mtg.	Basis for Recommended Assumptions	Possible Impact on IRM
Modeling Systems				
Modeling Tools	PRISM Version 3.7	PRISM Version 4.0	Per recommendation by PJM Staff. Latest available version.	
Modeling Tools	WeekPeakFreq (WKPKFQ) Version 3.7	WKPKFQ Version 4.0	Per recommendation by PJM Staff. Latest available version.	
Modeling Tools	Applications for Reliability Calculations (ARC) Version 3.7	ARC Version 4.0	Per recommendation by PJM Staff. Latest available version.	
Modeling Tools	Multi-Area Reliability Simulation (MARS) Version 2.92	Multi-Area Reliability Simulation (MARS) Version 3.01	Per recommendation by PJM Staff and General Electric Staff. Latest available version.	
Outside World Area Models	2nd 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. RFC Other region includes DLCO.	3 rd 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. Base Case world region include: NY, NE, MISO (East & Central), TVA and VACAR.	Updated per publicly available data and by coordination with other region's planning staffs.	

Appendix B
Description and Explanation of 2009 Study Sensitivity Cases

Case No.	Description and Explanation	Change in 2008 Base Case IRM (%)
<p>* Individual and New Modeling Characteristic Sensitivity Case</p> <p>The first six sensitivities use the previous 2008 reserve requirement study Base Case as the reference. For the sensitivity cases in red (Case No. 1-6), all differences are with respect to the 2008 Base Case result (PJM RTO IRM = 16.2 %).</p>		
1	Load model update – Weekly shape	Decrease by 0.9524 % *
	Modeling characteristics from the Weekly Peak distributions, or 52 mean and standard deviation values, were impacted by updating historic data.	
2	Load model update – Monthly Forecast shape	Decrease by 0.8815 % *
	Impact of using the monthly forecast from the 2009 PJM Load Forecast Report in place of the 2008 version.	
3	Load model update – Both weekly and monthly shape	Decrease by 1.0749 % *
	Impact of using both the 2009 PJM Load Forecast Report and the updated weekly parameters simultaneously. This is a combination of Case No. 1 and Case No. 2.	
4	PJM Capacity Model update	Increase by 0.0251 % *
	Impact of using updated PJM RTO capacity model and associated unit characteristics.	
5	World Capacity Model update	Increase by 0.3276 % *
	Impact of using updated World region capacity model.	
6	PJM RTO and World Capacity Model update	Increase by 0.3253 % *
	Impact of using both the updated PJM RTO Capacity Model and the updated World Capacity Model simultaneously. This is a combination of Case No. 4 and Case No. 5.	

Case No.	Description and Explanation	Change in <u>2009</u> Base Case IRM (%)
<p><u>Load Model Sensitivity Cases</u> Sensitivity numbers 7 and higher are based on the 2009 Base Case. All differences are with respect to the 2009 Base Case result.</p>		
7	No Load Forecast Uncertainty (LFU)	Decrease by 4.76 %
<p>This scenario represents “perfect vision” for forecast peak loads, assuming that the forecast peak loads for PJM RTO and the Outside World areas have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather and 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.</p> <p>This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.</p>		
8	Increase the Forecast Error Factor to 2.5% (#5028)	Increase by 0.88 %
<p>This two area sensitivity increases the FEF to 2.5% compared to the 1% used in the base case.</p> <p>This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.</p>		
9	Number of years in Load Model	See below
<p>Using PJM RTO 8 year (1997-2004), 9 year (1996-2004) and 10 year (1997-2006) load models, without ATSI, to show the impact of the load model period used in the single area case study.</p> <p>The 8 year load model gave a lower IRM (#5088), by 0.1035 %. The 9 year load model gave a lower IRM (#5087), by 0.3254 %. The 10 year load model gave a lower IRM (#5086), by 0.2532 %.</p> <p>This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.</p>		
10	Non-normal (Truncated Normal) Distribution shapes	Decrease, See below
<p>These two area sensitivity cases reduce and adjust the values of sigma in the 21 point curve representation, from the historic values used with a maximum 4.2 sigma. The intent is to consider impacts of various analyses of the load model shapes. The truncated normal distributions are used for both PJM and World load models. These runs were performed with an older two-area reliability modeling tool. Continued analysis of this issue is on-going including addressing issues of the World model, and all 23 PJM LDAs.</p> <p>Truncated normal truncated at 2.36, decrease by 1.2 %. Truncated normal truncated at 2.50, decrease by 0.9 %. Truncated normal truncated at 2.90, decrease by 0.39 %. Truncated normal truncated at 3.20, decrease by 0.25 %.</p> <p>This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount..</p>		

Generation Unit Model Sensitivity Cases		
11	Poor performing units (#4995)	Decrease by 0.97 %
	<p>Units identified as poor performers (substantially above the class average values) were removed from the case. Units with an EEFORd greater than or equal to 25% define a unit in this group of poor performers. Removing such poor performing units demonstrates 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. For this sensitivity case, the average pool EFORd was 6.02 %, and the average pool EEFORd was 6.54%.</p>	
12	High Ambient Temperature Unit Derating (#5057)	Decrease by 1.4 %
	<p>Assessment of performance of PJM RTO units on high ambient temperature conditions indicated that some units cannot 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.</p> <p>Currently PJM Staff is assessing the impacts of high ambient temperature conditions on unit performance compiling data and experience in operating the full PJM RTO. Once enough data and operating experience has been logged, this modeling assumption will be re-evaluated.</p> <p>This sensitivity removes the 2500 MW on planned outage for the peak summer period (weeks 6-15)</p>	
13	Substitute the EFORd Statistic for all units' Forced outage rate, replacing the EEFORd for all units in the model. (#5097)	Decrease by 0.71%
	<p>This case replaces the EEFORd statistic with the EFORd statistic, for all units. 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. The setting of the variance to zero was not done for this run.</p>	
14	Substitute the XEFORd Statistic for all units' Forced outage rate, replacing the EEFORd for all units in the model. (#5098)	Decrease by 1.36%
	<p>This case replaces the EEFORd statistic with the XEFORd statistic, for all units. 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. The XEFORd statistic does not consider any outage events associated with the GADS outage category Outside Management Control (OMC). The OMC category includes events in which a plant or unit cannot operate, with the operation staff having no reasonable ability to impact whether the plant operates or not. An example of OMC is when a tornado strikes a plant. The setting of the variance to zero was not done for this run.</p>	
15	Impact of change in EEFORd to IRM : F-Factor (#5030)	Increase by 1.45 %
	<p>There is a direct correlation to the forced outage rate of the PJM RTO units vs. the PJM IRM. This sensitivity changes</p>	

	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..	
Capacity Benefit Margin Sensitivity Cases		
16	Figure II-7, Various values of Capacity Benefit Margins	See Figure I-6
	Figure II-7 shows the impact to IRM as the value of Capacity Benefit Margin (CBM) is increased. CBM is a measure of transfer assistance available from the outside neighboring region. This graph indicated what value PJM's interconnected ties have on the calculated IRM, and where the value of CBM saturates (becomes constant). From this graph, previous assessments have chosen the CBM value to use in the study as 3,500 MWs as there is a small benefit for reduction of IRM compared to a larger benefit of OASIS ATC postings.	
Reserve Modeling Sensitivity Cases		
17	PJM RTO at cleared RPM auction (#5102)	RI = 62.8
	<p>Two area mixed-mode modeling, using the reserves per the most recent RPM auction. The Capacity is what was bid and cleared in the most recent RPM market. The cleared capacity in the 2012 / 2013 Delivery Year, Base Residual Auction, yielded a forecast reserve of 20.9%.</p> <p>The 2012/13 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 136,143 MW of unforced capacity in the RTO at a Resource Clearing Price of \$16.46/MW-day. This point on the RTO Variable Resource Requirement curve represents a 21.2% reserve margin; however when the Fixed Resource Requirement (FRR) load is considered the actual reserve margin for the entire RTO is 20.9%.”</p> <p>The full report can be found at http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item07</p> <p>PJM will have an expected loss of load event once every 63 years at this forecasted value.</p>	
18	PJM RTO IRM Vs. World Reserves (# 4998 - 5015)	No Significant impact
	<p>For a two area study 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 an installed reserve level) and PJM RTO is solved to its criterion (1 day in 10). See Figure II-14</p> <p>For the valid range of world reserves, as the reserves of the world increase, the IRM requirement for PJM RTO is not greatly impacted.</p>	
19	PJM RTO RI Vs. World Reserves (# 5034- 5049)	RI = 10.7
	<p>A two area study when 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 an installed reserve level) and PJM RTO is held to a constant reserve level (15.3 %).</p> <p>As the world reserves increase, from their criteria value(16%) to their maximum (19.9%) of the valid range, the PJM RTO RI increases from 10 to 10.7 (an outage every 10.7 years).</p>	

20	PRISM solved load and 50/50 peak load forecast (# 5105, 5106)	
<p>This sensitivity assesses concerns regarding the reported IRM, specifically the denominator used in the IRM calculation. The IRM is defined as the Installed capacity divided by the median forecasted peak. This sensitivity quantified the impacts of various technical data presented and discussed in the stakeholder process. This was done by running simulations using SAS. A summary of these results was presented to the RRAWG. A detailed summary will be posted on the RRAWG SharePoint site.</p>		
<p><i>Topologically Modeling Sensitivity Cases</i></p>		
21	Single Area PJM RTO(including ATSI) Model (#4990)	Increase 1.76 %
<p>This models only the PJM RTO 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 load carrying capability (LCC), multiplied by the reserve requirement, yields an approximate 2,880 MW of capacity that does not need to be inside the PJM RTO. This megawatt amount represents the value of the 3,500 MW CBM.</p>		
22	Include ATSI (FE West) zone in the World area (#4991)	Increase by 0.0075 %
<p>This sensitivity places the units in the ATSI zone into the World area. ATSI was in the PJM RTO area for the base case run. The total capacity of this zone is about 13,140 MW and a peak load of 12, 500 MW. For all ten years of the study model, no significant changes to the results were observed when the ATSI zone was moved into the PJM RTO area.</p>		
<p></p>		

Primary factors for recommended values Sensitivity Cases		
23	DR Factor (#5056,5053)	NA
	<p>This determines the Load carrying capability of the amount of load management modeled in the base case. This is a single area run. A needed input value is the PJM reserves. If the approved reserves change from the recommended value, this factor needs to be re-calculated. The amount of load management is input into the single area case, as a perfect performing unit. For 2013, DR Factor =0.957, 2012 DR Factor = 0.955. See page 31 for further discussion.</p> <p>Recent assessment work, using MARS, indicates that this modeling proxy is valid.</p>	
24	Maximum allowable amount for load management (#5062)	NA
	<p>For this single area run, the amount of load management is increased until the reliability benefit saturates at ten interruptions. Contractually, ten interruptions can be called by the PJM dispatcher to invoke Demand Resources and Interruptible Load for Reliability. Maximum amount of load management was found to be 11.1 % of unrestricted forecast peak load, or 17,844 MW. See Table II-9.</p> <p>The PJM dispatcher as never invoked all ten interruptions, in a given planning period.</p>	
25	CURTAIL analysis (#5053 - 5056)	NA
	<p>For this single area run the CURTAIL analysis assesses the reliability benefit for the number of interruptions invoked for load management. There are four runs needed for this assessment: 1) The base run, to establish the RI that the other runs are measured at, for a given delivery year. 2) Insufficiency, where the difference in the solved load from this run and base run is how the DR factor is calculated. Insert the amount of forecast Load Management (LM) as a perfect performing unit. 3) Necessity, where the solved load from the Insufficiency run is used with removing the unit associated with LM. This is needed for the CURTAIL assessment. And finally 4) Initiation, a large unit of approximately 1000 MW, with average forced outage rate, is taken out, to simulate when the need occurs for invoking load management to avoid a loss of load event. This is needed for the CURTAIL assessment. See Table II- 10.</p>	
26	Winter weekly reserve Target	NA
	<p>This MARS model run is consistent with the base case run. MARS is a more operations orientated model and method, allowing for a representative load model to drive results. This assessment is mainly driven by the load model characteristics. Currently the most representative hourly load shape for assessment work is calendar year 2002. The MARS model is a single area model for the PJM RTO. 1) Establish the reserves that yield MARS to give a 0.1 years/day LOLE. Adjust the monthly load factors in December, January and February, in that order respectively to adjust the weekly reserves down so that minimal risk is seen for some weeks of each month. Minimal risk is quantified by a value showing 10^{-4} LOLE.</p> <p>Report the reserves for the 13 weeks winter period once minimal risk in each month has been determined. See "Operations Related Assessments" section for details of assessment, Table II- 12.</p>	

Appendix C
Resource Planning Reserve Requirements
PJM's compliance with Standard BAL-502-RFC-02

A. Introduction

1. Title: Planning Resource Adequacy Analysis, Assessment and Documentation

2. Number: BAL-502-RFC-02

3. Purpose:

To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the Reliability *First* Corporation (RFC) region

4. Applicability

4.1 Planning Coordinator

5. Effective Date:

5.1 Upon RFC Board approval

Requirements

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall [*Violation Risk Factor: Medium*]:

R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year¹ analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median² forecast peak Net Internal Demand (planning reserve margin).

R1.2 Be performed or verified separately for each of the following planning years:

71 _____

1 The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

2 The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

R1.2.1 Perform an analysis for Year One.

R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 through 10 year period.

R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

R1.3 Include the following subject matter and documentation of its use:

R1.3.1 Load forecast characteristics:

Median (50:50) forecast peak Load.

Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

Load diversity.

Seasonal Load variations.

Daily demand modeling assumptions (firm, interruptible).

Contractual arrangements concerning curtailable/Interruptible Demand.

R1.3.2 Resource characteristics:

Historic resource performance and any projected changes

Seasonal resource ratings

Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

Resource planned outage schedules, deratings, and retirements.

Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

Criteria for including planned resource additions in the analysis

R1.3.3 Transmission limitations that prevent the delivery of generation reserves

R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

Availability and deliverability of fuel.

Common mode outages that affect resource availability

Environmental or regulatory restrictions of resource availability.

Any other demand (Load) response programs not included in R1.3.1.

Sensitivity to resource outage rates.

Impacts of extreme weather/drought conditions that affect unit availability.

Modeling assumptions for emergency operation procedures used to make reserves available.

Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis [*Violation Risk Factor: Lower*].

R2.1 This documentation shall cover each of the years in Year One through ten.

R2.2 This documentation shall include the planning reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

Measures

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor - Reliability *First* Corporation

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year

1.3. Data Retention

The Planning Coordinator shall retain information from the most current and prior two years.

The Compliance Monitor shall retain any audit data for five years.

2. Violation Severity Levels

Req. Number	VIOLATION SEVERITY LEVEL			
	LOWER	MODERATE	HIGH	SEVERE
R1	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from R1.1 as a percentage of the net Median forecast peak Load per R1.1.2 OR	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per R1.2 OR	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. OR The Planning Coordinator Resource

	<p>were not included OR The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.5</p>	<p>The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of its use OR The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under R1.3.2 and documentation of its use Or The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per R1.7</p>	<p>The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 through 10 year period or both per R1.2.2 OR The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of their use OR The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under R1.3.2 and documentation of their use OR The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use</p>	<p>Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per R1.1 OR The Planning Coordinator failed to perform an analysis for Year One per R1.2.1</p>
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Definitions:

Resource Adequacy - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.

Peak Period - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur

Year One - The planning year that begins with the upcoming annual Peak Period.

The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:

Direct Control Load Management – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.

Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load - An end-use device or customer that receives power from the electric system.

Transmission - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02 1 st Draft	06/24/08 Through 07/23/08	Posted for 1 st Comment Period	
BAL-502-RFC-02 2 nd Draft	08/18/08 Through 09/16/08	Posted for 2 nd Comment Period	
BAL-502-RFC-02 3 rd Draft	10/16/08 Through 10/30/08	Posted for 15-Day Category Ballot	
BAL-502-RFC-02 3 rd Draft	12/04/08	Reliability <i>First</i> Board Approved	
BAL-502-RFC-02	06/08/09	“Planning Reserve” changed to “planning reserve” in R2.2.	Errata

PJM's compliance with Standard BAL-502-RFC-02

This document lists all applicable documentation and evidence that demonstrates PJM's compliance with the requirements of the standard.

Standard Author: ReliabilityFirst Corporation

Standard Number: BAL-502-RFC-02

Title: Planning Resource Adequacy Analysis, Assessment and Documentation

Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RFC) region

Past Compliance Activities: Version "01" of the standard:

November 2008 – Compliant (PJM 3rd party audit)

June 2007 – Compliant (RFC self certification)

May 2007 – Complaint (RFC compliance audit)

R1. The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall [Violation Risk Factor: Medium]:

Measure 1. Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

The annual Reserve Requirement Study (RRS) is distributed to the PJM Planning committee for their October Meeting. For the 2009 RRS, the pages most pertinent to this general title include: Part I -Executive summary, Part I-Introduction, Part I-Summary of Results, Part I - Recommendations, and Appendix A, Base Case modeling assumptions.

This resource adequacy Study covers the eleven year period, 2009 to 2019. (Introduction - section 1 thru 5)

R1.1. Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year³ analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

³ The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

Processes and Procedures

Manual 20: PJM Resource Adequacy Analysis

Revision #3, Effective 06/01/2007

Section 1: Generating Capacity Requirement

PJM's Installed Reserve Margin (IRM) is defined as:

The installed capacity percent above the forecasted peak load required to satisfy a Loss Of Load Expectation (LOLE) of 1 Day / 10 Years. For a given delivery year, IRM is one of the two primary inputs needed for calculating the Forecast Pool Requirement (FPR).

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

2009 Reserve Requirement Study report, submitted for 10/22/2009 PJM Planning Committee meeting. See Summary of Results, Table I - 2.

R1.1.1. The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Appendix A (Study Assumptions), Emergency Operating Procedures parameter.

2009 RRS report, "Load Management (LM) Credit" section, page 32, and the 1st sentence of the "IRM and FPR" section on page 38. Load Forecasting section, page 15, paragraph above Table II -1.

R1.1.2. The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median⁴ forecast peak Net Internal Demand (planning reserve margin).

Processes and Procedures

Manual 20: PJM Resource Adequacy Analysis

Revision #3, Effective 06/01/2007

Section 1: Generating Capacity Requirement

PJM's Installed Reserve Margin (IRM) is defined as:

The installed capacity percent above the forecasted peak load required to satisfy a Loss Of Load Expectation (LOLE) of 1 Day / 10 Years. For a given delivery year, IRM is one of the two primary inputs needed for calculating the Forecast Pool Requirement (FPR).

⁴ The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

2009 RRS report, Table 1 -2, column A, page 6, and 1st bullet of Recommendations section, page 12. Page 38, 1st sentence of "IRM and FPR" section.

R1.2. Be performed or verified separately for each of the following planning years:

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Performed annually for forecast eleven year period, per 1st bullet of Executive Summary, page 2, RPM Market section page 38, and timeline shown in Appendix D. Table I-2 shows the values for each delivery year in the study.

R1.2.1. Perform an analysis for Year One.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Performed annually for forecast eleven year period, per 1st bullet of Executive Summary, page 2, RPM Market section page 38, and timeline shown in Appendix D. Table I-2 shows the values for each delivery year in the study.

R1.2.2. Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Performed annually for forecast eleven year period, per 1st bullet of Executive Summary, page 2, RPM Market section page 38, and timeline shown in Appendix D. Table I-2 shows the values for each delivery year in the study.

R1.2.2.1. If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Analysis is a current new study, not verification of previous results.

Performed annually for forecast eleven year period, per 1st bullet of Executive Summary, page 2, RPM Market section page 38, and timeline shown in Appendix D. Table I-2 shows the values for each delivery year in the study.

R1.3. Include the following subject matter and documentation of its use:

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

2009 RRS report, Part II - Modeling and Analysis Considerations section, pages 31-39.

R1.3.1. Load forecast characteristics:

- Median (50:50) forecast peak Load.
- Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal Load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable/interruptible Demand.

Processes and Procedures

Manual 19: Load Data Systems

Revision #14, Effective 12/01/2008

Median forecast Load - Revision 14, Page 11

Load Diversity - Dependent Variable - Load on page 9, pages 11-12

Load forecast Uncertainty - Revision 14, Pages 9-11

Daily demand modeling - Page 9

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

2009 RRS pages 15-19, Appendix B Sensitivity numbers 7-10, Page 12 1st paragraph

Seasonal Load - Page 15, 2nd bullet

Median forecast peak load - Discussion about IRM, Page 12 ; pages 18-19

Load forecast uncertainty - Forecast Error Factor, pages 15-16. Appendix A Row 3.

Median forecast load - Page 12, 1st Paragraph, pages 18-19.

Load Diversity - pages 17-18, Page 9, 2nd bullet

Curtable Load - Page 4, DR Factor ; Table I-2 column G ; Table II - 1 Restricted Load Columns ; DR Factor Pages 32-33 ; Page 38 RPM Market

Daily demand - Appendix A, Daily load forecast shape parameter column; Page 16

2009 Reserve Requirement Study Assumptions

Published 05/13/2009

Load forecast uncertainty - Page 1, item # 2 ; Page 6, item # 10.

Load diversity - Page 1, item #4 ; Page 2 item #6

Load Forecast Report

Published 01/01/2009

Curtable demand - Page 1, 4th bullet ; Table B7

Load Diversity - Table B1

Seasonal Load - Tables B1, B2, B3, B4, B5

R1.3.2. Resource characteristics:

- Historic resource performance and any projected changes.
- Seasonal resource ratings.
- Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.
- Resource planned outage schedules, deratings, and retirements.
- Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.
- Criteria for including planned resource additions in the analysis.

Processes and Procedures

Manual 21: Rules and Procedures for Determination of Generating Capability

Revision #7, Effective 06/01/2008

Seasonal ratings - Pages 10-12

Intermittent Resources - Pages 16-18, Appendix B

Manual 22: Generator Resource Performance Indices

Revision #13, Effective 06/01/2007

Page 10, Equivalent Maintenance outage factor(Pg 14), Equivalent planned outage rate.(pg 14), Equivalent demand forced outage rate(Pg 13), Effective equivalent demand forced outage rate (Pg 15). ; Page 11 f-Factor(Pg 15, 18-22); Page 12 variance (Pages 23-26)

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Resource Characteristics - Generation forecast section, pages 20-30

Historic & project Performance - Pages 20 -22, Table II - 4, Table II-5; Page Table II-6 & Figure II-2. Appendix A Unit Operational Factors parameter section.

Seasonal ratings - Page 9, first bullet; Appendix A, Generating unit capabilities parameter section.

Purchases and Sales - Appendix A, Firm Purchases and sales parameter section.

Planned schedules, deratings, retirements - Appendix A: Planned outages , Summer planned outage maintenance, ambient derate, retirements; parameter sections ; Table II-4 (POF column); Page 27 Ambient derate; Table II-8, retirements column.

Criteria for modeling resources - Page 21 -Generation owner review; Pages 28-30 ; Appendix A: Generating unit capacities , New units, Generation owner review; parameter rows.

Intermittent resource - Appendix A, Wind resources parameter row ; Table II-4, last two rows.

2009 Reserve Requirement Study Assumptions

Published 05/13/2009

Criteria for modeling resources - Page 7-8, item #4

R1.3.3. Transmission limitations that prevent the delivery of generation reserves.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Page 3, 5th bullet ; Figure I-6 and 1st bullet ; Page 30 - 31 Transmission system considerations.

Slides 10-15 of presentation, 2014 CETL/CETO, at: <http://www.pjm.com/committees-and-groups/committees/~media/committees-groups/committees/teac/20090715/20090715-teac-presentation.ashx>

R1.3.4. Criteria for including planned Transmission Facility additions in the analysis.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Transmission additions - Appendix A, Interface limits and New Transmission Capability parameter row; Page 30 , PJM Transmission planning evaluation of import capability, Transmission Projects.

Page 37, Standard BAL-502-RFC-02 clarification item

R1.3.5. Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Assistance from neighbors - Pages 9 - 11, third bullet on page 9 thru 1st bullet on page 11. ; Pages 30-31, Capacity Benefit Margin, Capacity Benefit of Ties, OASIS postings ; Appendix A, Transmission system parameter row. ; Appendix B sensitivity number 20. ;

R1.4. Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Availability and deliverability of fuel.
- Common mode outages that affect resource availability.
- Environmental or regulatory restrictions of resource availability.
- Any other demand (Load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather/drought conditions that affect unit availability.
- Modeling assumptions for emergency operation procedures used to make reserves available.
- Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

Processes and Procedures

Manual 23: eGADS User Manual

Revision #4, Effective 06/01/2007

Availability and deliverability of fuel

1) Appendix C, page 123, cause codes 9130 and 9135; 2) Page 8, 5th bullet.

Availability and deliverability of fuel

The GADS systems used at PJM are based on the NERC data reporting requirements, with a verification of these data done with the NERC staff on a quarterly basis. These reporting requirements are updated annually, available at the NERC web Site:

<http://www.nerc.com/page.php?cid=4|43|45> . PJM Manual 23 documents show a proprietary web based system is used to accommodate the NERC GADS reporting. Section 3 of the NERC data reporting instructions details the event reporting requirements where various cause codes are used. These events affect the statistical measures (Forced outages, Maintenance outages, Planned outages) used to quantify resource performance characteristics. See Requirements section R1.3.2 for evidence on these resource performance characteristics.

Environmental or regulatory restrictions of resource availability

1) Appendix C, page 123, cause codes 9150, 9500, 9502, 9504, 9505, 9510, 9590 ; 2) Page 8, 4th and 6th bullets.

Common mode outages that affect resource availability

1) Appendix C, page 123, cause codes 9025, 9030, 9035, 9036; 2) Page 8, 2nd bullet.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Sensitivity to Resource outages - Appendix B, sensitivity numbers 12 -15.

Impact of extreme weather - Appendix B Sensitivity 12. ; Page 27 ambient deratings

EOPs used - Page 40, final paragraph ; Appendix A, Emergency Operating Procedures parameter row.

Availability and Delivery of fuel - Page 37, Standard BAL-502-RFC-02 clarification item

Common Mode outages - Page 37-38, Standard BAL-502-RFC-02 clarification item

Environmental or regulatory restrictions

Page 38, Standard BAL-502-RFC-02 clarification item

Other Demand programs

Page 38, Standard BAL-502-RFC-02 clarification item

Availability and delivery of fuel

Page 37, Standard BAL-502-RFC-02 clarification item

2009 Reserve Requirement Study Assumptions

Published 05/13/2009

Market resources not committed to serving load. - Page 6, item number nine

NERC GADS Data reporting Instructions

Published 01/01/2009

Appendices B1, B2, B3, B4, B5, B6, B7, B8, B9

Common mode outages that affect resource availability

System / Component EXTERNAL cause codes 9000 - 9040.

Availability and deliverability of fuel - System / Component EXTERNAL cause codes, 9130, 9131, 9140.

Environmental or regulatory restrictions of resource availability

System / Component REGULATORY, SAFETY, ENVIRONMENTAL cause codes 9504 - 9590, 9600-9656, 9660 -9690.

- R1.5.** Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included.

Processes and Procedures

Manual 14B: PJM Regional Planning Process

Revision #12, Effective 08/08/2008

Pages 40-54, Attachment C - Load deliverability.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Page 31, Coordination with Capacity Emergency Transfer Objective (CETO)

Page 38, Standard BAL-502-RFC-02 clarification item

- R1.6.** Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Page 21, Generating unit owner review ; Appendix A, Generating unit Capacities, Generation owner review ; parameter rows ; Page 83-84 Appendix D.

- R1.7.** Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Page 15, 1st bullet.

Load Forecast Report

Published 01/01/2009

Tables B1 - B10

page 28, 2nd Note at bottom of Page.

- R2.** The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis [Violation Risk Factor: Lower].

Measure 2. Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

- R2.1.** This documentation shall cover each of the years in Year One through ten.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Page 2, bullet 2; Page 3 2nd to last bullet; Table I-2

- R2.2.** This documentation shall include the planning reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

Evidence

PJM Reserve Requirement Study

Published 10/13/2009

Table I-2, column A

- R2.3.** The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

Evidence

PJM.com website

See 2009 Reserve Requirement Study report at

<http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx>

Typically posted in October.

Appendix D Reserve Requirement Assumptions Working Group (RRAWG)

RRAWG Main Deliverables and Schedule

There are 3 primary deliverables of the RRAWG.

1. The assumptions letter for the upcoming RRS
Per the below time line, this activity is scheduled to start in February and be completed in May.
2. The IRM, FPR, Demand Resource Factor (DR Factor) Analysis Report
Per the below time line, this activity is scheduled to start in June and be completed in September.
3. The Winter Weekly Reserve Target in the Report
Per the below time line, this activity is shown as item number twelve, scheduled to be completed in September, for the upcoming winter period.

This technical working group was established by and reports to the PJM Planning Committee.

The activities of the PJM RRAWG are shown at the following web link:
<http://www.pjm.com/committees-and-groups/working-groups/rrawg.aspx>

Time Line for 2009 Reserve Requirement Study

Figure D - 1: Time Line for 2009 RRS

Annual Reserve Requirement Study (RRS) Timeline - Milestones (Green) and Deliverables (Blue)
Reserve Requirement Assumptions Working Group (RRAWG) related activities

Description	January	February	March	April	May	June	July	August	September	October	November	December	January	February
1 Data Modeling efforts by PJM Staff	Blue	Blue	Blue	Blue	Blue									
2 Produce draft assumptions for RRS		Blue	Blue											
3 RRAWG comments on draft assumptions			Blue	Blue										
4 RRAWG & PJM Staff finalize Assumptions				Green										
5 PC receive update and final Assumptions. Review/discuss/provide feedback			Blue	Blue										
6 PC establish / endorse Study assumptions					Green									
7 Generation Owners review Capacity model					Blue									
8 PJM Staff performs assessment/analysis					Blue	Blue	Blue							
9 PC establish hourly load time period							Green							
10 Status update to RRAWG by PJM staff							Blue							
11 PJM Staff produces draft report						Blue	Blue							
12 Draft Report, review by RRAWG								Blue	Blue					
13 RRAWG finalize report, distribute to PC. Winter Weekly Reserve Target Recommendation									Green					
14 Stakeholder Process for review, discussion, endorsement of Study results (PC, MRC,MC).									Blue	Blue	Blue	Blue		
14 A Planning Committee Review & Recommendation									Blue	Blue				
14 B Markets and Reliability Committee Review & Recommendation										Blue	Blue			
14 C Members Committee Review & Recommendation											Blue	Blue		
15 PJM Board of Managers approve IRM, FPR, DR Factors													Blue	
16 Posting of Final Values for RPM BRA - FPR & DR factors for 3 year forward Delivery year														Blue

The 2009 Study activities last for approximately 14 months. Some current Study activities, shown in items 1 and 2, overlap the previous Study timeframe. The posting of final values occurs on or about February 1st.

Appendix E

Method for assessing time period to use for PLOTS load model

1. Step 1 - Assess PJM load forecast model, for applicable delivery year (DY)
 - Use latest forecast model (January PJM Load forecast).
 - Determine distribution parameters based on results of methods used in load forecasting.
 - For the summer of the DY, there are 481 seasonal peaks values (corresponding to 37 years of weather X 13 weekday scenarios). The median represents the PJM RTO 50/50 summer seasonal peak.
 - Create a sorted distribution of values, determining cumulative probability of values.

2. Step 2 - Assess all possible combinations of time periods, staying within the guideline of using latest 7-10 years of data.
 - Assess PJM RTO loads only.
 - For each possible load model time-period combination, develop a summer seasonal peak forecast distribution:
 - From the forecasted summer daily peak distributions (for weeks 1 to 20), draw 5 random draws to represent the 5 weekday daily peaks.
 - From the 100 daily peaks (20 weeks multiplied by 5 daily peaks), determine the maximum value as a seasonal peak. To compare the values to the load forecast distribution, estimates are needed for seasonal peak not daily and weekly peaks.
 - Generate 481 seasonal peak forecasts and rank them by magnitude to develop a Cumulative Density Function (CDF).
 - Compare each of the 481 seasonal peaks from each of the load model combinations to the PJM Load Forecast values.
 - Rank each combination, based on an appropriate measure of error (compared to forecast values).
 - Identify top 5-10 Load Model combinations (the chosen load model combinations represent the RTO Load Forecast for Delivery Year (DY) better than the other load model combinations based on the chosen measure of error).

3. Step 3 - Assess relationship of world region load model to PJM RTO load model, based on result of Step 2.
 - Time period choice needs to be the same for both World & PJM RTO.
 - Focus on the significant 6-8 peak LOLE weeks, from PJM RTO model.
 - Determine historic patterns used in modeling. This is for the coincident peak (CP) of the combined World region, to determine a forecast CP distribution. A method was developed and is outlined as Table II – 3 in the 2009 RRS report. Further details are posted at several 2nd and 3rd quarter RRAWG 2009 meetings.
 - Determine calculation method to assess patterns and assess correlation of PJM RTO load model to the World region load model. Further details are posted from several 2nd and 3rd quarter RRAWG 2009 meetings.
 - Measure choice of load model against relationship patterns of Area 1 to Area 2. Apply engineering judgment in making a choice for the time period. Further details are posted from several 2nd and 3rd quarter RRAWG 2009 meetings.

Appendix F ISO Reserve Requirement Comparison

The following compares the MISO reserve requirement to the PJM RTO reserve requirement, on a 1) IRM, 2) IRM with Diversity, and 3) Unforced Margin with Diversity basis.

Observations from this comparison:

1. Care should be taken when comparing values, understanding the basis and underlying assumptions of the values will guide a correct “apples-to-apples” comparison.
2. When considering load diversity, the effect of GADS reported outside management control events, and unforced margins, the reserve requirements for the PJM RTO are lower than those in the MISO region.
3. On a comparable basis, the PJM RTO values are generally lower than the MISO values. The MISO and PJM footprints are of comparable size, characteristics and complexities.

A similar comparison was presented and discussed at the March 2009 PJM Planning Committee meeting and the April 2009 PJM RRAWG meeting.

Comparison of reserve requirements on a coincident, unforced basis. MISO vs. PJM

Table F - 1: Comparison of reserve requirements on a coincident, unforced basis. MISO vs. PJM

Delivery Year	<u>MISO</u> 2009	<u>PJM</u> 2009	<u>PJM</u> 2010	<u>PJM</u> 2011	<u>PJM</u> 2012	<u>PJM</u> 2013
IRM	15.40%	15.00%	15.50%	15.50%	15.40%	15.30%
Load Diversity	2.35%	3.90%	3.90%	3.9% *	3.9% *	3.9% *
IRM w/div	12.69%	10.52%	11.00%	11.00%	10.90%	10.80%
XEFORd	6.51%	6.13%	6.21%	6.21%	6.28%	6.30%
Unforced Margin	7.88%	7.95%	8.33%	8.33%	8.15%	8.04%
Unforced Margin w/div	5.35%	3.74%	4.10%	4.10%	3.93%	3.82%

*** Does not include ATSI in the PJM RTO region**

XEFORd = EFORd statistic without Outside Management Control (OMC) events.

Unforced Margin = $IRM * (1 - XEFORd)$

IRM w/div = $(1 + IRM) * (1 - Load\ Diversity)$

Unforced Margin w/div = $(1 + Unforced\ Margin) * (1 - Load\ Diversity)$

MISO values are from “2009-2010 LOLE Study – Preliminary Report”

The ISO-NE reserve requirement, shown in Figure I-4, of 10.15% was compared to the New York State Reliability Council’s IRM and found to be comparable. The PJM staff reviewed this comparison and is satisfied that the comparison was thorough and, as stated in the comparison: “This evaluation of risk is based on judgment and experience over many years. Each area has its own concerns, perspectives and weightings that are then incorporated into its reliability model in their attempt to capture those concerns within a structured modeling framework.” The draft comparison is available at: http://www.iso-ne.com/committees/comm_wkgrps/reblty_comm/pwrsuppln_comm/mtrls/2009/mar122009/comparison_of_irm_icr_2009.pdf

Appendix G RRAWG Review of Study -- Transmittal Letter to PC

October 16, 2009

Steven R. Herling
Chairman Planning Committee
PJM Interconnection
955 Jefferson Avenue
Norristown, PA 19403

Dear Mr. Herling,

The Reserve Requirement Assumptions Working Group (RRAWG) has completed its review of the 2009 PJM Reserve Requirement Study (RRS) report. The review efforts are in accordance with the RRAWG Charter, as approved by the Planning Committee and posted at: <http://www.pjm.com/committees/working-groups/rrawg/downloads/rrawg-charter.pdf>

The review included the following efforts:

- Development and completion of the Study assumptions, including an activity timeline
- Participation in WG meetings to discuss and review PJM staff progress in developing the Study model data
- Identification of modeling improvements for incorporation into the analysis and report, as described in the May 13 RRS Study Assumptions letter
- Participation in WG meetings to discuss and review preliminary analysis results
- Verification that all base case study assumptions are fully and completely adhered to
- Review of draft versions and final version of the study report
- Coordination with PJM staff to clarify reported items and incorporate WG member feedback

In the course of the work, the WG evaluated several modeling issues that were mentioned in the May 13 RRS Study Assumptions letter and eight issues requested by the Planning Committee. The results of these investigations are discussed in the body of the 2009 Report.

The 2009 Report presents a significant amount of detail. While the WG appreciates the technical detail, it does point out the importance of balancing the inclusion of a large amount of information with the need to explain study results and conclusions in a clear and concise manner. This report, although comprehensive, is a slightly reduced version of previous reports. Two items included in previous reports, modeling parameters and sub-regional summaries, will be provided through a separate web posting at a later date.

PJM did make changes to the final report based on feedback received from the WG. To gather input after this report is released, the Planning Committee and membership at large are requested to submit any substantive comments on the report to PJM by November 4, 2009. (This is one week prior to the November meeting of the Markets and Reliability Committee.)

After review and discussion of the study results, the WG endorsed the PJM recommendation shown in the table below. This recommendation is based on a WG vote of 4 parties in favor, 2 opposed and 2 abstentions.

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Avg. EFORd *	Recommended FPR	Recommended DR Factor
2009	2012 / 2013	15.4%	15.4%	6.28%	1.0815	0.955
2009	2013 / 2014	15.3%	15.3%	6.30%	1.0804	0.957

Note: Avg. EFORd does not include Outside Management Control generator outage events.

* EFORd = Equivalent Demand Forced Outage Rate

After review of the winter reserve analysis results, the WG unanimously endorsed the PJM recommendation of a 25 % winter weekly reserve target for the 2009/2010 winter period.

The review efforts of the RRAWG will be concluded upon acceptance of this report by the Planning Committee.

Respectfully,

Thomas A Falin
RRAWG Chairman

Appendix H

“Engineering Judgment” Considerations used in the RRS

The following list of “engineering judgment” items should be considered when approving the FPR based on RRS results. A general summary precedes this list.

This appendix’s intent is to document assumptions and modeling items that affect the calculated IRM for the base case run. The process of proper assessment concerning these modeling items and their impact, on a quantitative basis, is how the recommended value is chosen. Through reasoning, running the appropriate sensitivities, and assessment of the underlying data model, a defensible position for a recommended value can be made. Each model, based on the Study assumptions established well in advanced before the study results are known, needs an independent assessment based on proven guidelines which includes:

- Consider the significant drivers, as a primary source of information for assessing the best recommended value. These drivers, of the modeling data, cannot be over assessed, but are typically limited by resources including PJM staff and computer abilities.
- Trends observed over several Study models are significant.
- Consideration of forecast concerns and conditions in both Operations and the capacity markets are part of the considerations used in the assessment process.
- Historically significant drivers of the Study results included the overall unit forced outage rates, load model diversity, forecast reserve for both Area1(PJM RTO) and Area2(World), size of the neighboring region modeled, and time period used in the hourly load model to create the weekly statistical parameters.
- Both the sensitivity of Study results to the underlying data model and the confidence of the data quality are important. For example, if the results are not significantly changed by a certain part of the data model, resources should not be focused on improving this data quality or be a primary rationale for the choice of the recommended value.
- A technically based assessment and information concerning Adequacy, are the overriding considerations in choosing a recommended value. This involves using Engineering Judgment, as detailed in this Appendix.
- Mitigating uncertainty to the forward capacity market is an important consideration.
- Very high data quality is the objective for all modeling efforts.

2009 RRS Report assessment for the 2012/2013 and 2013/14 Delivery Years

1. Improvements to the process to select the time period for the hourly loads that are used to form the PLOTS load model.
2. Generation performance characteristics were stable compared to last year’s assessment.
3. PJM-World load diversity is expected to remain consistent with this study, due to load modeling improvements implemented in this study.
4. A recent FERC order mandates that all parameters concerning reserve requirement delivery years from 2012 forward will be re-established, on an annual basis.
5. Assessment work and sensitivity runs concerning projected forward capacity market resources indicate that PJM RTO will exceed its requirements.
6. The calculated base case IRMs, are in full compliance with the Study assumptions and RFC Standard BAL-502-RFC-02.
7. The PJM Staff recommend the Base Case calculated values, due to the above noted items which mitigated uncertainty in the forecasted reserve requirements.

Items shown in the three categories, Understate, Overstate, and Undetermined impacts, are ordered by impact to the study results, with Item #1 having the greatest impact.

Assumptions that Understate the IRM

Item #	Description
--------	-------------

- | | |
|---|--|
| 1 | <p>Independence of Unit Outage Events (no recognition of common cause failures)</p> <p>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 makeup 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.</p> |
| 2 | <p>Forecast Error Factor (FEF)</p> <p>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%. The RRS will model a 1% Forecast Error Factor for all delivery years. This modeling, which began in the 2005 Study from the previous practice of increasing the FEF as the planning horizon lengthens, reduces the calculated IRM for those delivery years past the second delivery year.</p> |
| 3 | <p>Intra-World Load Diversity</p> <p>The diversity values used are from an assessment of 13 years of historic data, using the average of the values seen over the summer season. This new assumption uses the average of the values seen over a consistent peak period (August). In the investigation of diversity, the hourly load data was used to show the monthly shape on an annual basis. This investigation led to discussions with the RRAWG and a decision to calculate an average monthly shape, using years that had an August peak. This insured consistency between the timing of the monthly peaks and the annual peak of the composite World region. See Table II – 3 for further details. In 7 of the 13 historic years, the diversity was lower than the average. Consideration for a choice of the appropriate World reserves level includes operational data and practices. Issues identified for further investigation include assessment of World loads at the time of the PJM RTO peaks, operational actions and levels at time of PJM RTO peak, and amount of OASIS reservations for forecast delivery years. MISO performs a similar diversity assessment, choosing to model the minimum of the historic diversity values. This approach was considered and discussed with the RRAWG, but determined to be too conservative when put in the broad context of all the modeling assumptions used in the RRS. A balance of all the modeling inputs is desired and using an average value for this specific aspect seemed to accomplish this.</p> |
| 4 | <p>Assistance from World area when commercial incentives are changing</p> <p>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.</p> |
| 5 | <p>Modeling all External NERC Regions in a Single Area</p> <p>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.</p> |

Assumptions that Overstate the IRM

Item #	Description
1	<p>Units out on planned maintenance over Summer peak period</p> <p>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 MW is modeled out to reflect reduced unit output during high ambient conditions (hot and humid). However, we need operations data for the full PJM RTO 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.</p>
2	<p>Holding World at known reserve requirement level rather than forecast reserves</p> <p>The IRM assumptions calls for modeling the World at the reserve requirement known for the surrounding individual sub-regions that make up the World region. 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. This was a new assumption implemented in the 2009 RRS, to use the known reserve requirements of surrounding regions (MISO, NYISO, ISO-NE). Consideration for a choice of the appropriate World reserve level includes operational data and practices. Issues identified for further investigation include assessment of World loads at the time of the PJM RTO peaks, operational actions and levels at time of PJM RTO peak, and amount of OASIS reservations for forecast delivery years. A value of 16% was deemed the appropriate choice for World reserves after discussions with the RRAWG and using engineering judgment. A World reserve level of 16% yields an RI equal to an LOLE of 1 day in 10 years, for this region. Historically, the world forecast reserves are higher than the 1d/10yr reserves.</p>
3	<p>Normal load model rather than non-normal load model</p> <p>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 daily peak 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 historic 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 distributions for each week of the model, and is in-process and testing for future implementation.</p> <p>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.</p>

Assumptions having an Undetermined Impact on IRM

Item #	Description
1	<p>PJM and World regions load diversity</p> <p>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. The PJM-World Diversity refers to the magnitude associated with the difference and reflects this</p>

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 ten years to reduce the volatility in PJM/World load diversity that has been observed in historic 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 impacts of study model characteristics once the load model time period assumptions are chosen. For this reason a new process was put into place for the 2009 RRS, to assess and evaluate this issue to choose the best time period for the current RRS modeling. (See Appendix E, step 3, and Table II-3)

2 Perfect correlation between two load models

The perfect correlation of the Study area load model shape with the neighboring world area load model has been used for all historic Studies. 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 cannot be determined yet.

3 Use of class average values for Market Integration zones

In the reporting of individual unit outage events, the generation 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 is available yet. The actual unit performance characteristics may be significantly different than the class average values. However, recent modeling is based on the PJM RTO fleet of units which may mitigate this difference.

End of 2009 PJM Reserve Requirement Study Report

11-year Planning Horizon: June 1st 2009 - May 31st 2020