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RECEIVED
MAY 30 2014
PUBLIC SERVICE COMMISSION

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May 30, 2014

HAND DELIVERED

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Administrative Case No. 387

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's responses to Staff's May 19, 2014 Data Requests concerning the Company's 2013 Annual Resource Assessment that was filed April 30, 2014.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

MRO

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF :

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	))))	ADMINISTRATIVE CASE NO. 387

****

RESPONSE OF KENTUCKY POWER COMPANY

TO

COMMISSION LETTER DATED MAY 19, 2014

May 30, 2014

KENTUCKY POWER COMPANY

REQUEST

Refer to Item 4 of the April 30, 2014 filing.

a. Provide the derivation of the 15.6 percent target reserve margin used for planning purposes. Include all necessary narrative descriptions of the steps in the derivation and the source of all data used in the calculation. Refer to Item 7 of Duke Energy Kentucky's March 31, 2014 filing for an example of the preferred format. The link to Duke Energy Kentucky's March 31, 2014 filing is:

   http://psc.ky.gov/PSCSCF/Post%20Case%20Referenced%20Correspond
   ence/2000%20cases/20000387/20140331Duke%20Energy%20Kentucky
   Annual%20Load%20Demand%20Forecast%20Report.pdf

b. Provide the derivation of the 37.4 percent reserve margin shown in attachment 1. Include all narrative descriptions of the steps in the derivation and the source of all data used in the calculation-specifically the reference in the line 22 denominator which includes "Question 5 attached Exhibit 5-2, column (6)." If applicable, refer to Item 7 of Duke Energy Kentucky's March 31, 2014 filing for an example of the preferred format.

RESPONSE

a. The Duke Energy Kentucky format is not fully applicable to Kentucky Power because the 15.6 percent IRM was developed independently by PJM to determine the amount of capacity resources required to serve the forecast PJM peak load and satisfy the reliability criterion. The Duke Energy Kentucky format is used in the calculation of subpart (b) below. The Kentucky Power peak that is coincident with the PJM peak is the relevant data point when considering Kentucky Power's obligation.

   For the description of the sources and calculations used to derive the 15.6 percent target reserve margin, please refer to pages 2 and 9 of the PJM document, "2012 PJM Reserve Requirement Study." The link for the PJM report is:

   http://www.pjm.com/~/media/planning/res-adeq/2012-pjm-reserve- requirement-study.ashx

A copy of the PJM document is provided as Attachment 1 to this response.

b. A description of the sources and steps for the calculation of the 37.4 percent reserve margin for the 2014/2015 Planning year is given below.

Description of the sources:

Factors

PJM Installed Reserve Margin (IRM, 15.9%): Determines the amount of capacity resources required to serve the forecast peak load and satisfy the reliability criterion. The reliability criterion is based on Loss of Load Expectation (LOLE) not exceeding one event in ten years.

PJM EFORd (6.05%): Based on the 5-year average PJM EFORd

Forecast Pool Requirement (1.089, FPR) = (1 + PJM Installed Reserve Margin (IRM)) * (1 – PJM EFORd) = (1 + 0.159) *(1- 0.0605) = 1.089

Obligations
Total Load Obligations (1,156 MW) = KPCo peak demand coincident with PJM

UCAP Obligation (1,259 MW) = Forecast Pool Requirement (FPR) * Total Load Obligation =
1.089 *1,156 MW = 1,259 MW

Resources
Net ICAP (2,250 MW) = KPCo total capacity (MW)

KPCo EFORd (20.77%) = Weighted average of KPCo unit EFORds

Available UCAP (1,783 MW) = Net ICAP *(1- KPCo EFORd) =
2,250 MW* (1 – 0.2077) = 1,783 MW

Position
Net UCAP Position (524MW) = Available UCAP – Total UCAP Obligation =
1,783 MW – 1,259 MW = 524 MW

Net ICAP Position (661MW) = Net UCAP Position /(1 – KPCo EFORd (weighted average of KPCo unit EFORds)) =

524 MW/ (1 – 0.2077) = <u>661 MW</u>

The KPCo Reserve Percent Required By PJM (37.4%) is calculated in the following two steps:

Step 1: The KPCo internal demand (1,156 MW, coincident with PJM) is divided into the Net ICAP position (661 MW) and multiplied by 100:
661 MW/ 1,156 MW* 100 = 57.2%

Step 2: The calculated value in Step 1 is subtracted from the KPCo reserve margin (94.6%):
94.6 – 57.2 = 37.4%

Other relevant definitions:
The PJM Installed Capacity (ICAP) value of a unit is based on the summer net dependable rating of a unit as determined in accordance with PJM's Rules and Procedures.

The PJM Unforced Capacity (UCAP) value of a unit is the ICAP that is not on average experiencing a forced outage or forced derating.

UCAP = ICAP x (1 - EFORd)

Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability of a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to operate.

Forecast Pool Requirement (FPR) is used to establish level of unforced capacity resources that will provide an acceptable level of reliability:

FPR = (1 + IRM)*(1-pool-wide avg. EFORd).

WITNESS: Ranie K Wohnhas

2012 PJM Reserve Requirement Study

11-year Planning Horizon: June 1st 2012 - May 31st 2023
Analysis Performed by PJM Staff

October 5, 2012

Reviewed by Resource Adequacy Analysis Subcommittee (RAAS)
DOCS #717099

Legal Notices

PJM expressly disclaims any obligation or any warranty of any kind, whether express or implied, as to any information or other matters whatsoever arising from this study. In no event shall PJM be liable for any damages of any kind, including, but not limited to, direct, indirect, general, special, incidental or consequential damages arising out of any use of the information contained herein.

2012 PJM Reserve Requirement Study (RRS)

Table of Contents — Page

Tables

Figures

Equations

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 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 FPR and DR Factor for the 2013/2014, 2014/2015, and 2015/2016 Delivery Years (DY) and establish the FPR and DR Factor for the 2016/17 Delivery Year.

- This Study is used as evidence to satisfy the North America Electric Reliability Corporation (NERC) / Reliability*First* Corporation (RFC) Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation. This Standard requires that the Planning Coordinator perform and document a resource adequacy analysis that applies a generation Loss of Load Expectation (LOLE) of one occurrence in ten years. Per the final 2010 NERC audit report, PJM was found to be 100% compliant with Standard BAL-502-RFC-02.

- Based on results from this Study (including the Appendix B sensitivity analyses), **PJM Staff recommends a 15.9% IRM for the 2013/2014 and 2014/2015** Delivery Years, **15.3% IRM for the 2015/2016** Delivery Year, and **15.6% IRM for the 2016/2017** Delivery Year.

- **The 15.6% IRM for 2016/2017 calculated in this year's study is slightly higher than the 15.4% IRM calculated for 2015/2016 in last year's study. This is the result of a flatter monthly load shape in the summer that increases the share of loss of load risk in August in comparison with last year's study.** Though the 2012 RRS model has slightly better performing units, which would tend to decrease the IRM, the flatter forecast monthly load shape more than offsets this decrease, resulting in an overall IRM increase of 0.2%. In addition, the value of the transmission ties with external regions is about the same as in the 2011 RRS model, which stabilizes the calculated IRM. (See Figures I-4, I-5, Table II-3)

- **As mentioned above, the generating unit performance characteristics improved slightly from the 2011 study.** However, this is primarily the result of the removal of below-average performing units that intend to retire in response to the implementation of the High Electric Demand Day (HEDD) and the Mercury and Air Toxic Standards (MATS) rules. (See Table II-5, and Figure I-3.)

- **The results of the 2012 RRS are summarized below. PJM Staff recommends the values shown in bold in the following chart. The RAAS unanimously endorsed this recommendation.**

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Average EEFORd	Average XEFORd	Recommended FPR	Recommended DR Factor
2012	2013 / 2014	15.92%	**15.9%**	6.73%	7.36%	6.05%	**1.0889**	**0.957**
2012	2014 / 2015	15.88%	**15.9%**	6.72%	7.36%	6.05%	**1.0889**	**0.956**
2012	2015 / 2016	15.31%	**15.3%**	6.59%	7.21%	5.91%	**1.0849**	**0.958**
2012	2016 / 2017	15.56%	**15.6%**	6.38%	6.97%	5.69%	**1.0902**	**0.955**

- For comparison purposes, the results from the 2011 RRS Study are below:

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Average EEFORd	Average XEFORd	Recommended FPR	Recommended DR Factor
2011	2012 / 2013	15 63%	15.6%	6 58%	7.13%	5.98%	1.0869	0.954
2011	2013 / 2014	15.40%	15.4%	6.52%	7.07%	5.90%	1.0859	0.956
2011	2014 / 2015	15.40%	15.4%	6.51%	7.06%	5.89%	1.0860	0.955
2011	2015 / 2016	15.39%	15.4%	6.52%	7.07%	5.90%	1.0859	0.955

- **The winter weekly reserve target for the 2012/2013 winter period is recommended to be 28%.** This is compared to the 29% value that was approved for the 2011/2012 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 on the previous page are reviewed and considered for endorsement by the following succession of groups.

    - Resource Adequacy Analysis Subcommittee (RAAS)
    - 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.

- 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), American Transmission System Inc. (ATSI),and Duke Energy Ohio and Kentucky (DEOK).

- On May 3, 2012, East Kentucky Power Cooperative (EKPC) filed a request with the Kentucky Public Service Commission to integrate its system into PJM. Pending regulatory approvals, the integration will occur on June 1, 2013. EKPC's capacity and load are not considered as part of PJM for this year's study (they are included as part of the World). Previous integration studies have indicated that the inclusion of a region of EKPC's size would have a negligible effect on the IRM.

- The Outside World (or -World") area consists of the North American Electric Reliability Corporation (NERC) regions adjacent to PJM. These regions include the U.S. portion of the Northeast Power Coordinating Council (NPCC), TVA and VACAR from the South Eastern Reliability Corporation (SERC), and the non-PJM portion of Reliability*First* Corporation (RFC).

- 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 external 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 2012 RRS, there is a net decrease of approximately 9,000 MW of generation within the PJM RTO, reflecting approximately 14,700 MW of retired generation and approximately 5,700 MW of new generation. This is over the eleven year time period of the study. The large amount of retired generation is attributed to the implementation of the High Electric Demand Day (HEDD) and the Mercury and Air Toxic Standards (MATS) rules.

- Compared to the 2011 RRS model, the 2012 RRS five-year average Effective Equivalent Demand Forced Outage Rate (EEFORd) decreased by 0.10% to 6.97%.

- The load model time period (1998-2006) is the same period as that used in the 2011 RRS Study and was endorsed on August 9, 2012 by the Planning Committee. This determination enhances stability of the underlying model and assessment results.

- For the calculated FPR, the Outside Management Control (OMC) events are excluded from the pool-wide average EFORd computation. The resulting statistic is called XEFORd and is used to calculate the FPR. eGADS users began to enter OMC events 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 Reliability*First* Corporation (RFC) Standard BAL-502-RFC-02 - Resource Planning Reserve Requirements, the 2012 RRS provides an eleven-year resource adequacy projection for the planning horizon that begins June 1, 2012 and extends through May 31, 2023. (See Table I-2)

- Results from the last twelve RRS Reports are summarized below:

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
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
2010	2012 /2013	15.5%	15.5%	6.26%	1.0827	0.954
2010	2013/2014	15.3%	15.3%	6.25%	1.0809	0.956
2010	2014/2015	15.3%	15.3%	6.25%	1.0809	0.956
2011	2012/2013	15.6%	15.6%	6.58%	1.0869	0.954
2011	2013/2014	15.4%	15.4%	6.52%	1.0859	0.956
2011	2014/2015	15.4%	15.4%	6.51%	1.0860	0.955
2011	2015/2016	15.4%	15.4%	6.52%	1.0859	0.955

- The most recently approved and recommended for approval IRM for each Delivery Year is in red text in the following link: http://pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/historical-pjm-installed-reserve-margins.ashx

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 Reliability*First* 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 serving 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), 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 PJM's load management products.

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)**

In addition to serve as inputs for the RPM market, the IRM and FPR calculated in the RRS are critical values as they satisfy compliance requirements for Reliability*First* Corporation (RFC). (See the Section Modeling and Analysis. For further details on the process, contact regional_compliance@pjm.com.)

The timetable for calculating and approving these values is shown in the April 2012 study assumptions letter to the PC, reviewed as agenda item 6 at the April 12, 2012 PC meeting.

- **DR Factor**

The DR Factor is used in RPM to determine the UCAP value of load management products and Energy Efficiency Resources. (For further details, refer to Section: Modeling and Analysis.) 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 15.9% for 2013/2014 and 2014/2015, 15.3% for 2015/2016, and 15.6% for 2016/2017 is approved by the PJM Board, the FPR and DR Factor would need to be re-calculated.

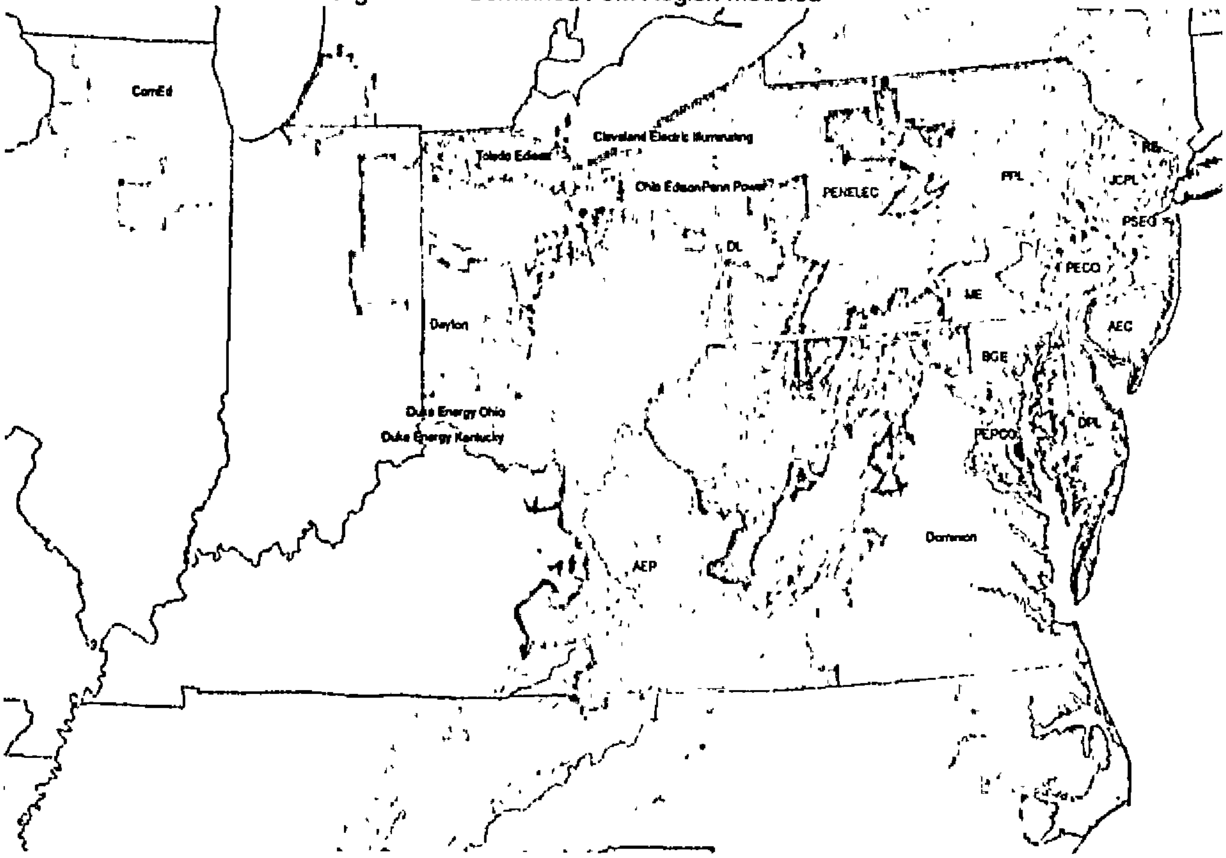
The timetable for calculating and approving the DR Factor is based on the RPM marketplace requirements.

- **Regional Modeling**

On May 3, 2012, East Kentucky Power Cooperative (EKPC) filed a request with the Kentucky Public Service Commission to integrate its system into PJM. Pending regulatory approvals, the integration will occur on June 1, 2013. EKPC's capacity and load are not considered as part of PJM for this year's study; they are included as part of the World. Previous integration studies have indicated that the inclusion of a region of EKPC's size would have negligible effects on the IRM.

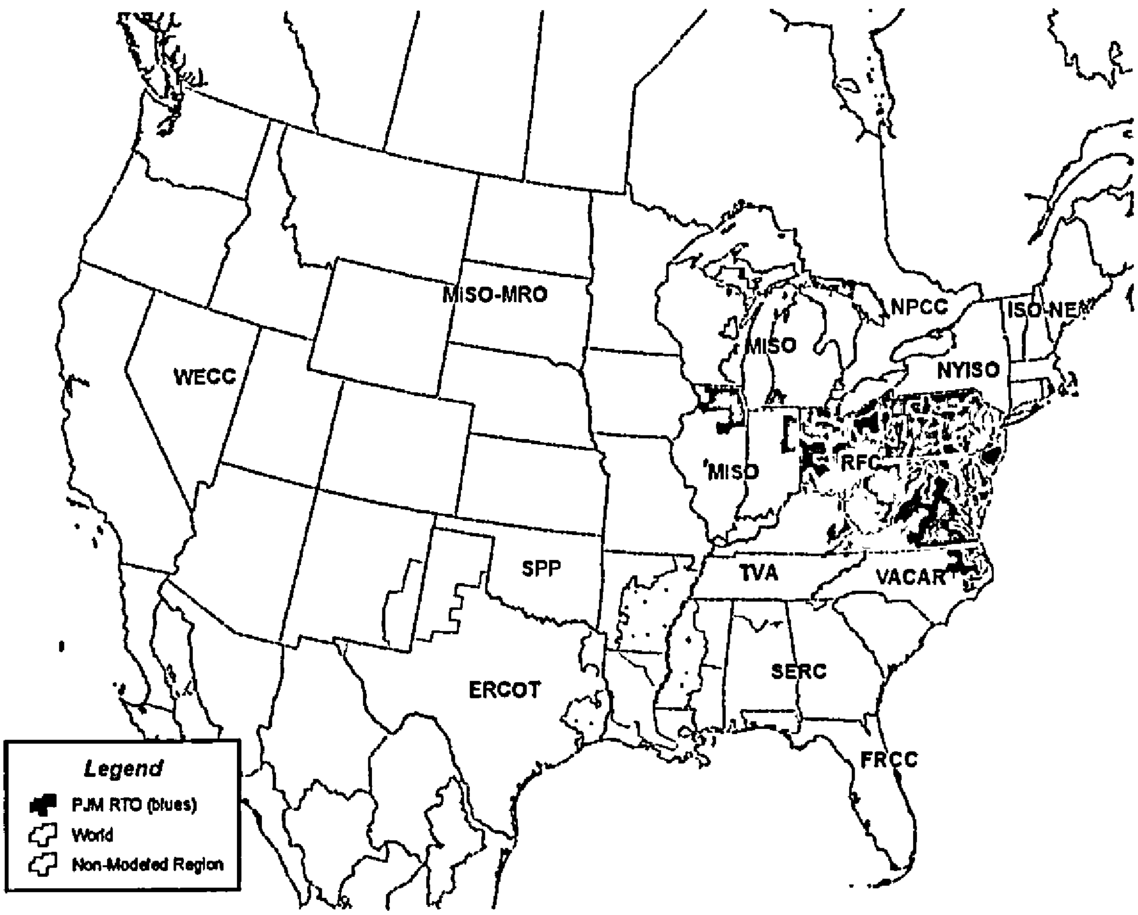
The study examines the combined PJM footprint area (Figure I-1) that consists of the PJM Mid-Atlantic Region plus Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (DOMVP), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI) and Duke Energy Ohio and Kentucky (DEOK).

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 MISO (which covers portions of RFC, SERC, and MRO), TVA and VACAR (both in SERC), and the USA portion of the Northeast Power Coordinating Council (NPCC) territory which include ISO-NE and NYISO. Areas outside of PJM and the World are not modeled in this study.

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 Years for which the parameters must be finalized are highlighted in yellow. These results do not reflect any previous modeling or approved values.

Table I - 2: Eleven-Year Reserve Requirement Study

	Calculated IRM					Forecast Reserve					Assumed IRM	
	A	B	C	D	E	F	G	H	I	J	K	L
Delivery Year	IRM PJM RTO % (2 area)	IRM Outside World %	Average PJM EEFORd %	Average Weekly Maintenance %	Forecast Pool Requirement (FPR)	Capacity MW	Restricted Load MW	Forecast Reserve PJMRTO %	Forecast Unrestricted Reserve PJM RTO %	Neighboring World region assumed reserves (1 in 10) %	Assumed IRM PJM RTO % (single area)	PJM Reliability Index (single area) Years/Day
2012	16.1%	14.9%	7.5%	6.9%	1.0887	188,141	144,645	28.7%	21.0%	14.9%	16.1%	5.4
2013	15.8%	14.8%	7.4%	7.0%	1.0889	184,257	145,526	26.6%	17.9%	14.8%	15.9%	5.4
2014	15.9%	14.8%	7.4%	6.8%	1.0889	185,147	144,673	27.8%	15.6%	14.8%	15.9%	5.3
2015	15.3%	14.8%	7.2%	6.7%	1.0849	161,733	146,199	22.8%	11.4%	14.8%	15.3%	5.1
2016	15.6%	14.9%	7.0%	6.9%	1.0902	178,837	150,722	17.2%	6.6%	14.9%	15.8%	5.2
2017	15.5%	14.9%	7.0%	6.9%	1.0893	178,645	152,484	16.0%	5.8%	14.9%	15.5%	5.2
2018	15.5%	14.8%	7.0%	6.9%	1.0894	177,161	154,063	15.0%	4.6%	14.8%	15.5%	5.3
2019	15.4%	15.0%	7.0%	6.8%	1.0885	177,181	155,891	13.8%	3.7%	15.0%	15.4%	5.2
2020	15.4%	14.8%	7.0%	6.9%	1.0885	177,181	157,824	12.3%	2.5%	14.8%	15.4%	5.1
2021	15.5%	15.0%	7.0%	6.9%	1.0894	177,181	159,689	11.0%	1.4%	15.0%	15.5%	5.2
2022	15.6%	15.0%	7.0%	6.8%	1.0903	177,161	161,451	9.7%	0.4%	15.0%	15.6%	5.2
11-year Average	15.6%	14.9%	7.1%	6.8%	1.0888	179,888	152,303	18.2%	8.3%	14.9%	15.6%	5.2

- **Calculated IRM Columns** (PRISM Run # 8115)
  - Calculated IRM, column A is at an LOLE criterion of 1 day in 10 years.
  - Column A is based on the PRISM solved load, not the January 2012 load forecast values issued by PJM. See page 18 for further details.
  - Calculated IRM, column B is at an LOLE criterion of 1 day in 10 years which is within the range shown in Figure I-4.
  - Results reflect "calculated" (to the nearest decimal) reserve requirements for the PJM RTO (column A) and the Outside World (column B).
  - Calculated IRM results are determined using a 3,500 MW Capacity Benefit Margin (CBM).
  - 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 1,500 units). These are not the forced outage rates to be used in the RAA Obligation formula (as mentioned earlier in the document, XEFORd values are used in the FPR formula). The EEFORd of each unit is based on a five-year period (2007-2011, for this year's study).
  - The average weekly maintenance (column D) is the percentage of the average annual total capacity in the model out on weekly planned maintenance.

- **Forecast Reserve Columns**

  - The capacity values in Column F include external PJM capacity purchases and sales per the EIA-411 Schedule 4 and the RPM database.
  - 2,500 MW of unit deratings were modeled to reflect generator performance impacts during extreme hot and humid summer conditions. These 2500 MW are included in the Column F value.
  - The Restricted Load in Column G corresponds to Total Internal Demand (at peak time) minus load management (DR and Energy Efficiency Resources).
  - The PJM forecast reserves for this study's eleven year period are above the calculated requirement (see Column H vs. Column A for years in yellow).
  - Reserves in Column H (as well as the capacity value in Column A) include about 5,700 MW of new generation projects identified through the Regional Transmission Expansion Plan (RTEP). All modeled generation projects have a commercial probability assigned to them. The commercial probability was computed by fitting a logistic regression model to the historical data found in PJM's Generation Interconnection queue.
  - Column H (and Column A) also reflect about 14,700 MW of announced generator retirements. Most of these retirements are in response to the implementation of the High Electric Demand Day (HEDD) and the Mercury and Air Toxic Standards (MATS) rules.
  - 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.
  - Forecast reserves for the neighboring World region (column I) are expressed as a percentage of total internal demand. The valid range of World reserves is shown in Figure I – 4, from 14.61 % to 21.52 %. The exact World reserve value depends on World load management actions at the time of the PJM RTO need for assistance. The World reserve level that yields an RI equal to an LOLE of 1 day in 10 years (14.8%-14.9%) is within the valid range and the associated World load management value was judged to be reasonable.

- **Assumed IRM Columns** (PRISM Run # 8147)

  - The IRM for the PJM RTO in column J is an assumed value. This is intended for information in the stakeholder review, endorsement and ultimately, PJM Board approval.
  - Column J values are used to determine the Column K values. 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 (in other words, this is a "zero import capability" scenario).
  - 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 is much lower. This comparison provides a sense of the value of PJM being strongly interconnected. More specifically, 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.

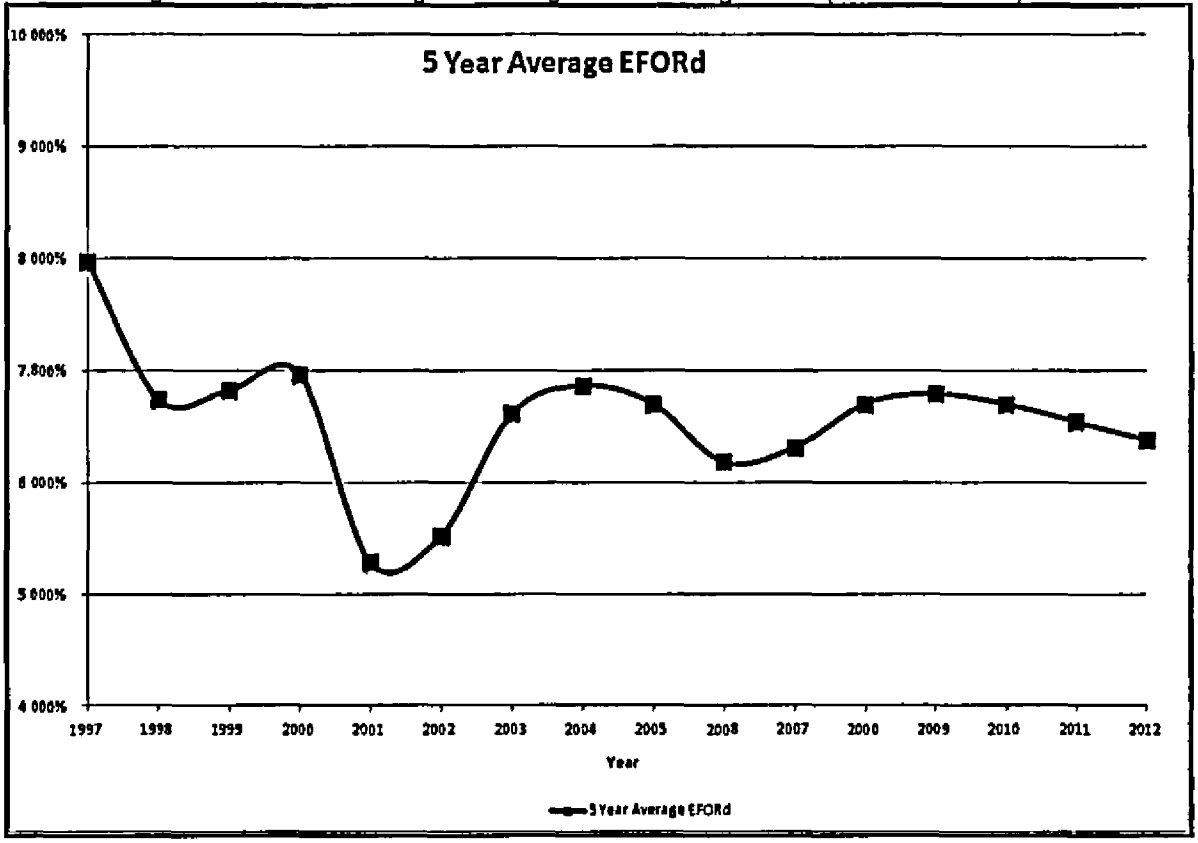
Key Observations

- **General Trends and Observations**
    - There is a slight improvement in unit performance in the 2012 study model, compared to the 2011 study model, which has a negligible effect on the IRM. Rolling the 2011 GADS data into the model and rolling the 2006 data out increases the average EEFORd, increasing the IRM. This effect is offset by the large amount of below-average performing units that are retired throughout the years of the study. These retirements tend to lower the average EEFORd, decreasing the IRM. Overall, the change on unit performance between 2011 and 2012 has a negligible effect on the IRM.
    - Considering long-term trends without focusing exclusively on individual study results is important when developing an IRM recommendation. Significant long-term trends in the study include: the historic trend of forced outage rates, assistance from neighboring systems, and forecasted load model shapes and associated uncertainties. In addition, the selection process for the load model time period (see Agenda item 7 at August 2012 PC Meeting) helps to produce a more stable calculated IRM as it reduces the fluctuation in the tie benefit that had been observed in previous studies.
    - Pool wide average forced outage rate values (EFORDs), in each of the 16 annual RRS capacity models, are shown in Figure I-3. The forced outage rates shown are based on the five-year period used in a given study. It is important to note that the collection of generators that contributes to each year's values varies greatly over time as new generators are brought in-service, some generators retire or mothball, and new generators are added due to PJM market expansion. These variations notwithstanding, the 5 year weighted-average exhibits a levelized trend (within the 6.9% - 6.1% range) in recent RRS capacity models.
    - 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.

PJM Staff coordinates the statistical parameters used in the RRS with those available on the PJM website'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 website, along with PJM Manual 22, contains 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.

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



The World reserves were assessed and modeled in a similar manner as performed in the 2011 RRS, per the Study assumptions. This modeling of World forecast reserves considered only those regions adjacent to the PJM RTO. Among them, the New York, New England and MISO regions have firm reserve requirements, while the TVA and VACAR regions have soft targets. The soft targets chosen are consistent with general statements of the NERC targets for these regions. Figure I - 4 summarizes the values used to determine a valid range for a World reserve level of 14.61 % to 21.52 %. The reserve requirements considered are shown in the IRM column. The diversity values shown are from an assessment of 15 years of historic data, using the average of the values seen over the summer season. See Table II – 3 for further details. Please reference Appendix F which presents a discussion of the modeling assumptions. After discussions with the RAAS, it was determined that the appropriate choice for World reserves is that one that satisfies the 1 in 10 reliability criteria for the World. This value is 14.91% and it is within the valid range shown in Figure I-4.

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

	NCP 2012	IRM	Diversity	CP 2012	LM 2012	LM as % NCP	NCP-LM (NID)	CAP based on NID	CP-LM	Reserves as % of CP	Reserves as % of CP-LM
NY	33295	16.0%	0.9540	31783	1862	5 59%	31433	36462	29901		
NE	27440	13.9%	0.9540	26178	2106	7.67%	25334	28855	24072		
MISO	75326	16.7%	0 9540	71861	4529	6.01%	70797	82620	67332		
TVA	36330	15.0%	0.9540	34659	1288	3.55%	35042	40298	33371		
VACAR	44046	15.0%	0.9540	42020	1944	4.41%	42102	48417	40078		
Total Composite Region =	216437			208481	11729	5 42%	204708	236653	194752	14 61%	21.52%

LM: Load Management NCP: Non-Coincident Peak CP: Coincident Peak

Data

NY and NE - NPCC Reliability Assessment for Summer 2012, Appendix VIII, Table 3a, April 2012
Available at http://www.npcc.org/Library/Seasonal%20Assessment/NPCC_2012_Summer_Reliability_Assessment_Final_Report.pdf
MISO - Planning Year 2012 LOLE Study Report, Section 2.3.1, November 2011
MISO as per old NERC boundaries "MAIN Other" plus "ECAR Other" excluding ATSI and Duke - The word "Other" indicates that any PJM footprint model is removed
Available at https://www midwestiso.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report pdf
TVA and VACAR - 2011 NERC ES&D Report
Schedule 3A, Total Internal Demand (Code=S02) 2nd Year column. TVA = SERC N x Factor Table, VACAR = SERC E
NE, NY, and MISO are modeled at their approved IRMs as per the documents below:
http://www iso-ne com/genrtion_resrcs/reports/nepool_oc_review/2012/icr_2015_2016_report_final pdf
http://www nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2012_GoldBook pdf
http://www.midwestiso.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report pdf
TVA and VACAR are modeled at the soft target IRM of 15%.

- Load diversity between PJM and the World is addressed by two modeling assessments. First, the number of years used in the hourly load model is determined by an established process, as approved at the August 2012 PC meeting (Agenda item 7). Second, the world monthly peak forecast corresponds to a coincident peak for the six individual sub-regions in the World model. This modeling stabilizes the load diversity between PJM and the World when comparing various studies' models from previous years.

- 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 best known target IRM 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 (at 14.61%) represents the World reserve level if no World load management were implemented with all such customers consuming at their maximum rates. The higher end (at 21.52%) 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 the impact of additional World Reserves on PJM's IRM is minimal when World Reserves are above 13%.

- **The PJM IRM at this "1 in 10" World reserve level is 15.56%. This is the basis for the recommended IRM, for Delivery Year 2016, of 15.6%.**

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

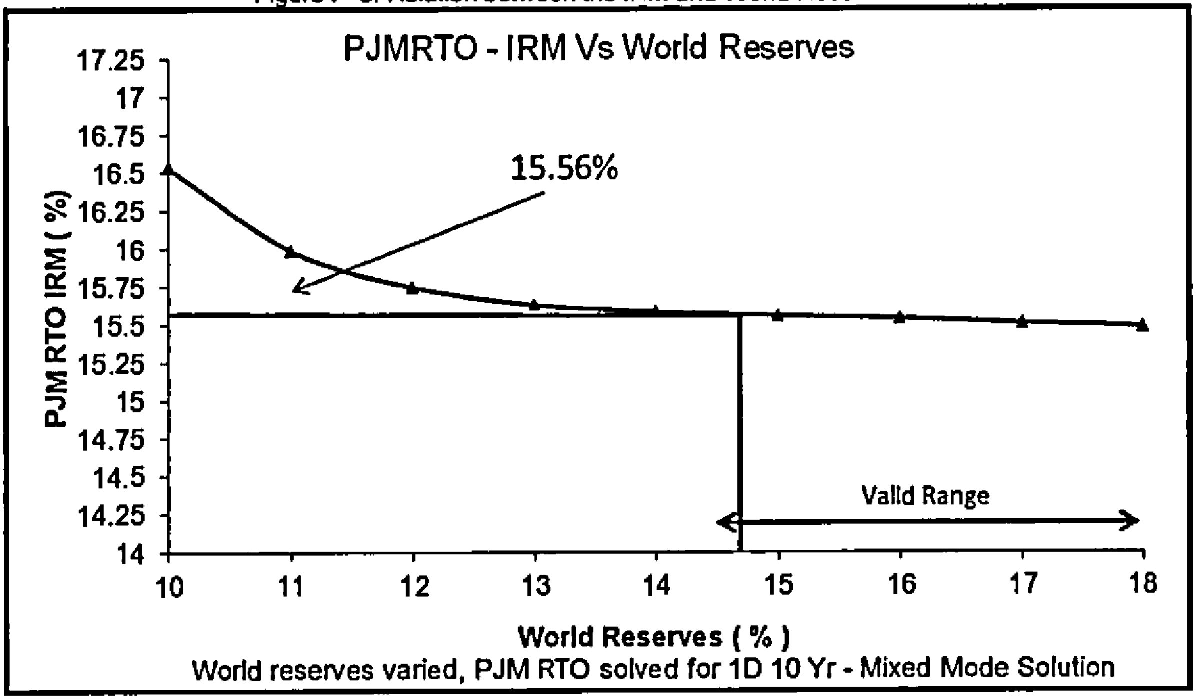
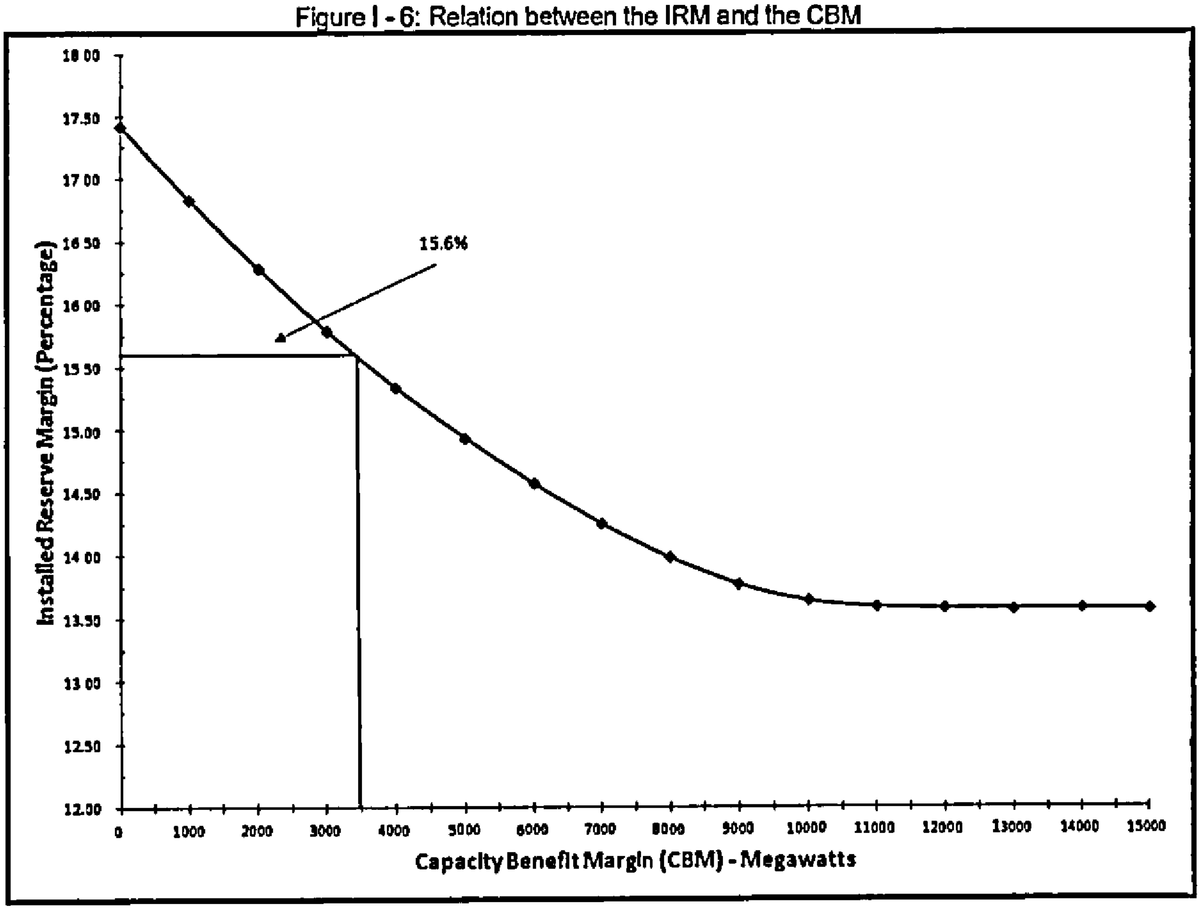


Figure I - 6: Relation between the IRM and the CBM



- 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 15.6%. Thus, the PJM IRM is reduced by 1.87% due to the CBM (from 17.4%, the intercept with the y-axis, to 15.6 %). Based on the forecasted load for 2016/2017, this 1.87% IRM reduction eliminates the need for about 165,691 MW x 1.87% =3,093 MW of installed capacity.

- This study used the load management and energy efficiency values from the recent January 2012 PJM Load Forecast Report, Table B-8, and recent load forecasts in line with known RPM auction results. The amount of load management and energy efficiency does not affect the IRM or the FPR. It does have an impact though on the DR Factor.

- A comparison between recent neighboring region's models and reports to the values used per the PJM study assumptions show that the World units may have a 1% lower forced outage rate. Sensitivity analysis, number 16 (see Appendix B), indicates no change (0.0001) in the PJM RTO IRM if all World units had a 1% change in their forced outage rate.

- Per the Sensitivities, contributing characteristics to the final calculated IRM of 15.6%include:
    - Unit performance => 8.9% - #15
    - Load Uncertainty => 4.2 % - # 7
    - Transmission (CBM) => 1.9 % + #21
    - Ambient impact on Units => 1.6% - #11
  - The contributions to the overall reserve level, from these individual characteristics, were similar in the previous 2011 RRS.

- Compared to the 2011 RRS, there are changes in the performance of generation units considered in the 2012 case. A summary of these changes for the most important unit types is below:

  - Coal and oil units exhibit a decreased performance (increase in forced outage rate).
  - Gas units exhibit an increase in performance (decrease in forced outage rate).
  - Combined Cycle units were slightly worse performing (increase in forced outage rate).
  - Pumped Hydro Units were slightly worse performing (increase in forced outage rate).
  - Overall, the existing units exhibited a slightly lower performance than in the 2011 RRS. However, the average EEFORd is very similar to that in the 2011 RRS, since this lower performance is offset by the retirement of several below-than-average performing units.

- The underlying modeling characteristics of 1) Load 2) Generation 3) Neighboring region reserves and tie size are the primary drivers for this study. Although consideration of the amount in MW of either load or generation can be a factor, it is not as significant due to the method used to adjust an area's load to its 1 day in 10 year level. Small changes to the parameters that capture uncertainties associated with load (FEF, STD, weekly and monthly shape) and generation (EEFORd, Variance, POF) can have non-trivial impacts on the assessment results.

- The reported CBOT value of 3093 MW is related to the total 3500 CBM value, with the 3093 MW value a mathematical expectation. The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor. The expected value is not something that is "expected" in the ordinary sense but is actually the long term average as the number of trials increase to infinity. It is often called the population mean. There are times in the assessment calculations when a value of the CBOT population does equal 3500 MW[1].

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[1] Power System Reliability Evaluation, Mathematical Expectation - page 12, Gordon and Beach, Science Publishers, –1970 – by Roy Billinton.

- When reserve requirements for the PJM RTO are compared to those of neighboring regions, the PJM requirements are similar on a coincident peak, unforced basis. See Appendix D 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 15.9% for 2013/2014 and 2014/2015 Delivery Years, 15.3% for 2015/2016 Delivery Year, and 15.6% for 2016/2017 Delivery Year. The IRM is applied to the official PJM Summer Peak Forecast. The Resource Adequacy Analysis Subcommittee reviewed these study results.

  Use of PRISM Peak Solution load for IRM

  - 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. 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 Avg. XEFORd)

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

2013 / 2014 Delivery Year	FPR = (1.159) * (1 – 0.0605) = **1.0889**
2014 / 2015 Delivery Year	FPR = (1.159) * (1 – 0.0605) = **1.0889**
2015 / 2016 Delivery Year	FPR = (1.153) * (1 – 0.0910) = **1.0849**
2016 / 2017 Delivery Year	FPR = (1.156) * (1 – 0.0569) = **1.0902**

- Demand Resource Factor (DR Factor) — The DR Factor is based on the approved IRM. The DR Factor is a measure of the reliability value of demand resources and energy efficiency resources. The load carrying capability of these resources is divided by the total amount of (DR+ EE) to yield the factor.

2013 / 2014 Delivery Year	**DR Factor =** 9,563 / 9,997 = **0.957**
2014 / 2015 Delivery Year	**DR Factor =** 13,540 / 14,165 = **0.956**
2015 / 2016 Delivery Year	**DR Factor =** 13,702 / 14,306 = **0.958**
2016 / 2017 Delivery Year	**DR Factor =** 13,668 / 14,306 = **0.955**

- Winter Weekly Reserve Target — **the recommended 2012 / 2013 winter weekly reserve target is 28%.** This recommendation is discussed later in the report and was unanimously endorsed by the RAAS.

Part II – Modeling and Analysis

Load Forecasting

- **PJM Load Forecast – January 2012 Load Report**

The January 2012 PJM Load Forecast is used in the 2012 RRS. The load report is available on the PJM web site at: http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2012-pjm-load-report.ashx. The methods and techniques used in the load forecasting process are documented in Manual 19 (Load Forecasting and Analysis).

- **Monthly Forecasted Unrestricted Peak Demand and Demand Resources**

The monthly loads used in the RRS are based on the forecasted monthly unrestricted peak loads. PJM monthly loads are from the 2012 PJM Load Forecast report. World loads are derived from NERC's Electric Supply and Demand (ES&D) 2011 data and coordination with neighboring regions' staffs.

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. The values in Table II-1 are shown in per-unit, based on the annual peak.

The total amount of Load Management (LM), including demand resources, in the current load forecasting efforts, which include updated RPM auction results, were used in this assessment per the following table:

	2012/2013 DY	2013/2014 DY	2014/2015 DY	2015/2016 DY	All following DYs
Total LM =	9,137 MW	10,726 MW	14,969 MW	14,969 MW	14,969 MW

Table II - 1: Load Forecast for 2016 / 2017 Delivery Years

		PJMRTO	WORLD
Delivery Year	Month	Unrestricted Loads	Unrestricted Loads
2016 / 2017	January	0.836298	0.837642
	February	0.805850	0.820575
	March	0.737222	0.755178
	April	0.687925	0.700767
	May	0.777339	0.790767
	June	0.937866	0.911630
	July	1.000000	0.954211
	August	0.960215	1.000000
	September	0.852195	0.864063
	October	0.684111	0.733068
	November	0.723111	0.739488
	December	0.813762	0.818609

- **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 was 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 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 daily peak load distributions aggregated on a weekly basis. The RRS uses a standard normal distribution as the forecast daily distribution. The standard normal distribution is represented using 21 points with a range of +/- 4.2 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 for further details.

  The 2012 RRS performed sensitivity analysis to determine the PJM IRM using truncated normal distributions (Refer to sensitivity 10 of Appendix B for details).

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

  The load model used to perform LOLE studies is developed using an application called WKPKFQ. The application's primary input is hourly data, determining the daily peak's mean and standard deviation for each week. Each week within each season for a year of historical data is magnitude ordered (highest to lowest) and those weeks are averaged across years to replicate 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. The resulting output is 52 weekly means and standard deviations that represent parameters for the daily normal distribution. The beginning of Week 1 corresponds to May 15th. Table II-2 shows these results of PJM RTO WKPKFQ run 2304 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 this link.

Table II - 2: PJM RTO Load Model Parameters (PJM LM 2304)

ARC WEEK	MEAN SEASONAL TREND	STANDARD DEVIATION
1	0.688548	0.041613
2	0.669161	0.040324
3	0.739888	0.061474
4	0.797426	0.063872
5	0.821017	0.068772
6	0.876655	0.063247
7	0.876759	0.07613
8	0.885508	0.032296
9	0.894968	0.083414
10	1	0.070239
11	0.936357	0.060174
12	0.969092	0.071881
13	0.940473	0.061649
14	0.891433	0.071047
15	0.841776	0.067275
16	0.832126	0.042733
17	0.753555	0.073324
18	0.772784	0.065183
19	0.721194	0.047237
20	0.66612	0.0211
21	0.717518	0.05327
22	0.672506	0.025555
23	0.678221	0.02813
24	0.688868	0.027603
25	0.696914	0.02757
26	0.705432	0.033035

ARC WEEK	MEAN SEASONAL TREND	STANDARD DEVIATION
27	0.720303	0.033561
28	0.73732	0.032316
29	0.734387	0.045706
30	0.787021	0.041608
31	0.789057	0.057854
32	0.805156	0.04864
33	0.761375	0.056108
34	0.807388	0.059054
35	0.778474	0.060639
36	0.812573	0.068082
37	0.833297	0.0587
38	0.769935	0.05218
39	0.775603	0.05091
40	0.754094	0.051492
41	0.756141	0.078753
42	0.752625	0.03401
43	0.764668	0.043285
44	0.706663	0.036085
45	0.722182	0.038668
46	0.685123	0.037949
47	0.6706	0.030441
48	0.658748	0.030422
49	0.682664	0.041914
50	0.657842	0.020841
51	0.668594	0.024189
52	0.720854	0.101314

Parameter	Value
Title	RRS2012 9YR
Description	PJM RTO 9 yr LM 98-06, 2012 Start, 2022 End, 2012 LF
Year Range	1998 - 2006
Growth Factor	0.011932885
Growth Start Year	2012/2013
Growth End Year	2022/2023
Report Select	1
Zones	AE*1,BGE*1,DPL*1,DUKE*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,VEPCO*1
Exclude Weekends	Y
Exclude Holidays	Y
Excluded Holidays	1,2,3,4,5,6,7,8

See "PJM Generation Adequacy Analysis: Technical Methods", dated October 2003 for discussion of how the daily LOLE is determined, at http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx. 52 weekly LOLEs are summed to get the annual LOLE.

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 assessed in the selection of the most appropriate load model time period for use in the RRS. A comprehensive method to evaluate and choose load models, with diversity as one of the considerations, was approved by the Planning Committee and used for the 2012 RRS. See Appendix E of the 2009 RRS report (http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2009-pjm-reserve-requirement-study.ashx) for further details about the approach.

During the 2010 RRS, historic hourly data was examined to determine the timing of the coincident peak of the composite World region. The sub-regions of the composite World regions were analyzed and it was determined that the composite World region typically peaks in August.

In the investigation of diversity, the historic hourly load data was used to show the monthly shape on an annual basis. An average monthly shape is calculated, 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.

To examine seasonal diversity, an average of all historic years was used. 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	2008	2009	diversity range	14 year avg
Winter*	4.22%	7.07%	4.03%	5.03%	10.27%	5.73%	8.05%	14.24%	8.76%	5.59%	7.19%	10.82%	4.94%	8.10%	8.15%	1995-2008	7.29%
Summer	3.84%	4.10%	5.45%	2.17%	4.10%	4.81%	2.80%	3.10%	8.91%	8.27%	4.98%	2.98%	8.40%	6.20%	4.75%	1995-2009	4.40%
Spring	4.37%	3.83%	8.85%	5.93%	8.34%	4.41%	8.23%	14.95%	16.80%	4.65%	10.00%	1.36%	7.07%	15.68%	9.76%	1995-2009	8.02%
Fall	5.37%	3.46%	1.62%	3.57%	4.40%	4.92%	5.44%	3.78%	11.26%	4.58%	6.00%	5.53%	3.99%	7.30%	4.50%	1995-2009	6.10%

MONTH NUMBER	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	diversity range	Average Diversity Using Aug Peak Years Only
1	87.4%	87.9%	88.4%	77.8%	85.4%	94.3%	83.2%	77.8%	84.9%	89.3%	82.4%	89.2%	76.8%	86.5%	90.4%	1995-2009	85.76%
2	86.9%	94.7%	80.9%	78.5%	79.3%	85.3%	76.4%	78.5%	82.0%	84.0%	73.9%	70.7%	80.8%	78.8%	88.3%	1995-2009	82.06%
3	78.6%	86.9%	72.7%	80.5%	77.1%	74.3%	74.4%	73.5%	73.8%	77.6%	72.9%	87.4%	70.3%	75.7%	82.4%	1995-2009	75.82%
4	71.8%	73.7%	71.5%	57.9%	67.5%	71.3%	66.2%	73.1%	71.4%	72.9%	84.4%	81.9%	63.0%	66.2%	72.9%	1995-2009	70.08%
5	76.0%	88.8%	72.5%	82.8%	72.9%	86.8%	73.9%	75.4%	71.1%	88.5%	86.2%	81.5%	77.9%	73.2%	71.2%	1995-2009	79.08%
6	86.4%	81.6%	97.7%	97.4%	93.2%	93.4%	88.9%	61.8%	93.4%	93.3%	92.9%	85.8%	82.5%	99.4%	87.7%	1995-2009	91.16%
7	100.0%	98.2%	100.0%	100.0%	100.0%	94.8%	95.8%	98.9%	93.7%	98.4%	100.0%	97.0%	81.8%	100.0%	90.7%	1995-2009	95.42%
8	99.6%	100.0%	91.5%	95.6%	96.9%	100.0%	100.0%	100.0%	100.0%	100.0%	86.8%	100.0%	100.0%	85.8%	100.0%	1995-2009	100.00%
9	83.6%	92.7%	90.0%	86.0%	88.9%	98.9%	83.4%	91.9%	82.6%	88.4%	87.6%	72.2%	86.6%	87.1%	79.8%	1995-2009	86.41%
10	71.1%	66.6%	78.4%	73.0%	70.6%	79.9%	68.1%	86.5%	71.2%	75.0%	75.6%	68.2%	79.7%	70.6%	68.1%	1995-2009	73.31%
11	78.5%	78.3%	79.7%	71.9%	79.2%	84.1%	66.3%	71.9%	79.6%	79.2%	71.5%	97.9%	88.6%	76.6%	72.2%	1995-2009	73.95%
12	86.6%	85.6%	83.0%	79.7%	78.7%	61.4%	73.2%	90.3%	81.7%	90.2%	80.4%	75.0%	70.8%	83.1%	91.9%	1995-2009	81.86%

*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 2008 only use one month of data, December 2009. This value should be disregarded.
*Average Diversity for Winter was recalculated to not include 2009

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 the eGADS' help selection available through the PJM site at: https://egads.pjm.com/pjmpgads/login .

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://standards.ieee.org/findstds/standard/762-2006.html

The PJM Reliability Assurance Agreement (RAA), Schedule 4 and Schedule 5 are related to the concepts used in generation forecasting.

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 process is called blending. Blending is therefore used for future units, neighboring system units, and for those PJM units with less than five years of GADS events. The term blending is used when a given generating unit does not have actual reported outage events for the full five-year period being evaluated.

The 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 73 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 (2007-2011 for 2012 RRS). A generator class category is given for each unit type, primary fuel and size of unit. 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 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. 14 indicates that a 1% increase in the pool-wide EEFORd will cause a 1.35% increase in the IRM – indicating a direct, positive correlation between unit performance and the solved IRM.

- **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 Resource Adequacy Planning Staff. This review 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, EEFORd and XEFORd**

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. 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.

  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 ($EEFOR_d$)

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

  The statistic used for MO is the equivalent maintenance outage factor (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.

- **EFORd Excluding Outside Management Control (OMC) Events (XEFORd)** – 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.

For the calculated FPR, the pool-wide average EFORd value excludes outage events considered outside management control. Determining the FPR in this manner is consistent with the way that generator unforced capacity (UCAP) values are determined in the PJM capacity market. The reported EFORd value is directly from the level II clean eGADS event submissions, for each unit.

Table II - 4: PJM RTO Fleet Class Average Generation Performance Statistics (2007-2011)

Start Date	End Date	Unit Type & Primary Fuel Category	Gen Class Key	POF Weeks/Year	EFORd	EEFORd	EMOF	Variance	XEFORd
1/1/2007	12/31/2011	FOSSIL All Fuel Types All Sizes	1	4	10.67%	11.61%	1.89	12314	9.80%
1/1/2007	12/31/2011	FOSSIL All Fuel Types 001-099	2	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL All Fuel Types 100-199	3	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL All Fuel Types 200-299	4	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL All Fuel Types 300-399	5	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL All Fuel Types 400-599	6	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL All Fuel Types 600-799	7	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL All Fuel Types 800-999	8	4	7.11%	7.88%	1.61	74348	6.98%
1/1/2007	12/31/2011	FOSSIL All Fuel Types 1000 Plus	9	4	7.11%	7.88%	1.61	74348	6.98%
1/1/2007	12/31/2011	FOSSIL Coal Primary All Sizes	10	4	10.67%	11.61%	1.89	12314	9.80%
1/1/2007	12/31/2011	FOSSIL Coal Primary 001-099	11	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL Coal Primary 100-199	12	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL Coal Primary 200-299	13	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Coal Primary 300-399	14	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Coal Primary 400-599	15	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Coal Primary 600-799	16	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Coal Primary 800-999	17	4	7.11%	7.98%	1.61	74348	6.96%
1/1/2007	12/31/2011	FOSSIL Coal Primary 1000 Plus	18	4	7.11%	7.88%	1.61	74348	6.98%
1/1/2007	12/31/2011	FOSSIL Oil Primary All Sizes	19	4	10.67%	11.61%	1.89	12314	9.80%
1/1/2007	12/31/2011	FOSSIL Oil Primary 001-099	20	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL Oil Primary 100-199	21	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL Oil Primary 200-299	22	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Oil Primary 300-399	23	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Oil Primary 400-599	24	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Oil Primary 600-799	25	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Oil Primary 800-999	26	4	7.11%	7.88%	1.61	74349	6.98%
1/1/2007	12/31/2011	FOSSIL Gas Primary All Sizes	28	4	10.67%	11.61%	1.89	12314	9.80%
1/1/2007	12/31/2011	FOSSIL Gas Primary 001-099	29	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL Gas Primary 100-199	30	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL Gas Primary 200-299	31	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Gas Primary 300-399	32	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Gas Primary 400-599	33	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Gas Primary 600-799	34	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Gas Primary 800-999	35	4	7.11%	7.88%	1.61	74348	6.98%
1/1/2007	12/31/2011	FOSSIL Lignite Primary All Sizes	37	4	10.67%	11.61%	1.89	12314	9.80%
1/1/2007	12/31/2011	NUCLEAR All Types	38	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR All Types	39	3	2.72%	2.99%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR All Types	40	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR All Types	41	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR PWR All Sizes	42	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR PWR 400-799	43	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR PWR 800-999	44	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR PWR 1000 Plus	45	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR BWR All Sizes	46	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR BWR 400-799	47	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR BWR 800-999	48	3	2.72%	2.69%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR BWR 1000 Plus	49	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	NUCLEAR CANDU All Sizes	50	3	2.72%	2.89%	0.36	27063	2.43%
1/1/2007	12/31/2011	JET ENGINE All Sizes	51	1	11.97%	12.51%	1.12	399	10.26%
1/1/2007	12/31/2011	JET ENGINE 001-019	52	1	15.67%	16.38%	1.04	25	14.47%
1/1/2007	12/31/2011	JET ENGINE 20 Plus	53	2	11.47%	12.00%	1.11	140	10.06%
1/1/2007	12/31/2011	GAS TURBINE All Sizes	54	1	11.97%	12.51%	1.12	399	10.26%
1/1/2007	12/31/2011	GAS TURBINE 001-019	55	1	15.67%	16.38%	1.04	25	14.47%
1/1/2007	12/31/2011	GAS TURBINE 020-049	56	2	11.47%	12.00%	1.11	140	10.06%
1/1/2007	12/31/2011	GAS TURBINE 50 Plus	57	2	9.51%	10.09%	1.16	870	7.35%
1/1/2007	12/31/2011	COMBINED CYCLE All Sizes	58	3	7.27%	7.91%	1.05	2525	6.17%
1/1/2007	12/31/2011	HYDRO All Sizes	59	4	10.18%	10.64%	0.91	14	8.75%
1/1/2007	12/31/2011	HYDRO 001-029	60	4	10.18%	10.64%	0.91	14	8.75%
1/1/2007	12/31/2011	HYDRO 30 Plus	61	4	10.18%	10.64%	0.91	14	8.75%
1/1/2007	12/31/2011	PUMPED STORAGE All Sizes	62	4	2.78%	3.10%	0.67	1383	2.34%
1/1/2007	12/31/2011	MULTIBOILER/MULTI-TURBINE All Sizes	63	4	10.67%	11.61%	1.99	12314	9.80%
1/1/2007	12/31/2011	DIESEL Landfill	64	0	18.09%	18.45%	0.46	3	18.21%
1/1/2007	12/31/2011	DIESEL All Sizes	65	0	9.35%	9.78%	0.75	2	8.14%
1/1/2007	12/31/2011	FOSSIL Oil/Gas Primary All Sizes	66	4	10.67%	11.61%	1.99	12314	9.80%
1/1/2007	12/31/2011	FOSSIL Oil/Gas Primary 001-099	67	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL Oil/Gas Primary 100-199	68	3	10.96%	12.01%	1.98	1398	10.25%
1/1/2007	12/31/2011	FOSSIL Oil/Gas Primary 200-299	69	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Oil/Gas Primary 300-399	70	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Oil/Gas Primary 400-599	71	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Oil/Gas Primary 600-799	72	5	10.72%	11.59%	1.80	21179	9.47%
1/1/2007	12/31/2011	FOSSIL Oil/Gas Primary 800-999	73	4	7.11%	7.88%	1.61	74348	6.98%
1/1/2007	12/31/2011	Wind All sizes	74	0	0.00%	0.00%	0	0	0.00%
1/1/2007	12/31/2011	Solar All sizes	75	0	0.00%	0.00%	0	0	0.00%

Table II - 5: Comparison of Class Average Values - 2011 RRS vs. 2012 RRS

Unit Type & Primary Fuel Category	Gen Class Key	POF Change Weeks/Year	EFORd Change	EEFORd Change	XEFORd Change	EMOF Change	Variance Change
FOSSIL All Fuel Types All Sizes	1	-3	3.55%	3.90%	5.69%	-0.46%	6099
FOSSIL All Fuel Types 001-099	2	-2	2.12%	2.70%	6.06%	0.06%	1114
FOSSIL All Fuel Types 100-199	3	-3	4.07%	4.43%	6.25%	-0.60%	-1247
FOSSIL All Fuel Types 200-299	4	-1	3.63%	3.82%	4.63%	-0.95%	17608
FOSSIL All Fuel Types 300-399	5	-2	5.04%	5.35%	6.43%	-0.45%	17149
FOSSIL All Fuel Types 400-599	6	-3	3.65%	3.94%	5.20%	-0.51%	14390
FOSSIL All Fuel Types 600-799	7	-4	3.53%	3.90%	4.92%	-0.21%	11352
FOSSIL All Fuel Types 800-999	8	-4	3.72%	4.03%	4.76%	-0.22%	68674
FOSSIL All Fuel Types 1000 Plus	9	-5	-1.25%	-1.09%	1.33%	-0.66%	48513
FOSSIL Coal Primary All Sizes	10	-2	3.76%	4.08%	5.56%	-0.59%	7891
FOSSIL Coal Primary 001-099	11	0	-0.45%	-0.22%	-0.50%	0.36%	169
FOSSIL Coal Primary 100-199	12	0	-0.45%	-0.22%	-0.50%	0.36%	169
FOSSIL Coal Primary 200-299	13	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Coal Primary 300-399	14	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Coal Primary 400-599	15	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Coal Primary 600-799	16	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Coal Primary 800-999	17	0	1.10%	1.35%	1.03%	0.53%	9439
FOSSIL Coal Primary 1000 Plus	18	0	1.10%	1.35%	1.03%	0.53%	9439
FOSSIL Oil Primary All Sizes	19	-6	-5.21%	-4.79%	4.32%	-0.17%	4156
FOSSIL Oil Primary 001-099	20	0	-0.45%	-0.22%	-0.50%	0.36%	169
FOSSIL Oil Primary 100-199	21	0	-0.45%	-0.22%	-0.50%	0.36%	169
FOSSIL Oil Primary 200-299	22	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Oil Primary 300-399	23	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Oil Primary 400-599	24	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Oil Primary 600-799	25	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Oil Primary 800-999	26	0	1.10%	1.35%	1.03%	0.53%	9439
FOSSIL Gas Primary All Sizes	28	-2	3.78%	4.18%	6.58%	-0.26%	6809
FOSSIL Gas Primary 001-099	29	0	-0.45%	-0.22%	-0.50%	0.36%	169
FOSSIL Gas Primary 100-199	30	0	-0.45%	-0.22%	-0.50%	0.36%	169
FOSSIL Gas Primary 200-299	31	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Gas Primary 300-399	32	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Gas Primary 400-599	33	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Gas Primary 600-799	34	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Gas Primary 800-999	35	0	1.10%	1.35%	1.03%	0.53%	9439
FOSSIL Lignite Primary All Sizes	37	-2	4.64%	5.44%	6.47%	0.55%	6380
NUCLEAR All Types	38	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR All Types	39	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR All Types	40	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR All Types	41	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR PWR All Sizes	42	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR PWR 400-799	43	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR PWR 800-999	44	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR PWR 1000 Plus	45	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR BWR All Sizes	46	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR BWR 400-799	47	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR BWR 800-999	48	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR BWR 1000 Plus	49	0	0.32%	0.32%	0.06%	-0.01%	3503
NUCLEAR CANDU All Sizes	50	0	0.32%	0.32%	0.06%	-0.01%	3503
JET ENGINE All Sizes	51	-1	2.97%	2.89%	6.69%	-1.36%	287
JET ENGINE 001-019	52	0	-0.04%	-0.05%	-0.56%	-0.02%	0
JET ENGINE 20 Plus	53	1	-1.08%	-1.07%	-1.38%	0.02%	-2
GAS TURBINE All Sizes	54	-2	3.06%	3.23%	7.70%	-0.39%	96
GAS TURBINE 001-019	55	0	-0.04%	-0.05%	-0.56%	-0.02%	0
GAS TURBINE 020-049	56	1	-1.08%	-1.07%	-1.38%	0.02%	-2
GAS TURBINE 50 Plus	57	1	0.04%	0.11%	-0.20%	0.20%	-122
COMBINED CYCLE All Sizes	58	0	-0.47%	-0.33%	-1.22%	0.07%	-831
HYDRO All Sizes	59	-5	4.65%	4.92%	8.52%	-0.62%	-180
HYDRO 001-029	60	0	0.96%	1.23%	0.43%	0.53%	0
HYDRO 30 Plus	61	0	0.96%	1.23%	0.43%	0.53%	0
PUMPED STORAGE All Sizes	62	1	0.27%	0.21%	0.23%	-0.11%	-179
MULTIBOILER/MULTI-TURBINE All Sizes	63	1	1.69%	2.04%	6.25%	-0.45%	7974
DIESEL Landfill	64	-4	-2.06%	-2.04%	-2.48%	0.16%	-1
DIESEL All Sizes	65	0	-3.61%	-3.65%	-3.40%	0.16%	-1
FOSSIL Oil/Gas Primary All Sizes	66	-3	2.02%	2.42%	8.05%	-0.24%	6135
FOSSIL Oil/Gas Primary 001-099	67	0	-0.45%	-0.22%	-0.50%	0.36%	169
FOSSIL Oil/Gas Primary 100-199	68	0	-0.45%	-0.22%	-0.50%	0.36%	169
FOSSIL Oil/Gas Primary 200-299	69	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Oil/Gas Primary 300-399	70	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Oil/Gas Primary 400-599	71	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Oil/Gas Primary 600-799	72	1	0.52%	0.59%	0.14%	0.15%	1482
FOSSIL Oil/Gas Primary 800-999	73	0	1.10%	1.35%	1.03%	0.53%	9439
Wind All sizes	74	0	0.00%	0.00%	0.00%	0.00%	0
Solar All sizes	75	0	0.00%	0.00%	0.00%	0.00%	0

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

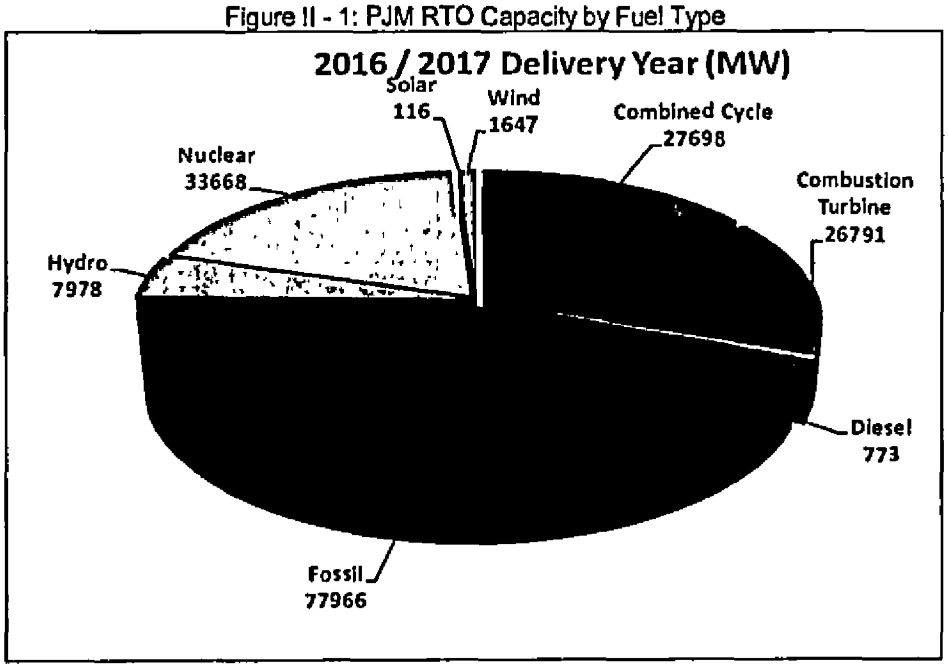
The PJM RTO fleet of units is summarized, by primary fuel, in Table II-6 for the 2016/2017 delivery year. This summary reflects the blending process discussed above to determine the table values. This summary also uses the actual summer net dependable rating (SND) of all units.

The outage rate for wind and solar units, however, reflects the PJM stakeholder process modeling, not actual outage event data. Figure II-1 charts all PJM RTO capacity by fuel type for the 2016/2017 Delivery Year.

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

2016 / 2017 Delivery Year	# of Units	Actual Capacity MW	% Total MW	Forced Outage Rates %	Ambient Temperature Derating (MW)
Combined Cycle	168	27,698	15.7%	5.0%	884
Combustion Turbine	461	26,791	15.2%	10.1%	392
Diesel	144	773	0.4%	12.2%	978
Fossil	273	77,966	44.1%	8.9%	
Hydro	184	7,978	4.5%	3.0%	247
Nuclear	33	33,668	19.1%	2.9%	
Solar	104	116	0.1%	0.0%	
Wind	117	1,647	0.9%	0.0%	
PJM RTO Total	**1484**	**176,637**	**100.00%**	**6.9%**	**2501**

Figure II - 1: PJM RTO Capacity by Fuel Type



- **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 captures the increased risk due to limited output from certain generators caused by more extreme-than-expected ambient weather conditions.

Per the 2012 RRS, 2,500 MW were derated in the peak summer period to model this risk through planned outage maintenance. This modeling assumption was developed through close coordination with the PJM Operations Staff, 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 1.58%.

Units selected for maintenance outage 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.

- **Generation Interconnection Forecast**

Commercial probabilities are computed to determine the likelihood of a unit (in the interconnection queue) coming in-service. The procedure that computes the probabilities is designed to account for the potential combined impact of factors such as current stage in the queue (feasibility, impact, facilities, interconnection service agreement (ISA)), unit type (coal, gas, wind, etc) and unit size (in MW) on the odds of a unit coming in-service. The procedure uses logistic regression models that are fitted to the historic data. The resulting models showed that stage in the queue and unit type were statistically significant factors. To determine if unit size were a significant factor, the data was split by stage and unit type (e.g., Feasibility-Wind, Impact-Wind, Facilities-Wind, ISA-Wind, Feasibility-Gas, so on and so forth). Logistic regression models were then fitted to each of these data subsets. Unit size was found to be a statistically-significant factor in most of the models. In the few models where unit size was not a significant factor, a proportion model (number of units that came in service/ total number of units) was used.

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

Status	Average Commercial Probability
In the Queue, up to Feasibility Study Stage	12%
All of the above, plus Impact Study Completed	26%
All of the above, plus Facilities Study Completed	61%
All of the above and ISA Executed	66%
Successful Completion	100%

The average commercial probabilities shown in Table II - 7 are calculated by dividing the total expected MW (after applying the "predictive" equation yielded by the logistic regression model to each queue unit) by the total actual MW for each stage in the queue.

Transmission System Considerations

- **PJM Transmission Planning (TP) Evaluation of Import Capability**

  The PJM Reliability Integration Division Staff previously conducted a Simultaneous transmission Import Limit (SIL) Study to evaluate the emergency import limits of the PJM RTO under summer peak conditions. Ongoing efforts by PJM staff continue to assess the transmission limits to be compliant with current FERC orders and the PJM stakeholder process. On August 6, 2008 FERC approved the SIL study which showed that 9,200 MW could be imported into the PJM RTO over summer peak conditions. This FERC submitted study, per FERC order 697, is available upon request. 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.

- **Capacity Benefit Margin (CBM)**

  The CBM value of 3500 MW is specified in the PJM Reliability Assurance Agreement (RAA), Schedule 4. 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 1.87%. This value is influenced by the amount of PJM-World load diversity, and the World reserve level (Compare Figure I-6 to Figure II-5).

  Per an effective date of April 1, 2011 concerning capacity benefit margin implementation documentation, compliant with NERC MOD Standard MOD-004-1, PJM staff has developed a CBM Implementation document (CBMID) that meets or exceed the NERC Standards, and NAESB Business Practices. This document is part of the PJM compliance efforts and is available via the PJM stakeholder process by contacting regional_compliance@pjm.com . Please also reference the MOD-004-01 clarifications within this report.

- **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 # 21 (Appendix B). In this run, the CBOT result was 1.87% of the PJM forecasted load or roughly 3093 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 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 OASIS web site, specifically the ATC for further specifics (www.pjm.com => Markets and Operations => eTools => OASIS => ATC Information). The transmission path calculations, which allocate the total 3,500 MW CBM to individual paths, are given at: http://www.pjm.com/markets-and-operations/etools/oasis/~/media/etools/oasis/atc-information/afc-atc-algorithms.ashx

Modeling and Analysis Considerations

- **Generating Unit Additions / Retirements**

  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, from the generation interconnection process queues. Table II-7 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 (2012-2022) – as of April 2012

Zone Name	Total Additions (MW)	Retirements (MW)	Total
AEC	892	309	583
AEP	291	3,910	-3,619
Allegheny Energy (APS)	537	1,051	-514
ATSI	272	3,140	-2,868
BGE	647	0	647
ComEd	486	858	-372
Dayton	118	160	-42
DLCO	0	0	0
DomVP	571	738	-167
DPL	262	160	102
DQE	0	171	-171
DUKE	82	1,049	-967
JCPL	467	160	307
METED	62	644	-582
PECO	153	0	153
Penelec	100	597	-497
PEPCO	142	1,030	-888
PPL	215	0	215
PSEG	457	757	-300
UGI	0	0	0
Grand Total	**5,754**	**14,734**	**-8,980**

- **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 20. The DR Factor is applicable to RPM resources such as DR and EE (Energy Efficiency). Please refer to PJM Manual 18 for further details. A related reference is Manual 18B: Energy Efficiency Measurement & Verification.

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.

For the 2016/2017 delivery year, the DR Factor is 0.955 (PRISM # 8145). 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 0.955 MW of peak load reduction.

- **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. Per the May study assumptions, approved at the April 12, 2012 PJM Planning Committee meeting, each of the individual regions was modeled at its required reserve requirement. The world region immediately adjacent to the PJM RTO was deemed to be the most appropriate region to use in the study, per previous RRS assessments. Modeling the immediately adjacent region helps to address concerns for deliverability of outside world resources to the PJM RTO border.

Only New York, New England, and MISO regions have a firm reserve requirement target. For these regions, their latest published reserve requirements were used for the delivery years of this study. For the TVA and VACAR sub regions of SERC, a reserve target of ~15% was used; this is consistent with NERC's modeling for assessment purposes.

Figure II - 2: PJM and Outside World Regions - Summer Capacity Outlook

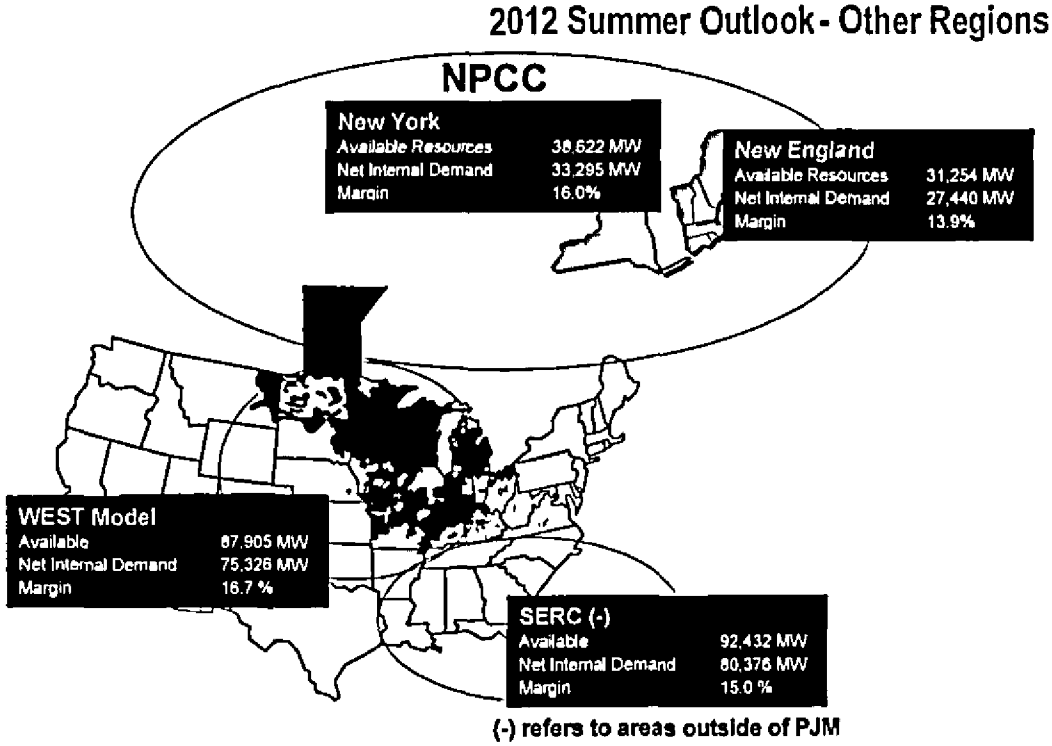


Figure II - 2 depicts the summer outlook for capacity within each of the "Outside World" regions that are adjacent to PJM for the delivery year 2012 (Jun 2012 to May 2013). The West region includes the old zones: MAIN Other (The Gateway values are in this zone), and ECAR Other. The SERC minus region includes the World zones: TVA (Old), and VACAR Other.

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 without including a mechanism to convert historical data to 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. Modeling specifics known to PJM staff thru public reports, networking of ISO and regional staff, and confidential interregional working group data is used in this translation effort to model the new boundary.

Figure II - 3 depicts the previous regions (including the former ECAR, MAIN, and MAAC regions) while Figure II-4 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 - 3: Previous NERC World Regions (Includes ECAR and MAIN)

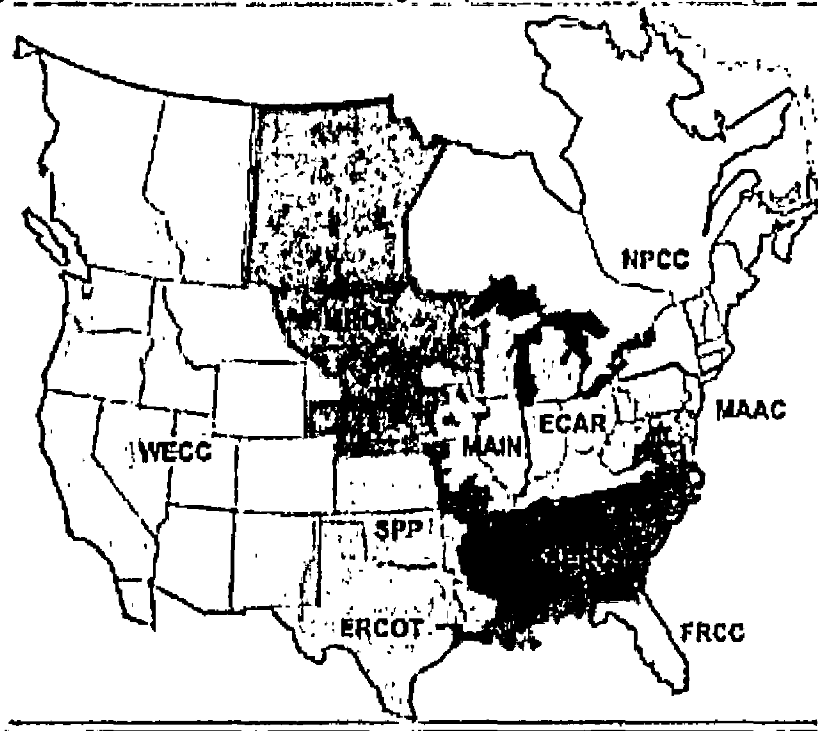


Figure II - 4: Current NERC defined World Regions (Includes RFC)

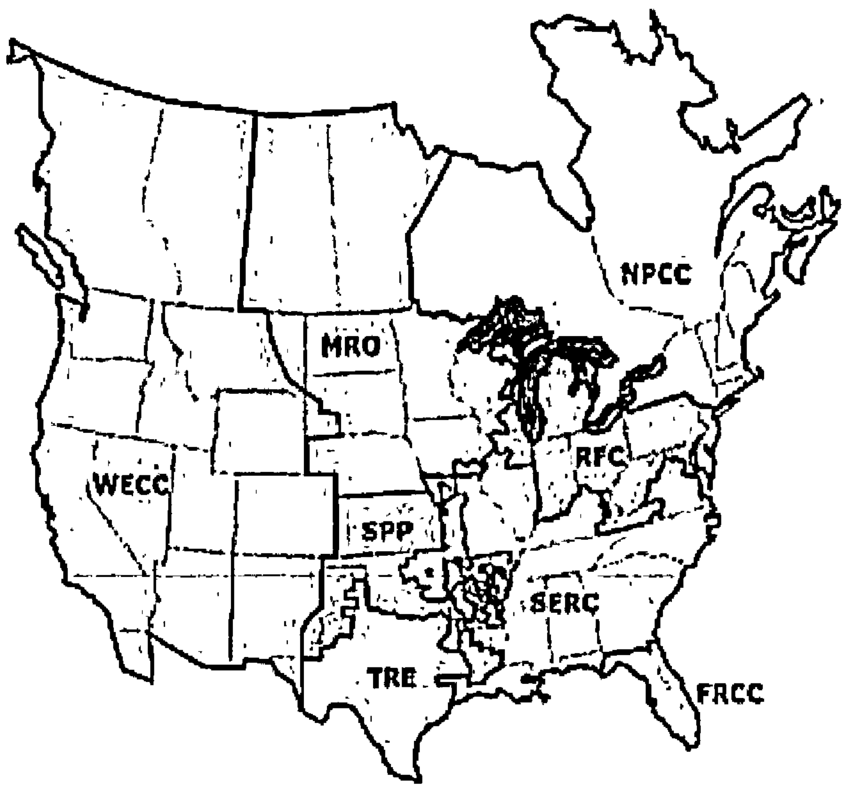


Figure II - 5: Relation between IRM and CBM when World reserves are 21.52%

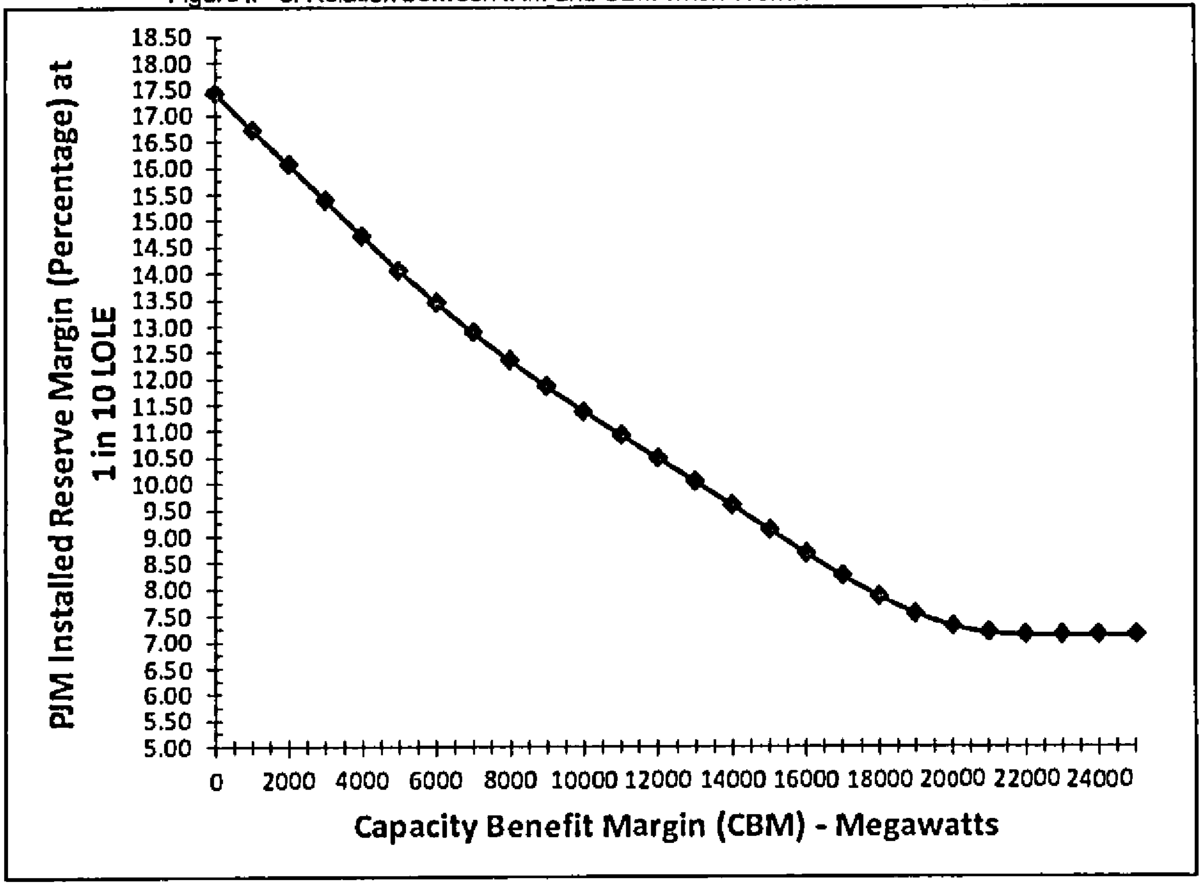


Figure I – 4 shows the valid range of the reserves to consider for the World region model. The maximum value is shown to be 21.52%. Figure II – 5 holds the World region at this maximum reserve value, varying the capacity benefit margin (CBM) up to 24,500 megawatts, in steps of 500 MW. This analysis is comparable to what is shown in Figure I – 6 for the Base Case (in Figure I-6, however, the World is assumed to be at 1 in 10 with 14.91% reserves). Saturation of the value for CBM is at about 21,000 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), LOLE Weekly Values, Convolution Solution, IRM Audience**

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, 99.9% of the risk is concentrated 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, for clarification and specifics of how the EWM is used and the resulting weekly LOLE). The EWM value is calculated per the following equation:

Equation II - 2: Expected Weekly Maximum

$$EWM_x = \mu_x + 1.16295 * \sqrt{\sigma_x^2 + FEF^2}$$

Where:
μ_x = Weekly Mean,
1.16295 = A Constant, the Order Statistic when n=5
σ_x^2 = Weekly variance
FEF = Forecast Error Factor, for given delivery Year
x ranges from 1 to 52

In Figure II-6, the following EWM pattern can be seen for the PJM RTO and World regions. For all weeks not shown, the weekly LOLE approaches zero. The pattern is slightly different compared to the 2011 RRS, as the forecasted ratio of the August to July 2012 PJM peak is slightly higher. The World region continues to peak in August (See Load Forecasting section discussion around Table II-2 and Table II-3), maintaining similar PJM-World diversity between the 2012 and 2011 RRS models.

Figure II - 6: Expected Weekly Maximum Comparison – 2011 RRS vs. 2012 RRS

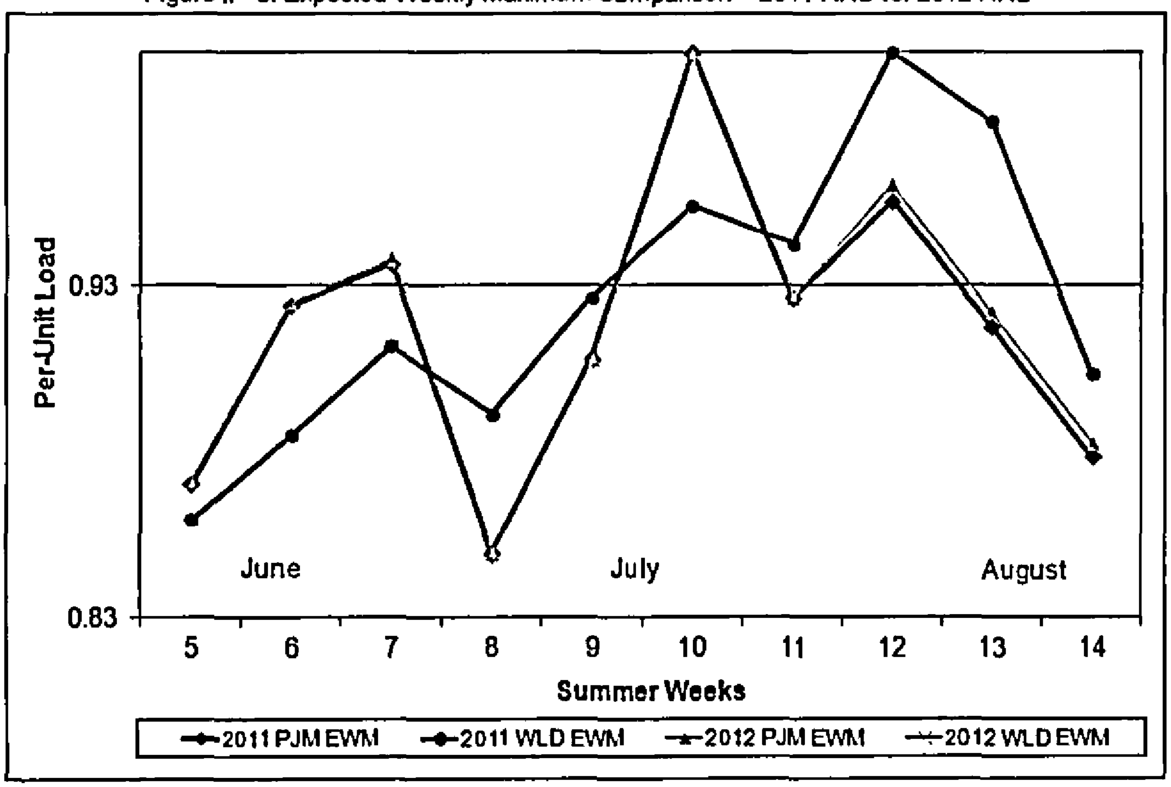


Figure II-7 compares the LOLE patterns for PJMRTO. For the 2012 RRS the LOLE is peaky, with most of the risk occurring in weeks 10, 12, and 7. This is a result of the PJM-World diversity and the EWM load shape. These two graphs show that the diversity between the PJMRTO and the World impacts the results.

Figure II - 7: PJMRTO LOLE Comparison- 2011 RRS vs. 2012 RRS

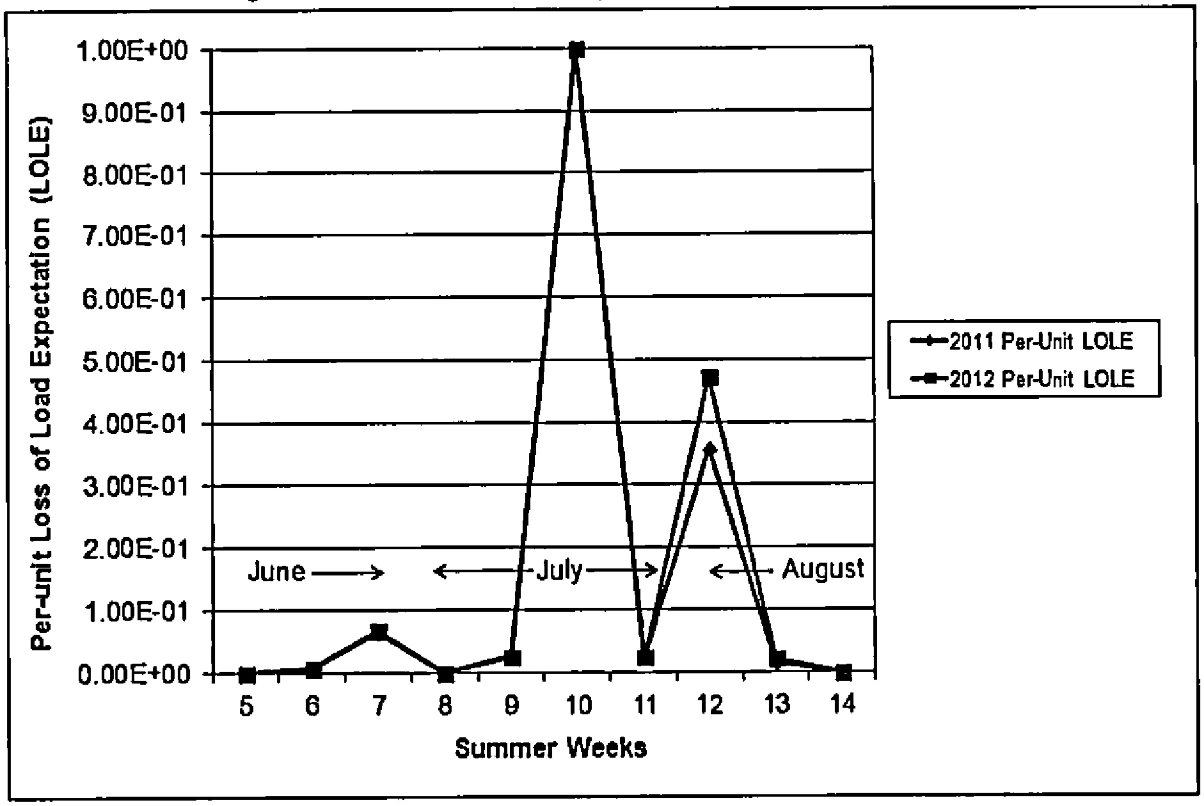
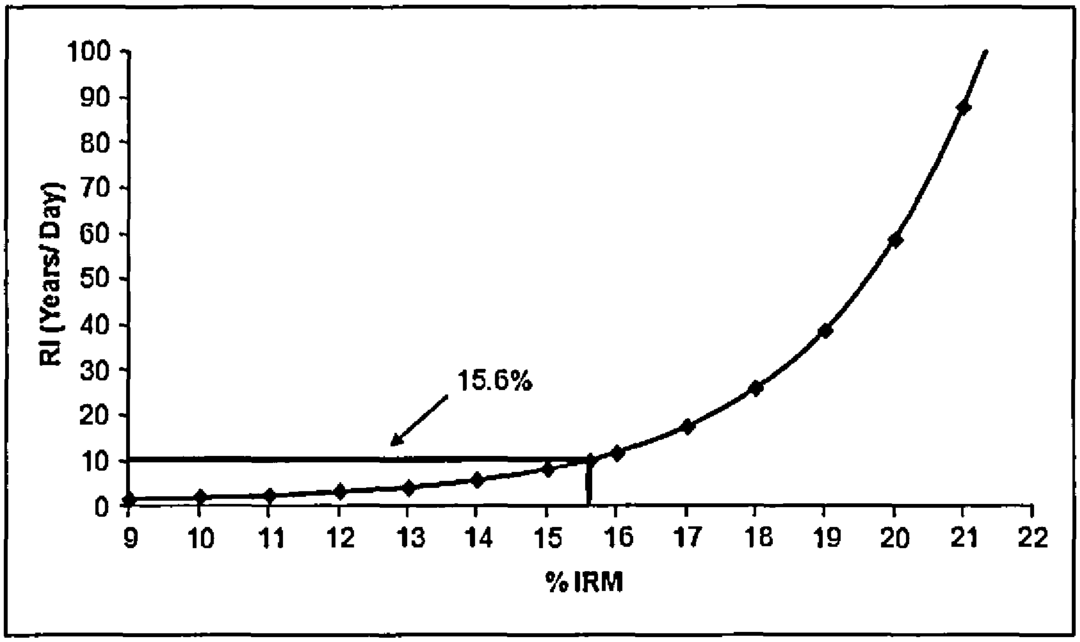


Figure II-8 shows how the Reliability Index (RI) varies with installed reserve margin, for the PJM RTO area. The analysis is a two area study, manually varying the PJM RTO reserve levels while keeping the World at the 1 Day/ 10 Year reserve level.

The relationship of the reserve level in the PJM RTO to the forecast expectation for outage events is shown in Figure II-8. This figure shows that a reserve level of about 15.6% yields a loss of load event once every ten years.

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



World at minimum target range reserves, PJMRTO solved for Load

PRISM Calculation – Convolution of Load and Generation

The calculations used in PRISM are based on use of forecast statistical parameters for both the load and generation distributions. PRISM uses a numerical method to simulate the joining of a given load distribution point with the associated generation distribution point. This joining is performed by a "lookup" table approach using the cumulate probability (Cum Prob) distribution of the generation distribution.

The distributions used are both forecast and probabilistic. The first step is to build the cumulative probability array, based on the individual generation unit forced outage rates. This calculation is widely documented[2].

The creation of this Cum Prob table is the most calculation-intensive aspect of the method used in PRISM, done for each week in the model. The table is created using the binominal expansion method[3]. Once the Cum Prob distribution pattern is determined for the generation model, the load model distribution is used to look up the associated Loss-of-Load Expectation (LOLE). This lookup is when the actual load distribution is "convolved" with the generation distribution.

A graphical depiction of the numerical look-up method is shown in Figure II-9, as an illustration only. The red-shaded area of Figure II-9 depicts when load exceeds the available generation – and results in a loss-of-load event. Each load level has a defined probability of occurrence and the red region is at significant high loads that have a low probability of occurrence.

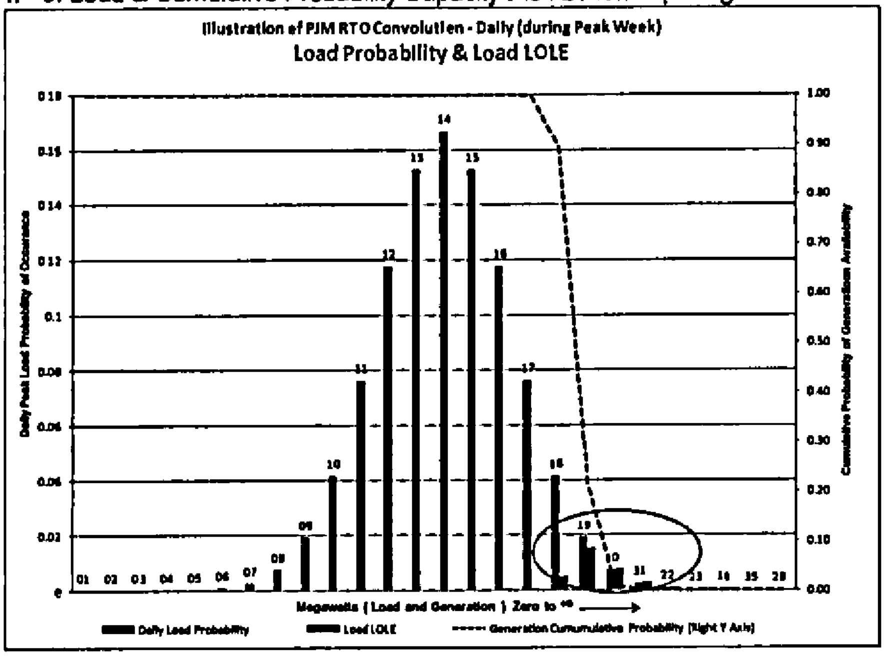
38

[2] Refer to Roy Billinton's book, *"Power System Reliability Evaluation"*, Gordon and Beach, Science Publishers, or a simple example shown in Appendix B of the Paper titled *"Reinvent Legacy Software with SAS, the Web, and OLAP Reporting"* available at the following link: http://www.qix.com/whitepapers/25-2008.pdf.

[3] Probability Calculation of Generation Reserves - March 1969 - by C.J. Baldwin and published by The Westinghouse Engineer. This paper is copyright protected but can be purchased online at infotrieve; article information accession number 00434361 (800-422-4633; www.infotrieve.com).

The term -convolution" is illustrated by a method known as the recursive method[4]. Note that science and engineering problems approach this single concept of convolution from two different directions[5]. The load model derived from the hourly load (Daily Peak) curve is convolved with the generation system model for computing the LOLE[6]

Figure II - 9: Load & Cumulative Probability Capacity Distribution depicting PRISM calculations



Figures II-9 and II-9B are for illustration, but 21 points are used in the calculations. The number of points used was due to practical considerations of speed and accuracy. Therefore twenty one points are used for each daily peak lookup.

The red bars indicate when a loss of load state (LOLE) occurs –when the load is excessively large (which rarely occurs and shown in green oval –see bars 19 and beyond). The cumulative probability of available generation is low at these excessively large loads. The daily peak load probability of occurrence scale is shown on the left Y axis. Example calculations used to determine the load model lookup value (into the cumulative probability array), is shown in Figures 3A and 3B of the PRISM-MARS comparison report posted here.

For the extremely high-load levels encircled by the green oval, the red LOLE bars increase because of the higher cumulative probability of unavailable generation –at least until a certain higher load value is reached.

39

[4] Dr James McCalley's course notes, module PE.PASU19.5 on Generation adequacy evaluation, Convolution techniques, item U19.7.3 on page 43, http://www.ee.iastate.edu/~jdm/ee653/ee653schedule.htm
[5] The Scientist and Engineer's Guide to Digital Signal Processing, By Steven W. Smith, PhD, copyright © 1997-2006 by California Technical Publishing – http://www.dspguide.com/pdfbook.htm
[6] Dr. Chanan Singh, course notes: Electrical Power System Reliability, part3 Discrete Convolution Method, page 30, copyright 1995, http://www.ece.tamu.edu/People/bios/singh/coursenotes/part3.pdf

Figure II - 9B: Extreme high loads. Detail of green oval

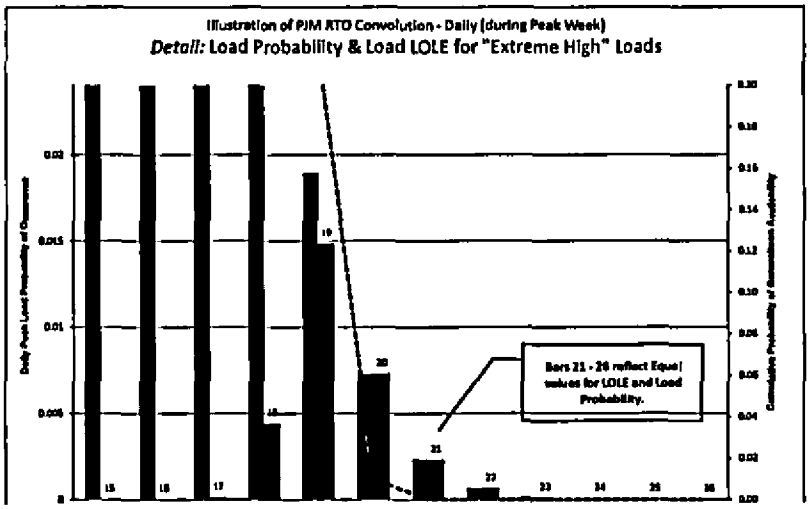


Figure II-9B shows a magnified view of the green oval area, extreme load that have LOLE states. After reaching an LOLE peak (in 19th bar from left), the red bars taper off due to the diminishing likelihood of higher loads. (I.e. Such very high loads do not often occur while the generation probability (of unavailability) saturates at a value of 1.0 –generation probability (of availability– dashed line) declines as megawatts increase.

As generation unavailability saturates (approaching a value of 1), generation resources will not be able to serve that load level (generation availability approaches zero). Even though there is a much greater risk of generation unavailability as load increases, the LOLE is reduced because of the very small chance of that higher load occurring.

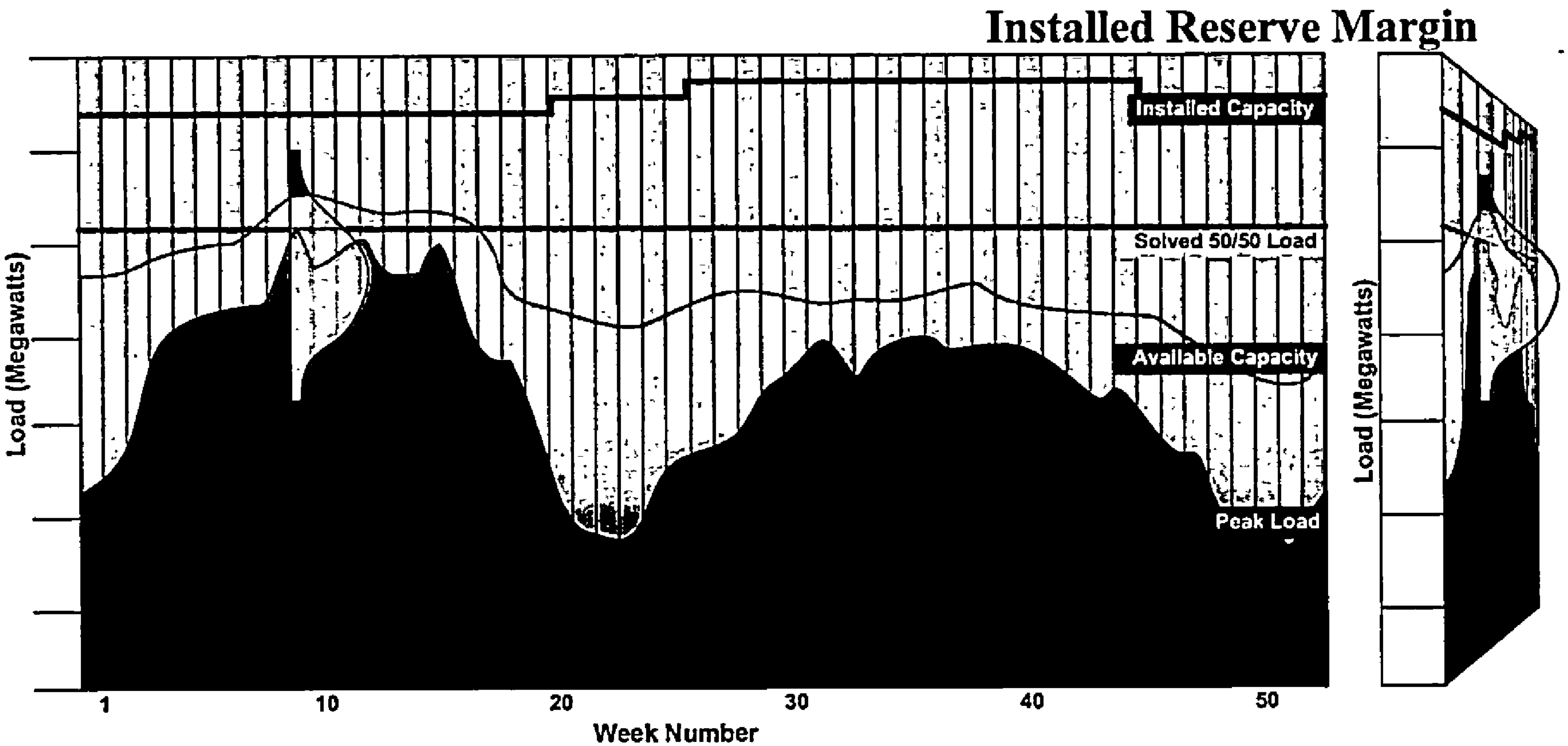
It is important to note that the blue bars of this graph include PJM RTO loads up approximately 200,000 MW.[7] There is a higher risk of generation unavailability (until saturation when a total generation is less than load) as the load increases, but a lower likelihood that a higher load will occur.

Figure II – 10 is a graphical illustration for how the automatic solution is performed, to determine the installed reserve margin that meets the 1 day in 10 Years criterion. A change in load is used as a proxy for a change in capacity resources[8]. Each day is evaluated independently, combining the five week days (Monday – Friday) into the same week for processing. The load shape is adjusted vertically, up or down, once an initial estimate is given for the load level that satisfies the 1 day in 10 years criterion. All weeks that have "tails" above the green available capacity line will contribute to the annual risk. The red region shown is an example of a "tail" that contributes to the loss of load risk. This risk is a function of the load exceeding the available generation resources, applying the appropriate probability of occurrence. The solution process in Figure II – 10 is another vantage point to explain the general convolution process discussed in Figure II –9.

40

[7] PJM 2011 Load Forecast Report shows a 50/50 peak for the 2015 forecast delivery year of 166,506 MW.
[8] This has been evaluated in previous RRS models and found to be an accurate modeling assumption. **Northeast Power Coordinating Council Tie Benefits Methodology**, by Glenn Haringa and Philip Fedora, November 5-6, 2008, Best LOLE Practices meeting held at California ISO offices, Agenda Item 8. See slide 12, last bullet.

Figure II - 10: Installed Reserve Margin Automatic Solution



The Peak Load Line is shifted vertically until the 1-day-in10-years criterion is met (See Convolution Diagram). 260 week day LOLEs (aggregated Into 52 weeks) are summed to get annual LOLE. (Note: PJM RTO Weekends have zero risk)

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 was 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 (long solution times). 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. 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, per BAL-502-RFC-02. 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 12; 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.

- **Standard MOD - 004 - 01, requirement 6, clarification Items**

  - Capacity Benefit Margin (CBM) is established per the Reliability Assurance Agreement (RAA) section 4 and used in Planning Division studies and assessments. The Regional Transmission Expansion Planning Process (RTEP) provides a 15 year forecast period while the reserve requirement study provides an 11 year forecast period. Each individual year of these periods (15 and 11) are assessed. The RTEP and Reserve Requirement Study (RRS) are performed on an annual basis.

  - The RTEP and the RRS processes use full network analysis. Available Transmission Capability (ATC) and Flowgate analysis disaggregates the full network model in the short term (daily, weekly, monthly through month 18) as a proxy for full network analysis. The Available Flowgate Capability (AFC) calculator applies the impacts of transmission reservations (or schedules as appropriate) and calculates the AFC by determining the capacity remaining on individual flowgates for further transmission service activity. The disaggregated model used for the AFC calculation provides faster solution time than the full network model. The RTEP assessment is coordinated with the CBM, shown in the RAA, by its use of Capacity Emergency Transfer Objective (CETO) and load forecast modeling. CETO requirements are based on Loss of Load Expectation (LOLE) requiring appropriate aggregation of import paths for a valid statistical model.

  Evidence:

  - Annual RTEP baseline assessment report http://www.pjm.com/planning/rtep-development/baseline-reports.aspx
  - Reliability Assurance Agreement (http://www.pjm.com/documents/~/media/documents/agreements/raa.ashx)
  - Annual RRS report(s) http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx
    - CETO load deliverability studies
    - Section 4, Manual 20 (http://www.pjm.com/~/media/documents/manuals/m20.ashx)
    - Section C.4, Manual 14B (http://www.pjm.com/~/media/documents/manuals/m14b.ashx)
  - AFC/ATC calculations, Section 2 and 3 of PJM Manual 2 http://www.pjm.com/~/media/documents/manuals/m02.ashx

- **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 - 3: Calculation of Forecast Pool Requirement (FPR)

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

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. 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 RAAS meetings, will continue. These historic engineering judgments are documented in Appendix F.

Operations Related Assessments

- **Winter Weekly Reserve Target Analysis**

PJM Staff recommends 28% as the minimum winter reserve target to be applied to the PJM RTO for the upcoming 2012 / 2013 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 29%. The 28% target is based on unit summer ratings and is expressed as a percentage of the forecasted weekly peak load.

The procedure used for this assessment uses Multi-Area Reliability Simulation (MARS) modeling and Monte-Carlo solution techniques. MARS has many event driven table entries which allow for a closer match to Operation's practices.

Table II-8 shows the results of the MARS analysis for the 2012 / 2013 winter period. The average reserve level over the 13 week winter period is 27.8%. This margin is slightly lower than the 28.5% calculated in last year's study.

Similar to the 2011 RRS assessment, for the non-Summer period, the load management resources in the step 2 of the Emergency Operating Procedure Table were set to zero. Load management is not subject to a specified penalty metric for non-performance outside the summer period (see Section 8.5 of PJM Manual 18). Based on this procedure and the analysis, PJM Planning staff believes that maintaining a minimum 28% reserve target for the 2012/2013 13-week winter operating period ensures that the actual winter loss of load risk is consistent with that modeled in the 2012 PJM RRS. This recommendation was unanimously endorsed by the RAAS.

With this recommendation, the PJM Operations Department would coordinate generator maintenance scheduling over the winter period to seek to preserve a 28% margin after units on planned and maintenance outages are removed. **This margin is a guide to be used by PJM Operations and is not an absolute requirement.**

Endorsement of the 28% Winter Weekly Reserve Target from the PJM Planning Committee (PJM-PC) will be requested at the October 11, 2012 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.

There are six Emergency Operating Procedure (EOP) levels available to report LOLE: 1) Operating reserves, 2) Load Management resources (DR), 3) 30 minute reserves, 4) Voltage reduction, 5) 10 minute reserves, and 6) Appeals for public curtailment. Reported LOLE values in Table II - 8 are after implementation of the 30 minute reserve EOP level.

Table II - 9: Winter Weekly Reserve Target

Month	% Weekly Reserves level for 1D/10 YR	LOLE (3rd Margin State)
December	22.22	6.94E-05
	22.25	3.97E-05
	24.78	0.00E+00
	29.91	0.00E+00
January	32.91	1.07E-04
	24.36	3.47E-05
	30.06	0.00E+00
	30.88	0.00E+00
	28.02	0.00E+00
February	25.27	9.67E-05
	28.95	0.00E+00
	22.56	9.92E-06
	38.97	0.00E+00
Average Weekly Reserves	**27.8**	

Glossary

Adequacy

The ability of a bulk electric system to supply the aggregate electric demand and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components. One part of the Reliability term.

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, which integrated 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/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 section 4, 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/Pages/home.aspx)

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.dpandl.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. DR is a component of PJM's Load Management (LM) program. The DR is bid into the RPM Base Residual Auction (BRA). See Load Management (LM).

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 Interruptible Load for Reliability (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 (PJM-World 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/)

Duke Energy Ohio – Kentucky (DEOK)

Duke Energy Kentucky, part of Duke Energy, is a Kentucky-based control area. Duke Energy has approximately 35,000 megawatts of electric generating capacity in the Carolinas and the Midwest, and natural gas distribution services in Ohio and Kentucky. Headquartered in Charlotte, N.C, Duke Energy Kentucky was integrated into the

PJM RTO on January 1, 2012. Duke Kentucky is adjacent to the western portion of the AEP region. (http://www.duke-energy.com/kentucky.asp)

Duke Energy Ohio, part of Duke Energy, is an Ohio-based control area. Duke Energy has approximately 35,000 megawatts of electric generating capacity in the Carolinas and the Midwest, and natural gas distribution services in Ohio and Kentucky. Headquartered in Charlotte, N.C., Duke Energy Ohio is currently part of MISO with a target integration date into the PJM RTO on January 1, 2012. Duke Ohio is adjacent to the western portion of the AEP region. (http://www.duke-energy.com/Ohio.asp)

East Kentucky Power Cooperative (EKPC)

EKPC is a not-for-profit electric utility with headquarters in Winchester, Ky. EKPC generates and transmits wholesale energy to 16 owner-member cooperatives. The owner-member cooperatives distribute that energy to more than 1 million Kentucky citizens across 87 counties.

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 ¼ of the equivalent maintenance outage factor. See manual 22, pages 14-15 (http://www.pjm.com/~/media/documents/manuals/m22.ashx)

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 762-2006 (March 15, 2007).

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 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. FEF is held constant at 1.0% for all delivery years in the RRS, per stakeholder agreement of the approved assumptions.

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 program in the conduct and evaluation of IRM studies at PJM. (See PRISM.) GEBGE does prove useful to measure reliability calculations and to increase PJM staff efficiency in some sensitivity assessments.

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.

ILR

Interruptible Load for Reliability (IRL) 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. (See SIL)

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 ReliabilityFirst 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 25 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 Demand Resources (DR), Energy Efficiency, and Interruptible Load for Reliability (ILR) – ILR is only applicable in RPM markets prior to the 2012/13 delivery year, with ILR an inherent piece of all forecast load management values.

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:

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

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

Where

$P =$ probabilty of outcome

$X =$ definded 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.[9]

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 Probabilty 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:

55

[9] Power System Reliability Evaluation", Roy Billinton, 1970, Gordon and Breach, Science Publishers for further details on calculation methods.

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

Where

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

$PD(XD)$ = Probabilty 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.

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.

LSE

Load Serving Entity (LSE) is defined and discussed thoroughly at the following link. This is a PJM training class concerning requirements of an LSE, including LSE Obligations, Who are LSEs?, PJM Membership, Capacity Obligations (RAA) for PJM, Agreements and Tariffs, Transmission Service, FTRs, Ways to supply Energy, Energy Load Pricing, Energy Market – Two Settlement, Ancillary Services, http://www.pjm.com/sitecore/content/Globals/Training/Courses/ol-req-lse.aspx .

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) is 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 Atlanta, GA, 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 the eGADS User Manual, Section 2.5 and 2.6 for further details –available as the help selection in the eGADS web application (https://egads.pjm.com/pjmpgads/login).

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 Subcommittee (TSS), Relay Testing Subcommittee (RTS), Regional Planning Process Task Force (RPPTF), and the Resource Adequacy Analysis Subcommittee (RAAS).

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, using the SAS programming language. 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.

Reliability

In a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service. Bulk Power electric reliability cab be addressed be considering two basic and functional aspects of the bulk power system – adequacy and security.

Reliability*First* 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. 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.
(http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx)

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. (http://www.pjm.com/markets-and-operations/rpm.aspx)

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 and FPR, 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. (http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx)

Resource Adequacy Analysis Subcommittee (RAAS)

Reporting to the PC, the RAAS assists PJM staff in performing the annual Reserve Requirement Study (RRS) and maintains the reliability analysis documentation (http://pjm.com/committees-and-groups/subcommittees/raas.aspx). See Resource Adequacy Analysis Subcommittee web site.

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. (http://www.pjm.com/planning/rtep-upgrades-status.aspx)

Security

The ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components or switching operations. One part of the Reliability term.

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)

SIL

Simultaneous transmission Import Limit (SIL) study is a series of power flow studies that, per FERC order 697, assess the capabilities of all PJM transmission facilities connected to neighboring regions under peak load conditions to determine the simultaneous import capability. FERC Order, 124 FERC 61,147, issued August 6, 2008; found that PJM's studies, as amended, met the requirements for a SIL study. The purpose is to assist our members in responding to FERC regarding their two Market Power Indicative screens and their Delivered Price Test Analysis.

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.

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 = Td – (0.55 – 0.55RH) * (Td - 58) where Td is the dry-bulb temperature and RH is the percentage of relative humidity.

Unrestricted Peak Load

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

Variance

A measure of the variability of a unit's partial forced outages which is used in reserve margin calculations. See PJM manual 22, page 12 and Section 3 Item C, (http://www.pjm.com/~/media/documents/manuals/m22.ashx).

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.

XEFORd

XEFORd is a statistic that results from excluding OMC events from the EFORd calculation. It is used in the FPR calculation.

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

Appendix A
Base Case Modeling Assumptions for 2012 PJM RRS

Parameter	2011 Study Modeling Assumptions	2012 Study Modeling Assumptions April 12, 2012 letter to PC Approved at April 12, 2012 PC mtg.	Basis for Assumptions
Load Forecast			
Unrestricted Peak Load Forecast	166,506 MW (2015/16 DY)	165,691 MW (2016/17 DY)	Forecasted Load growth per 2012 PJM Load Forecast Report, using 50/50 normalized peak.
Historical Basis for Load Model	1998 - 2006	TBD	Will use the load model selection method approved at the July 15, 2009 PC meeting.
Forecast Error Factor (FEF)	Forecast Error held at 1 % for all delivery years.	Forecast Error held at 1 % for all delivery years.	Consistent with consensus gained through PJM stakeholder process.
Monthly Load Forecast Shape	Consistent with 2011 PJM Load Forecast Report and 2009 NERC ES&D report (World area).	Consistent with 2012 PJM Load Forecast Report and 2010 NERC ES&D report (World area).	Updated data.
Daily Load Forecast Shape	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Consistent with consensus gained through PJM stakeholder process.
Capacity Forecast			
Generating Unit Capacities	Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review.	Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review.	New RPM Market structure required coordination to new database Schema. Consistency with other PJM reporting and systems.
New Units	Generation Interconnection Queues coordinated with May 2011 version of forecast reserve margin graph which uses commercial probability. See http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx.	Modeling of new PJM generators will be based on May 2012 version of forecast reserve margin graph which uses commercial probability. See http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx.	Requirement using commercial probability for planned projects.
Wind Resources	Derived from hourly wind data over summer peak hours. Units can use a capacity factor of 13% or actual performance once historic data is available.	Derived from hourly wind data over summer peak hours. Units can use a capacity factor of 13% or actual performance once historic data is available.	Based on Manual 21 Appendix B for Intermittent Capacity Resources. 13% capacity factor based on PJM stakeholder process, February 22, 2008 Planning Committee, Agenda Item 9.

Parameter	2011 Study Modeling Assumptions	2012 Study Modeling Assumptions April 12, 2012 letter to PC Approved at April 12, 2012 PC mtg.	Basis for Assumptions
Solar Resources	Derived from hourly solar data over summer peak hours. Units can use a capacity factor of 38% or actual performance once historic data is available.	Derived from hourly solar data over summer peak hours. Units can use a capacity factor of 38% or actual performance once historic data is available.	Based on Manual 21 Appendix B for Intermittent Capacity Resources. 38% capacity factor based on PJM stakeholder process, May 21, 2008 Planning Committee, Agenda Item 6.
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 RPM 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 RPM auctions.	Match EIA-411 submission and RPM 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 May 2011.
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.

Parameter	2011 Study Modeling Assumptions	2012 Study Modeling Assumptions April 12, 2012 letter to PC Approved at April 12, 2012 PC mtg.	Basis for Assumptions
Unit Operational Factors			
Forced and Partial Outage Rates	5-year (2006-10) GADS data. (Those units with less than five years data will use class average representative data).	5-year (2007-11) 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.
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.	In review of recent Summer periods, no Planned outages have occurred.	Review of historic 2007 to 2011 unit operational data for PJM RTO footprint.
Gas Turbines, Fossil, Hydro Nuclear Ambient Derate	Ambient Derate includes several categories of units. Based on additional assessments of operational data, for a wider time period, and discussion with Operations Staff the 2,500 MW out on planned outage over summer peak was determined to be the best value to use at this time.	Ambient Derate includes several categories of units. Based on additional assessments of operational data, for a wider time period, and discussion with Operations Staff the 2,500 MW out on planned outage over summer peak was determined to be the best value to use at this time.	Operational history and Operations Staff experience indicates unit derates during extreme ambient conditions. Additional assessments were not conclusive; identifying data granularity reporting issues that require additional efforts to derive any correlation between ambient conditions on unit performance.
Generator Performance	Peak period generator performance is consistent with year-round generator performance	Peak period generator performance is consistent with year-round generator performance.	Additional assessments were not conclusive to adjust the model. Assessments continue to quantify any change in the summer and non-summer unit performance or within the summer period (20 wks).
Class Average Statistics	PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel.	PJM RTO fleet Class Average values. 73 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 - (DR, ILR) and Energy Efficiency (EE)			
Load Management and Energy Efficiency	PJM RTO load management modeled per the January 2011 PJM Load Forecast Report (Table B8).	PJM RTO load management modeled per the January 2012 PJM Load Forecast Report (Table B8).	Model latest load management and energy efficiency data.

Parameter	2011 Study Modeling Assumptions	2012 Study Modeling Assumptions April 12, 2012 letter to PC Approved at April 12, 2012 PC mtg.	Basis for Assumptions
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 an 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 an 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.
New Transmission Capability	Consistent with PJM's RTEP as overseen byTEAC.	Consistent with PJM's RTEP as overseen by TEAC.	Consistent with PJM's RTEP as overseen by TEAC.
Modeling Systems			
Modeling Tools	PRISM Version 4.4	PRISM Version 4.6	Per recommendation by PJM Staff. Latest available version.
Modeling Tools	WKPKFQ Version 4.4	WKPKFQ Version 4.6	Per recommendation by PJM Staff. Latest available version.
Modeling Tools	ARC Version 4.4	ARC Version 4.6	Per recommendation by PJM Staff. Latest available version.
Modeling Tools	Multi-Area Reliability Simulation (MARS) Version 3.01	Multi-Area Reliability Simulation (MARS) Version 3.12	Per recommendation by PJM Staff and General Electric Staff. Latest available version.
Outside World Area Models	5rd 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.	6rd 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 2012 Study Sensitivity Cases

Case No.	Description and Explanation	Change in 2011 Base Case IRM (%)
Individual and New Modeling Characteristic Sensitivity Case		
	The first six sensitivities use the previous 2011 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 2011 Base Case result (2015 DY PJM RTO IRM = 15.3913 %).	
1	**Load model update – Weekly shape (#8169 2Area)**	**Decrease by 0.0132 ***
	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 (#8177 2Area)**	**Increase by 0.1689 ***
	Impact of using the monthly forecast from the 2012 PJM Load Forecast Report in place of the 2011 version.	
3	**Load model update – Both weekly and monthly shape (#8178 2Area)**	**Increase by 0.1563 ***
	Impact of using both the 2012 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**	**Decrease by 0.00 ***
	Impact of using updated PJM RTO capacity model and associated unit characteristics.	
5	**World Capacity Model update**	**Increase by 0.00 ***
	Impact of using updated World region capacity model.	
6	**PJM RTO and World Capacity Model update**	**Decrease by 0.00 ***
	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 2012 Base Case IRM (%)
Load Model Sensitivity Cases		
	Sensitivity numbers 7 and higher are based on the 2012 Base Case. All differences are with respect to the 2012 Base Case result (2016 DY).	
7	No Load Forecast Uncertainty (LFU) (#8181)	Decrease by 4.22 %
	This scenario represents "perfect vision" for forecast peak loads, i.e., 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. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
8	Increase the Forecast Error Factor to 2.5% (#8163)	Increase by 0.87 %
	This two area sensitivity increases the FEF to 2.5% compared to the 1% used in the base case. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
9	Number of Years In Load Model	See below
	Using PJM RTO 7 year (2002-2008), 7 year (1998-2004), and 8 year (1998-2005) load models, to show the impact of the load model period used in the single area case study. The 7 year (2002-2008) load model gave a higher IRM (#8182), by 0.5599 %. The 7 year (1998-2004) load model gave a higher IRM (#8183), by 0.2592 %. The 8 year (1998-2005) load model gave a higher IRM (#8184), by 0.0309 %. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
10	Truncated Normal Distribution Shapes	Decrease, See below
	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 GEBGE two-area reliability modeling tool. Truncated normal truncated at 2.36, decrease by 1.30 %. Truncated normal truncated at 2.50, decrease by 1.00 %. Truncated normal truncated at 2.90, decrease by 0.46 %. Truncated normal truncated at 3.20, decrease by 0.31 %. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	

Generation Unit Model Sensitivity Cases		
11	High Ambient Temperature Unit Derating (#8164 2Area)	Decrease by 1.58
	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 type of derating 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. This sensitivity removes tha 2500 MW on planned outage for the peak summer period (weeks 6-15)	
12	Replace the EEFORd values with EFORd values for all units in the model. (#8166 2Area)	Decrease by 0.95
	This case replaces the EEFORd statistic with the EFORd statistic, for all units. It assumes that EMOF is not included in the EEFORd computation.	
13	Replace the EEFORd values with XEFORd values for all units in the model. (#8167 2Area)	Decrease by 1.83
	This case replaces the EEFORd statistic with the XEFORd statistic, for all units. It assumes that OMC events as well as the EMOF are excluded from the EEFORd computation.	
14	Impact of change in EEFORd: F-Factor (#8186 1Area)	Increase by 1.35
	There is a direct correlation to the forced outage rate of the PJM RTO units vs. the PJM IRM. This sensitivity increases the (EEFORd) by 1 percentage point.	
15	Perfect performing units : (#8176 1Area)	Decrease by 8.94
	Adjust the performance characteristics for all base units to approximate perfect performing units i.e., each unit has a FOR of zero, planned outages of zero and zero maintenance outages.	
16	Impact of 1 % change in WLD EEFORd (#8188 2Area)	Increase by 0.0001
	The World units' EEFORd is increased by 1 percentage point.	
Capacity Benefit Margin Sensitivity Cases		
17	Various values of Capacity Benefit Margins	See Figure I-6 and Figure II-5
	Figures I-6 and II-5 show 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).	
Reserve Modeling Sensitivity Cases		
18	PJM RTO at cleared RPM auction (#8230)	RI = 63.3

	In this sensitivity, PJMRTO reserves are modeled as per the most recent RPM auction while the World is solved to meet the 1 in 10 criterion. The 2015/2016 Reliability Pricing Model (RPM) Base Residual Auction cleared 164,561.2 megawatts (MW) of capacity. The actual reserve margin for the entire RTO will be 20.2%. The full report can be found at http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx	
19	**PJM RTO IRM Vs. World Reserves (#8128-8140)**	**No Significant Impact**
	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 I-5. For the valid range of world reserves, as the reserves of the world increase, the IRM requirement for PJM RTO is not greatly impacted.	
20	**PJM RTO RI Vs. PJM RTO Reserves (#8231-8244)**	**See below**
	A two area study when PJM RTO reserves were varied from the calculated requirement (1 day in 10). The runs are made by solving the PJM RTO for a fixed load (corresponding to an installed reserve level) and World is at its 1D/10 YR level. As the PJM RTO reserves increase, the reliability index (measured by the LOLE value) increases exponentially. See Figure II-8.	

Topological Modeling Sensitivity Cases		
21	**Single Area PJM RTO Model (#8117)**	**Increase 1.87 %**
	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 3,093 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 that is specified in Schedule 4 of the PJM Reliability Assurance Agreement (RAA).	
22	**PJMRTO Forecast Monthly load shape (#8204)**	**See Below**
	The forecast monthly load shapes in the model have historically come directly from the most recent load model forecast, for this study that is the January 2012 load forecast. Several PRISM runs were made to assess the impacts of the PJMRTO monthly shape on the study characteristics and ultimately the IRM results. It was found that the monthly load shape is a significant load characteristic. Small changes in the pattern can cause non-trivial changes in the model and IRM results. This sensitivity examines the impact on the IRM in forthcoming delivery years if an 11 year average for the monthly patterns was used instead of the pattern directly out of the load forecast.	

IRM (%) Using Different Monthly Load Patterns

Delivery Year	PRISM Run #8115 2012 Load Forecast Shape	PRISM Run #8204 11 Year Average Shape	Difference
2013/14	15.92	15.97	-0.05
2014/15	15.88	15.95	-0.07
2015/16	15.31	15.41	-0.10
2016/17	15.56	15.46	0.10

23	**Single Area World Model (#8225)**	**See Below**
	This models only the World in a single area case. The solution is for a Reliability Index (RI) of 10, or once every 10 years. The 2012 RRS World Model has a single area IRM of 16.4304% compared to the 2011 RRS model's single area World IRM of 17.0715%.	

24	**One Area Model for whole region (PJM RTO plus World) -2500 MW out on PO (#8229)**	**Increase by 1.55 %**
	This sensitivity models the entire modeling region, PJM RTO and the surrounding world as one area, using WKPKFQ #2197. This assumes no seams issues, no transmission constraints, and a single unit commitment dispatch for the large region. This region is the closest modeling representation for the Eastern Interconnection. Although one might expect a decrease in IRM due to the larger population of units that are in the single area, it seems that the PJMRTO is sufficiently large for this benefit to be saturated for the generation characteristics modeled (good performing units). The load model diversity and assistance from any outside region are not considered in this single area modeling and these multi-area model characteristics are significant. A total of 2500 MW were scheduled out on Planned maintenance to model the reduction in capacity due to ambient conditions.	
25	**Two Area Model with Ambient Derates for World Area - 3630 MW out on PO for World area (#8245)**	**Increase by 0.0008**
	This sensitivity models the Base Case with ambient derates for the World region too. The same proportion of impact of ambient conditions on the World fleet of units is modeled as are modeled for the PJM generation fleet. The impact of ambient conditions on the generation fleet affects several generation categories as shown in Table II-6. Ambient conditions are modeled as Planned outages over the ten week Summer period, similar to the 2,500 MW derating used in the PJMRTO area.	
26	**Relationship between IRM and ambient impact on unit performance (#8246-8263)**	**See Below**
	This sensitivity adjusts the total amount of ambient derates, for the appropriate generation categories affected by high ambient (THI) conditions (See Table II-6 for categories). Ambient derates are modeled as planned outages over the high LOLE summer period. Sensitivity Number 12 is related to this analysis. The range of impact to the unit fleet due to high ambient conditions, for the entire PJM RTO fleet of units, was 0 – 8,000 megawatts. The increase in the IRM for every additional 500 megawatts of ambient derates, on average, was 0.314. The regression fit equation is IRM=13.99561 + 0.0006272 * ambient derate amount.	
27	**Adjusted the seasonal factors to adjust units' ratings to reflect expected winter ratings (#8264)**	**No Change-0.00 %**
	This sensitivity increases the units' winter ratings to historically known values (before market influenced reporting). This value was 1.0562 which represents an increase of 5.62% due to colder ambient temperatures. This value for the winter capacity is indicative of historic values previously not influenced by current reporting practices. (Base Case has a winter factor of 1.0007, or 0.07% increase –a decrease from the 1.01088 value used in the 2011 base case) No change was observed in the IRM using the higher winter factors. However, for related and subsequent Adequacy LDA assessments, when a LDA has risk in the non-summer period, these winter ratings might impact (raise) the requirement to meet established criteria. LDAs that in recent studies have risk in the non-summer include: SMA, WMA, PN, PLGRP, MetEd, PEPCO, BGE, AEP, DLCO, and Dom.	

Appendix C
Resource Adequacy Analysis Subcommittee (RAAS)

RAAS Main Deliverables and Schedule

There are 3 primary deliverables of the RAAS.

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 thirteen, 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.

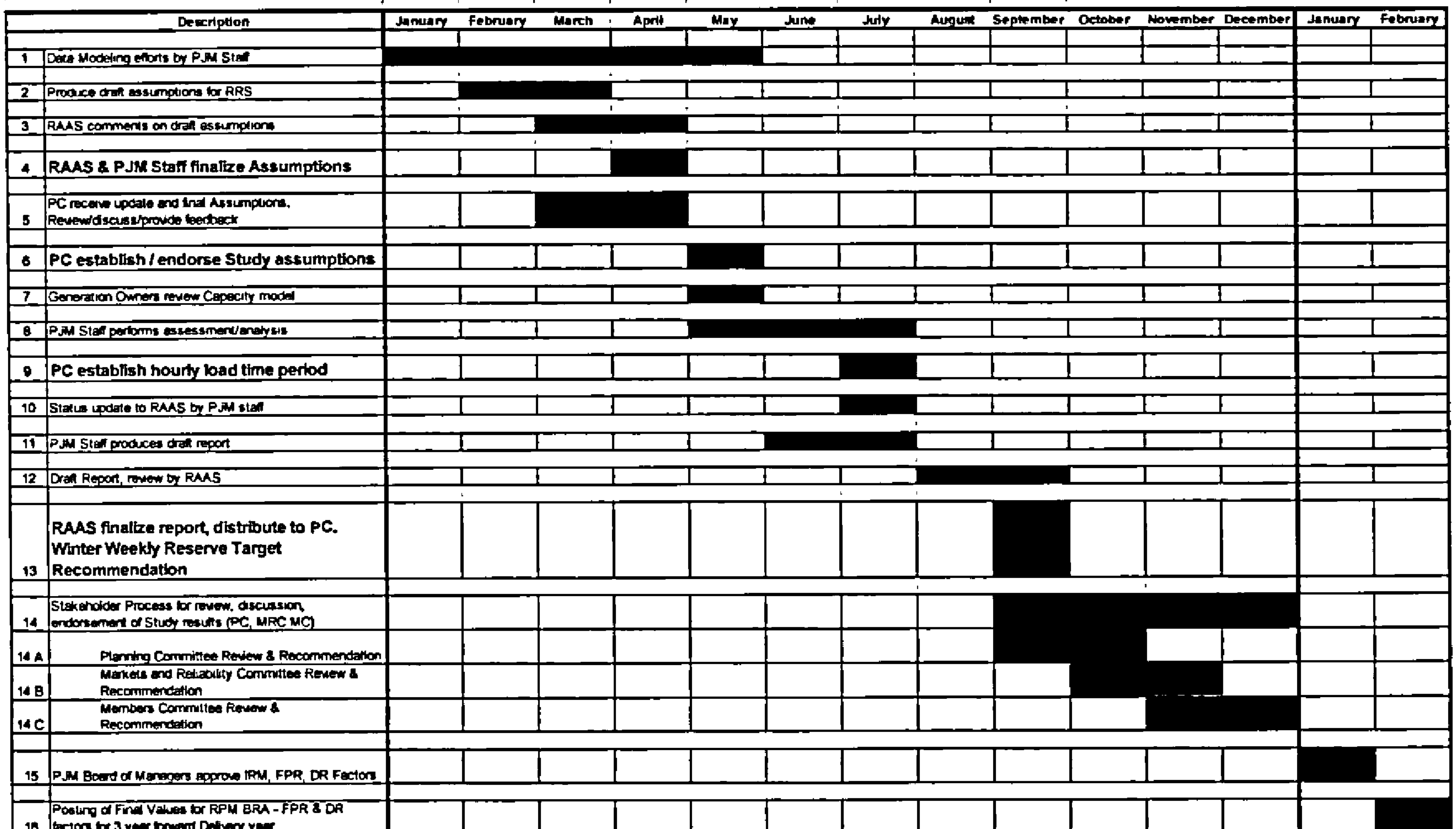
The activities of the PJM RAAS are shown at the following web link:
http://pjm.com/committees-and-groups/subcommittees/raas.aspx

Time Line for 2012 Reserve Requirement Study

Figure C - 1: Time Line for 2012 RRS

Annual Reserve Requirement Study (RRS) Timeline - Milestones (Green) and Deliverables (Blue)

Resource Adequacy Analysis Subcommittee (RAAS) related activities



The 2012 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.

KPSC Administrative Case No. 387
Calendar Year 2013
Additional Questions
Letter Dated May 19, 2014
Item No. 1
Page 78 of 83

Appendix D
ISO Reserve Requirement Comparison

The following compares the MISO, NYISO, ISO-NE and PJM RTO reserve requirements, on a 1) IRM, 2) IRM with Diversity, and 3) Unforced Margin with Diversity basis.

Observations from this comparison:

- When considering load diversity as well as the effect of GADS reported outside management control events and unforced margins, the reserve requirements for the PJM RTO are comparable to those in the MISO region. Note that the MISO and PJM footprints are also of comparable size, characteristics and complexities.
- PJM RTO unforced margin with diversity values are generally slightly higher than the MISO values due to the higher average XEFORd of MISO units; PJM RTO's IRM with diversity values, on the other hand, are lower than MISO's. The smaller NYISO and ISO-NE regions, due to their comparatively low load diversity, have higher unforced margin with diversity values. Compared to the same table in the 2011 RRS Report, PJM's unforced margin with diversity values are higher in some years due to the higher IRMs calculated in this year's study.

Table D - 1: Comparison of reserve requirements on a coincident, unforced basis.

	MISO	ISO-NE	NYISO	PJM	PJM	PJM	PJM	PJM
Delivery Year	2012	2015	2012	2012	2013	2014	2015	2016
IRM	**16.70%**	**13.90%**	**16.00%**	**16.10%**	**15.90%**	**15.90%**	**15.30%**	**15.60%**
Load Diversity	4.61%	0.79%	2.00%	4.00%	4.01%	4.05%	4.09%	3.93%
IRM (adj. by div)	**11.56%**	**13.01%**	**13.73%**	**11.63%**	**11.43%**	**11.39%**	**10.77%**	**11.23%**
XEFORd	6.77%	4.90%	6.12%	6.21%	6.05%	6.05%	5.91%	5.69%
Unforced Margin	8.80%	8.32%	8.90%	8.89%	8.89%	8.89%	8.49%	9.02%
Unforced Margin (adj. by div)	**4.00%**	**7.47%**	**6.77%**	**4.70%**	**4.69%**	**4.65%**	**4.22%**	**4.90%**

XEFORd = EFORd statistic without Outside Management Control (OMC) events.
Unforced Margin = ((1 + IRM) * (1- XEFORd)) - 1
IRM w/div = ((1 + IRM) / (1 + Load Diversity)) - 1
Unforced Margin w/div = (IRM w/div * (1 - XEFORd) / (1 + Load Diversity)) - 1
PJM RTO Load Diversity includes both inter-regional and intra-regional diversity, per Table B1 of the January 2012 load forecast report (Diversity Interregional plus Diversity PJM Western plus Diversity Mid-Atlantic)

ISO-NE and NYISO columns use estimated values for load diversity and XEFORd.

MISO values are from -2012-2013 LOLE Study Report", dated November 2011.

Appendix E
RAAS Review of Study - Transmittal Letter to PC

September 30, 2012

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

Dear Mr. Herling,

The Resource Adequacy Analysis Subcommittee (RAAS) has completed its review of the 2012 PJM Reserve Requirement Study (RRS) report.

The review efforts are in accordance with the RAAS Charter, as approved by the Planning Committee and posted at: http://pjm.com/committees-and-groups/subcommittees/~/media/committees-groups/subcommittees/raas/postings/charter.ashx

The review included the following efforts:

- Development and completion of the Study assumptions, including an activity timeline
- Participation in subcommittee meetings to discuss and review PJM staff progress in developing the Study model
- Identification of modeling improvements for incorporation into the analysis and report, as described in the April 12, 2012 RRS Study Assumptions letter
- Participation in subcommittee meetings to discuss and review preliminary analysis results
- Verification that all base case study assumptions are fully and completely adhered to
- Review of a draft version of the study report

After review and discussion of the study results, the subcommittee unanimously endorsed the PJM recommendation shown in the table below.

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Average EEFORd	Average XEFORd	Recommended FPR	Recommended DR Factor
2012	2013 / 2014	15.92%	15.9%	6.73%	7.36%	6.05%	1.0889	0.957
2012	2014 / 2015	15.88%	15.9%	8.72%	7.36%	8.05%	1.0889	0.956
2012	2015 / 2016	15.31%	15.3%	6.59%	7.21%	5.91%	1.0849	0.958
2012	2018 / 2017	15.56%	15.6%	6 38%	8.97%	5.69%	1.0902	0.955

After review of the winter weekly reserve analysis results, the subcommittee unanimously endorsed the PJM recommendation of a 28% winter weekly reserve target for the 2012/2013 winter period.

PJM will be requesting Planning Committee endorsement of the recommendations detailed above at the October 11, 2012 meeting.

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

Respectfully,

Thomas A Falin
RAAS Chair

Appendix F
Discussion of Assumptions

This appendix's intent is to document assumptions and modeling items that affect the calculated IRM for the base case run. The following considerations were included in the modeling and analysis

- Trends observed over several Study models are significant and are considered at the time of validating the recommendations resulting from this report.
- Historically significant drivers of the Study results include the overall unit forced outage rates, forecasted monthly load profile, 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.
- The sensitivities presented in Appendix B provide an important tool for validating assumptions and results of the study.
- Mitigating uncertainty to the forward capacity market is an important consideration..

A discussion of the assumptions considered in the study is presented below,

Independence of Unit Outage Events (no recognition of common cause failures): Historically, this has been an assumption widely used throughout the industry. All production grade commercial applications used to perform probabilistic reliability indexes use this assumption. However, 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.

Forecast Error Factor (FEF): The RRS models a 1% Forecast Error Factor for all delivery years. This modeling, which began in the 2005 Study, represents a switch from the previous practice of increasing the FEF as the planning horizon lengthens.

Intra-World Load Diversity: The diversity values used are from an assessment of 15 years of historic hourly data, using the average of the values seen over the summer season, more specifically the month of August. This ensures 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 8 of the 15 historic years, the diversity was lower than the average. Using the average of the historic diversity values was considered to be a reasonable assumption (as opposed to using the minimum of the values which was deemed to be very conservative).

Assistance from World area: The value of the outside world's assistance is associated with two modeling characteristics: the timing of PJM's need for assistance and 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.

Modeling all External NERC Regions in a Single Area: PRISM is limited to a 2-area model: PJM and the World Area. Thus, all external NERC regions are modeled in a single area. This approach assumes that all external NERC regions share loss-of-load events which are not the case in practice. 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".

Units out on planned maintenance over summer peak period: The moving of planned outage events to the summer peak period is an assumption that has been used since 1992. This is consistent with what has been observed by Operations over the summer period and reflects PJM's experience with a control region that includes about 1300 units. Currently, 2500 MW are modeled out to reflect reduced unit output during high ambient conditions (hot and humid).

Holding World at known reserve requirement level rather than forecast reserves: The World is modeled at the reserve requirement known for each of the surrounding individual sub-regions that make up the World region. This assumption ensures 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 the amount of assistance available to PJM from the World area.

Normally-distributed load model: The uncertainty in the daily peak load model is assumed to be normally distributed. The normal distribution is approximated using a histogram with 21 points ranging from -4.2 to +4.2 standard deviations from the mean. This 21-point approximation is used in all weeks (and in each of the 5 days within a week) of the analysis. The means and standard deviations vary from week to week and are computed by a separate program. This program uses historic weekly load data, magnitude ordered within a season, to compute the mean and standard deviation for each of the 52 weeks in the model. The 21 point daily peak distribution is defined by each week's mean and standard deviation in the calculation of loss of load expectation.

PJM and World regions load diversity: The value of the Capacity Benefit Margin (CBM) is associated with the timing of PJM load model peaks relative to the timing of the World load model peaks. This difference in timing is assessed by the PJM-World Diversity. The PJM-World Diversity is a measure of the World's load value at the time of PJM's annual peak. This measure is expressed as a percentage of the World's annual peak. Currently, this value is computed by using 15 years of historical hourly peak loads for the World (see Table II-3). Note that the greater the diversity, the more capacity assistance the World can provide at PJM's peak (or other PJM high load events). The value of PJM-World diversity might change depending on the dataset of historical hourly peaks considered.

Perfect correlation between two load models: As mentioned earlier in the report, PJM's load is assumed to be normally distributed (approximated via a 21-point histogram). The World's load model is modeled in the same way. When PJM is assumed to be facing a particular load level (for instance, load level 2, the second highest load level), the World is assumed to be facing the corresponding magnitude-ordered load level (i.e. the second highest out of the 21 load levels for the World). In other words, there is a perfect correlation between the two load models. In practice though, the World could be facing any other of the 20 remaining load levels.

KENTUCKY POWER COMPANY

REQUEST

Refer to Item No. 5, Attachment 1, note (f). Provide the margin in MWs and percent of Demand relative to PJM requirements.

RESPONSE

Attachment 1 to this response provides the margins and percent of demand relative to PJM requirements for KPCo for the winter seasons 2013/14 through 2017/18.

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY
Projected Winter Margins Relative to PJM Requirements

Winter Season	PJM ICAP Position After Interruptible w/ New Capacity: Reserve % Required By PJM	PJM ICAP Position After Interruptible w/ New Capacity: Net Position MW
Dec. 2013 - Mar. 2014	37.4	(538)
Dec. 2014 - Mar. 2015	18.4	556
Dec. 2015 - Mar. 2016	17.2	(228)
Dec. 2016 - Mar. 2017	17.7	(252)
Dec. 2017 - Mar. 2018	17 8	(189)

KENTUCKY POWER COMPANY

REQUEST

Refer to Item No. 5 Attachment 2, PJM/ICAP Position After Interruptible w/New Capacity, Reserve % required by PJM. Explain the drivers that elevate Kentucky Power's PJM reserve margin to 37.4 percent for 2014 and for each successive year through 2018.

RESPONSE

The primary driver to the Kentucky Power PJM reserve margin is the Kentucky Power EFORd (weighted average of unit EFORds) which is used to calculate capacity (on a UCAP basis), for Kentucky Power's resources. A higher EFORd will result in elevated Kentucky Power reserve margins. For the period 2014- 2018, the Kentucky Power EFORds are shown below. The higher EFORd in 2014/2015 is the result of a 2013 Big Sandy Unit 2 extended forced outage. The EFORd drops in the subsequent years because Big Sandy Unit 2 is retired and no longer impacts the EFORd calculation.

PJM Planning Year	EFORds
2014/15	20.77%
2015/16	8.09%
2016/17	7.43%
2017/18	7.43%
2018/19	7.42%

WITNESS: Ranie K Wohnhas