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Date of Hearing: 10-24-12 VOL III

Case No. 12-2190-EL-POR

PUCO Case Caption:

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company For Approval of Their Energy Efficiency and Peak Demand Reduction Program Portfolio Plans for 2013 through 2015

List of exhibits being filed:

IEU 2

3

4

Reporter's Signature: Karen Gibson

Date Submitted: 10-30-12

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Review of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company for Approval of Their Energy Efficiency and Peak Demand Reduction Program Portfolio Plans for 2013 through 2015. : Case No. 12-2190-EL-POR : Case No. 12-2191-EL-POR : Case No. 12-2192-EL-POR

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PROCEEDINGS

before Mr. Gregory Price and Ms. Mandy Willey Chiles, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 10:00 a.m. on Wednesday, October 24, 2012.

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VOLUME III

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EXHIBIT
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Working to Perfect the Flow of Energy

PJM Manual 18:

PJM Capacity Market

Revision: 14

Effective Date: February 23, 2012

Prepared by

PJM Capacity Market Operations

PJM Manual 18:

PJM Capacity Market

Table of Contents

Table of Exhibits

Approval

Approval Date: 02/23/2012
Effective Date: 02/23/2012

Jeff Bastian, Manager

Capacity Market Operations

Current Revision

Revision 14 (02/23/2012):

- Conforming Revisions for FERC Order ER11-2287, accepted on 01/31/2011, and effective 01/31/2011 to revise the definition of an Existing Generation Resource for the purposes of must-offer and mitigation provisions (Section 1.2, 5.6.1, 5.7.1).
- Conforming Revisions needed to include updates to Installed Reserve Margin, Pool-wide average EFORd, Forecast Pool Requirement, CETO, and CETLs prior to Incremental Auctions and conform to Attachment DD of Open Access Transmission Tariff. (Sections 2.1.1, 2.1.3, 2.1.4, and 2.3)
- Conforming Revisions for FERC Order ER11-2287, accepted on 01/31/2011 and effective 02/01/2011 to establish three product alternatives (limited, extended summer, and annual) for demand resources seeking to participate in PJM's capacity market. (Sections 2.4.3, 4.3, 4.3.1, 4.3.2, 4.3.7, 5.3, 5.3.1, 5.4, 5.6.2, 5.7.5, 5.8.1, 8.2.2, 8.5, 8.5.1, 8.5.2, 8.6, 8.7, 9.1.7, 9.1.9, 11.1.3, 11.3, 11.9.1)
- Conforming Revisions for FERC Order ER11-3365, accepted on 6/6/2011 and effective 06/17/2011, to refine the calculations of the amount of capacity commitments that PJM seeks to procure or release in Incremental Auctions and the amount of Excess Committed Credits commencing with the 2012/2013 Delivery Year (Sections 3.5 and 8.7.2)
- Conforming Revisions for FERC Order ER05-1410-015, et al., accepted on 05/20/2010 to implement the use of an Updated VRR Curve Increment/Decrement in developing PJM Buy Bids/Sell Offers in Incremental Auctions (Section 3.5).
- Conforming Revisions for FERC Order ER12-125 accepted on 12/02/2011 and effective 12/19/2011 to clarify that PJM Emergency Load Response Registrations must be submitted to PJM no later than one day before the tenth business day preceding the relevant Delivery year, and must be approved on or before May 31st preceding the relevant Delivery Year (Section 4.3.7)
- Conforming Revisions for FERC Order ER10-1003, accepted on 05/05/2010, and effective 06/01/2010 to revise PJM's credit risk management rules for certain bilateral transactions (unit-specific transactions for cleared capacity, Auction Specific MW transactions, and Locational UCAP transactions) (Sections 4.6.2, 4.6.6, and 4.6.7).

- Conforming Revisions needed to clarify the Auction Credit Rate and conform to Attachment Q of Open Access Transmission Tariff. (Section 4.8.3)
- Conforming Revisions for FERC Order ER11-2913, accepted on 4/13/2011and effective 04/20/2011, to allow Credit-Limited Offers in RPM Auctions for planned resources (whether generation, demand resources, or energy efficiency) (Section 4.8.4).
- Conforming Revisions for FERC Order ER11-4143, accepted on 09/12/2011 and effective 06/01/2007, to correct time periods for critical peak periods for the assessment of Peak Hour Period Availability from eastern prevailing time (EPT) to local prevailing time (LPT) (Section 8.4).
- Conforming Revisions for FERC Order ER09-412, accepted on 03/26/2009, and effective 06/01/2009 to allow excess available capacity that satisfies all capacity resource obligations of a committed resource to serve as replacement capacity to offset potential peak hour period availability penalties. (Sections 8.4.5 and 8.4.5.1)
- Conforming Revisions for FERC Order ER10-2917, accepted on 10/29/2010, and effective 11/23/2010 to further clarify that PJM considers committed capacity first in determining net peak hour period capacity shortfalls in an LDA and then considers uncommitted, available capacity to adjust the net peak hour period capacity shortfall in an LDA only to extent necessary to mitigate or eliminate any availability shortfalls for committed capacity (Sections 8.4.5 and 8.4.5.1).
- Conforming Revisions for FERC Order ER12-271, accepted on 12/27/2011 and effective 12/30/2011, to modify the bill timing of the Demand Resource and ILR Compliance Penalty Charge such that charges are assessed and billed in two phases. (Section 9.1.9)
- Conforming Revisions needed to clarify Fixed Resource Requirement Alternative business rules in Section 11.3 and conform to Schedule 8.1 of the Reliability Assurance Agreement.
- Conforming Revisions for FERC Order ER11-2875 regarding MOPR (Section 5.3.5)

Introduction

Welcome to the PJM Manual for *PJM Capacity Market*. In this Introduction you will find information about PJM Manuals in general, an overview of this PJM Manual in particular, and information on how to use this manual.

- What you can expect from the PJM Manuals (see "About PJM Manuals").
- What you can expect from this PJM Manual (see "About This Manuals).
- How to use this manual (see "Using This Manual").

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and billing
- PJM administrative services
- Miscellaneous.

About This Manual

The PJM Manual for ***PJM Capacity Market*** is one of the PJM procedure manuals. This manual focuses on the capacity markets, including the Reliability Pricing Model and the Fixed Resource Requirement Alternative, and the requirements for resource providers and Load Serving Entities (LSEs) to participate in these markets and their responsibilities as signatories to the Open Access Transmission Tariff, Reliability Assurance Agreement and Operating Agreement of PJM Interconnection, L.L.C.

This manual also refers to other PJM manuals, which define in detail the operating procedures, obligations, reporting requirements, and accounting procedures established to ensure reliable and efficient capacity market operation.

The PJM Manual for ***PJM Capacity Market*** *consists* of 11 sections and 5 attachments (labeled A through E). Both the sections and the attachments are listed in the table of contents beginning on page ii.

Intended Audience

The intended audiences for this PJM Manual for *PJM Capacity Market* are:

- Applicants to the RAA, OA and OATT Operating Agreement of PJM Interconnection, L.L.C.

- Resource providers and those interested in providing adequate Capacity Resources that will be made available to provide reliable service to loads within the PJM Region.
- Load Serving Entities (LSEs) for load served in the PJM Region.
- PJM Members
- PJM staff

References

There are other PJM documents that provide both background and detail on specific topics. These documents are the primary source for specific requirements and implementation details. This manual does not replace any of the information in those reference documents. The references for the PJM Manual for *PJM Capacity Market* are:

- PJM Manual for Scheduling (M-11)
- PJM Manual for Generation and Transmission Interconnection Planning (14b)
- PJM Manual for Load Data Systems (M-19).
- PJM Manual for Reserve Requirements (M-20).
- PJM Manual for Rules and Procedures for Determination of Generating Capability (M-21)
- PJM Manual for Generator Resource Performance Indices (M-22).
- PJM Manual for Open Access Transmission Tariff Accounting (M-27).
- PJM Manual for Billing (M-29).

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with the "big picture." Then we present details, procedures or references to procedures found in other PJM manuals.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections and attachments
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions
- Attachments that include additional supporting documents, forms, or tables
- A section at the end detailing all previous revisions of this PJM Manual.

Section 1: Overview of the PJM Capacity Market

Welcome to the *Overview of the PJM Capacity Market* section of the *PJM Manual for the PJM Capacity Market*. In this section, you will find the following information:

- An overview description of the PJM Capacity Market (see "Overview of the PJM Capacity Market")
- The business rules for participation in the PJM Capacity Markets (see "Participation in the PJM Capacity Market")
- A definition and purpose of the Reliability Pricing Model (see "Definition and Purpose of the Reliability Pricing Model")
- The timeframe for implementation of the Reliability Pricing Model (see "Implementation of the Reliability Pricing Model")

1.1 Overview of the PJM Capacity Market

The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. In PJM, the capacity market structure provides transparent information to enable forward capacity market signals to support infrastructure investment. The capacity market design provides a forward mechanism to evaluate the ongoing reliability requirements in a transparent way to provide opportunity for generation, demand response, energy efficiency, and transmission solutions.

In the PJM Region, the basis for the capacity market design is the Reliability Pricing Model (RPM). The goal of RPM is to align capacity pricing with system reliability requirements and to provide transparent information to all market participants far enough in advance for actionable response to the information. In RPM, the fundamental elements to achieve this are:

- Locational Capacity Pricing to recognize and quantify the locational value of capacity
- Variable Resource Requirement mechanism to adjust price based on the level of resources procured
- Forward Commitment of supply by generation, demand resources and qualified transmission upgrades cleared in a multi-auction structure
- A Reliability Backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability

The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement (FRR) Alternative. The Fixed Resource Requirement Alternative provides a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

Unless otherwise specified, the rules presented throughout this Manual are focused on the Reliability Pricing Model. Information on the Fixed Resource Requirement Alternative can be found in ***Section 11 of this Manual*** and on PJM.com.

1.2 Participation in the PJM Capacity Market

Participants in the PJM Capacity Market, both Load Serving Entities and resource providers, must comply with all applicable provisions of the PJM Open Access Transmission Tariff, PJM Operating Agreement, and the PJM Reliability Assurance Agreement. PJM Capacity Market participants must be signatories of the appropriate Agreements and Full Members of PJM. All participants must comply with the procedures and requirements as set forth by these agreements and in PJM Manuals.

1.2.1 Participation of Load Serving Entities

Participation by Load Serving Entities (LSEs) in the RPM for load served in the PJM region is mandatory, except for those LSEs that have elected the Fixed Resource Requirement (FRR) Alternative and submitted an approved FRR Capacity Plan for their load served in an FRR Service Area. Under RPM, each LSE that serves load in a PJM Zone during the Delivery Year shall be responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in the Zone multiplied by the Final Zonal Capacity Price applicable to that Zone. LSEs may choose to hedge their Locational Reliability Charge obligations by directly offering and clearing resources in the Base Residual Auction and Second Incremental Auction or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction. Such action may wholly or partially offset an LSE's Locational Reliability Charges during the Delivery Year depending upon how the clearing prices of the resources compare to the Final Zonal Capacity Prices that apply to their unforced capacity obligations.

Participants with Non-Zone Load, as defined in the PJM Agreements, may be included in the Reliability Pricing Model depending if the load that is located outside of the PJM Region is included in the PJM load forecasts and served by generation resources located within the PJM Region. The treatment of Non-Zone Load is described in Section 7 of this Manual.

1.2.2 Participation of Resource Providers

Resource providers with existing generation, planned generation, bilateral contracts for unit-specific capacity resources, existing Demand Resources, Planned Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades may participate in PJM's Capacity Market, either in PJM's Reliability Pricing Model or the Fixed Resource Requirement Alternative, if these products meet the requirements specified in this Manual. Existing generation that is located outside of the PJM market footprint may also be offered into PJM's Capacity Market, either in the Reliability Pricing Model or the Fixed Resource Requirement Alternative, if the external generation meets the requirements specified in the PJM Manuals and PJM Agreements.

Participation is mandatory for resource providers with:

- Available unforced capacity from existing generation located within the PJM market footprint; or
- Bilateral contracts for available unit-specific capacity resources that are existing generation units located within the PJM market footprint.

- Generation is treated as existing for the purpose of must-offer requirement and mitigation provisions when the generation is (a) in service at the commencement of an RPM Auction or (b) not yet in service but has cleared an RPM Auction for any prior Delivery Year. The Minimum Offer Price Rule (MOPR), as described in Section 5.3.5, applies to a Planned Generation Resource until the first year for which it clears an RPM Auction.

Resource providers do have the option to export available capacity outside the PJM market footprint if the generator is exporting per the requirements specified in PJM Manuals and PJM Agreements.

Participation is voluntary for resource providers with:

- External generation
- Planned generation (including planned upgrades to existing units)
- Planned external generation (including planned upgrades to existing units)
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources
- Qualifying Transmission Upgrades.

All participation by resource providers is subject to the market power mitigation rules described in Attachment DD, Section 6 of the PJM Open Access Transmission Tariff.

1.3 Definition and Purpose of the Reliability Pricing Model

The Reliability Pricing Model is the PJM resource adequacy construct that ensures that adequate Capacity Resources, including planned and existing Generation Resources, planned and existing Demand Resources, Energy Efficiency Resources, and Interruptible Load for Reliability[1] (ILR) will be made available to provide reliable service to loads within the PJM Region.

The purpose of the RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM is also designed to add stability and a locational nature to the pricing signal. The RPM is a multi-auction structure designed to procure resource commitments to satisfy the region's unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

> *Base Residual Auction* - The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. The Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.

[1] Interruptible Load for Reliability option is eliminated effective with the 2012/13 Delivery Year. Instead, a RTO Short-Term Resource Procurement Target of 2.5% of RTO Reliability Requirement will be held back for future procurement.

Incremental Auctions – Up to three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.

Prior to the 2012/13 Delivery Year:

- *The First and Third Incremental Auctions* are conducted to allow for an incremental procurement of resource commitments when there is a decrease in the value of committed resources as a result of a resource cancellation, delay, derating, EFORd increase, or a decrease in the nominated value of a Planned Demand Resource. The cost of procurement in these Auctions is allocated to resource providers that caused the need for additional resources to be procured.
- *The Second Incremental Auction* is conducted to allow for an incremental procurement of resource commitments when there is an increase in the region's unforced capacity obligation as a result of a load forecast increase. The cost of procurement in the Second Incremental Auction is allocated to Load Serving Entities through a Locational Reliability Charge.

Effective 2012/13 Delivery Year:

- *The First, Second, and Third Incremental Auctions* are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.
- *A Conditional Incremental Auction* may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

  The Bilateral Market – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge. The bilateral market is facilitated through the eRPM system.

1.4 Implementation of the Reliability Pricing Model

The implementation of the Reliability Pricing Model began with the 2007/2008 Delivery Year. PJM's Planning Period is defined as an annual period from June 1 to May 31. The Delivery Year is the Planning Period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2007/2008 Delivery Year corresponds to the June 1, 2007 - May 31, 2008 Planning Period.

The Transition Period of the RPM takes place during the 2007/2008 through 2010/2011 Delivery Years.

The steady-state condition of the RPM begins with the 2011/2012 Delivery Year. Unless otherwise specified, the rules and timeframes presented throughout this Manual are for the steady-state condition of RPM. Information on the Transition Period can be found in an ***Appendix C of this Manual*** and on PJM.com.

Section 2: Resource Adequacy

Welcome to the *Resource Adequacy* section of the *PJM Manual for the PJM Capacity Market*. In this section, you will find the following information:

- An overview description of resource adequacy (see "Overview of Resource Adequacy")
- The role of load deliverability in the Reliability Pricing Model (see "Role of Load Deliverability in the Reliability Pricing Model")
- The business rules for Locational Constraints in the Reliability Pricing Model ("see Locational Constraints in the Reliability Pricing Model")
- The definitions of Reliability Requirements (see "Reliability Requirements")

2.1 Overview of Resource Adequacy

The purpose of PJM RTO resource adequacy is to determine the amount of capacity resources that can be required to serve the forecast load that satisfies the PJM reliability criterion. PJM performs an assessment of resource adequacy each year for a ten-year future period. The analysis considers load forecast uncertainty, forced outages of generation capacity resources, as well as planned and maintenance outages. In PJM, studies are performed using the installed capacity values of resources. The reliability value of a resource depends on two variables: the installed capacity of the resource and a measure of the probability that a resource will not be available due to forced outages or forced de-ratings. The reliability criterion is based on Loss of Load Expectation (LOLE) not exceeding one occurrence in ten years. The resource requirement to meet the reliability criterion is expressed as the Installed Reserve Margin (IRM) as a percentage of forecast peak load.

2.1.1 Installed Reserve Margin

The Installed Reserve Margin (IRM) for the Delivery Year is the measure calculated to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the PJM Reliability Principles and Standards. The IRM is determined by PJM in accordance with ***the PJM Reserve Requirements Manual (M-20).***

The ***Installed Reserve Margin*** (IRM) is approved by the PJM Board of Managers and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. An Updated IRM is approved by the PJM Board of Managers and posted one month prior to its use in an Incremental Auction for the Delivery Year. The Updated IRM that is posted for the Third Incremental Auction for the Delivery Year is the final IRM for the Delivery Year.

2.1.2 Peak Load Forecasts

PJM produces peak load forecasts for use in the RPM auction clearing processes and for planning purposes. In RPM, the load forecasts will be used to determine the RTO Reliability Requirement. PJM will determine ***annual peak load forecasts*** for the RTO and zones for use in the RPM Auction clearing process.

The Preliminary RTO Peak Load Forecast and the Preliminary Zonal Peak Load Forecasts for the Delivery Year are determined by PJM in accordance with ***the Load Data Systems Manual (M-19).***

The Preliminary RTO and Zonal Peak Load Forecasts are determined and posted by February 1 prior to the Base Residual Auction for the Delivery Year.

Effective with 2012/13 Delivery Year, Updated RTO and Zonal Peak Load Forecasts for the Delivery Year are determined by PJM in accordance with the Load Data Systems Manual.

Effective with 2012/13 Delivery Year, ***Updated RTO and Zonal Peak Load Forecasts*** are posted no later than one month prior to the First and Second Incremental Auctions.

The Final RTO Peak Load Forecast and the Final Zonal Peak Load Forecasts for the Delivery Year are determined by PJM *in accordance with the Load Data Systems Manual.*

Prior to the 2009/10 DY, *the Final RTO and Zonal Peak Load Forecasts* are determined and posted by February 28 prior to the Second Incremental Auction.

Effective with the 2009/10 Delivery Year, the ***Final RTO and Zonal Peak Load Forecasts*** are posted no later than one month prior to the Third Incremental Auction.

Load forecasts are also used in the determination of other planning and auction parameters such as Capacity Emergency Transfer Limit (CETL), Capacity Emergency Transfer Objective (CETO), and RPM Zonal Scaling Factors. These parameters are discussed in detail in later sections of this Manual.

2.1.3 Pool-wide Average EFORd

To account for the forced outage rates of generation capacity resources, an Equivalent Forced Outage Rate (EFORd) for each generating unit in the PJM RTO is calculated. Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. See ***Generator Resource Performance Indices Manual (M-22)*** for equations and details.

The Pool-wide Average EFORd for the Delivery Year is the average of the forced outage rates based on five years history, weighted for unit capability and expected time in service, attributable to all units that are planned to be in service during the Delivery Year. Effective 2010/2011 Delivery Year, the Pool-Wide Average EFORd will not include forced outage events that are outside management control (referred to as OMC events). The Pool-wide Average EFORd is determined by PJM in accordance with ***the PJM Reserve Requirements Manual (M-20).***

The ***Pool-wide average EFORd*** is posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. An updated Pool-wide average EFORd is posted one month prior to its use in an Incremental Auction for the Delivery Year. The Pool-wide average EFORd that is posted for the Third Incremental Auction for the Delivery Year is the final pool-wide average EFORd for the Delivery Year.

2.1.4 Forecast Pool Requirement

While IRM multiplied by peak load forecasts provides the installed capacity required to meet the reliability criterion, the Forecast Pool Requirement (FPR) multiplied by peak load forecasts provides unforced capacity values, required to meet the reliability criterion. Therefore, to express the Installed Reserve Margin (IRM) as an unforced capacity value, the calculation of the Forecast Pool Requirement must consider the forced outage rates of all generating units, or the Pool-wide Average EFORd.

The Forecast Pool Requirement is the measure determined for the specified Delivery Year to establish the level of unforced capacity (UCAP) that will provide an acceptable level of reliability consistent with PJM Reliability Principles and Standards.

The following parameters are values used in the determination of Forecast Pool Requirement:

- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd
- The Forecast Pool Requirement (FPR) for the Delivery Year is calculated by PJM and is equal to (1 + Installed Reserve Margin) times (1-Pool-wide Average EFORd).[2]

$$ForecastPoolRequirement\ (FPR) = (1 + InstalledReserveMargin) * (1 - PoolWideAverageEFORd)$$

The ***Forecast Pool Requirement (FPR)*** is approved by the PJM Board of Managers and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. An Updated FPR is approved by the PJM Board of Managers and posted one month prior to its use in an Incremental Auction for the Delivery Year. The Updated FPR that is posted for the Third Incremental Auction for the Delivery Year is the final FPR for the Delivery Year.

2.2 Role of Load Deliverability in the Reliability Pricing Model

The process of determining the Installed Reserve Margin (IRM) that meets the PJM reliability criterion assumes that the internal RTO transmission is adequate and any generation can be delivered to any load without transmission constraints. This process helps in determining the minimum possible IRM for the RTO. However, since transmission may have limitations, after IRM is determined a Load Deliverability analysis is conducted. The RTO is divided into different sub-regions for this analysis. These sub-regions are referred to as Locational Deliverability Areas (LDAs) in the Reliability Pricing Model.

The first step in the Load Deliverability analysis is to determine the transmission import capability required for each LDA to meet the area reliability criterion of Loss of Load Expectation of one occurrence in 25 years. This import capability requirement is called Capacity Emergency Transfer Objective (CETO), expressed in megawatts and valued as unforced capacity. The standard generation reliability evaluation model is used to determine CETO. For more details regarding the CETO analysis, please see ***Manual 20: Reserve Requirements.***

[2] The terms in this equation are expressed in decimal form.

The second step in Load Deliverability analysis is to determine the transmission import capability limit for each LDA using the transmission analysis models. For this analysis, a Transmission Upgrade including transmission facilities at voltages of 500 kV or higher that is in an approved Regional Transmission Expansion Plan ("Backbone Transmission") will be included in the system model only if it satisfies the project development milestones set forth in the tariff. This import capability limit is called Capacity Emergency Transfer Limit (CETL), expressed in megawatts and valued as unforced capacity. For more details regarding CETL analysis, please see ***Manual 14b: Generation and Transmission Interconnection Planning, Attachment C: PJM Deliverability Testing Methods.***

If CETL value is less than CETO value, transmission upgrades are planned under the Regional Transmission Expansion Planning Process (RTEPP). However, higher than anticipated load growth and unanticipated retirements may result in the CETL value being less than CETO value with no lead time to build transmission upgrades to increase CETL value. These conditions could result in locational constraints in the RTO.

2.3 Locational Constraints in the Reliability Pricing Model

When a capacity market does not have the ability to price capacity on a locational basis, all the resources in the market are valued equally throughout the RTO. When this occurs, it is possible to have excess reserves in the RTO and relatively low capacity prices. This market signal will result in generation capacity retirements. In some areas of the RTO these retirements will create reliability violations. These conditions will indicate that a higher value for resources is required to be recognized in constrained locations to incent existing generating capacity to remain in service, and new capability to be built in the form of generation resources, demand resources, or merchant transmission upgrades. One of the key features of RPM is the recognition of locational value of capacity.

Locational Constraints are localized capacity import capability limitations (low CETL margin over CETO) that are caused by transmission facility limitations or voltage limitations that are identified for a Delivery Year in the PJM Regional Transmission Expansion Planning Process (RTEPP) prior to each Base Residual Auction. Such Locational Constraints are included in the RPM to recognize and to quantify the locational value of capacity.

CETOs and CETLs for the LDAs to be modeled in all RPM Auctions for the Delivery Year are posted by February 1 prior to their use in the Base Residual Auction for the Delivery Year. Updated CETOs and CETLs for the modeled LDAs are posted one month prior to its use in an Incremental Auction for the Delivery Year.

2.3.1 Locational Deliverability Areas

In the development of the Reliability Pricing Model, the RTEP Process identified 25 sub-regions referred to as Locational Deliverability Areas for evaluating the locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

The 25 LDAs (highlighted in boldface) and an LDA's relationship to an immediate parent LDA are listed below:

RTO=> Western PJM

RTO => Western PJM => **ComEd**

RTO => Western PJM => **AEP**

RTO => Western PJM => **Dayton**

RTO => Western PJM => **DLCO**

RTO => Western PJM => **APS**

RTO => Western PJM => **ATSI**

RTO => Western PJM => DEOK

RTO => Dominion

RTO => **MAAC**

RTO => MAAC => **WMAAC**

RTO => MAAC => WMAAC => **MetEd**

RTO => MAAC => WMAAC => **PPL**

RTO => MAAC => WMAAC => **Penelec**

RTO => MAAC => **EMAAC** (includes RECO)

RTO => MAAC => EMAAC => **AE**

RTO => MAAC => EMAAC => **PSEG**

RTO => MAAC => EMAAC => PSEG => **PSEG N**

RTO => MAAC => EMAAC => **PECO**

RTO => MAAC => EMAAC => **JCPL**

RTO => MAAC => EMAAC => **DPL**

RTO => MAAC => EMAAC => DPL => **DPL S**

RTO => MAAC => **SWMAAC**

RTO => MAAC => SWMAAC => **BGE**

RTO => MAAC => SWMAAC => **PEPCO**

2.3.2 Constrained Locational Deliverability Areas (LDAs)

An LDA with Capacity Emergency Transfer Limit (CETL) less than 1.15 times Capacity Emergency Transfer Objective (CETO) will be modeled as a constrained LDA in RPM. In addition, an LDA will be modeled if (a) such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; (b) such LDA is determined by PJM to likely have a Locational Price Adder based on historic offer price levels; and (c) starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC

LDAs will be modeled as constrained LDAs regardless of the outcome of the above tests.[3] PJM may decide to model the LDA as a constrained LDA regardless of the outcome of the above tests if there are other reliability concerns. A Reliability Requirement and a Variable Resource Requirement Curve will be established for each constrained LDA to be modeled in the RPM Base Residual Auction. See ***Section 5 of this Manual*** for the details. The *constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year* with their Reliability Requirements and the VRR Curves will be posted on the PJM website by February 1 prior to the commencement of the Base Residual Auction for that Delivery Year.

If an LDA clears with a Locational Price Adder in any Base Residual Auction, PJM shall perform an analysis to determine if any new generation, new demand resource or Qualifying Transmission Upgrades were cleared in that LDA in such Base Residual Auction. New generation or new demand resources include incremental upgrades to existing resources beyond historic installed capacity levels or new resource installations. If any LDA has a Locational Price Adder and if no new generation, new demand resource or Qualifying Transmission Upgrades have cleared in the LDA for two consecutive Base Residual Auctions, then PJM shall evaluate a transmission upgrade as part of the RTEPP that would reduce the Locational Price Adder to zero.

The evaluation of such transmission upgrade shall include an evaluation of the cost of the upgrade as compared to the incremental benefit of reducing Locational Price Adder to zero in the LDA. If the transmission upgrade is feasible and cost beneficial over the next ten year period, then the transmission upgrade shall be included in the Regional Transmission Expansion Plan as soon as possible. The annual costs of such upgrade shall be allocated to all LSEs serving load in the LDA, pro rata based on such loads.

2.3.3 Creation of New Locational Deliverability Areas (LDAs)

A prudent planning practice is to continuously monitor system performance and study transmission constraints as they develop. Triggers and criteria to consider a new LDA are specified in Manual 14B "PJM Regional Transmission Planning Process", Attachment C: PJM Deliverability Testing Methods, based on RTEP Market Efficiency Analysis and RTEP Long Term Planning. PJM will make a filing with FERC to amend RAA Schedule 10.1 to add a new LDA (including a new LDA that is an aggregate of Zones), if such new area is projected to have a CETL less than 1.15[4] times the CETO of the area, or if warranted by other reliability concern. In addition, any Party may propose, and PJM would evaluate, possible LDAs under such standards.

2.3.4 Transition Period

During the Transition Period, Locational Deliverability Areas for Each Transition Delivery Year shall be as follows:

[3] Prior to the 2012/2013 Delivery Year, an LDA with CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. *No additional criteria were considered in the modeling of a constrained LDA prior to* the 2012/2013 Delivery Year.

[4] Prior to the 2012/2013 Delivery Year, the CETL/CETO threshold was 1.05.

Transition Delivery Year	Locational Deliverability Areas
2007/2008, 2008/2009, 2009/2010	• PJM Mid-Atlantic Region and APS • Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL, and RECO) • Southwestern MAAC (PEPCO & BG&E) • RTO
2010/2011	• All 23 LDAs.
2011/2012 and later	• All 25 LDAs.

The LDAs that were modeled in the Base Residual Auction for a Delivery Year will remain in the model for all Incremental Auctions for that Delivery Year with the same Capacity Emergency Transfer Limits.

2.4 Reliability Requirements

In the PJM Capacity Market, reliability requirements, or reserve requirements, represent the *target level of reserves required to meet PJM Reliability Standards and Principles. It is* important to note that the Installed Reserve Margin (IRM) and the Forecast Pool Requirement (FPR) represent the level of reserves required, but are expressed in different capacity values. The IRM is expressed as the installed capacity reserve as a percent (e.g. 15%) of the forecast peak load, whereas the FPR (e.g., 1.079) when multiplied by forecast peak load provides of the total unforced capacity required. The installed capacity (ICAP) value of a generation resource is based on the summer net dependable rating of a unit as determined in accordance with PJM's Rules and Procedures, also referred to as "Iron in the Ground". The unforced capacity (UCAP) value of a generation resource is installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced de-rating.

In the RPM clearing process, the Reliability Requirements for the RTO and the LDA are used to establish the target reserve levels, valued as unforced capacity that will be cleared in the RPM Auctions.

The final Reliability Requirements, used in the clearing of RPM Auctions, will be adjusted to account for entities that have elected the Fixed Resource Requirement Alternative. Therefore, when known, the Unforced Capacity Obligations for FRR entities will be removed from the calculation of the Reliability Requirements for the RTO and any LDAs.

2.4.1 PJM Region Reliability Requirement

The PJM Region Reliability Requirement, valued in unforced capacity terms, is the RTO Peak Load Forecast, multiplied by the approved Forecast Pool Requirement for the PJM Region, less the sum of Preliminary Unforced Capacity Obligations of the FRR Entities in the PJM Region.

$$RelReq_{PJMRegion} = (RTOPeakLoadForecast) \times (FPR) - \sum PrelimUnforcedCapObligations_{FRREntities}$$

2.4.2 Reliability Requirement in Locational Deliverability Areas

The Locational Deliverability Area Reliability Requirement is the projected internal capacity (in UCAP terms) in the LDA plus the Capacity Emergency Transfer Objective (CETO) for the Delivery Year, as determined by the RTEP process, less the minimum internal resources (in UCAP terms) required for the FRR Entities located in the LDA.

$$RelReq_{LDA} = ProjectedInternalCap + CETO - (Min\,Internal\,Resources_{FRREntities})$$

2.4.3 Minimum Annual/Extended Summer Resource Requirements

Starting with the 2014/2015 Delivery Year, two additional demand resource products have been established - one available throughout the year (Annual DR) and another available for an extended summer period (Extended Summer DR). These new products have fewer limitations than the Limited Demand Resource product (Limited DR). New auction rules effective with the 2014/2015 BRA recognize the greater reliability value associated with less limited resources by establishing and enforcing a minimum requirement on the commitment of less limited products. The Minimum Annual Resource Requirement is the minimum amount of capacity sought to be procured in each auction from Annual Resources (Annual Resources include generation capacity resources, energy efficiency resources and annual demand resources). The Minimum Extended Summer Resource Requirement is the minimum amount of capacity sought to be procured in each auction from Extended Summer Demand Resources and Annual Resources.

Minimum Annual and Minimum Extended Summer Resource Requirements are established for the RTO and each modeled LDA and the auction clearing process can select Extended Summer DR or Annual Resources out of merit order, if necessary, to procure the minimum required quantities, similar to the way in which RPM auctions can select resources out of merit order to address locational constraints. In those cases where one or both of the minimum resource requirements do bind in the auction solution, just as with resources selected to resolve locational constraints, resources selected to meet the necessary minimum resource requirements will receive an adder to the system marginal price of capacity (in addition to any locational price adder(s) received to resolve locational constraints).

For the RTO, the Minimum Annual Resource Requirement is equal to the RTO Reliability Requirement minus [the Extended Summer Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement is equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Extended Summer Demand Resource Reliability Target for the LDA in Unforced Capacity]. The LDA CETL may be adjusted pro-rata for the amount of load in the LDA served under the FRR Alternative. The Extended Summer Demand Resource Reliability Target for the PJM Region or an LDA is the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability as more fully described in the ***PJM Manual for Reserve Requirements (M-20).***

For the RTO, the Minimum Extended Summer Resource Requirement is equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the RTO *in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement* is equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited

Demand Resource Reliability Target for the LDA in Unforced Capacity]. The LDA CETL may be adjusted pro-rata for the amount of load in the LDA served under the FRR Alternative. *The Limited Demand Resource Reliability Target for the PJM Region or an LDA is the* maximum amount of Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability as more fully described in the ***PJM Manual for Reserve Requirements (M-20).***

Section 3: Demand in the Reliability Pricing Model

Welcome to the Demand in the Reliability Pricing Model section of the PJM Manual for the Reliability Pricing Model. In this section, you will find the following information:

- An overview description of demand in the Reliability Pricing Model (see "Overview of Demand in the Reliability Pricing Model")
- The definition and purpose of the Variable Resource Requirement
- The method for plotting the Variable Resource Requirement Curve (see "Plotting the Variable Resource Requirement Curve")
- A description of the demand curves in the Incremental Auctions (see "Demand Curves in the Incremental Auction")

3.1 Overview of Demand in the Reliability Pricing Model

In the Reliability Pricing Model, the demand for installed capacity reserve is met when supply is procured as a function of the clearing of the RPM Auctions. In each auction, a demand curve is defined in advance and will either be downward-sloping or vertical-sloping depending on the purpose of the specific auction.

In the Base Residual Auction, the demand curve is downward sloping and based on the variable resource requirement concept. In RPM, a variable resource requirement is defined as a function of price. The variable resource requirement is a family of price/quantity points that provide a specified price for various levels of resources procured relative to the Installed Reserve Margin. If the price exceeds the limit on the VRR, then the quantity of resources that is procured may be less than the IRM requirement. Alternatively, if the price is low, additional resources may be procured at a level greater than the IRM requirement. The cost of the supply that is procured at the clearing price will be allocated to the Load Serving Entities. Therefore, a variable resource requirement curve will reflect the reality that additional capacity above a target installed reserve margin nevertheless has value.

There are at least four sources of this value:

(1) One source of value is that in the face of uncertain load growth, weather and capacity availability, the probability of available capacity being less than what is required to meet load and operating reserves never reaches zero, even for large reserve margins. Thus, reserves beyond the target are valuable for reducing the risk of capacity shortfalls.

(2) The second source of value is that the slope of the curve can lessen the risk of large suppliers being pivotal or otherwise able to exercise market power.

(3) A third source of value is that excess resources can reduce the frequency and duration of scarcity energy prices in the system and provide energy savings to Load Serving Entities.

(4) The fourth source of value is the reduction in capacity price volatility and the resulting investment risk to capacity resources, in particular to the generating resources. Lower investment costs would tend to reduce capacity prices

3.2 Definition and Purpose of the Variable Resource Requirement

As mentioned in the previous section, the Variable Resource Requirement Curve is a demand curve used in the clearing of the Base Residual Auction that defines the price for a given level of Capacity Resource commitment relative to the applicable reliability requirement. Variable Resource Requirement Curves are defined for the PJM Region and each of the constrained LDAs within the PJM region.

The purpose of the Variable Resource Requirement concept is to recognize the value of excess resources above the reliability requirement and provide revenue to resources. The price on the Variable Resource Requirement is higher when the resources are less than the reliability requirement and lower when the resources are in excess.

3.3 Parameters of the Variable Resource Requirement

Prior to the clearing of the Base Residual Auction, Variable Resource Requirement Curves are defined for the PJM Region and each of the constrained Locational Delivery Areas (LDA) within the PJM region. The Variable Resource Requirement Curves for the PJM Region and each Locational Delivery Area (LDA) are based on the following parameters defined prior to the RPM Auctions:

- A target level of reserve
- Cost of New Entry
- Net Energy & Ancillary Services (E&AS) Revenue Offset

The initial posting of the Variable Resource Requirement Curves will be based on the adjustments related to FRR Entities' Preliminary Unforced Capacity Obligations known at the time of posting. A later posting of the Variable Resource Requirement Curves with the FRR adjustments will be made shortly after the approval of the FRR Capacity Plans for the RPM Auction Delivery Year considering any changes in the FRR elections.

The parameters of the Variable Resource Requirement Curve (i.e., RTO and LDA Reliability Requirements, Cost of New Entry, and Net E&AS Revenue Offsets) will be posted by **February 1** prior to the conduct of the Base Residual Auction for the Delivery Year.

The Variable Resource Requirement Curve for the PJM Region is based on a target level (i.e., the PJM Region Reliability Requirement less the Forecast RTO ILR Obligation prior to 2012/2013 or the PJM Region Reliability Requirement less the Short Term Resource Procurement Target for Delivery Years 2012/2013 and beyond), Cost of New Entry, and Net Energy & Ancillary Services (E&AS) Revenue Offset.

For each LDA, the LDA Variable Resource Requirement Curve is based on a target level (i.e., the LDA Reliability Requirement less the Forecast LDA ILR Obligation prior to 2012/2013 or the LDA Reliability Requirement less the LDA Short Term Resource Procurement Target for Delivery Years 2012/2013 and beyond), Cost of New Entry, and Net E&AS Revenue Offset. However, the Forecast ILR Obligation will be reduced by the amount of Load Management used in establishing the LDA Capacity Emergency Transfer Objective before subtracting it from the LDA Reliability Requirement.

Inclusion of Variable Resource Requirement Curves in the Base Residual Auction clearing may result in the level of resources being committed for a Delivery Year exceeding the applicable PJM Region Reliability Requirement less the Forecast RTO ILR Obligation (prior to 2012/2013 or the Short Term Resource Procurement Target for Delivery Years 2012/2013 and beyond) or the LDA Reliability Requirement less the Forecast LDA ILR Obligation (prior to 2012/2013 or the LDA Short Term Resource Procurement Target for 2012/2013 and beyond), if the total cost of resource procurement for the PJM Region or LDA is lower at the higher level of reliability than it would be at the target level and the associated Variable Resource Requirement Curve price.

3.3.1 Cost of New Entry

The value for Cost of New Entry (in ICAP terms) is determined in accordance with the Open Access Transmission Tariff. There may be different values for the Cost of New Entry for different Locational Deliverability Areas. The Cost of New Entry values are posted in the Tariff. (See Tariff Section 5.10, (iv),(A)) The Cost of New Entry for a Locational Deliverability Area shall be determined based upon the geographic location of the Locational Deliverability Area within the PJM Region. A Cost of New Entry is determined for each of the following five combinations of zones (if the LDA covers more than one of these five sub-regions, the lowest Cost of New Entry is used for defining the LDA's VRR curve) referred to as CONE Areas:

1. AE, DPL, JCPL, PECO, PSEG, RECO;
2. BGE, PEPCO
3. AEP, APS, COMED, DAYTON, DLCo, ATSI, DEOK;
4. METED, PENELEC, PPL; and
5. Dominion

The CONE values to be posted with the Planning Parameters for BRA will be escalated using the most recently published twelve-month change in Total Other Plant Production Plant Index shown in the Handy Whitman Index (HWI) of Public Utility Construction Costs. The North Atlantic Region HWI will be used for CONE Areas 1, 2, and 4. The North Central Region HWI will be used for CONE Area 3. The South Atlantic Region HWI will be used for CONE Area 5.

The value of Cost of New Entry used in the development of the RTO VRR Curve and the VRR Curve for each modeled LDA is expressed in UCAP Terms.

3.3.2 Net Energy and Ancillary Services Offset

The Net Energy & Ancillary Services (E&AS) Revenue Offsets for PJM Region and each modeled LDA (in ICAP Terms) is determined by PJM using the Peak-Hour Dispatch in accordance with the **Open Access Transmission Tariff, Section 5.10, (v)**.

For the first three Delivery Years that RPM is in place (2007/2008, 2008/2009, and 2009/2010 Delivery Years), a historical average of the six most recent calendar years of Energy & Ancillary Services revenue data for a reference combustion turbine was used to calculate the Net Energy & Ancillary Services Offset. For subsequent Delivery Years, the Net E&AS Revenue Offset is based on the three most recent calendar years of Energy & Ancillary Services revenue for a reference combustion turbine.

The value of Net E&AS Revenue Offset used in the development of the RTO VRR Curve and the VRR Curve for each modeled LDA is expressed in UCAP Terms.

3.4 Plotting the Variable Resource Requirement Curve

The Variable Resource Requirement Curve is plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis using the following three points (a), (b), and (c):

a. The price is equal to 1.5 times (the Cost of New Entry minus the Net E&AS Revenue Offset, referred to as "Net CONE") divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity is equal to [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% minus 3%) divided by (100% plus approved IRM %)] minus the RTO Short-Term Resource Procurement Target (for 2012/2013 and beyond) or the Forecast RTO ILR Obligation (for Delivery Years prior to 2012/2013)

Basis for Price at Point a:

$$\frac{[1.5(CONE - E\&AS)]}{1 - Pool\ Wide\ EFORd}$$

Basis for Quantity at Point a:

$$\left[Rel\,Req \frac{(100\% + IRM - 3\%)}{(100\% + IRM)} \right] - \begin{matrix}\text{Short - Term Resource}\\ \text{Procurement Target}\end{matrix}$$

b. The price is equal to Net CONE divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 1%) divided by (100% plus approved IRM%)] minus the RTO Short-Term Resource Procurement Target (for 2012/2013 and beyond) or the Forecast RTO ILR Obligation (for Delivery Years prior to 2012/2013).

Basis for Price at Point b:

$$\frac{[1.0(CONE - E\&AS)]}{1 - Pool\ Wide\ EFORd}$$

Basis for Quantity at Point b:

$$\left[Rel\,Req \frac{(100\% + IRM + 1\%)}{(100\% + IRM)} \right] - \begin{matrix}\text{Short - Term Resource}\\ \text{Procurement Target}\end{matrix}$$

c. The price is equal to 0.2 times the Net CONE divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 5%) divided by (100% plus approved IRM %) minus the RTO Short-Term Resource Procurement Target (for 2012/2013 and beyond or the Forecast RTO ILR Obligation (for Delivery Years prior to 2012/2013).

Basis for Price at Point c:

$$\frac{[0.2(CONE - E\&AS)]}{1 - Pool\ Wide\ EFORd}$$

Basis for Quantity at Point c:

$$\left[Rel\,Req \frac{(100\% + IRM + 5\%)}{(100\% + IRM)} \right] - \begin{matrix}\text{Short - Term Resource}\\ \text{Procurement Target}\end{matrix}$$

3.4.1 Plotting the Variable Resource Requirement Curves

The graph below illustrates the process for plotting the Variable Resource Requirement curves:

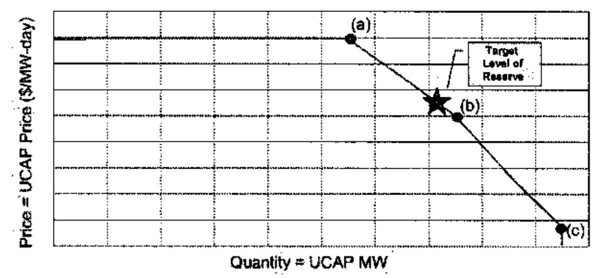


Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve

The same process shall be used to establish the Variable Resource Requirement Curve for each LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement, and the LDA Short-Term Resource Procurement Target (for 2012/2013 and beyond) or the Forecast Zonal ILR Obligation (for Delivery Years prior to 2012/2013) for the Zones associated with such LDA shall be substituted for the Forecast RTO ILR Obligation and the FRR adjustments will be for the FRR Entities in the LDA.

Beginning no later than for the Delivery Year 2015/2016, and continuing no later than for every third Delivery Year thereafter, PJM will perform a review of the shape of the Variable Resource Requirement Curve, CONE values, and Energy & Ancillary Services methodology.

3.5 Demand Curves in the Incremental Auctions

Prior to the 2012/2013 Delivery Year, demand curves that are created and used in the clearing of the Incremental Auctions are not based on the Variable Resource Requirement concept.

In the First and Third Incremental Auctions, when the auction is cleared due to the decrease in value of resource commitments, the demand curve in these auctions is built based on buy bids that are submitted by auction participants.

In the Second Incremental Auction, when the auction is cleared due to the increase in load forecast, the demand curve has a vertical slope and is built based on the buy bid that is created by PJM to procure the targeted amount for the RTO and each LDA. In the Second Incremental Auction, the bid price for each buy bid is set equal to the price corresponding to the IRM on the Variable Resource Requirement curve from the Base Residual Auction.

Effective with the 2012/2013 Delivery Year, all three Incremental Auctions provide both a forum for capacity suppliers to purchase replacement capacity, and a means for PJM to adjust previously committed capacity levels due to reliability requirement increases or decreases and to recoup the appropriate share of the deferred Short-Term Resource Procurement Target. The demand curve in these auctions will be built based on a combination of buy bids submitted by market participants and buy bids, if any, submitted by PJM.

PJM will recalculate the RTO and each LDA Reliability Requirement prior to each of the First, Second, and Third Incremental Auctions based on an updated peak load forecast, updated Installed Reserve Margin, and an updated Capacity Emergency Transfer Objective. The recalculated Reliability Requirements are compared to the Reliability Requirements used in the prior auction for the same Delivery Year and a determination is made as to the need for the procurement and/or sale of capacity by PJM.

For the RTO and each LDA, PJM will sum the following component quantities to determine the total quantity that it will seek to procure or release in each Incremental Auction:

- the Short-Term Resource Procurement Target Applicable Share (STRPTAS). For a 1st or 2nd Incremental Auction, the STRPTAS is equal to 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction (BRA). For a 3rd Incremental Auction, the STRPTAS is equal to 0.6 times the Short-Term Resource Procurement Target used in the Base Residual Auction (BRA),
- plus the difference between the Updated Reliability Requirement minus the Reliability Requirement utilized in the most recent prior auction conducted for that Delivery Year. For a 1st or 2nd Incremental Auction, this difference is only considered if the change in Reliability Requirement is greater than the lesser of 500 MW or 1% of the prior auction's Reliability Requirement. Note that this quantity is negative if the Updated Reliability Requirement is less than the Reliability Requirement utilized in the most recent prior auction.
- plus/minus the amount of committed capacity that PJM sought to procure/release that did not clear in previous Incremental Auctions for the same Delivery Year.
- minus any capacity PJM seeks to release in a parent LDA as a result of any Conditional Incremental Auction commitments for the same Delivery Year.

If the result of such summation is a positive quantity, PJM will seek to procure such quantity by employing a PJM buy bid represented by the portion of the Updated VRR Curve Increment extending right from the left-most portion on that curve in a MW amount equal to the positive quantity. PJM will employ a PJM buy bid represented by the entire portion of the Updated VRR Curve if the prior auction's RTO/LDA Reliability Requirement less Short-Term Resource Procurement Target exceeds the total capacity committed in all prior auction's by the threshold (lesser of 500 MW or 1% of prior auction's Reliability Requirement). The Updated VRR Curve Increment is the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

If the result of such summation is a negative quantity, PJM will seek to release such quantity by employing a PJM sell offer represented by the portion of the Updated VRR Curve Decrement extending and ascending to the left from the right-most portion on that curve in a MW amount equal to the negative quantity. The Updated VRR Curve Decrement is the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced

Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

Starting with the 2014/2015 Delivery Year, prior to each Incremental Auction, PJM will calculate an updated Minimum Annual Resource Requirement and a Minimum Extended Summer Resource Requirement for the RTO and each LDA. The difference between the updated Minimum Annual Resource Requirement minus the amount of previously procured capacity from Annual Resources will determine the portion of a PJM buy bid that must be satisfied by Annual Resources. If PJM is seeking to release capacity in the auction, this difference will determine the maximum amount of Annual Resources that PJM is willing to release. The difference between the Minimum Extended Summer Resource Requirement minus the combined total amount of previously procured Annual Resource and Extended Summer Demand Resources will determine the portion of a PJM buy bid that must be satisfied by Annual Resources and Extended Summer DR. If PJM is seeking to release capacity in the auction, this difference will determine the maximum amount of Annual Resources and Extended Summer DR that PJM is willing to release.

In a Conditional Incremental Auction, the quantity at the appropriate location required to address the identified reliability violation will be procured using a Buy Bid equal to 1.5 times Net CONE.

Section 4: Supply Resources in the Reliability Pricing Model

Welcome to the *Supply Resources in RPM* section of the *PJM Manual for the PJM Capacity Market*. In this section, you will find the following information:

- An overview description of supply in the Reliability Pricing Model (see "Overview of Supply in the Reliability Pricing Model")
- The business rules for generation resources (see "Generation Resources")
- The business rules for load management products (see "Load Management Products")
- The business rules for energy efficiency resources (see "Energy Efficiency Resources")
- The business rules for qualified transmission upgrades (see "Qualified Transmission Upgrades")
- The business rules for bilateral transactions (see "Bilateral Transactions")
- The business rules for resource portfolios in RPM (see "Resource Portfolios")
- The credit requirements in RPM (see "Credit Requirements")

4.1 Overview of Supply in the Reliability Pricing Model

In the Reliability Pricing Model, the supply of installed capacity is procured to meet demand as a function of the clearing of the RPM Auctions. In each auction, a supply curve is defined based on the offers submitted by providers with installed capacity resources. Supply, valued as unforced capacity, that is procured in the RPM multi-auction clearing and the ILR certification process, ensures that sufficient resources are committed to meet the PJM Reliability Principles and Standards.

A party's supply resource portfolio in eRPM may consist of:

- Generation Resources;
- Load Management Resources;
- Energy Efficiency Resources; and
- Qualifying Transmission Upgrades.

Key qualifications and requirements for generation resources are presented in Existing Generation, Planned Generation, and Bilateral Unit-Specific Transaction sections of this Manual. Key qualifications and requirements for load management products are presented in the Load Management section of this Manual. Key qualifications and requirements for Energy Efficiency Resources are presented in the Energy Efficiency Resources section of this Manual. Key qualifications and requirements for Qualified Transmission Upgrades are presented in the Qualified Transmission Upgrade section of this Manual.

Prior to any RPM auction, RPM suppliers must confirm the modeling of each of their capacity resources. RPM suppliers must verify the following characteristics of generation units and demand resources:

- **Zone assignment**
- **LDA assignment**
- **Unit Location by State**
- **Unit Type**

4.2 Generation Resources

A party's Generation Resource portfolio may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Qualifications and requirements for generation resources are presented in the sections below.

4.2.1 Existing Generation Resources - Internal

Existing generation located within the PJM region is eligible to be offered into RPM Auctions or traded bilaterally if it meets the following requirements:

- The unit is pre-certified by PJM as meeting the generation deliverability test. PJM's certification process for internal generating resources is described in ***the Tariff and the Operating Agreement***
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit.
- The unit resides in the eRPM resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having an "Approved" Capacity Modification in the eRPM system.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.
- The unit must have been offered in the Base Residual Auction for the Delivery Year in order to be eligible to offer into the First, Second or Third Incremental Auctions for that Delivery Year.

4.2.2 Existing Generation Resources - External

Existing generation located outside the PJM region is eligible to be offered into an RPM Auction if it meets the following requirements:

- An indication of the intended ATC path to deliver the existing external capacity into PJM is provided. (Firm transmission service from the unit to the border of PJM and generation deliverability in PJM must be demonstrated by the start of the Delivery Year.)

- The unit resides in the eRPM resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having a "Provisionally Approved" or "Approved" unit-specific transaction with "External Party" (i.e., "EXT") as the "Seller" of the transaction in the eRPM system.
- Twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's EFORd.
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit.
- The external capacity without firm transmission must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.

The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year. Existing generation located outside the PJM region is eligible to be traded bilaterally if the unit resides in the eRPM resource portfolio of a signatory of the PJM Operating Agreement through the accomplishment of an "Approved" unit-specific transaction with "External party" (i.e., "EXT") as the "Seller" of the transaction in the eRPM system. An "Approved" unit-specific transaction status will not be granted until firm transmission service from the unit to the border of PJM has been obtained and generation deliverability has been demonstrated into PJM by (1) obtaining firm point-to-point transmission service on the PJM OASIS from the border into the PJM transmission system (this applies to service on the PJM transmission system) or (2) obtaining "Network External Designated" transmission service with an expected completion date prior to June 1st of the delivery year. Either of the above options for demonstrating deliverability may require transmission upgrades to be completed prior to June 1st of the delivery year. All of the above options follow the study process for participant-funded upgrades as defined in Part VI of the PJM Open Access Transmission Tariff. The following requirements for existing external generation are still applicable:

- Twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's EFORd.
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.

- A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.

Existing generation located outside the PJM region that is offered into an RPM auction is treated in the auction process as capacity delivered into the unconstrained area of the RTO.

If existing generation located outside the PJM region cleared in the Base Residual Auction, First Incremental, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction and does not procure firm transmission service from the unit to the PJM border and demonstrate generation deliverability by the start date of associated bilateral transaction, the status of the associated bilateral transaction in the eRPM system will be changed from "Provisionally Approved" to "PJM Withdrawn".

4.2.3 Planned Generation Resources - Internal

Planned generation that is participating in PJM's Regional Transmission Expansion Planning Process (RTEPP) is eligible to be offered into PJM's RPM Auctions if it meets the following requirements:

- The planned unit's start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, an Impact Study Agreement has been executed for the unit to participate in the Base Residual Auction.[5]
- An Interconnection Service Agreement (ISA) or Wholesale Market Participant Agreement (WMPA) has been executed for the unit to participate in an Incremental Auction.
- A planned unit with an Interim ISA can offer only into the BRA or Incremental Auction for which the Interim ISA is valid.
- A Capacity Modification for the planned unit has been submitted and "Provisionally Approved" in eRPM.
- Planned Generation Resources must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- If the planned generation was committed through the Base Residual Auction and the ISA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied" so that the planned generation will no longer be included in a resource provider's eRPM Generation Resource portfolio.
- If an ISA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification will need to be

[5] During the Transition Phase, the minimum requirement is an executed Interconnection Service Agreement for the 2007/2008 and 2008/2009 Base Residual Auctions and an Executed Impact Study Agreement for the 2009/2010 – 2010/11 Base Residual Auctions.

submitted and "Provisionally Approved" in order to be re-included in a resource provider's eRPM Generation Resource portfolio.

- If the planned generation is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied". A new Capacity Modification will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.

4.2.4 Planned Generation Resources – External

Planned external generation is eligible to be offered into PJM's RPM Auctions. Such resources will be treated in a manner comparable to planned internal generation resources and existing external generation resources. Prior to participation in any RPM Auction, the Resource Provider must demonstrate that it has executed an interconnection agreement (functionally equivalent to a System Impact Study Agreement for a Base Residual Auction and an Interconnection Service Agreement for an Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being connected, and if applicable with the transmission provider. A planned external generation resource must provide evidence to PJM it has been studied as a Network Resource, or such other similar interconnection product in the external Control Area.

- An indication of the intended ATC path to deliver the external planned capacity into PJM is provided. (Firm transmission service from the unit to the border of PJM and generation deliverability in PJM must be demonstrated by the start of the Delivery Year.)
- The planned unit's start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, a functionally equivalent System Impact Study Agreement has been executed for the unit to participate in the Base Residual Auction.
- A functionally equivalent Interconnection Service Agreement has been executed for the unit to participate in an Incremental Auction.
- A Capacity Modification for the planned unit has been submitted and "Provisionally Approved" in eRPM.
- Planned Generation Resources must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- If the planned generation was committed through the Base Residual Auction and the ISA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied" so that the planned generation will no longer be included in a resource provider's eRPM Generation Resource portfolio.
- If an ISA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification will need to be

submitted and "Provisionally Approved" in order to be re-included in a resource provider's eRPM Generation Resource portfolio.

- If the planned generation is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied". A new Capacity Modification will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.
- Once operational, the resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- Once operational, the resource owner or operator performs winter and summer testing as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.

4.2.5 Equivalent Demand Forced Outage Rate (EFORd)

Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. ***See Generator Resource Performance Indices Manual (M-22) for equation.***

The EFORd of a unit is based on forced outage data from an October through September period. If a unit does not have a full one-year history of forced outage data, the EFORd will be calculated using class average EFORd and the available history as described in the ***Reliability Assurance Agreement, Schedule 5, Section B.***

Since no forced outage data is collected for intermittent resources, an EFORd is not calculated for intermittent resources. The EFORd of intermittent resources is set to zero in the eRPM system.

New units are initially assigned a class average EFORd. The class average EFORds that are used by PJM to calculate a unit's EFORd are posted to the PJM website by November 30 prior to the Delivery Year.

The Effective EFORd is the EFORd that is effective for the delivery day in the eRPM system. Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the eRPM system. During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year.

The EFORd that is effective for the Delivery Year is considered locked in the eRPM system by November 30 prior to the execution of the Third Incremental Auction.

4.2.6 Capacity Modifications (CAP Mods)

Capacity Modifications (CAP MODs) are a type of eRPM transaction used by generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in eRPM, or to request a MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

The purpose of a CAP MOD is to establish the installed capacity value of a generation resource in the eRPM system. CAP MOD transactions represent permanent changes to the installed capacity value of a generation unit.

CAP MODs are also used by a generation owner to establish the capacity value of an intermittent resource to be offered into the PJM Capacity Market and by PJM to establish the Delivery Year capacity value of an intermittent resource.

The following are business rules that apply to Capacity Modifications (CAP Mods):

- CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and "Provisionally Approved" or "Approved" by PJM in the eRPM system prior to the opening of the Base Residual Auction's or Incremental Auction's bidding window in order for the CAP MODs to be considered in a party's Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction, Incremental Auction or bilateral unit-specific transaction.
- All other CAP MODs must be submitted a minimum of 2 business days prior to the start date of the CAP MOD. The CAP MOD must be "Approved" by PJM in the eRPM system prior to the start date of the CAP MOD in order to be considered in a party's final Daily Generation Resource Position.
- If the status of a "Provisionally Approved" CAP MOD changes to "Denied" or "PJM Withdrawn", there will be no change to any party's RPM Resource Commitments.
- CAP MODs cannot be created during an RPM Auction's bidding window and clearing week.
- CAP MODs that are not in the "Approved" status by the start date of the CAP MOD will have their status changed to "PJM Withdrawn".
- CAP MODs that would cause the summer rating of a generation resource or the capacity value of an intermittent resource to exceed such unit's Capacity Injection Rights will be "Denied" by PJM.
- CAP MODs for wind resources that would cause the capacity value for a wind resource to be less than 0.85 times the Design Capacity Value of the wind resource will be "Denied" by PJM, unless the generation owner provides data to PJM and the MMU that supports a capacity value that is less than 0.85 times the Design Capacity Value. The Design Capacity Value of a wind resource is equal to a Capacity Factor times the Net Maximum Capacity as described in ***Rules and Procedures for Determination of Generating Capability (M-21)***.

4.3 Load Management Products

Load management is the ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

A load management program (e.g., Direct Load Control, Firm Service Level, or Guaranteed Load Drop program) is eligible to be offered by a resource provider as:

(1) A **Demand Resource (DR)** offered into the Base Residual Auction or an Incremental Auction and paid the Resource Clearing Price; or

(2) An **Interruptible Load for Reliability (ILR) resource** certified at least three months prior to the Delivery Year (for Delivery Years prior to 2012/2013) and paid the Final Zonal ILR Price.

4.3.1 Requirements of Load Management Products in RPM

A resource provider who has RPM Resource Commitments for their demand resource or certified ILR resources must meet the following requirements:

- Must be registered in the Emergency Load Response Program (see more detail in later the Emergency Load Response Registration section)
- Provide (or contract with another party to provide) supplemental status reports during the Delivery Year, detailing availability of the load management resource, as requested by PJM System Operations in accordance with the ***PJM Manuals;***
- Provide (or contract with another party to provide) customer-specific compliance and verification information within 45 days after the end of the month in which a PJM-initiated Load Management event occurred, in accordance with the Load Management Compliance section of Section 8 of this Manual.
- Load drop estimates for all Load Management events (whether initiated by PJM or the resource provider) in accordance with ***PJM Manual 19: Load Forecasting & Analysis.***

These requirements are described in terms of the customer response and qualifications. The specifics of the customer contract and tariffs are the responsibility of the resource provider and the regulatory process. PJM does not have direct involvement with customers. The entity requesting load management must verify that each customer's load management meets the following criteria:

- Availability for PJM-initiated interruptions in accordance with the availability requirements of the demand resource product type.
- Limited DR – Limited DR is available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time.

- Extended Summer DR (Effective 2014/2015 Delivery Year) – Extended Summer DR is available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time.
- Annual DR (Effective 2014/2015 Delivery Year) – Annual DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
- Load management must be able to be implemented within two hours of notification to the resource provider of a PJM-initiated load management event.
- Initiation of load interruptions upon request of PJM must be within the authority of the resource provider dispatcher without any additional approvals being required.
- DLC programs are certified based on load research and customer subscription data. Load Research guidelines are outlined in ***PJM Manual 19: Load Forecasting & Analysis***.

Providers of Planned Demand Resources must provide a timeline including the milestones, which demonstrates to PJM's satisfaction that the Planned Demand Resources will be available for the start of the Delivery Year, 15 business days prior to an RPM Auction. PJM may verify the provider's adherence to the timetable at any time including, but not limited to, 30 days prior to an Incremental Auction.

4.3.2 Types of Load Management Programs

PJM recognizes three types of Load Management programs:

- Direct Load Control (DLC) – Load management that is initiated directly by the resource provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).
- Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the resource provider's market operations center or its agent.
- Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the resource provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of recognized Load Management Program, there can be two notification periods:

- Step 1 (Short Lead Time) – Load management which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.
- Step 2 (Long Lead Time) – Load management which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

4.3.3 Demand Resources

Both Existing and Planned Demand Resources may participate in RPM Auctions, provided the resource resides in a party's portfolio for the duration of the Delivery Year. A Demand Resource is added to a party's portfolio through the creation of a Demand Resource Modification transaction in eRPM. More information on Demand Resource Modification transactions is available in the next section.

Existing Demand Resources are defined as 1) those resources that are currently linked to emergency load reduction customer(s) in the Load Response application or 2) resources that have already been certified as Interruptible Load for Reliability by the participant in a prior Delivery Year and have been designated by the Curtailment Service Provider as being available in the future Delivery Year for which an Auction is being held.

Planned Demand Resources are defined as resources that do not currently have the capability to provide reduction in demand or to otherwise control load in PJM, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year.

Planned Demand Resources must establish an RPM Credit Limit prior to an RPM Auction. Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

A resource provider may offer Demand Resources (Planned or Existing) associated with Behind the Meter Generation for an entire Delivery Year into the Base Residual or Incremental Auctions. If the DR offer clears in an RPM auction for a given Delivery Year, the Behind the Meter Generation cannot be netted from load for the purposes of calculating the Peak Load Contributions for that Delivery Year. Requests for Behind the Meter changes for capacity obligations must be received by PJM by December 1 prior to the start of the Delivery Year as outlined in ***PJM Manual 14D: Load Generator Operational Requirements***.

If offering as a Demand Resource in the Base Residual Auction or Incremental Auction, a sell offer must be submitted in the Base Residual Auction or Incremental Auction. Demand Resources offered and cleared in a Base Residual or Incremental Auction will receive the corresponding LDA Resource Clearing Price determined by the optimization algorithm. However, prior to 2013/2014, if a resource provider cannot provide Demand Resource data on individual LDA basis in a Zone with multiple LDAs, Demand Resources will be paid a Weighted Zonal Resource Clearing Price based on the resource provider's distribution of registered sites in each LDA that are approved before June 1st of the Delivery Year. Effective 2013/2014, resource providers must offer DR resources in the lowest level LDA in order to receive proper payment. No Weighted Prices will be calculated effective 2013/2014.

4.3.4 Demand Resource Modifications (DR Mods)

In order to offer a Demand Resource into an RPM Auction, the resource must be in a party's portfolio for the duration of the Delivery Year. A Demand Resource Modification transaction is the mechanism to add a demand resource to a party's portfolio. ILR Resources do not need to create Demand Resource Modification transactions to represent the value of an ILR resource.

Demand Resource Modifications (DR MODs) are a type of eRPM transaction used by PJM to track an increase or decrease of the nominated value of the DR resource in a party's resource portfolio in eRPM. The following are business rules that apply to Demand Resource Modifications (DR Mods):

- DR MODs must be submitted by the resource provider within the eRPM system for Planned Demand Resources and for Demand Resources that have not yet participated in an RPM Auction.
- DR MODs may be submitted to reflect changes in the Peak Load Contributions or EDC loss factors of customers associated with a Demand Resource.
- PJM will "provisionally approve" DR MODs for Planned DR resources after verifying that the Planned DR resource has posted the appropriate credit and after completing a review of the submitted timeline and milestones to ensure that the Planned Demand Resource will be available for the start of the Delivery Year.
- PJM will "provisionally approve" DR MODs for existing demand response sites that have not yet participated in an RPM Auction after completing a review of the sites currently registered by this resource provider in the PJM Load Response system to ensure that the nominated value of the Demand Resource will be available for the start of the Delivery Year.
- PJM will "approve" DR MODs for DR resources once the demand resource sites have been registered and approved for the Full Program Option of the Emergency Load Response Program in the PJM Load Response system.
- DR MODs must be in a "Provisionally Approved" or "Approved" status in order for the DR MOD to be considered in a party's Demand Resource Position and in the calculation of Available ICAP to offer for an RPM Auction.
- DR MODs that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

4.3.5 ILR Resource Certification

To be certified as an ILR resource, the resource must be registered and approved for the Full Program Option or the Capacity Only Option of the Emergency Load Response Program in the PJM Load Response system no later than three months prior to the Delivery Year (for Delivery Years prior to 2012/2013). A Demand Resource that is offered in the RPM Auctions and does not clear may be certified as an ILR Resource no later than three months prior to the Delivery Year (for Delivery Years prior to 2012/2013).

Certified ILR resources will be paid the Final Zonal ILR Price.

Effective for the 2009/10 through the 2011/12 Delivery Years, an ILR Provider may, by written notice to PJM no later than one day prior to the start of the relevant Delivery Year, withdraw certified ILR. If an ILR Provider withdraws their resource, the provider will receive no ILR Credit for such resource during the relevant Delivery Year.

Load Serving Entities that are charged a Locational Reliability Charge will not be charged for the ILR resources that have withdrawn their commitments prior to June 1 of the Delivery Year. An adjustment will be made to the Final Zonal Capacity Price to reflect the updated value of the certified ILR.

4.3.6 Combined DR and ILR

A single customer site may be registered as both a DR and ILR resource for the same Delivery Year. These sites must meet the requirements of a DR resource in terms of Emergency program selection, as those requirements are more stringent than those for an ILR resource. The sites must meet the timing requirements of their respective programs, i.e., the ILR portion of the resource must be registered and approved in the Emergency Load Response program by the ILR Certification Deadline and the DR portion of the resource must be registered and approved by the Delivery Day in order to avoid Commitment Compliance penalties.

4.3.7 Emergency Load Response Registration

Emergency Load Response Registration is the process of providing the following information through the submittal of an Emergency Load Response registration into PJM's Load Response system (eLRS). As part of an Emergency Load Response registration, resource providers will submit the following types of information:

- Customer-specific load management information for planning and verification purposes (i.e., EDC account number, Zone, etc)
- Customer-specific information to establish nominated load management levels (i.e., Peak Load Contribution, EDC Loss Factor, notification period, Firm Service Level data, Direct Load Control data, Guaranteed Load Drop data)
- Load Management Program information (ILR and/or DR; Demand Resource Name if applicable)
- Load Management product type for customer site (Limited DR, Extended DR, Annual Summer DR) (Effective with the 2014/2015 Delivery Year)
- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process

A resource provider who has RPM or FRR Resource Commitments for their demand resource or certified ILR resources must register customers in a capacity-related Emergency Load Response Programs. ILR and Demand Resources have the option of registering in either the Full Emergency or Capacity Only Emergency Programs. A single customer site that is registered as both a DR and an ILR resource must be registered in the Full Emergency Program.

The Full Emergency Program and Capacity Only Emergency Program enable a resource provider that has approved registration for the Delivery Year prior to the applicable registration deadline to receive Capacity Credits (in the form of RPM Auction Credits or ILR Credits) for that Delivery Year. Full Emergency Program resource providers may claim an energy settlement for a PJM-initiated Load Management Events. Capacity Only Emergency Program resource providers may not claim an energy settlement for a PJM-initiated Load Management Event for Capacity Only Emergency registrations.

Customer sites registered in the Energy Only Emergency Program are not eligible to receive capacity credits.

Effective with the 2014/2015 Delivery Year, a provider with RPM or FRR Resource Commitments for their Demand Resource must register customer sites that are of the same product-type (Limited, Extended Summer, or Annual) as the committed Demand Resource.

A completed Emergency Load Response registration in eLRS for a DR resource must be submitted no later than one day before the tenth business day preceding the relevant Delivery Year. All registrations that have not been approved on or before May 31st preceding the relevant Delivery year shall be rejected by PJM.

Full details of the Emergency Load Response registration and approval process may be found in ***Section 10 of PJM Manual for Scheduling Operations (M-11).***

4.3.8 End-Use Customer Aggregation

A resource provider may aggregate multiple end-use customer sites to create a single Demand Resource for the purposes of submitting an offer in the RPM Auctions, if all the end-use customer sites have the same following characteristics:

- Curtailment Service Provider
- Electric Distribution Company (EDC)
- Transmission Zone

The mechanism for aggregating end-use customer sites to create a single Demand Resource is to select the same Demand Resource for multiple end-use customer sites during the process of registering end-use customers as Full Emergency Load Response customers.

A resource provider may aggregate multiple end-use customer sites to create a single ILR resource for the purposes of ILR Resource Certification.

4.3.9 Determination of Nominated Values for Load Management

Once an end-use customer is registered in the Emergency Load Response Program (Full Emergency or Capacity Only), a nominated load reduction value is calculated for that customer. The determination of the value of the load reduction is consistent with the process for determination of the capacity obligation for the customer. Nominated value of a load management resource is equivalent to the Installed Capacity value of generation resource. Nominated load reductions are effective for an entire RPM Delivery Year.

For existing Demand Resources, the maximum load reduction (used in determining the Nominated DR Value) is based on the Peak Load Contributions in place at the time of the

Full Program Option of the Emergency Load Response Program registration in the Load Response system.

Nominated Value of Firm Service Level Resources

The nominated value for a Firm Service Level customer will be based on the Peak Load Contribution for the customer, as determined by the 5CP methodology.

The nominated value for a Firm Service Level (FSL) customer will be equal to the difference between its Peak Load Contribution (PLC) and its pre-determined firm load adjusted for system losses

*Nominated Value of FSL = PLC – (FL * LossF)*

Where:

PLC = the customer's EDC-assigned Peak Load Contribution;

FL = Firm Load level;

LossF = the customer's EDC-assigned loss factor.

Nominated Value of Guaranteed Load Drop Resources

The nominated value for a Guaranteed Load Drop (GLD) customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the resource provider. The value nominated shall not exceed the customer's Peak Load Contribution.

Nominated Value of GLD = GLD (LossF)

Where:

GLD =Customer's Load Reduction;

LossF = the customer's EDC-assigned loss factor.

Nominated Value of Direct Load Control Resources

The nominated value for a Direct Load Control (DLC) program will be based on load research and customer subscription. The value of the program is equal to the PJM-approved per-participant load reduction (evaluated at average peak day weather conditions and adjusted for the switch operability rate) multiplied by the number of active participants, adjusted for system losses

*Nominated Value of DLC = PPI * Cust * LossF*

Where:

PPI = the PJM-approved Per-Participant Impact;

Cust = the number of active participants;

LossF = the EDC-assigned loss factor.

The per-participant impact is to be estimated at long-term average local weather conditions at time of the RTO summer peak. Load research studies to support per-participant impacts must comply with the Guidelines for DLC load research studies presented in ***PJM Manual 19: Load Forecasting & Analysis of this Manual.***

4.3.10 Determination of the UCAP Value of Load Management

The Unforced Capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the Demand Resource Factor (DR Factor) and the Forecast Pool Requirement (FPR).

$$UCAPvalueofLoadManagementProduct = NominatedValue \times DRFactor \times FPR$$

4.4 Energy Efficiency Resources

An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then-current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of *Schedule 6 (section M) of the Reliability Assurance Agreement*. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site (during the defined EE Performance Hours[6]) that is not reflected in the peak load forecast used for the Base Residual Auction for the Delivery Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention.

An EE installation is eligible to offer into an RPM auction if it meets the following criteria:

- EE installation must be scheduled for completion prior to DY;
- EE installation is not reflected in peak load forecast posted for the BRA for the DY initially offered;
- EE installation exceeds relevant standards at time of installation as known at time of commitment;
- EE installation achieves load reduction during defined EE Performance Hours; and
- EE installation is not dispatchable[7].

Existing or Planned EE Resources may be offered in an RPM auction starting with the 2011/12 Delivery Year. An Existing EE Resource is defined as an EE Resource with a PJM approved Post-Installation Measurement & Verification (M&V) Report. A Planned EE

[6] The EE Performance Hours are between the hour ending 15:00 Eastern Prevailing Time (EPT) and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday.

[7] Dispatchable demand may be offered as a Demand Resource in the PJM Capacity Market.

Resource is defined as an EE Resource that does not have a PJM approved Post-Installation M&V Report. An EE Resource that clears in an RPM Auction will receive the Resource Clearing Price of the Locational Deliverability Area in which the EE Resource resides.

An EE Resource may participate in RPM Auctions for a maximum of up to four consecutive Delivery Years. The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year. The time period of Energy Efficiency installations and their associated eligibility, in addition to the modeling of EE Resources in the PJM Capacity Market, is presented in ***PJM Manual 18B: Energy Efficiency Measurement &Verification.***

An EE Resource must meet the following minimum requirements:

- Submit Initial Measurement &Verification (M&V) Plan no later than 30 days prior to RPM Auction in which the EE Resource is initially offered;
- Submit Updated M&V Plan no later than 30 days prior to next RPM auction in which EE Resource is subsequently offered;
- Establish credit with PJM Credit Department prior to RPM Auction (for Planned EE Resources);
- Submit Energy Efficiency Resource Modification (EE MOD) in eRPM system;
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed;
- Submit Updated Post-Installation M&V Reports no later than business 15 days prior to each subsequent Delivery Year that the EE Resource is committed; and
- Permit Post- Installation M&V Audit(s) by PJM or Independent Third Party.

PJM Manual 18B: Energy Efficiency Measurement & Verification establishes the requirements for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports, and the M&V Audit.

4.4.1 Determination of Nominated Value of EE Resource

The Nominated EE Value of an EE Resource is the expected average demand (MW) reduction during the defined EE Performance Hours in the Delivery Year. The minimum Nominated EE Value accepted in the PJM Capacity Market is 0.1 MW. The Measurement & Verification (M&V) Plan describes the methods and procedures for determining the *Nominated* EE *Value of an* EE *Resource and confirming* that the Nominated EE Value is achieved.

The Nominated EE Value approved by PJM in EE Resource Provider's Initial/Updated M&V Plan establishes the Nominated EE Value that may be offered in an RPM Auction.

The last Post-Installation M&V Report submitted and approved by PJM prior to the Delivery Year that the EE Resource is committed establishes the final Nominated EE Value that is used to measure RPM Commitment Compliance during the Delivery Year. Failure to submit an Initial/Updated Post-Installation M&V Report or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Final Nominated EE Value equal to zero MWs for the relevant

Delivery Year. If an M&V Audit is performed and results finalized prior to the start of a Delivery Year, the Nominated EE Value confirmed by the Audit becomes the Final Nominated EE Value that is used to measure RPM Commitment Compliance during the Delivery Year. If the M&V Audit is performed and results finalized after the start of a Delivery Year, the Nominated EE Value confirmed by the M&V Audit becomes the basis to determine if any incremental RPM Commitment Compliance Shortfall needs to be assessed retroactively from June 1 of the Delivery Year to May 31 of the Delivery Year.

4.4.2 Determination of the UCAP Value of EE Resource

The Unforced Capacity (UCAP) value of an Energy Efficiency Resource is equal to the Nominated **EE** Value of the **EE** Resource multiplied by the Demand Resource Factor (DR Factor) and the Forecast Pool Requirement.

$$UCAPvalueofEE\ Resource = NominatedEEValue \times DRFactor \times FPR$$

4.4.3 Energy Efficiency Resource Modifications (EE MODs)

In order to offer an Energy Efficiency Resource into an RPM Auction, the resource must be in a party's portfolio for the duration of the Delivery Year. An Energy Efficiency Resource Modification transaction is the mechanism to add an EE Resource to a party's portfolio.

Energy Efficiency Resource Modifications (EE MODs) are a type of eRPM transaction used by PJM to track an increase or decrease of the Nominated EE Value of an EE Resource in a party's resource portfolio in eRPM. The following are business rules that apply to EE MODs:

- EE MODs must be submitted by the resource provider within the eRPM system for an EE Resource that has not yet participated in an RPM Auction.
- EE MODs may be submitted to reflect changes in the number of planned installations, changes in the demand reduction value based on M&V activities, and changes in EDC loss factors.
- PJM will "provisionally approve" an EE MOD after PJM has approved the Initial/Updated M&V Plan and the Nominated EE Value, and adequate credit for the EE Resource has been posted.
- PJM will "approve" an EE MOD once PJM has reviewed the Initial/Updated Post-Installation M&V Report and approved the Final Nominated EE Value of the EE Resource.
- PJM will "deny" an **EE** MOD if the increase in Nominated **EE** Value results in the total value of the **EE** Resource being greater than the PJM approved Final Nominated EE Value for the Delivery Year.
- EE MODs must be in a "Provisionally Approved" or "Approved" status in order for the EE MOD to be considered in a party's **EE** Resource Position and in the calculation of Available ICAP to offer for an RPM Auction.
- EE MODs that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

4.5 Qualified Transmission Upgrades

A Qualifying Transmission Upgrade may be offered into the Base Residual Auction to increase import capability into a transmission-constrained LDA (Sink LDA) from a Source LDA. Such transmission upgrade must meet the following minimum requirements.

- Must have been approved and an incremental import capability value must have been assigned by the PJM Planning Dept at least 45 days prior to the auction.
- The planned transmission upgrade in-service date must be on or before the start of the Delivery Year.
- At a minimum, a Facilities Study Agreement must be executed for the proposed transmission upgrade, in order for approval to be granted and the transmission upgrade
- Must conform to all applicable standards of the PJM Regional Transmission Expansion Planning Process.
- Qualified Transmission Upgrades must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

If a Qualifying Transmission Upgrade that was cleared in the Base Residual Auction is not completed by the start of the Delivery Year, the party who submitted the offer shall provide a replacement in the form of an equivalent amount of capacity resource within the Sink LDA by the start of the delivery Year. If replacement capacity is not provided, a Transmission Upgrade Delay Penalty shall apply.

A Qualifying Transmission Upgrade that cleared in the Base Residual Auction will be paid *the Locational Price Adder of the Sink LDA less the Locational Price Adder of the Source* LDA, multiplied by the megawatt quantity of incremental import capability cleared. A cleared Qualifying Transmission Upgrade is not automatically included in CETL analysis for future delivery years.

Once the Qualifying Transmission Upgrade is in service, the Qualifying Transmission Upgrade is eligible to continue to offer the approved incremental import capability value into future RPM Auctions.

4.6 Bilateral Transactions

Bilateral Transactions in the Reliability Pricing Model are transactions for capacity between a buyer and seller. Bilateral Transactions may be reported to PJM for inclusion in the PJM billing process for unit-specific capacity or for non unit-specific capacity. Parties in all bilateral transactions reported to PJM agree to indemnify PJM against non-performance by their counterparties in such transactions.

PJM posts reference prices at various points in order to facilitate bilateral trading on the part of market participants. The posted pricing points include LDA and Hub pricing points (associated with a Base Residual Auction (BRA) Resource Clearing Price in a LDA), Net Load pricing points (associated with a Final Zonal Capacity Price less Final Zonal CTR Credit Rate), PZonal pricing points (associated with Preliminary Zonal Capacity Price), FZonal (associated with Final Zonal Capacity Price), FCTR pricing points (associated with Final Zonal CTR Credit Rate), and FILR pricing points (associated with the Final Zonal ILR Price), and 3IA pricing points (associated with a Third Incremental Auction (3IA) Resource Clearing Price in an LDA). The available pricing points and their definitions are posted on the PJM website.

Additional pricing points will be added by PJM if requested by stakeholders. However, the definition of the pricing points will remain static once created.

4.6.1 Unit-Specific Bilateral Transactions

The purpose of reporting a unit-specific bilateral transaction to PJM (regardless of the type of capacity transacted) is to transfer the rights to or control of a specified amount of installed capacity from the Seller to the Buyer. Bilateral contracts for unit-specific capacity resources may be offered into PJM's RPM if these products meet the requirements specified in this Manual.

PJM will provide electronic bulletin board functionality in eRPM. The bulletin board allows participants to post and view requests to buy or offers to sell capacity resources. The purpose of the bulletin board functionality is to facilitate bilateral transaction activity.

4.6.2 Entering Unit-Specific Bilateral Transactions

Unit-specific bilateral transactions reported to PJM may wholly or partially offset an LSE's Locational Reliability Charges in the PJM billing process provided that Available installed capacity purchased through the bilateral transaction is directly offered and cleared in a Base Residual Auction or Incremental Auction or is designated as a self-scheduled resource in a Base Residual Auction (i.e., the RPM Auction Credits received may offset the Locational Reliability Charges assessed in your PJM bill).

The smallest increment of installed capacity that may be reported to PJM as unit-specific transactions is 0.1 MW.

PJM does not recognize "slice of system" or unforced capacity credit bilateral transactions in RPM Auctions.

Both parties of a unit-specific transaction must confirm the transfer of installed capacity from the seller to the buyer via the eRPM system prior to the start date of the transaction.

Unit-specific transactions to an "External Party" (i.e., "EXT") must be in "Pending PJM" status two business days prior to the start date of the transaction.

All unit-specific bilateral transactions that cover the Delivery Year must be in "Provisionally Approved" or "Approved" status in the eRPM system prior to the opening of the Base Residual Auction or an Incremental Auction's bidding window in order for the transactions to be considered in a party's Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction or an Incremental Auction or to be used for self-scheduling in the Base Residual Auction.

Unit-specific transactions cannot be created during an RPM Auction's bidding window and clearing week.

Unit-specific transactions that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

Unit–specific bilateral transactions may be reported for the following installed capacity types: Available, Unoffered, or Cleared.

Unit specific transactions reported for either Available or Unoffered capacity must specify:

- The unit to be transacted
- A start and end date for the transaction
- An installed capacity (ICAP) MW value

Unit specific transactions reported for Cleared capacity must specify:

- The unit to be transacted
- A start and end date for the transaction
- The auction in which the unit cleared
- An unforced capacity (UCAP) MW value. Once approved, the unforced capacity MW value will be converted to an installed capacity MW value using the then-current Effective EFORd for the specified unit. The installed capacity MW value is capped at the ICAP Owned by the Seller.

The following are business rules that apply to Unit-Specific Bilateral Transactions:

- If available capacity type is selected, the eRPM system will validate that the Seller has Daily Available ICAP to offer for the entire term of the transaction. The Daily Available ICAP to offer on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP - (Daily RPM Resource Commitments/(1-Effective EFORd)) – Daily FRR Capacity Plan Commitments.
- Available installed capacity purchased through a bilateral unit-specific transaction that is registered in PJM's eRPM system may be directly offered into the Base Residual Auction or Incremental Auctions or designated as a self-scheduled resource in the Base Residual Auction.
- If unoffered capacity type is selected, the eRPM system will validate that the Seller has Daily Unoffered ICAP to offer for the entire term of the transaction and validate that the Seller is either External Party (EXT) or FRR Entity.
- The unoffered capacity type may be selected for a unit-specific bilateral transaction if selling a unit externally (formerly known as "delisting") after the Base Residual Auction has been cleared for the specified transaction dates. To delist a unit before the Base Residual Auction has been run, a party may select the Available capacity type to transact installed capacity to an External Party (EXT).
- If cleared capacity is selected, the eRPM system will validate that the Seller has cleared capacity to offer for the entire term of the transaction.
- Approved unit-specific transactions reported to PJM for Cleared capacity will result in a transfer of the Auction Credit for the specified number of UCAP MW from the Seller

to the Buyer. In addition, the RPM Resource Commitment for the specified number of UCAP MWs is also transferred from the Seller to the Buyer.

- The Buyer in a unit-specific transaction for cleared capacity will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of such transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the unit-specific capacity transaction for cleared capacity.
- To the extent that capacity identified in the unit-specific transaction for cleared capacity is a resource that has an RPM Credit Requirement, the Buyer must have sufficient credit in place with respect to the credit exposure associated with the obligations of the acquired RPM Resource Commitment.

4.6.3 Exporting a Generation Resource

Exporting (formerly known as "Delisting") a generation resource is accomplished by reporting a bilateral transaction with "External Party" (i.e., "EXT") listed as the "Buyer" in the unit-specific transaction.

Exporting any portion of a generation resource below a party's Daily RPM Resource Commitments/(1-Effective EFORd) plus Daily FRR Capacity Plan Commitments for the term of the transaction is not permitted. Only Available or Unoffered ICAP on the unit may be exported.

Exporting of a generation resource may only be done by the party that submitted the Capacity Modification for the unit.

If a portion of a generation resource is to be exported, appropriate documentation must be submitted to PJM to demonstrate that the party exporting the generation resource has a financially and physically firm commitment to an external sale of its capacity and therefore, is exempt from the offer requirement for capacity resources in ***Attachment DD, Section 6.6 of the PJM Open Access Tariff.*** In order for a generation resource that is exported to be considered in the Preliminary Market Structure Screen, the associated unit-specific bilateral transaction must be in an "Approved" status by the date the MMU collects data for the Preliminary Market Structure Screen.

In order for a generation resource that is being exported to be reflected in a party's Available ICAP Position for an RPM Auction, the associated unit-specific transaction must be in an "Approved" status by the opening of the RPM Auction's bidding window.

Capacity Export Charge

A Capacity Export Transmission Customer may procure capacity in one PJM Zone and export the capacity from another Zone to outside PJM. Under the FERC approved tariff effective June 1, 2008, the Capacity Export Transmission Customer will pay a Capacity Export Charge and receive a credit similar to the CTR credit if the Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported is higher than the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located. The Capacity Export Charge collected less the credit will be allocated to the LSEs in the Zone from which capacity is exported.

This Capacity Export Charge and credit are assessed daily and billed monthly. These calculations are independent from the CTR calculations based on Base Residual Auction

and Second Incremental Auction. The LSE CTR credits and the Incremental CTR credits will not be changed due to Capacity Export Charge/credit calculations.

A Capacity Export Charge is applicable when a firm transmission service is reserved from export source to export interface. There will not be a capacity export charge if non-firm transmission service is purchased to support the capacity export as PJM would have the right to curtail the non-firm transmission service at any time due to limitations in available transmission capability.

If more than one Zone forms the interface with the Control Area to which capacity is exported, the Export Reserved Capacity will be apportioned among the Zones. The Export Reserved Capacity is completely apportioned to the Zone if a fully controllable facility crosses the interface (e.g. dc line). The power flow distribution among multiple interface zones for a capacity export would be based on the PJM RTEP Base Power Flow case for the applicable Delivery Year. The power flow distribution calculations are done by modeling the de-listed generator as the source and the designated external load as the sink for the specific capacity exports to be analyzed.

Capacity Export Transmission Customer incurs for each day a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service multiplied by (the Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported minus the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located).

To recognize the value of firm Transmission Service held, the Capacity Export Transmission Customer receives a credit similar to Capacity Transfer Rights (CTRs) credits. The credit is the Final Zonal Capacity price difference used in determining the Capacity Export Charge times Export Customer's Allocated Share of the Export Path Import.

4.6.4 Importing an External Generation Resource

Importing an external generation resource is accomplished by entering into a bilateral transaction with "External Party" (i.e., "EXT") listed as the "Seller" in the unit-specific transaction. Unit-specific transactions that represent capacity imports will not be granted a "Provisionally Approved" status unless an indication of the intended ATC path to deliver the external capacity to PJM is provided. An "Approved" unit-specific transaction status will not be granted until firm transmission service from the unit to the border of PJM has been obtained and generation deliverability has been demonstrated into PJM.

External generators must demonstrate generation deliverability into PJM by (1) obtaining firm point-to-point transmission service on the PJM OASIS from the border into the PJM transmission system (this applies to service on the PJM transmission system) or (2) obtaining "Network External Designated" transmission service with an expected completion date prior to June 1st of the delivery year. Either of the above options for demonstrating deliverability may require transmission upgrades to be completed prior to June 1st of the delivery year. All of the above options follow the study process for participant-funded upgrades as defined in **Part VI of the PJM Open Access Transmission Tariff**.

Unit-specific transactions that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

Unit-specific transactions that are not "Approved" should refer to the RPM credit business rules for their associated credit requirements.

4.6.5 Treatment of Unit-Specific Capacity Transactions that Start/End Mid-Delivery Year

Unit-specific transactions reported with a Start Date that does not correspond to June 1 or an End Date that does not correspond to May 31 will result in installed capacity that cannot be offered into the Base Residual Auction since a single party does not own the installed capacity for the entire Delivery Year. In addition, this installed capacity will be tracked as Unoffered Capacity after the Base Residual Auction. To address this issue, PJM will facilitate a voluntary process to enable the installed capacity to be offered into the Base Residual Auction for the Delivery Year.

In order to participate, each party of the unit-specific transaction that starts/end Mid-Delivery Year must sign and submit a Self-Schedule Authorization Form found in ***Attachment E of this Manual***, which authorizes PJM to self-schedule the capacity on behalf of the parties in the Base Residual Auction for the Delivery Year. The Authorization Form must be submitted to RPM_Hotline@pjm.com at least 5 business days prior to the opening of the bidding window.

Each party of the unit-specific transaction that starts/ends Mid-Delivery Year must submit a new unit-specific transaction in eRPM with "Self-Scheduling Coordinator (SELFSC)" as the Buyer prior to the opening of the Base Residual Auction bidding window, so the capacity will be transferred into the SELFSC account for the entire Delivery Year at the time of the Base Residual Auction.

Provided the Self-Schedule Authorization Forms are received and the required unit-specific transactions are submitted, PJM will self-schedule and clear the capacity on-behalf of the parties in the Base Residual Auction for the Delivery Year. A submitted EFORd equal to the Effective EFORd at the time of the Base Residual Auction will be used in the resource-specific sell offer in the Base Residual Auction.

After the Base Residual Auction results are posted, PJM will submit unit-specific transactions for Cleared MWs with "SELFSC" as the Seller to transfer capacity back to the Parties (i.e., Buyer in the unit-specific transaction) for the appropriate time periods. No confirmation is required by the Buyer of the unit-specific transaction. The approved unit-specific transactions for Cleared MWs will result in the transfer of ICAP Owned, RPM Resource Commitments, and Auction Credits from the SELFSC account to the Buyer. The Buyer of the Cleared MWs is responsible for any Capacity Resource Deficiency Charges that may be assessed during the term of the unit-specific transaction. In addition, the Buyer of the Cleared MWs is responsible for their share of any Peak-Hour Period Availability Charges, Generation Resource Rating Test Failure Charges, or Peak Season Maintenance Compliance Penalty Charges that may be assessed during the Delivery Year.

4.6.6 Auction Specific MW Transactions

RPM Market Participants have the ability to report Auction Specific MW Transactions to PJM through the eRPM system. Auction Specific MW Transactions must be for the transfer of physical MW of capacity from a seller to a buyer at the location of the physical resources identified as supplying the transaction.

The following are business rules that apply to Auction-Specific MW Transactions

- Auction Specific MW Transactions are not eligible to be offered in an RPM auction.

- Auction Specific MW Transactions for a Delivery Year may be submitted following the completion of the Third Incremental Auction for the delivery year to which the transaction applies.
- Both the Buyer and the Seller of Auction Specific MW Transaction must confirm the Auction Specific MW Transaction via the eRPM system before the start date of theDelivery Year.
- An Auction Specific MW Transaction must specify the buyer, seller, start and end dates of the transaction.
- The Seller of the Auction Specific MW must also specify the resource(s) (generation resource or demand resource or Energy Efficiency Resource), Auction Type (Base, First, Second, Third, or Conditional), and the MW amount of Auction Specific MW to be transacted from each resource. PJM will verify that the MW of capacity from each of the resources identified as supplying the Auction Specific MW Transaction have cleared in an RPM auction and that at least the MW of cleared capacity indicated for each resource is not committed in any other bilateral transactions. If such sufficient cleared capacity does not exist on any of the indicated resources, PJM will reject reporting of the transaction.
- Auction Specific MW Transactions may not extend past the last day of the delivery year containing the start date of the transaction.
- Auction Specific MW Transactions are priced at the weighted average of the Resource Clearing Prices from the RPM auctions in which the MW from the units supplying the transaction cleared.
- The smallest increment that may be transacted through an Auction Specific MW Transaction is 0.1 MW.
- The Seller of the Auction Specific MW is subject to all applicable resource performance assessments.
- The Buyer will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of the Auction Specific MW transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the Auction Specific MW transaction.
- PJM reserves the right under the PJM Operating Agreement and PJM Open Access Transmission Tariff, to deny reporting of Auction Specific MW Transactions in the event one of the parties fails to meet any requirements for such reporting.
- The Seller of an Auction Specific MW Transaction will receive a charge equal to the transaction amount (in MW) times the price associated with in the transaction.
- The Buyer of an Auction Specific MW Transaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction.

4.6.7 Cleared Buy Bid Transactions

RPM Market Participants have the ability to report Cleared Buy Bid Transactions through the eRPM system. A Cleared Buy Bid Transaction allows the holder of a Cleared Buy Bid from an Incremental Auction to transfer Cleared Buy Bid MWs to another party for the term of the transaction. A Cleared Buy Bid Transaction will not change the resource position or load obligation of an entity. However, the Buyer may use the Cleared Buy Bid MWs as a replacement resource in a Replacement Capacity Transaction.

The following are business rules that apply to Cleared Buy Bid Transactions

- Cleared Buy Bid MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of Cleared Buy Bid MWs must confirm the Cleared Buy Bid transaction via the eRPM system by 23:59 EPT before the start date of the transaction.
- A Cleared Buy Bid Transaction must specify the buyer, seller, start and end dates of the transaction, the transaction amount (in MW), the LDA and Incremental Auction associated with the Cleared Buy Bid.
- The smallest increment that may be transacted through a Cleared Buy Bid Transaction is 0.1 MW.
- Cleared Buy Bid transaction results in the "Buyer" receiving the Cleared MWs in the applicable LDA and the associated Incremental Auction Charges that would have been assessed to the Seller for the term of the transaction.

4.6.8 Locational Unforced Capacity (UCAP) Transactions

RPM Market Participants have the ability to report Locational UCAP Transactions through the eRPM system. A Locational UCAP Transaction allows a party with available resource-specific capacity to transfer Locational UCAP (MWs) to another party. A Locational UCAP Transaction will not change the resource position or load obligation of an entity. However, the Buyer may use the Locational UCAP as a replacement resource in a Replacement Capacity Transaction.

The following are business rules that apply to Locational UCAP Transactions:

- Locational UCAP MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of Locational UCAP MWs must confirm the Locational UCAP Transaction via the eRPM system by 23:59 EPT before the start date of the transaction.
- Locational UCAP transactions for a Delivery Year will be restricted as follows during the following periods:
- Prior to the locking of the Delivery Year EFORd (Nov. 30th prior to the Delivery Year): Locational UCAP transactions will not be accepted.
- After the locking of the Delivery Year EFORd, but before the Delivery Year's Third Incremental Auction bidding window opens: Locational UCAP transactions may be accepted; however, the Buyer of the Locational UCAP transaction must demonstrate prior to the Third Incremental Auction that the Locational UCAP was used in a replacement capacity transaction. If the Buyer fails to enter into a replacement capacity transaction prior to the Third Incremental Auction, the Locational UCAP transaction will be denied by PJM.
- During the Delivery Year's Third Incremental Auction: Locational UCAP transactions will not be accepted.

- After the Delivery Year's Third Incremental: Locational UCAP transactions will be accepted.
- A Locational UCAP Transaction must specify the buyer, seller, product type (i.e., Limited, Extended Summer, or Annual) effective with the 2014/2015 Delivery Year, start and end dates of the transaction.
- The Seller of the Locational UCAP must also specify the resource (generation resource or demand resource) and the MW amount of locational UCAP to be transacted. The resource specified in the transaction must be of the same product type specified in the Locational UCAP transaction.
- The smallest increment that may be transacted through a Locational UCAP Transaction is 0.1 MW.
- A Locational UCAP transaction results in an RPM Resource Commitment (in UCAP terms), equal to the MW amount of locational UCAP transacted, being placed on the Seller's resource for the term of the transaction.
- The Seller of the Locational UCAP retains ownership of the resource specified in the Locational UCAP Transaction.
- The Seller of the Locational UCAP is subject to all applicable resource performance assessments.
- The Buyer in a Locational UCAP transaction will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of such transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the Locational UCAP transaction.

4.7 Resource Portfolio

A party's resource portfolio in eRPM may consist of Generation Resources, Demand Resources, ILR Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades. A party's Generation Resource portfolio may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Qualification requirements for generation resources are presented in Existing Generation, Planned Generation, and Bilateral Unit-Specific Transaction Sections of this Manual.

4.7.1 Resource Position for Generation Resources

A party's Daily Generation Resource Position is calculated dynamically by the eRPM system for each unit and is equal to the party's Daily ICAP Owned on a unit multiplied by one minus the unit's Effective EFORd.

A party's Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases. The Installed Capacity (ICAP) Value of a unit is based on the summer net dependable rating of the unit as determined in accordance with ***PJM Manual for the Rules and Procedures for the Determination of Generating Capability (M-21).***

A unit that is in a party's Generation Resource portfolio may be traded bilaterally if the party has Daily Available ICAP to offer from the unit for the entire term of the bilateral unit-specific transaction. If the Daily Available ICAP for the unit varies for the term of the bilateral unit-specific transaction, only the minimum Daily Available ICAP may be sold in the bilateral unit-specific transaction.

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP - (Daily RPM Resource Commitments/(1-Effective EFORd)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP = DailyICAPOwned - DailyUnofferedICAP - \left(\frac{DailyRPMResourceCommitments}{1 - EffectiveEFORd}\right) - DailyFRRCapacityPlanCommitments$$

A unit that is in a party's Generation Resource portfolio may be offered into RPM Auctions if the party has available capacity to offer from the unit for the entire term of the RPM Auction Year. For each RPM Auction, PJM will calculate a Current Available ICAP Position, Minimum Available ICAP Position, and Maximum Available ICAP Position.

A party's Current Available ICAP Position on a unit for an RPM Auction is equal to the minimum Daily Available ICAP for such unit during the Delivery Year.

$$CurrentAvailableICAPPosition_{unit} = Min(DailyAvailableICAP)$$

A party's Minimum Available ICAP Position represents the minimum amount that must be offered into an RPM Auction. A party's Minimum Available ICAP Position on a unit for an RPM Auction is equal to the *minimum* Daily Minimum Available ICAP for such unit during the Delivery Year.

$$MinimumAvailableICAPPosition_{unit} = Min(DailyMinAvailableICAP)$$

A party's Daily Minimum Available ICAP is equal to Daily ICAP Owned minus the Daily Unoffered ICAP minus Daily Cleared ICAP in RPM Auctions minus Daily FRR Capacity Plan Commitments. Daily Cleared UCAP in RPM Auctions is converted to Daily Cleared ICAP using the greater of the EFORd $_{1\,yr}$ at the time of the Base Residual Auction, EFORd $_{5\,yr}$ at the time of the Base Residual Auction, or the party's Sell Offer EFORd from the Base Residual Auction.

$$\text{Daily Min Available ICAP} = DailyICAPOwned - DailyUnofferedICAP - \left[\frac{DailyClearedUCAP}{(1 - Max(\text{BRA EFORd 1yr}, BRAEFORd\,5yr, \text{BRA SellOfferEFORd}))}\right] - DailyFRRCapPlanCommitments$$

A party's Maximum Available ICAP Position represents the maximum amount that a participant may offer into an RPM Auction. A party's Maximum Available ICAP Position on a unit for an RPM Auction is equal to the *minimum* Daily Maximum Available ICAP for such unit during the Delivery Year.

$$MaximumAvailableICAPPosition = Min(DailyMaxAvailableICAP)$$

A party's Daily Maximum Available ICAP is equal to Daily ICAP Owned minus the Daily Unoffered ICAP minus Daily Cleared ICAP in RPM Auctions minus Daily FRR Capacity Plan Commitments. Daily Cleared UCAP in RPM Auctions is converted to Daily Cleared ICAP using a zero EFORd.

$$\text{DailyMaxAvailableICAP} = DailyICAPOwned - DailyUnofferedICAP - \left[\frac{DailyClearedUCAP}{(1-0)}\right] - DailyFRRCapacityPlanCommitments$$

For the Base Residual Auction and Third Incremental Auction, a party's Minimum Available ICAP Position and Maximum Available ICAP Position for a unit will be equal to the party's Current Available ICAP Position for such unit.

A party's Daily Unoffered ICAP for a specific unit is calculated by adding the sum of any Daily Unoffered ICAP for such unit in RPM Auctions to Daily Unoffered ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

$$DailyUnOfferedICAP_{unit} = DailyUnofferedICAP_{RPMAuctions} + DailyUnofferedICAP_{BilateralSales/Purchases}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a generation resource is equal to the party's Minimum Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$DailyUnofferedICAP_{GenResource} = MinimumAvailableICAPPosition_{unit} - OfferedICAP$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity and the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific unit are equal to the total amount of installed capacity that was committed from the unit for the FRR Capacity Plan.

A party's Daily RPM Generation Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(1-Effective EFORd).

$$DailyRPMPosition_{GenResources} = (Daily\,ICAPOwned - Daily\,FRRCapPlan\,Commitments - Daily\,Unoffered\,ICAP) \times (1 - EffectiveEFORd)$$

During the Delivery Year, a party's Daily RPM Generation Resource Position is compared to their Daily RPM Resource Commitments for the generating unit to determine if a Capacity Resource Deficiency Charge is to be assessed.

4.7.2 Resource Position for Demand Resources

A party's Demand Resource portfolio may consist of existing Demand Resources or Planned Demand Resources. Qualification requirements for Demand Resources are presented in Load Management Products Section of this Manual.

A party's Daily Nominated DR Value for a specific demand resource is equal to the Daily Nominated DR Value as determined by party's "Provisionally Approved" or "Approved" DR Modifications.

A party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the eRPM system and is equal to the Daily Nominated DR Value * DR Factor * Forecast Pool Requirement.

$$DailyResourcePosition_{DemandResource} = DailyNominatedDRValue \times DRFactor \times FPR$$

A Demand Resource that is in a party's Demand Resource portfolio may be offered into RPM Auctions, if there is Daily Available ICAP to offer from the Demand Resource for the entire term of the RPM Auction.

For a party, the Daily Available ICAP for a specific demand resource is equal the resource's Daily Nominated DR Value – Daily Unoffered ICAP - ((Daily RPM Resource Commitments/(DR Factor *Forecast Pool Requirement)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP_{DR} = DailyNominatedDRValue - DailyUnofferedICAP - \left(\frac{DailyRPMResourceCommitments}{(DRFactor \times FPR)}\right) - DailyFRRCapCommitments$$

A party's Daily Unoffered ICAP for a specific demand resource is calculated by adding the sum of any Daily Unoffered ICAP for such demand resource in RPM Auctions.

$$DailyUnOfferedICAP_{demandresource} = \sum DailyUnofferedICAP_{RPMAuction}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a specific demand resource is equal to the demand resource's Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$Daily\ Unoffered\ ICAP_{DemandResource} = Available\ ICAP\ Position - Offered\ ICAP$$

A party's Available ICAP Position for a specific demand resource is equal to the minimum Daily Available ICAP for such demand resource during the Delivery Year.

$$AvailableICAPPosition_{DemandResource} = Min(DailyAvailableICAP)$$

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such demand resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific demand resource are equal to the total amount of Nominated DR that was committed from the demand resource for the FRR Capacity Plan.

A party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily Nominated DR Value – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)* DR Factor * Forecast Pool Requirement.

$$DailyRPMPosition_{DR} = (DailyNomDRValue - DailyFRRCapPlanCom - DailyUnofferedICAP) \times DRFactor \times FPR$$

During the Delivery Year, a party's Daily RPM Demand Resource Position is compared to their Daily RPM Resource Commitments for the demand resource to determine if a Capacity Resource Deficiency Charge is to be assessed on the delivery day.

4.7.3 Resource Position for ILR Resources

A party's ILR Resource portfolio may consist of existing ILR resources. Qualification requirements for ILR resources are presented in the Load Management Products and ILR Certification Requirements Sections of this Manual. An ILR Resource that is in a party's ILR Resource portfolio is eligible to receive ILR Credits during the Delivery Year. A party's Daily

Nominated ILR Value for a specific demand resource is equal to the Daily Nominated ILR Value as determined by party's approved Emergency Load Response Registration.

A party's Daily ILR Resource Position for an ILR Resource is calculated by the eRPM system and is equal to the Daily Nominated ILR Value * DR Factor * Forecast Pool Requirement.

$$DailyILRResourcePosition = DailyNominatedILR \times DRFactor \times FPR$$

4.7.4 Resource Position for Energy Efficiency Resources

A party's EE Resource portfolio may consist of existing or planned EE Resources. Qualification requirements for EE Resources are presented in Energy Efficiency Resource Section of this Manual.

A party's Daily Nominated EE Value for a specific EE Resource is equal to the Daily Nominated EE Value as determined by party's "Provisionally Approved" or "Approved" EE Modifications.

A party's Daily EE Resource Position for an EE Resource is calculated dynamically by the eRPM system and is equal to the Daily Nominated EE Value * DR Factor * Forecast Pool Requirement.

$$DailyResourcePosition_{EEResource} = DailyNominatedEEValue \times DRFactor \times FPR$$

An EE Resource that is in a party's EE Resource portfolio may be offered into RPM Auctions, if there is Daily Available ICAP to offer from the EE Resource for the entire term of the RPM Auction.

For a party, the Daily Available ICAP for a specific EE Resource is equal the resource's Daily Nominated EE Value – Daily Unoffered ICAP - ((Daily RPM Resource Commitments/(DR Factor *Forecast Pool Requirement)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP_{EE} = DailyNominatedEEValue - DailyUnofferedICAP - \left(\frac{DailyRPMResourceCommitments}{(DRFactor \times FPR)}\right) - DailyFRRCapCommitments$$

A party's Daily Unoffered ICAP for a specific EE Resource is calculated by adding the sum of any Daily Unoffered ICAP for such EE Resource in RPM Auctions.

$$DailyUnOfferedICAPEEResource = \sum DailyUnofferedICAP_{RPMAuction}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a specific EE Resource is equal to the EE Resource's Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$Daily\ Unoffered\ ICAP_{EEResource} = Available\ ICAP\ Position - Offered\ ICAP$$

A party's Available ICAP Position for a specific EE Resource is equal to the minimum Daily Available ICAP for such EE Resource during the Delivery Year.

$$AvailableICAPPosition_{EEResource} = Min(DailyAvailableICAP)$$

A party's Daily RPM Resource Commitments for a specific EE Resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such EE Resource in RPM

Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific EE Resource are equal to the total Nominated EE Value that was committed from the EE Resource for the FRR Capacity Plan.

A party's Daily RPM EE Resource Position for a specific EE Resource is equal to the (Daily Nominated EE Value – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)* DR Factor * Forecast Pool Requirement.

$$DailyRPMPosition_{EE} = (DailyNomEEValue - DailyFRRCapPlanCom - DailyUnofferedICAP) \times DRFactor \times FPR$$

During the Delivery Year, a party's Daily RPM EE Resource Position is compared to their Daily RPM Resource Commitments for the EE Resource to determine if a Capacity Resource Deficiency Charge is to be assessed on the delivery day.

4.7.5 Resource Position for Qualified Transmission Upgrades

A party's Qualifying Transmission Upgrade portfolio may consist of planned Qualifying Transmission Upgrades. Qualification requirements for Qualifying Transmission Upgrades are presented in Qualifying Transmission Upgrade Section of the RPM Business Rules.

A Qualifying Transmission Upgrade that is in a party's Qualifying Transmission Upgrade portfolio may be offered into a Base Residual Auction if incremental import capability value into Sink LDA from a Source LDA has been approved by PJM System Planning Department.

A party's Daily Qualifying Transmission Upgrade Position for a Qualifying Transmission Upgrade is calculated dynamically by the eRPM system and is equal to the incremental import capability value into Sink LDA from a Source LDA that has been assigned by PJM System Planning Department.

A party's Daily RPM Resource Commitments for a specific Qualifying Transmission Upgrade are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such Qualifying Transmission Upgrade in RPM Auctions to any decreases of RPM Resource Commitments due to the specification of replacement resources.

During the Delivery Year, a party's Daily RPM Qualifying Transmission Upgrade Position for a qualifying transmission upgrade is compared to their Daily RPM Resource Commitments for the qualifying transmission upgrade to determine if a Transmission Upgrade Delay Penalty is to be assessed.

4.8 Credit Requirements

The purpose of the RPM credit requirement is to encourage future physical performance, but not necessarily fully guarantee financial obligations related to Capacity. Credit requirements for participating in the RPM, therefore, may be different from the other requirements established separately in the PJM Credit Policy, which are intended for other activities and general financial obligations to PJM.

These business rules are intended to be descriptive of the credit requirements for participants in the RPM, but if any conflict arises between provisions in these rules and provisions in the PJM Operating Agreement or PJM Open Access Transmission Tariff

(which includes the PJM Credit Policy as Attachment Q), then the provisions in the Operating Agreement and/or Tariff shall govern.

Since LSE payments due to PJM are included in monthly PJM bills, LSE payment obligations are considered to already be measured and covered by provisions of PJM's Credit Policy. Accordingly, no separate credit requirement will be imposed on LSEs under the RPM.

Participants offering into an RPM Auction existing resources (whether generators, demand resources, energy efficiency resources, or external generation resources with firm transmission), are not required to establish credit for the RPM Auctions.

Participants offering into an RPM Auction any Planned Demand Resource, Planned Energy Efficiency Resource, Planned Generation Resource, Qualified Transmission Upgrade, or external capacity without firm transmission (these four together considered herein to be Resources Requiring Credit for RPM) must establish an RPM Credit Limit prior to an RPM Auction.

4.8.1 RPM Credit Limit

Acceptable sources of credit for the RPM Credit Limit may be either of the following:

- Any unsecured credit or collateral available, according to provisions of the PJM Credit Policy, which has not already been designated or required for financial obligations under the Credit Policy or for other financial obligations within PJM.
- For RPM credit purposes only, if a supplier has a history of being a net seller into PJM, on average, over the past 12 months, then PJM will count as available unsecured credit twice the average of that participant's total net PJM bills over the past 12 months.
- A supplier may combine more than one source of credit for RPM credit purposes. Credit provided for RPM must be non-cancelable until at least 10 days after payment is due for the last month for which a committed financial obligation could be created or owed.

Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction. Credit previously established with PJM for general market activity will not be available for RPM unless the participant specifically makes such a request to the PJM Treasury Department.

Although credit provided by a participant may be administratively separated for RPM (or FTR, etc.), all credit supplied by a PJM member or customer, whether or not designated for RPM (or FTR, or any other PJM obligation), may be utilized to cover any PJM financial obligation, should the member or customer default.

PJM will return or release RPM credit provided by participants upon request, as long as such release would not cause a participant's RPM Credit Requirement to exceed its RPM Credit Limit. Furthermore, PJM reserves the right to establish a maximum frequency of such returns or releases, but no less frequent than once per calendar quarter.

A participant must, at all times, maintain its RPM Credit Limit at least sufficient to meet its RPM Credit Requirement. If a participant's RPM Credit Requirement ever exceeds its RPM Credit Limit, PJM may exercise any of the remedies afforded by the Credit Policy, Tariff, Operating Agreement, or other agreements, business rules or manuals, including demand for additional credit and/or declaration of default. Failure to exercise a remedy at any given time shall not preclude PJM from exercising such remedy at a later time.

4.8.2 RPM Credit Requirement

An RPM Credit Requirement will be established for all participants that are offering into an RPM Auction or have already committed into RPM any Resources Requiring Credit for RPM. The RPM Credit Requirement will be equal to the sum of the individual credit requirements for such resources. The credit requirement for a given resource offered into an RPM auction will be a fixed Auction Credit Rate times the unforced MW offered, times an RPM Credit Adjustment Factor. The credit requirement for a given resource committed into RPM will be a fixed Auction Credit Rate times the unforced MW committed, times an RPM Credit Adjustment Factor.

RPM Credit Adjustment Factor

- The RPM Credit Adjustment Factor for a given resource depends on its status in becoming a fully qualified resource as follows The Credit Adjustment Factor for all Resources Requiring Credit for RPM will be one ("1") except as follows:
- For Planned Demand Resources, the Credit Adjustment Factor will be (1-X), where "X" is the Nominated DR that is certified through an Emergency Load Response Registration divided by the Nominated DR value in the DR Modification for the planned demand resource.
- For Planned Energy Efficiency Resource, the Credit Adjustment Factor will be (1-X), where "X" is the Nominated EE Value that is confirmed through a PJM approved Post-Installation M&V Report divided by the Nominated EE value in the EE Modification for the planned energy efficiency resource.
- For existing external generation resources without firm transmission, the Credit Adjustment Factor will be zero if the Participant has demonstrated that firm transmission has been procured.
- For Planned generation resources, the Credit Adjustment Factor will be 0.5 (50%) if a full (not provisional) Interconnection Service Agreement has been successfully executed but Interconnection Service has not yet begun, and will be zero on or after the start date of Interconnection Service.
- For Qualifying Transmission Upgrades, the Credit Adjustment Factor will be 0.5 (50%) if a full (not provisional) Interconnection Service Agreement has been successfully executed but Interconnection Service has not yet begun, and will be zero on the date the Qualifying Transmission Upgrade is placed in service.
- PJM will consider credit adjustment factors other than these on a case-by-case basis.

If a Participant offers a Resource Requiring Credit for RPM into an RPM auction, but the Participant's RPM Credit Limit is insufficient for the participant's RPM Credit Requirement including the new offer, then the offer will be rejected. If the offer was made as part of a sell offer upload file (multiple resources offered simultaneously), then the entire file upload will be rejected. Previous offers made and accepted into an auction will not be rejected solely because a subsequent offer was rejected.

A participant that has procured capacity in an Incremental Auction may incur a change in credit requirement if the cost of the procured capacity differs from the cost of the originally-committed capacity.

4.8.3 Auction Credit Rate

An Auction Credit Rate is calculated prior to each RPM Auction for such Delivery Year.

Prior to 2012/2013 Delivery Year, the RPM Credit Rate is defined as:

- Greater of $20/MW-day or .24 * BRA Resource Clearing price of the LDA where the resource is modeled, times the number of days in the Delivery Year.
- One rate is calculated and applied for each year and each binding LDA, regardless of the Auction the resource is committed.

Effective 2012/2013 Delivery Year onward:

- Prior to the posting of the BRA results, the RPM Credit Rate is equal to the greater of (i) $20/ MW-day or (ii) .3 * applicable Delivery Year's Net CONE for the RTO (in $/MW-day), times the number of days in the Delivery Year.
- Upon posting the BRA clearing results, the RPM Credit Rate used for planned resource commitments in the BRA is equal to the greater of (i) $20/MW-day or (ii) .2 times the Capacity Resource Clearing Price for the LDA and resource product type (i.e., limited, extended summer, and annual) that applies to the planned resources, times the number of days in the Delivery Year.
- For any planned resource not previously committed for a Delivery Year that participates in an Incremental Auction, the Auction Credit Rate is equal to the greater of (i) 0.3 times the applicable Delivery Year's Net CONE for the RTO or (ii) 0.24 times the Capacity Resource Clearing Price in the BRA for the applicable Delivery Year for the LDA and resource product type that applies to the planned resource or (iii) $20 per MW-day, times the number of days in the Delivery Year.
- Upon posting the results of an Incremental Auction, the Auction Credit Rate used for planned resources committed in the Incremental Auction is equal to the greater of (i) $20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price in such Incremental Auction for the LDA and resource product type that applies to the planned resource , but no greater than the pre-clearing Incremental Auction Credit Rate for such Incremental Auction times the number of days in the Delivery Year.
- One rate is calculated for each Auction, binding LDA, and resource product type, and applied according to the Auction, LDA, and resource product type in which the capacity was committed.

4.8.4 Credit-Limited Offers in RPM Auctions

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Seller electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement (i.e., Maximum Post-Auction Credit

8 Resource product types are effective with the 2014/2015 Delivery Year.

Exposure), in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the post-auction Auction Credit Rate; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Seller electing this alternative, the RPM Auction Credit Requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-Limited Offer (i.e., Maximum Post-Auction Credit Exposure), and the RPM Auction Credit Requirement subsequent to posting of the results will be the Auction Credit Rate times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The following business rules apply to Credit-Limited Offers:

- A supplier must notify PJM prior to the opening of the RPM Auction bidding window if they intend to submit a credit-limited offer.
- A Maximum Post-Auction Credit Exposure is assigned separately to each Planned Resource.
- The sum of the Maximum Post-Auction Credit Exposure nominated for each Planned Resource may not exceed the party's total available credit. Coupled Demand Resource Offers may not utilize the Credit Limited Offer functionality.

Section 5: RPM Auctions

Welcome to the *RPM Auctions* section of the ***PJM Manual for the Reliability Pricing Model***. In this section, you will find the following information:

- An overview description of the RPM Auctions (see "Overview of the RPM Auctions")
- The auction timeline for RPM Auctions (see "RPM Auction Timeline")
- The auction parameters for the RPM Auctions (see "RPM Auction Parameters")
- The business rules for sell offers in RPM (see "Sell Offers in RPM")
- The business rules for buy bids in RPM (see "Buy Bids in RPM")
- The requirements to offer in the PJM Energy Market (see "Energy Market Offer Requirements")
- The business rules for the Base Residual Auction (see "Base Residual Auction")
- The business rules for the Incremental Auctions (see "Incremental Auctions")
- The business rules for the auction clearing results (see "Auction Clearing Results")
- An overview description of the reliability backstop mechanism (see "Reliability Backstop")

5.1 Overview of RPM Auctions

The Reliability Pricing Model (RPM) is a multi-auction structure designed to procure resource commitments to satisfy the region's unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

Base Residual Auction - The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.

Incremental Auctions – Up to three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.

The Bilateral Market – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge determined as a result of the RPM Auction process. The bilateral market is facilitated through the eRPM system.

Effective for the 2007/2008 through 2011/2012 Delivery Years:

- *The First and Third Incremental Auctions* are conducted to allow for an incremental procurement of resource commitments when there is a decrease in the amount of committed resources due to a resource cancellation, delay, derating, EFORd increase, or a decrease in the nominated value of a Planned Demand Resource. The cost of procurement in these Auctions is allocated to resource providers that caused the need for additional resources to be procured.

- *The Second Incremental Auction* is conducted to allow for an incremental procurement of resource commitments when there is an increase in the region's unforced capacity obligation due to a load forecast increase. The cost of procurement in the Second Incremental Auction is allocated to LSEs through a Locational Reliability Charge.

Effective 2012/13 Delivery Year:

- *The First, Second, and Third Incremental Auctions* are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.
- *A Conditional Incremental Auction* may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

5.2 RPM Auction Timeline

The following Auction timeline provides the deadline for key RPM activities:

RPM Activity	Deadline
Data collected by MMU for Preliminary Market Structure Screen (MSS)	4 Months prior to the Base Residual Auction
Post results of Preliminary MSS	3 Months prior to the Base Residual Auction
Post Planning Parameters for BRA	3 Months prior to the Base Residual Auction
Data Submittal (Avoidable Cost Data, Opportunity Cost, & Projected Market Revenues) to MMU if submitting non-zero sell offer price for resource in LDA or Unconstrained LDA Group that fails Preliminary MSS	2 Months prior to the Base Residual Auction
MMU to notify Capacity Market Sellers of Market Seller Offer Caps	1 Month prior to the Base Residual Auction
Base Residual Auction	May, 3 years prior to the Delivery Year
Post Updated Planning Parameters for First Incremental Auction	1 Month prior to First Incremental Auction
First Incremental Auction	September, 20 months prior to the Delivery Year
Post Updated Planning Parameters for Second Incremental Auction	1 Month prior to Second Incremental Auction
Second Incremental Auction	July, 10 months prior to the Delivery Year

RPM Activity	Deadline
Final EFORd fixed for Delivery Year	By November 30th prior to the Delivery Year
Post Final Planning Parameters for Third Incremental Auction	1 Month prior to Third Incremental Auction
Third Incremental Auction	February, 3 months prior to the Delivery Year (for 2011/2012 and later)
ILR Certification[9]	3 months prior to the Delivery Year 2010/2011 2 months prior to the Delivery Year 2011/2012
Conditional Incremental Auction	As Needed

Exhibit 2: RPM Auction Timeline

5.3 RPM Auction Parameters

The following information shall be posted by PJM for each Base Residual Auction by February 1st prior to the commencement of the Base Residual Auction offer period:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Interruptible Load for Reliability (ILR) Forecasts for each modeled LDA (for Delivery Years prior to 2012/2013)
- Short Term Resource Procurement Target (for 2012/2013 and beyond)
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd
- Forecast Pool Requirement (FPR)
- Demand Resource (DR) Factor
- Reliability Requirements of the PJM Region and each modeled LDA
- Variable Resource Requirement (VRR) Curves of the PJM Region and each modeled LDA without FRR Entity adjustments. Adjusted VRR Curves with FRR Entity adjustments will be posted after FRR Capacity Plans are approved.
- CETO and CETL values for each modeled LDA
- Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements for the PJM Region and each Modeled LDA (for the 2014/2015 Delivery Year and beyond)
- Transmission Upgrades projected to be in service for the Delivery Year
- Bidding window schedule for the Base Residual Auction
- Cost of New Entry (CONE) for the PJM Region and each modeled LDA

[9] The ILR product is only valid in Delivery Years 2007/2008 through 2011/2012.

- Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
- Results of the Preliminary Market Structure Test
- Auction Credit Rate

Prior to the 2012/2013 Delivery Year, with the exception of the Preliminary PJM Region Peak Load Forecast and the Variable Resource Requirement Curves, the information above will continue to be posted and applicable for the First, Second, and Third Incremental Auctions for each Delivery Year. The Preliminary PJM Region Peak Load Forecast and the Variable Resource Requirement Curves are only used in the Base Residual Auction.

If the Second Incremental Auction is conducted, the following information shall be posted by PJM prior to the commencement of the offer period for the Second Incremental Auction:

- The Final PJM Region Peak Load Forecast
- The allocation to each zone of the incremental obligations resulting from the final forecast. Sell Offers in RPM

For the Delivery Year 2012/2013 and beyond, the amount of unforced capacity to be procured by PJM due to increase in Reliability Requirement or the amount to be released from the commitment due to a reduction in Reliability Requirement will be posted one month prior to the First, Second, or Third Incremental Auctions. The changes in the CETL values and the amount of unforced capacity to be procured for each LDA will be posted one month prior to an Incremental Auction.

5.3.1 Resource-Specific Sell Offer Requirements

Sell Offers for the Base Residual and Incremental Auctions must be submitted in PJM's eRPM system. Sell offers are only accepted during a fixed bidding window which is open for at least five (5) business days.[10] The bidding window for a Base Residual Auction and Incremental Auctions will be posted on the PJM website. Sell offers may not be changed or withdrawn after the bidding window for a Base Residual Auction or Incremental Auction is closed.

The following are business rules that apply to Resource-Specific Sell Offers:

- The smallest increment that may be offered into any auction is 0.1 MW
- A resource-specific sell offer will specify, as appropriate:
- Specific Generating Unit or Demand Resource
- Effective with the 2014/2015 Delivery Year, a demand resource with the potential to qualify as two or more product types may submit separate but coupled Sell Offers for each product type for which it qualifies at different sell offer prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution.. Separate resources will be modeled in the eRPM system for each product type. For coupled Sell Offers, the offer price of the Annual Demand Resource offer must be at least $.01/MW-day greater than the offer price of the coupled Extended Summer Demand Resource offer and the offer price of an Extended Summer Demand

[10] During the Transition Period, the bidding window may be less than five business days.

Resource must be at least $.01/MW-day greater than the offer price of the coupled Limited Demand Resource offer.

- Base Offer Segment minimum and maximum amount of installed capacity offered in MWs for the resource
- Base Offer Segment price willing to receive in $/MW-day (in UCAP terms)
- Regular Schedule, Self-Schedule or Flexible Self-Schedule flag
- EFORd to apply to the offered MWs (only applicable in the Base Residual Auction, First Incremental Auction, and Second Incremental Auction) for generation resources
- EFORd Offer Segment MW value (in ICAP terms) and price in $/MW-day (in UCAP terms) for generation resources[11]
- New Unit Pricing participation flag for generation resources
- The ICAP MW quantity specified in the Base Offer Segment or EFORd Offer Segment will be converted into an UCAP MW quantity by the sell offer EFORd for use in the auction clearing. The sell offer price specified in the Base Offer Segment or EFORd Offer Segment is in UCAP terms and will not be converted for use in the auction clearing.
- The Base Offer Segment may be offered as either a single price quantity for the capacity of the resource or divided into up to ten offer blocks with varying price-quantity pairs that represent various segments of capacity from the resource. The Base Offer Segment will consist of block segments at the specified price-quantity pairs.
- The seller specifies the EFORd to apply if participating in a Base Residual Auction, First Incremental Auction, or Second Incremental Auction.
- The EFORd cannot exceed the greater of the EFORd calculated based on outage data for 12 months ending September 30th prior to the Base Residual Auction, the 5 Year Average EFORd based on outage data for 12 months ending September 30th prior to the Base Residual Auction, or the EFORd submitted by the market participant in their Base Residual Auction Sell Offer.[12]
- The EFORd applied to the Third Incremental Auction will be determined by PJM using the forced outage data for the 12 months ending on September 30 prior to the Delivery Year.
- The seller may specify a single EFORd Offer Segment for their ownership portion of a specific resource.
- The EFORd Offer Segment will be an installed capacity MW quantity not to exceed the product of the resource's summer net capability of installed capacity and the potential increase in EFORd as determined in accordance with Section 6.7 (d) (iii) of Attachment DD of the PJM Tariff.[13]

[11] The EFORd segment was eliminated on March 27, 2009.
[12] Prior to March 27, 2009, the EFORd could not exceed the EFORd calculated based on outage data for 12 months ending September 30th prior to the auction.
[13] The EFORd segment was eliminated on March 27, 2009.

- The ICAP MW limit for the EFORd Offer Segment for a resource that is owned by multiple parties will be established pro rata based on ownership share of the resource.
- The seller is willing to accept the clearing of any amount equal to or greater than the minimum MW amount offered and equal to or less than the maximum MW offered.
- If the self-scheduled flag is enabled in the sell offer, the sell offer price must be set to zero and the minimum and maximum amounts specified in the sell offer must be equal.
- Units with Reliability Must Run (RMR) Contracts must offer their capacity in an RPM Auction with a sell offer price less than or equal to their avoidable cost. RMR units that do not have full year RMR contract must also offer the capacity into the auction. If the unit clears it would be expected to be in service for the entire delivery year. RMR payments will be reduced by the RPM auction credits.
- The acceptance of the sell offer is based on the party's Maximum Available ICAP Position at the opening of the auction's bidding window.
- If a participant has a positive Maximum Available ICAP Position, PJM only accepts a sell offer up to the Maximum Available ICAP Position.
- If a participant has a zero or negative Maximum Available ICAP Position, PJM will reject the sell offer.
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" as presented in the FRR Business Rules will be rejected.
- For Planned Resources and external resources without firm transmission, sell offers for which the RPM Credit Requirement exceeds the credit available will be rejected.
- All sell offers for a supplier that fails the Three-Pivotal Supplier Test will be capped within the mitigated LDA
- Cleared sell offers and offers receiving Make-Whole payments are binding commitments to provide capacity.

5.3.2 Flexible Self Scheduling

An LSE may specify offer segments as flexible self-scheduled in the Base Residual Auction to provide a mechanism to manage the quantity uncertainty related to the Variable Resource Requirement.

To specify a segment as a flexible self-scheduled segment, an LSE must specify the following:

- For each such segment, "flexible self-scheduled" must be selected as the offer type of the segment.
- A flexible self-schedule sell offer must specify an offer price that will be utilized in the market clearing in the event that the resource is not needed to cover the calculated capacity obligation. This is in addition to the data required of a self-schedule resource-specific sell offer.

- In conjunction with an offer of a flexible self-schedule segment, the LSE must also submit through eRPM a percentage of the Preliminary Zonal Peak Load Forecast in each transmission zone the LSE wishes to cover with self-scheduled and flexible self-scheduled resources. This percentage of the peak load forecast will be used to calculate the LSE's resulting capacity obligation through the auction clearing process that considers the Variable Resource Requirement.

If the same LSE offers both self-scheduled and flexible self-schedule segments to serve an Unforced Capacity Obligation within the same LDA, those segments that are self-scheduled will be used first to meet the obligation. The flexible self-scheduled segments will be automatically cleared in the auction if they are needed to supply the LSEs resulting capacity obligation. In the event that the LSE does not need all of the segments that were specified as flexible self-scheduled to meet its resulting capacity obligation, the RPM clearing function will consider the excess as offered into the market at the price specified with the flexible self-scheduled segment. The segments that are considered excess for this LSE will be those that have the highest specified offer prices.

5.3.3 New Entry Pricing

New Entry Pricing is an incentive provided to Planned Generation Resources where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are capped. New Entry Pricing allows Planned Generation Resources to recover the amount of their cost of entry-based offer for up to two additional consecutive years under certain conditions.

New Entry Pricing is applicable under the following conditions:

(1) The new entry must select the New Entry Pricing option at the time the sell offer into the initial BRA is submitted

(2) The capacity cleared from the new entry would move the total LDA resources cleared from below the LDA Reliability Requirement to a point on the VRR Curve where the price is less than or equal to 40% of the Net CONE divided by the quantity one minus pool-wide average EFORd

(3) The seller submits offers into the two following BRAs to sell the entire capacity of the unit at a price equal to the lesser of the price offered in the BRA where the resource was classified as planned generation; or 90% of the then-current Net CONE in UCAP basis.

New entry revenues:

(1) If the new entry meets the conditions in the previous rule and clears the market in Year 1, it sets the resource clearing price and receives revenues based on this price

(2) If the new entry clears its capacity in the two subsequent BRAs, it will receive revenues based on the clearing price.

(3) If the new entry does not clear, it will be resubmitted at the highest offer price at which the amount committed, including the any make-whole amount, for the first-year BRA will clear. The resource clearing price and the resources cleared will be determined from this clearing. The new entry will receive revenues based on the sell offer price submitted for the subsequent BRA in which it

cleared. The difference between the sell offer price and the clearing price and any difference between cleared quantity and committed quantity will be paid as a Resource Make-Whole payment to the new entry and the other capacity resources will receive the clearing price.

While the New Entry Pricing is effective, the LDA in which the New Entry was cleared will be modeled as an LDA in Years 2 and 3 regardless of the amount of LDA Capacity Emergency Transfer Limit margin over Capacity Emergency Transfer Objective in the PJM RTEP Process. After the New Entry Pricing period, the LDA will be maintained only if deemed necessary in the PJM RTEP Process.

Market Monitor's existing authority and review responsibilities shall include "New Entry Pricing." Market Monitor shall analyze and report on "New Entry Pricing" in the State of the Market Report.

5.3.4 Sell Offer Caps

<u>Preliminary Market Structure Screen (PMSS)</u>

- Four months prior to the Base Residual Auction, the PJM Market Monitoring Unit (MMU) will gather the following data for June 1 of the Delivery Year from the eRPM system to perform the PMSS.
- List of owned generating resources by participant and by transmission zone
- Gross amount of installed capacity owned by participant
- Effective EFORd
- Three months prior to the Base Residual Auction the MMU will post the results of the Preliminary Market Structure Screen.

<u>Submission of the Avoidable Cost Rate (ACR) Data</u>

- Two months prior to the Base Residual Auction participants in any LDA that failed the PMSS must submit the data specified in ***Section 6.7 of Attachment DD of the Open Access Transmission Tariff*** in order to submit a non-zero Sell Offer in the Base Residual Auction.
- Capacity resource owners must supply PJM with their avoidable cost data through the RPM Avoidable Cost Rate (ACR) System.
- The avoidable cost calculation is based on the categories of cost that are specified in ***Section 6.8 of Attachment DD of the Open Access Transmission Tariff.*** The calculation should be based on the annual costs that would be avoidable assuming the unit would otherwise retire.
- Where multiple units exist at a single plant, the plant's total avoidable costs shall be allocated to each individual unit in an appropriate manner. The sum of such costs assigned to each unit shall equal the total plant costs.
- The avoidable cost data should be for the 12 months preceding the month in which the data must be provided.
- For units that are jointly-owned, only one owner, typically the operator is expected to provide avoidable cost data and Projected PJM Market Revenues for the unit.

- All joint-owners of a unit can input their own bilateral revenues/costs, opportunity costs and transition adder.
- If a unit is not expected to be operational during the Delivery Year, no avoidable cost and opportunity cost data are required, but notice of status is required.

<u>Calculation of Sell Offer Caps</u>

- Sell offer caps shall be calculated as specified in Section 6.4 of Attachment DD of the Open Access Transmission Tariff.
- If a unit does not submit ACR data, specify an opportunity cost, default rate, or specify a transition adder in the RPM ACR System, the offer cap for that unit will be set to $0/MW-day.
- If no Projected PJM Market Revenues are submitted for a unit by a capacity resource owner, then PJM will use its own calculation of PJM Market Revenues in calculating the Sell Offer Cap of a unit.
- Sell Offer Cap(s) will be calculated by Market Participant, by unit, by segment.
- One month prior to the Base Residual Auction the MMU shall calculate and notify the Capacity Market Seller of their Sell Offer Cap consistent with Section 6 of Attachment DD of the Open Access Transmission Tariff. All unforced capacity of all existing Generation Capacity Resources shall be offered in the Base Residual Auction unless one of the following conditions is met:
- The resource is reasonably expected to be physically unable to participate in the relevant Delivery Year. The resource has a financially and physically firm commitment to an external sale of its capacity. The resource was interconnected to the Transmission System as an Energy Resource and not converted to a Capacity Resource.
- No offer caps are applied to sell offers of Planned Generation Resources.
- No offer caps are applied to sell offers of Demand Resources or Planned Energy Efficiency Resources.
- For the purposes of offer capping in the RPM Auctions, a resource not yet in operation shall be considered a planned resource for only the first RPM Auction that its' offer is cleared. The resource is considered a Existing Resource, for the purposes of offer capping, for any subsequent Auction except in the case of New Entry Pricing.

5.3.5 Minimum Offer Price Rule (MOPR)

The Minimum Offer Price Rule (MOPR) of Section 5.14(h) of Attachment DD of the PJM OATT applies to sell offers of certain planned generation capacity resources including planned upgrades of existing generation capacity resources. The MOPR does not apply to sell offers based on nuclear, coal, integrated gasification combined cycle, hydroelectric, wind or solar facilities. Also, the MOPR applies only to resources located in an LDA for which a separate VRR Curve is established and is applicable until the resource clears an RPM auction. For each Delivery Year, PJM determines the Net Cost of New Entry (CONE) for a combustion turbine generator and for a combined cycle generator. Unless a MOPR exception is requested and approved according to the process and timelines described below, a sell offer submitted in any BRA or Incremental Auction that is less than 90% of the applicable Net CONE shall be set equal to 90% of the applicable Net CONE. If there is no otherwise applicable asset class as described above and the sell offer is less than 70% of the Net CONE for a combustion turbine generator then the sell offer shall be set equal to 70% of the Net CONE for a combustion turbine generator.

A sell offer below the MOPR screen price shall be permitted and not be re-set if the capacity market seller obtains a determination from PJM prior to the RPM Auction that the seller offer is permissible because the offer is consistent with the competitive, cost-based, fixed net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. A capacity market seller wishing to offer below the MOPR screen price may request such a determination according to the MOPR exception process described below.

1) MOPR Exception Process Timelines

   a. Requests for exceptions must be submitted no later than 60 days prior to the start of an RPM auction. Requests must provide all relevant information and are submitted to both the IMM and PJM

   b. The IMM has 30 days from receipt of the request to make a determination regarding the exceptions and report its findings to the seller requesting the exception and PJM.

   c. If the seller does not agree with the IMM findings it may appeal to PJM to review its request for exception

   d. PJM has 45 days from the receipt of the exception request to notify the seller of its determination regarding the exception request. (15 days following the IMM determination)

2) Documentation Required in MOPR Exception Request

   The capacity market seller must include in its request for an exception documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as offsetting net revenues. The requests must include a certification, signed by an officer of the capacity market seller, that the claimed costs accurately reflect the seller's reasonable expected costs of new entry and that the request satisfies all standards for an exception. Supporting documentation of for project costs may include, as applicable and available, the following:

   - a complete project description;
   - environmental permits;
   - vendor quotes for plant or equipment;
   - evidence of actual costs of recent comparable projects;
   - bases for electric and gas interconnection costs and any cost contingencies;
   - bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs;

   - financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments;
   - the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling; and
   - identification and support for any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer.

The request also shall include all revenue sources relied upon in the sell offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period. In making such demonstration, the capacity market seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to PJM and the Market Monitoring Unit. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. The capacity market seller shall provide any additional supporting information requested by PJM or the Market Monitoring Unit to evaluate the selloOffer.

An evaluated sell offer shall be permitted if the information provided reasonably demonstrates that the sell offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the capacity market seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM to develop the minimum offer level. Capacity market sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the capacity market seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable PJM to make a determination will result in denial of an exception by PJM.

5.3.6 Qualified Transmission Upgrade Sell Offer Requirements

A Qualifying Transmission Upgrade sell offer will specify, as appropriate:

- Increase in CETL provided by the upgrade (maximum MW, as certified by PJM Transmission Planning Department)
- Minimum MW offered (min = max for upgrades that involve a single equipment upgrade, min could be less than max where participant is proposing multiple upgrades or upgrades to several pieces of equipment)
- Source and sink LDAs associated with the upgrade

- Price willing to receive for each segment in $/MW-day specified as the price difference between the sink LDA price and the source LDA price

The increase in CETL provided by a Qualifying Transmission Upgrade must be certified by PJM at least 45 days prior to the Base Residual Auction.

Cleared sell offers and offers receiving Make-Whole payments are binding commitments to provide capacity.

5.4 Buy Bids in RPM

Buy Bids for the Incremental Auctions must be submitted in PJM's eRPM system. Buy Bids are only accepted during a fixed bidding window which is open for at least five (5) business days. Buy Bids may not be changed or withdrawn after the bidding window for an Incremental Auction is closed.

A Buy Bid must specify:

- Quantify of unforced capacity resources desired, in increments of 0.1 MWs;
- Maximum price willing to pay for unforced capacity resources in $/MW-day;
- Type of unforced capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource (for 2014/2015 and beyond);
- Desired location (Locational Deliverability Area) for the replacement capacity.

Buy Bids may not specify a minimum MW amount. The Buy Bid may clear any MW amount equal to or less than the quantity of unforced capacity resources desired in the Buy Bid.

In the event of a delay or cancellation of a Qualifying Transmission Upgrade, the Buy Bid will specify the purchase of capacity resources in the LDA for which the Qualifying Transmission Upgrade was to increase the CETL (Sink LDA).

Cleared Buy Bids are binding commitments to purchase capacity.

5.5 Energy Market Offer Requirements

All generation resources that have an RPM Resource Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources that have an RPM Resource Commitment must be registered in the Full Program Option of the Emergency Load Response Program and thus available for dispatch during PJM-declared emergency events. Please refer to the ***Manual for Scheduling Operations (M-11)*** for details on PJM Energy Market participation.

5.6 Base Residual Auction

The Reliability Pricing Model includes a single Base Residual Auction for each Delivery Year. A Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Base Residual Auctions are conducted in accordance with the auction schedule posted on the PJM website.

5.6.1 Participation in the Base Residual Auction

Products that resource providers can offer into PJM's Base Residual Auction include:

- Existing generation

- Planned generation
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources
- Qualifying Transmission Upgrades

Existing Generation in a party's RPM Resource Portfolio that have available capacity to offer and are not offered into the Base Residual Auction for the Delivery Year shall be excluded from participation in any and all Incremental Auctions conducted for the Delivery Year. Generation is treated as existing when the generation is (a) in service at the commencement of the Base Residual Auction or (b) not yet in service but has cleared in an RPM Auction for any prior Delivery Year. These unoffered MWs from existing generation resources shall be ineligible to serve as capacity resources on behalf of any RPM entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts for generation and demand resources.

The following are business rules that apply to the Base Residual Auction:

- Existing generation, existing Demand Resources, and Energy Efficiency Resources that have CAP MOD, DR MOD, or EE MOD increases that are approved after the Base Residual Auction are eligible to offer the capacity increase into an Incremental Auction for the Delivery Year if the CAP MOD, DR MOD, or EE MOD increase is approved prior to the opening of the Incremental Auction bidding window.
- For the Base Residual Auction, a party's Current, Minimum and Maximum Available ICAP Position for a specific unit are equal to the minimum of (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for the Delivery Year.

$$AvailICAPPosition_{Gen\,unit} = MinimumDailyValue_{forDY}(DailyICAPOwned - DailyFRRCapPlanCommitments)$$

- For the Base Residual Auction, a party's Available ICAP Position for a demand resource is equal to the minimum of (Daily Nominated DR Value – Daily FRR Capacity Plan Commitments) for the Delivery Year.

$$AvailICAPPosition_{DR} = MinDailyValue_{forDY}(DailyNomDRValue - DailyFRRCapPlanCommitments)$$

- Following a Base Residual Auction, a party's Daily Unoffered ICAP for a generation resource or demand resource is calculated and is equal to the Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$DailyUnofferedICAP_{GenorDR} = AvailICAPPosition - OfferedICAP$$

- Resources may be directly offered into the Base Residual Auction by specifying a MW quantity and sell offer price in the sell offer or may be self-scheduled into the Base Residual Auction by enabling the self-schedule flag in the sell offer. See the Resource-Specific Sell Offer Requirements Section for further details.
- The product offered in the Base Residual Auction must be resource-specific or apply to a Qualifying Transmission Upgrade.

- The smallest increment that may be offered into a Base Residual Auction is 0.1 MW.

5.6.2 Auction Clearing Mechanism – Base Residual Auction

The Base Residual Auction clearing software is an optimization algorithm. This algorithm has the objective of minimizing capacity procurement costs given the supply offers, Variable Resource Requirement Curve(s), Locational Constraints, and starting with June 1, 2014, the Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements . All self-scheduled resources in the Base Residual Auction will automatically clear at their maximum MW amount specified in the sell offer. The Base Residual Auction clearing price for each LDA is determined by the optimization algorithm. The Resource Clearing Price within each LDA is the sum of:

- The marginal value of system capacity and
- Annual Resource Price Adder, if any, and
- Extended Summer Price Adder, if any, and
- Locational Price Adder(s), if any relevant to such LDA.

The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Price Adder is applicable for Annual Resources and Extended Summer DR..

In the event that the Sell Offers forming the supply curve do not result in an intersection with the Variable Resource Requirement Curve, the marginal value of system capacity will be set along the Variable Resource Requirement Curve by extending the supply curve vertically from its end point until it intersects the Variable Resource Requirement Curve.

5.6.3 Resource Make-Whole Payments in the Base Residual Auction

Only the resource provider that offered and cleared fewer MWs than the minimum MW specification in the Base Residual Auction would receive a Resource Make-whole payment.

The Resource Make-whole Payment is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the Base Residual Auction.

$$ResourceMakewholePayment = ResourceClearingPrice \times (SellOfferMinMW - ClearedMW_{BRA})$$

Make-whole payments required in the BRA will be charged to all LSEs in the LDA via the Final Zonal Capacity Price.

Only cleared Qualifying Transmission Upgrades, cleared resource-specific sell offers, and cleared flexible self-scheduled offers in excess of their self-scheduled quantity are eligible for make-whole payments in the BRA.

5.6.4 Posting of Base Residual Auction Results

Base Residual Auction results are posted to a participant's eRPM account and summary results are posted to a public portion of the PJM website. For any Base Residual Auction, clearing results will not be posted until after 4 p.m. EPT on Friday of Auction Clearing week

Participants can view the resolution of their sell offer in the BRA through eRPM. The results of their sell offer will be categorized as cleared, uncleared, offered, unoffered, or make-whole.

Base Residual Auction sales are credited monthly during the Delivery Year as the unforced capacity is actually utilized.

5.7 Incremental Auctions

Prior to the 2012/2013 Delivery Year, the Reliability Pricing Model can include up to three Incremental Auctions in advance of each Delivery Year.

The First and Third Incremental Auctions allow for an incremental procurement of resource commitments for a decrease in the value of resource commitments due to:

- A resource cancellation
- A resource delay
- A generation resource derating
- EFORd increase for a generation resource
- Decrease in the nominated value of a Planned Demand Resource or
- Delay or cancellation of Qualifying Transmission Upgrade.

The Second Incremental Auction may be conducted to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase.

Effective 2012/13 Delivery Year:

- *The First, Second, and Third Incremental Auctions* are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.
- *A Conditional Incremental Auction* may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

5.7.1 Participation in the Incremental Auctions

Existing generation in a party's RPM Resource Portfolio that have available capacity to offer and are not offered into an Incremental Auction for the Delivery Year shall be excluded from participation in any subsequent Incremental Auctions conducted for the Delivery Year. Generation is treated as existing when the generation is (a) in service at the commencement of the Incremental Auction or (b) not yet in service but has cleared an RPM Auction for any prior Delivery Year. These unoffered MWs from existing generation shall be ineligible to serve as capacity resources on behalf of any entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts of generation and demand resources.

Products that resource providers can offer into an Incremental Auction include:

- Existing generation that was offered and not cleared in a prior auction for the same Delivery Year
- Planned generation

- Existing Demand Resources or Energy Efficiency Resources that were offered and not cleared in a prior auction for the same Delivery Year
- Planned Demand Resources or Energy Efficiency Resources
- Transmission upgrades are not eligible to be offered into Incremental Auctions. (*Transmission upgrades are only eligible to be offered into Base Residual Auction*)

The following are business rules that apply to the Incremental Auctions:

- The product offered in the Incremental Auction must be resource-specific.
- The smallest increment that may be offered into an Incremental Auction is 0.1 MW.
- Planned generation Planned Demand Resources, or Energy Efficiency Resources that were not eligible to participate at the time of the Base Residual Auction or prior Incremental Auction, are eligible to participate in subsequent Incremental Auctions if the planned generation, Planned Demand Resource, or Energy Efficiency Resource meets the requirements specified in Section 4 of this manual.
- Existing generation and existing Demand Resources or Energy Efficiency Resources that have CAP MOD increases, DR MOD increases, or EE MOD increases that are provisionally approved or approved after an Incremental Auction are eligible to offer the capacity increase into a subsequent Incremental Auction for the Delivery Year if the CAP MOD, DR MOD, or EE MOD increase is provisionally approved or approved prior to the opening of the subsequent Incremental Auction bidding window.
- For Incremental Auctions, a Current Available ICAP Position, Minimum Available ICAP Position, and Maximum Available ICAP Position are calculated.

A party's Current Available ICAP Position on a unit for an Incremental Auction is equal to the minimum Daily Available ICAP for such unit during the Delivery Year.

$$CurrentAvailableICAPPosition_{unit} = Min(DailyAvailableICAP)$$

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP – (Daily RPM Resource Commitments/(1-Effective EFORd)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP = DailyICAPOwned - DailyUnofferedICAP - \left(\frac{DailyRPMResourceCommitments}{1 - EffectiveEFORd}\right) - DailyFRRCapacityPlanCommitments$$

A party's Minimum Available ICAP Position represents the minimum amount that must be offered into an RPM Auction. A party's Minimum Available ICAP Position on a unit for an RPM Auction is equal to the *minimum* Daily Minimum Available ICAP for such unit during the Delivery Year.

$$MinimumAvailableICAPPosition_{unit} = Min(DailyMinAvailableICAP)$$

A party's Daily Minimum Available ICAP is equal to Daily ICAP Owned minus the Daily Unoffered ICAP minus Daily Cleared ICAP in RPM Auctions minus Daily FRR Capacity Plan Commitments. Daily Cleared UCAP in RPM Auctions is converted to Daily Cleared ICAP using the greater of the EFORd $_{1yr}$ at the time of the Base Residual Auction, EFORd $_{5yr}$ at

the time of the Base Residual Auction, or the party's Sell Offer EFORd from the Base Residual Auction.

$$DailyMinAvailableICAP = DailyICAPOwned - DailyUnofferedICAP - \left[\frac{DailyClearedUCAP}{(1 - Max(\text{BRA EFORd 1yr}, \text{BRA EFORd 5yr}, \text{BRA SellOfferEFORd}))}\right] - DailyFRRCapacityPlanCommitments$$

A party's Maximum Available ICAP Position represents the maximum amount that a participant may offer into an RPM Auction. A party's Maximum Available ICAP Position on a unit for an RPM Auction is equal to the *minimum* Daily Maximum Available ICAP for such unit during the Delivery Year.

$$MaximumAvailableICAPPosition_{unit} = Min(DailyMaxAvailableICAP)$$

A party's Daily Maximum Available ICAP is equal to Daily ICAP Owned minus the Daily Unoffered ICAP minus Daily Cleared ICAP in RPM Auctions minus Daily FRR Capacity Plan Commitments. Daily Cleared UCAP in RPM Auctions is converted to Daily Cleared ICAP using a zero EFORd.

$$DailyMaxAvailableICAP = DailyICAPOwned - DailyUnofferedICAP - \left[\frac{DailyClearedUCAP}{(1-0))}\right] - DailyFRRCapacityPlanCommitments$$

For the Third Incremental Auction, a party's Minimum Available ICAP Position and Maximum Available ICAP Position for a unit will be equal to the party's Current Available ICAP Position for such unit.

A party's Daily Unoffered ICAP for a specific unit is calculated by adding the sum of any Daily Unoffered ICAP for such unit in prior RPM Auctions to Daily Unoffered ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

$$DailyUnofferedICAP_{GenResource} = \sum(DailyUnofferedICAP_{FromPriorRPMAuctions} + UnofferedICAPBilateralSales/Purchases$$

For an Incremental Auction, a party's Daily Unoffered ICAP for generation resource is equal to the Minimum Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$DailyUnofferedICAP_{Gen} = MinimumAvailableICAPPosition - OfferedICAP$$

For an Incremental Auction, the party's Available ICAP Position for a specific demand resource is equal to the minimum Daily Available ICAP for such demand resource during the Delivery Year.

$$AvailableICAPPosition_{DemandResource} = Min(DailyAvailableICAP)$$

The Daily Available ICAP for a specific demand resource is equal the resource's Daily Nominated DR Value – Daily Unoffered ICAP - ((Daily RPM Resource Commitments/(DR Factor *Forecast Pool Requirement)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP_{DR} = DailyNominatedDRValue - DailyUnofferedICAP - \left(\frac{DailyRPMResourceCommitments}{DRFactor \times FPR}\right) - DailyFRRCapPlanCommitments$$

A party's Daily Unoffered ICAP for a specific demand resource is calculated by adding the sum of any Daily Unoffered ICAP for such demand resource in prior RPM Auctions.

For an Incremental Auction, a party's Daily Unoffered ICAP for a demand resource is equal to the Available ICAP Position for the demand resource minus the Offered ICAP in the party's sell offer.

$$DailyUnofferedICAP_{DR} = AvailableICAPPosition - OfferedICAP$$

5.7.2 Timing of the Incremental Auctions

Prior to the 2012/2013 Delivery Year:

The First Incremental Auction is held during the month of June twenty-three (23) months prior to the start of the Delivery Year. The First Incremental Auction provides an opportunity for an incremental procurement of resource commitments to satisfy a decrease in the amount of committed resources due to resource cancellations, delay, derating, EFORd increase or decrease in the nominated value of a Planned Demand Resource, or delay or cancellation of a Qualifying Transmission Upgrade.

Fifteen (15) months prior to the start of the Delivery Year, PJM performs a reliability assessment to compare the original unforced capacity obligation procurement plus any capacity receiving a Make-whole Payment in the Base Residual Auction, to the PJM Region Reliability Requirement based on the Final RTO Peak Load Forecast, less the Forecast RTO ILR Obligation less Preliminary Unforced Capacity Obligation of the FRR Entities. If PJM determines that an unforced capacity resource shortage exceeds 100 MW of unforced capacity, then the Second Incremental auction will be held to commit the necessary incremental capacity. The costs of such incremental procurement of capacity resources shall be recovered by adjusting the Preliminary Zonal Capacity Prices determined from the Base Residual Auction.

The Second Incremental Auction is held during the month of April thirteen (13) months prior to the start of the Delivery Year. The Second Incremental Auction is held ONLY if PJM determines that an unforced capacity resource shortage for the entire PJM region exceeds 100 MW due to a higher load forecast. If the Second Incremental Auction is deemed necessary, the auction will be held to commit the necessary incremental capacity.

The Third Incremental Auction is held during the month of January four (4) months prior to the start of the Delivery Year. The Third Incremental Auction provides an opportunity for the incremental procurement of resource commitments to satisfy a decrease in the amount of committed resources due to resource cancellations, delay, derating, EFORd increase, decrease in the nominated value of a Planned Demand Resource, or delay or cancellation of a Qualifying Transmission Upgrade.

For the 2012/2013 Delivery Year and beyond:

The First Incremental Auction is held during the month of September, twenty (20) months prior to the start of the Delivery Year.

The Second Incremental Auction is held during the month of July, ten (10) months prior to the start of the Delivery Year.

The Third Incremental Auction is held during the month of February, three (3) months prior to the start of the Delivery Year.

Incremental Auctions are conducted in accordance with the auction schedule posted on the PJM website.

5.7.3 Resource Make-Whole Payments in Incremental Auctions

Only the resource provider that offered and cleared fewer MWs than its minimum MW specification in an RPM Auction would receive a resource make-whole payment. This situation occurs because of the minimum MW specification in the sell offer data. This can occur at most for one resource in each LDA and for a one resource in the unconstrained market region.

The Resource Make-whole Payment is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the Auction. Make-whole payments required in the Auction will be charged to all cleared buy bids on pro-rata basis based on the MWs cleared in such auction. Only cleared resource-specific sell offers are eligible for make-whole payments in an Incremental Auction.

Make-whole charges assessed to buy bids cleared by PJM will be assessed to LSEs in the LDA via the Final Zonal Capacity Price.

5.7.4 Allocation of Costs in Incremental Auctions

Effective through the 2011/2012 Delivery Year:

The costs of the incremental commitments that are cleared in the First and Third Incremental Auctions are allocated to resource providers that cleared Buy Bids in that Incremental Auction.

The costs of the incremental procurement of capacity resources from the Second Incremental Auction shall be recovered by adjusting the Preliminary Zonal Capacity Prices.

Effective 2012/2013 and forward:

The costs of the incremental commitments that are cleared in Incremental Auctions are allocated to resource providers that cleared Buy Bids in that Incremental Auction based on the cleared Buy Bid MW quantity and the clearing price and to LSEs by adjusting the Zonal Capacity Price.

5.7.5 Auction Clearing Mechanism – Incremental Auctions

The clearing of the Incremental Auctions is determined by the intersection of the supply curve and the demand curve. In the event the Sell Offers forming the supply curve do not intersect with the Buy Bids forming the demand curve, one of the following will occur:

(1) The clearing will be set along the demand curve by extending the supply curve vertically upward from its end point unit it intersects the demand curve, or

(2) The clearing will be set along the supply curve by extending the demand curve vertically downward from its end point until it intersects the supply curve, or

If no intersections occur as a result of the supply curve extension or the demand curve extension, no capacity will be cleared in the Incremental Auction. The Incremental Auction clearing prices for each Buy Bid or Sell Offer cleared is determined by the same optimization algorithm used in the Base Residual Auction clearing. The Resource Clearing Price within an LDA is equal to the sum of:

- The marginal value of system capacity and

- Annual Resource Price Adder, if any, and
- Extended Summer Price Adder, if any, and
- The Locational Price Adder(s), if any relevant for such LDA.

The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Price Adder is applicable for Annual Resources and Extended Summer DR .

The First, Second, and Third Incremental Auction clearing software is an optimization algorithm. The algorithm has the objective of minimizing the cost of committing capacity for the submitted Buy Bids given the Locational Constraints, Minimum Annual Resource Requirements, Minimum Extended Summer Resource Requirements and submitted supply offers.

5.7.6 Posting of Incremental Auction Results

The Incremental Auction results are posted to a participant's eRPM account and summary results are posted to a public portion of the PJM website. For any Incremental Auction, clearing results will not be posted until after 4 p.m. EPT on Friday of Auction Clearing week.

Participants may view the resolution of their sell offer in the Incremental Auction through eRPM. The results of their sell offer will be categorized as cleared, offered, unoffered, or make-whole.

Incremental Auction purchases/sales are charged/credited monthly during the Delivery Year.

5.8 Auction Clearing Results

5.8.1 Zonal Capacity Prices

Zonal Capacity Prices for a Delivery Year are calculated following the Base Residual Auction for the Delivery Year and are adjusted following each Incremental Auction for the Delivery Year (for Delivery Years prior to the 2012/2013 Delivery Year, Zonal Capacity Prices are only adjusted following the Second Incremental Auction).

Preliminary Zonal Capacity Prices are calculated and posted following the Base Residual Auction for each Delivery Year. The Preliminary Zonal Capacity Price for each Zone is the sum of:

(1) The marginal value of system capacity for the PJM Region;

(2) The Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA);

(3) An adjustment, if any, to account for adders paid to Annual Resources and Extended Summer DR in the LDA for which the zone is located (effective for the 2014/2015 Delivery Year); and

(4) An adjustment in the Zone, if required, to account for any resource make-whole payments.

Make-whole payments are allocated to the entire obligation associated with the area in which the resource is cleared. If the resource clears in the unconstrained area, the make-whole payment is allocated to the entire RTO obligation. If the resource that is made whole

clears in located in a constrained LDA, the make-whole payment is allocated to the entire obligation of the constrained LDA.

The following are business rules that apply to the Preliminary Zonal Capacity Prices:

- The Weighted Zonal Capacity Price for a Zone that includes multiple non-overlapping LDAs is the weighted average of the Zonal Capacity Prices for such LDAs, weighted by the Unforced Capacity of Resources Cleared (including Make whole MW) in each such LDA. If the Zone has a smaller LDA within a larger LDA then the Weighted Zonal Capacity Price is calculated using the smaller LDA and the remaining portion of the larger LDA.
- The Locational Price Adder is an addition to the marginal value of unforced capacity within an LDA as necessary to reflect the price of resources required to relieve the applicable binding locational constraints.
- A Locational Price Adder shall not be a negative number.

Preliminary Zonal Capacity Prices for the Delivery Year are posted by PJM at the end of the Base Residual Auction clearing process.

- Zonal Capacity Prices for a Delivery Year are adjusted following each Incremental Auction for the Delivery Year (for Delivery Years prior to the 2012/2013 Delivery Year, Zonal Capacity Prices are only adjusted following the Second Incremental Auction).
- The Adjusted Zonal Capacity Prices for each Zone is the sum of:

  (1) The average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity);

(2) The average Locational Price Adder, if any, weighted by the Unforced Capacity cleared in all auctions previously conducted for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity);

(3) An adjustment, if any, to account for adders paid to Annual Resources and Extended Summer DR for all auctions previously conducted for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); and

(4) An adjustment, if required, to account for any resource make-whole payments for all auctions previously conducted for the Delivery Year (excluding any resource make-whole payments to be charged to the buyers of replacement capacity).

Adjusted Zonal Capacity Prices for the Delivery Year are posted by PJM with the Second Incremental Auction clearing results for Delivery Years prior to and including the 2011/2012 Delivery Year. Effective for the 2012/2013 Delivery Year, Adjusted Zonal Capacity Prices for the Delivery Year are posted following each Incremental Auction for that Delivery Year.

The Final Zonal Capacity Prices reflect the final price adjustments that are necessary to account for potential changes in the unforced value of the Interruptible Load for Reliability (ILR) resources certified for the Delivery Year in comparison to the Forecast RTO ILR Obligation (prior to the 2012/2013 Delivery Year) and for potential decreases in RPM Auction Credits to existing demand resources that were granted relief from Capacity Resource Deficiency Charges due to permanent departure of load.

The Final Zonal Capacity Prices are calculated such that the total amount of payments received by CTR holders, Incremental CTR Holders, certified ILR resources, resources cleared for LSEs in all RPM Auctions for a given Delivery Year , and the Qualifying Transmission Upgrades cleared in the Base Residual Auction equals to the total amount of Locational Reliability Charges assessed to loads. The Final Zonal Capacity Price is not net of the Final Zonal CTR Credit Rate.

The ***Final Zonal Capacity Prices*** for the Delivery Year are posted by PJM after the ILR resources are certified for Delivery Years prior to and including the 2011/2012 Delivery Year. Effective for the 2012/2013 Delivery Year, ***Final Zonal Capacity Prices*** for the Delivery Year are posted following the Third Incremental Auction for that Delivery Year.

5.8.3 CTR Credit Rates

The Base Zonal CTR Credit Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of the Base Residual Auction divided by the Base Zonal UCAP Obligation.

$$BaseZonalCTRCreditRate_{(\$/MW-Day)} = \frac{EconomicValueofCTRs_{AllocatedtoLSEsinBRA}}{ZonalUCAPObligation}$$

The ***Base Zonal CTR Credit Rate*** is posted with the Base Residual Auction results.

The Final Zonal CTR Credit Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of all RPM Auctions for the Delivery Year divided by the Final Zonal UCAP Obligation.

$$FinalZonalCTRCreditRate(\$/MW-day) = \frac{EconomicValueofCTRs_{AllocatedtoLSEsinthBRAnd2ndIA}}{FinalZonalUCAPObligation}$$

The Final Zonal CTR Credit Rates are posted by PJM with the Second Incremental Auction clearing results.

5.8.4 CTR Settlement Rates

The CTR Settlement Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of all RPM Auctions for a Delivery Year divided by the Total CTR MWs allocated to LSEs

$$CTRSettlementRate_{(\$/MW-day)} = \frac{EconomicValueofCTRs_{AllocatedtoLSEsintheBRAnd2ndIA}}{TotalCTRMWs_{AllocatedtoLSEs}}$$

The CTR Settlement Rates are posted by PJM with the Second Incremental Auction clearing results.

5.8.5 Zonal ILR Prices[14]

Preliminary Zonal ILR Price is calculated by subtracting the Base Zonal CTR Credit Rate from the Preliminary Zonal Capacity Price.

$$PrelimZonalILRPrice = PrelimZonalCapPrices - BaseZonalCTRCreditRate$$

The ***Preliminary Zonal ILR Prices*** are posted by PJM with the Base Residual Auction clearing results.

Final Zonal ILR Price is calculated by subtracting the Final Zonal CTR Credit Rate from the Adjusted Zonal Capacity Price.

$$FinalZonalILRPrice = AdjustedZonalCapPrice - FinalZonalCTRCreditRate$$

The ***Final Zonal ILR Prices*** are posted by PJM with the Second Incremental Auction clearing results.

5.9 Reliability Backstop

The Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by:

- Lack of sufficient capacity committed through the RPM Auctions or
- Near-term transmission deliverability violations identified after the Base Residual Auction is conducted

The purpose of the Reliability Backstop is to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The Reliability Backstop mechanism is based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources committed as a result of the RPM Auctions.

Details on the Reliability Backstop, including the triggering conditions and auction clearing procedures, can be found in ***Section 16 of Attachment DD of the Open Access Transmission Tariff.***

[14] ILR Prices are only applicable for the 2007-2008 through 2011/2012 Delivery Years

Section 6: Capacity Transfer Rights

Welcome to the *Capacity Transfer Rights* section of the PJM Manual for the *Capacity Market*. In this section, you will find the following information:

- The definition and purpose of Capacity Transfer Rights (see "Definition and Purpose of Capacity Transfer Rights")
- The business rules for determining Capacity Transfer Rights (see "Determination of Capacity Transfer Rights"
- The business rules for allocation of Capacity Transfer Rights (see "Allocation of Capacity Transfer Rights")
- The business rules for determining Capacity Transfer Right credits (see "Capacity Transfer Rights Credits")
- The business rules for transferring Capacity Transfer Rights (see "Capacity Transfer Rights Transfer")

6.1 Definition and Purpose of Capacity Transfer Rights

The purpose of Capacity Transfer Rights is to allocate the economic value of transmission import capability that exists into a constrained LDA to holders of Capacity Transfer Rights. Therefore, Capacity Transfer Rights serve to offset a portion of the Locational Price Adder charged to load in constrained LDAs.

As explained in Sections 3 and 4 constrained Locational Deliverability Areas (LDAs) are modeled with their own VRR curves in the auction clearing process. The transmission import capability limit into a constrained LDA would require clearing resources with higher offer prices in the LDA (but at less than the prices on the LDA VRR Curve) to achieve the highest possible reliability in the LDA. This process would typically result in a price separation with LDA clearing price being higher than the unconstrained RTO clearing price. The Zonal Capacity Prices calculated in the constrained LDA would also be higher as they are a function of this higher clearing price. LSE Locational Reliability Charge in a zone is the LSE unforced capacity obligation multiplied by the Zonal Capacity Price. However, part of the LSE unforced capacity obligation is met by imported resources that receive auction credits at a lower price than the LDA clearing price. The credit to account for these lower-priced imported resources is achieved by allocating Capacity Transfer Rights (CTRs) to LSEs. CTRs would amount to dollar credits that would reduce the LSE load charges.

It is important to note that the LDA Reliability Requirement (based on the internal generation and CETO) used in the clearing process is typically higher than the unforced capacity obligation (based on coincident peak load) used for load charges and the CTR determination. Since the concept of CTRs is to provide credit towards the portion of the obligation met by imported resources, CTRs are calculated as the difference between the zonal (LDA) unforced capacity obligation and [the unforced capacity cleared in the zone (LDA) plus the zonal (LDA) ILR forecast prior to 2012/2013 Delivery Year or Short-Term Resource Procurement Target starting from 2012/2013 Delivery Year]. The total CTRs are typically lower than the LDA import capability (CETL) while the CETL is fully utilized in meeting the LDA Reliability Requirement and calculating the LDA clearing price. LSEs in the

constrained LDA benefit when the CETL into the LDA is increased by transmission upgrades.

A transmission upgrade may be funded by a New Service Customer (or, for facilities or upgrades in PJM queue prior to March 1, 2007 to an Interconnection customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade. In this case, the customer is allocated Incremental CTRs (Participant-Funded Project ICTRs). Alternately, a transmission upgrade may be offered as a Qualified Transmission Upgrade (QTU) in the Base Residual Auction. A cleared QTU will receive auction credits.

Effective 2012/2013 Delivery Year, Incremental Capacity Transfer Rights associated with Regionally Assigned Facilities (i.e., Regional Project ICTRs) will be allocated to Responsible Customers to whom the costs of the Regionally Assigned Facilities are assigned.

In these cases the total CTRs are reduced to provide credits to these parties before distributing the CTRs to LSEs.

6.1.1 Capacity Transfer Rights

The following are business rules that apply to Capacity Transfer Rights:

- Capacity Transfer Rights are applicable only for the Delivery Year for which they were defined.
- Capacity Transfer Rights are specified to the nearest 0.1 MW.
- Prior to the 2012/13 Delivery Year, the total amount of Capacity Transfer Rights that are allocated to LSEs in an LDA are equal to the total Base Unforced Capacity Imported into such LDA in the Base Residual Auction for the Delivery Year less the Incremental Capacity Transfer Rights that are allocated into the LDA for the Delivery Year less the amount of import capability increase into the LDA attributed to Qualifying Transmission Upgrades for the Delivery Year.
- Effective 2012/13 Delivery Year and beyond, the total amount of Capacity Transfer Rights that are allocated to LSEs in an LDA are equal to the total Base Unforced Capacity Imported into such LDA in the Base Residual Auction for the Delivery Year less [the Participant-Funded ICTRs and Regional Project ICTRs that are allocated into the LDA for the Delivery Year less the amount of import capability increase into the LDA attributed to Qualifying Transmission Upgrades for the Delivery Year].
- Capacity Transfer Rights (CTRs) will be allocated in MWs across each Locational Constraint that is modeled in the Base Residual Auction for a Delivery Year.

The economic value (in $/day) of Capacity Transfer Rights, as a result of the Base Residual Auction, is equal to:

i. The Locational Price Adder in the Base Residual Auction, of the LDA for which the Capacity Transfer Rights are associated minus the Locational Price Adder for the LDA from which Unforced Capacity is imported, multiplied by

ii. The megawatt amount of the Capacity Transfer Right.

Prior to the 2012/13 Delivery Year, for an LDA that is import limited in the Second Incremental Auction, the economic value of Capacity Transfer Rights associated with such

LDA is calculated as follows. The economic value (in $/day) of the Capacity Transfer Rights are equal to the Locational Price Adder in the Second Incremental Auction of the LDA for which the Capacity Transfer Rights are associated minus the Locational Price Adder in the LDA from which unforced capacity is imported, times the MW amount of the Capacity Transfer Rights, multiplied by the increase in Unforced Capacity Imported into such LDA in the Second Incremental Auction compared to the Base Residual Auction, divided by the Base Unforced Capacity Imported into such LDA.

Effective starting with the 2012/13 Delivery Year, for an LDA that is import limited in any Incremental Auction, the economic value of Capacity Transfer Rights associated with such LDA is calculated as follows: The economic value (in $/day) of the Capacity Transfer Rights are equal to the difference between the charges for the incremental Daily Unforced Capacity Obligation and the credits to be paid to the incremental Unforced Capacity cleared in the LDA plus incremental Unforced Capacity imported.

6.1.2 Participant-Funded Project Incremental Capacity Transfer Rights

Incremental Capacity Transfer Rights are allocated to a New Service Customer (or, for facilities or upgrades in PJM queue prior to March 1, 2007 to an Interconnection customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade, to the extent such upgrade or facility increases the import capability into an LDA. Such incremental Capacity Transfer Rights allocation is based on the incremental increase in import capability across a Locational Constraint that is caused by the transmission facility upgrade.

Incremental Capacity Transfer Rights will be effective for thirty years or the life of the facility or upgrade, whichever is less. Under conditions when the internal resources cleared in the LDA are high, the total amount of Capacity Transfer Rights is limited. The Incremental Capacity Transfer Rights will be limited to the total amount of Capacity Transfer Rights.

If a customer funds advancement of a network transmission upgrade, the customer will receive Incremental CTRs for the years the upgrade is advanced based on the incremental CETL into a constrained LDA as certified by PJM. The customer should request PJM to certify the Incremental CTRs due to an advancement of a network transmission upgrade at least 90 days prior to the Base Residual Auction.

An equivalent Incremental Capacity Transfer Right will be calculated using the Weighted Zonal Resource Clearing Price if the sink LDA of the Incremental Capacity Transfer Right is a sub-zone.

An equivalent import capability will be calculated using the Weighted Zonal Resource Clearing Price if the sink LDA of a Qualifying Transmission Upgrade is a sub-zone.

Participants must request PJM to certify the Incremental CTRs into the constrained LDAs modeled in RPM at least 90 days prior to the Base Residual Auction. PJM will certify the Incremental CTRs into the constrained LDA at least 45 days prior to the Base Residual Auction.

6.1.3 Regional Project Incremental Capacity Transfer Rights

"Regionally Assigned Facilities" are RTEP transmission upgrade projects 500 kV or higher. "Responsible Customers", as defined in Schedule 12 of the Tariff, are Network Customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners that are assigned cost responsibility for a Regional Assigned Facility.

Effective 2012/2013 Delivery Year, ICTRs associated with Regionally Assigned Facilities are determined and allocated to Responsible Customers. The allocation will be for the first Delivery Year for which such the facilities are to be in service and based on the facility costs allocated to the Responsible Customers. The ICTRs are available for allocation for 30 years or the life of the project, whichever is less. The ICTRs are re-allocated annually to reflect the annual recalculation of Transmission Enhancement Charges under section (c) of Schedule 12.

PJM determines the increase in CETL into an applicable LDA as a result of the Regionally Assigned Facilities planned for the Delivery Year. The increase in the CETL represents the ICTRs into the LDA. If a project increases CETL into multiple LDAs, PJM will calculate 'simultaneous' increases in CETL into the LDAs. These increases in the CETL represent the ICTRs into the multiple LDAs.

During the Delivery Year, each Network Customer (LSE) within a zone will be allocated a share of the zone's Regional Project ICTRs in proportion to the customer's share of the zonal NSPL. These allocations may change day to day as end-use customers change from LSE to LSE.

ICTRs may be traded similar to CTRs.

The economic value of ICTRs may change from year to year and will become zero when the LDA into which the ICTRs exist is not constrained.

6.2 Determination of Capacity Transfer Rights

Prior to the 2012/13Delivery Year, the total amount of Capacity Transfer Rights that are allocated to LSEs in an LDA with a binding Locational Constraint are equal to the total Base Unforced Capacity Imported into such LDA in the Base Residual Auction for the Delivery less the Incremental Capacity Transfer Rights that are allocated into the LDA for the Delivery Year less the amount of import capability increase into the LDA attributed to Qualifying Transmission Upgrades for the Delivery Year.

$$LSECapacityTransferRights_{LDA} = totalBaseUnforcedCapacityImported_{LDA} - ImportCapIncreasefromQTU - ICTRs$$

Where:

The Base Unforced Capacity Imported into an LDA is equal to the Base LDA Unforced Capacity Obligation less the LDA's Unforced Capacity cleared in the Base Residual Auction less LDA Forecast ILR Obligation.

- The Base LDA Unforced Capacity Obligation is equal to the sum of the Base Zonal Unforced Capacity Obligations for the zones in the LDA.
- LDA Forecast ILR Obligation is the sum of the Forecast Zonal ILR Obligations for the zones in the LDA.

Starting with the 2012/13 Delivery Year, the total amount of Capacity Transfer Rights in an LDA with a binding Locational Constraint are equal to the total Base Unforced Capacity Imported into such LDA in the Base Residual Auction for the Delivery Year. The Total CTRs into a constrained LDA are reduced by (1) QTU import capability cleared, (2) Participant-Funded Project ICTRs, and (3) Regional Project ICTRs, and the remaining CTRs are allocated to the LSEs in the LDA (Zone). ICTRs may be reduced if the Total CTRs calculated for a constrained LDA are limited in any Delivery Year. If the total CTRs are limited, they will be reduced first to provide credits to a cleared QTU. The remaining CTRs will be allocated to Generation or Transmission Interconnection Customers and to Responsible Customers pro rata based on their original ICTR allocations.

$$LSECapacityTransferRights_{LDA} = totalBaseUnforcedCapacityImported_{LDA} - ImportCapIncreasefromQTU - AllICTRs$$

Where:

The Base Unforced Capacity Imported into an LDA is equal to the Base LDA Unforced Capacity Obligation less the LDA's Unforced Capacity cleared in the Base Residual Auction less the LDA Short-Term Resource Procurement Target.

- The Base LDA Unforced Capacity Obligation is equal to the sum of the Base Zonal Unforced Capacity Obligations for the zones in the LDA.
- LDA Short-Term Resource Procurement Target is the sum of the Short-Term Resource Procurement Targets for the zones in the LDA.

If the LDA into which the Incremental Capacity Transfer Rights are allocated or import capability is increased by a Qualifying Transmission Upgrade is a part of a zone, the calculations will be made based on the zone instead of the LDA using the Weighted Zonal Resource Clearing Price to determine an equivalent Incremental Capacity Transfer Rights into the zone or an equivalent import capability into the zone in the case of a Qualifying Transmission Upgrade.

6.3 Allocation of Capacity Transfer Rights

The allocation of the total Capacity Transfer Rights is performed on a pro-rata basis for each LSE based on the Daily Unforced Capacity Obligation that they serve in zones included in the constrained LDA. The allocated CTRs will be reallocated to LSEs on a daily basis as load switches between retail suppliers within each zone.

When a Zone and its sub-zones are constrained LDAs, CTR calculations are performed on a Zonal basis. The Weighted Zonal Resource Clearing Price is the average of the Resource Clearing Price of the sub-zones, weighted by the Unforced Capacity of Resources Cleared in the sub-zones.

When an LDA is entirely contained within another LDA (e.g., a Zone is a smaller LDA within a Group of Zones which is a larger LDA), a portion of the larger LDA Capacity Transfer Rights will be allocated to the smaller LDA, based on the smaller LDA's proportion of the larger LDA's unforced capacity obligation.

6.4 Capacity Transfer Rights Credits

LSEs that were allocated CTRs will receive a daily zonal CTR Credit as described in the Settlements section of this Manual.

Participants that were allocated Incremental CTRs will receive a daily zonal Incremental CTR Credit equal to the total Incremental CTRs allocated times the Final Zonal Incremental CTR Credit Rate.

The Final Zonal Incremental CTR Credit Rate is equal to the sum of (1) Locational Price Adder of the Sink LDA minus the Locational Price Adder of the Source LDA from the Base Residual Auction; and (2) Locational Price Adder of the Sink LDA minus the Locational Price Adder of the Source LDA from the Second Incremental Auction multiplied by the increase in Unforced Capacity Imported into the sink LDA in the Second Incremental Auction compared to the Base Residual Auction, divided by the Base Unforced Capacity Imported into the Sink LDA. Starting from 2012/2013, the Incremental CTR Credit Rate determination will reflect the results of all Incremental Auctions.

6.5 Capacity Transfer Rights Transfers

RPM Market Participants will have the ability to request CTR or ICTR Transfers by notifying PJM. The purpose of a CTR Transfer is to transfer the ownership of a specified amount of CTR MWs in a given zone from the Seller to the Buyer.

The following are business rules that apply to Capacity Transfer Rights Transfers:

- CTR Transfer requests must specify the buyer, seller, start and end dates of the transfer, the transfer amount (in MW), and the zone from which to transfer the CTRs.
- CTR Transfers will result in the "Buyer" receiving the credit that would have been due to the "Seller" of the CTRs.
- The smallest increment of CTRs that may be transferred is 0.1 MW.
- Both the Buyer and the Seller of a CTR Transfer Transaction must submit the CTR Transfer request to PJM before the following daily accounting deadlines (all times in Eastern Prevailing Time):
    - 1:00 PM (Tuesday – Friday) for transactions beginning on the previous day
    - 5:00 PM (Monday) for transactions beginning on Friday, Saturday, and Sunday
    - 5:00 PM (a day after the holiday) for transactions beginning on a holiday

Section 7: Load Obligations

Welcome to the *Load Obligations section* of the *PJM Manual for the PJM Capacity Market*. In this section, you will find the following information:

- An overview description of Load Obligations (see "Overview of Load Obligations")
- The business rules for determining Interruptible Load for Reliability (ILR) obligations (see "Interruptible Load for Reliability (ILR) Obligations")
- The business rules for determining Unforced Capacity Obligations (see "Unforced Capacity Obligations")
- The business rules for determining RPM Scaling Factors (see "RPM Scaling Factors")
- The business rules for determining Obligation Peak Load values (see "Obligation Peak Load")
- The process for determining load obligations (see "Process for Determining Load Obligations")
- The business rules for the treatment of Non-Zone Load (see "Non-Zone Load)

7.1 Overview of Load Obligations

In the Reliability Pricing Model, Unforced Capacity is the basis for the market product that is cleared in each auction. Unforced Capacity (UCAP) is installed capacity rated at summer conditions that is not, on average, experiencing a forced outage or forced de-rating. While unforced capacity (UCAP) is the basis for the valuation of generating capacity, in RPM, this concept is also used to value load management (Demand Resources (DR) and Interruptible Load for Reliability (ILR)), Energy Efficiency, Reliability Requirements of RTO and LDAs, and to define load obligations of Load Serving Entities. Load obligations are obligations to serve load or obligations to reduce load during the Delivery Year valued as unforced capacity.

Prior to 2012/2013, load Obligations are based the Unforced Capacity Obligation procured in Base Residual Auction and the Second Incremental Auction if conducted. Effective 2012/2013, load Obligations will be based on the Unforced Capacity Obligation procured in Base Residual Auction and all the Incremental Auctions.

7.2 Interruptible Load for Reliability (ILR) Obligation

7.2.1 Determination of ILR Obligations

Load management is the capability to provide a reduction in demand or otherwise control load in accordance with PJM Standards. In the Reliability Pricing Model, the amount of load management is forecasted for the RTO, zones and all Locational Delivery Areas for each Delivery Year, and then converted into unforced capacity obligation values.

Interruptible Load for Reliability (ILR) Obligation is load to be reduced during the delivery year in unforced capacity terms. However, since the participants do not certify the value of Interruptible Load for Reliability until three (3) months prior to the Delivery Year, the zonal

ILR obligation values are forecasted on an aggregate basis prior to the clearing of the RPM Auctions as an input into the clearing process. The following parameters, described in detail below, are inputted values in the determination of ILR Obligations:

- RTO ILR Forecast
- Zonal ILR Forecast
- Demand Resource (DR) Factor

The RTO ILR Forecast and Zonal ILR Forecasts are determined by PJM in accordance with the *Load Data Systems Manual (M-19)*.

The ***RTO and Zonal ILR Forecasts*** are determined and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year (for Delivery Years prior to 2012/2013).

Demand Resource (DR) Factor

The Demand Resource (DR) Factor is used to determine the reliability benefit of demand resource products and to assign an appropriate value to demand resource products. The DR Factor for the Delivery Year is calculated by PJM *in accordance with the* ***PJM Reserve Requirements Manual (M-20)***.

The ***DR Factor used in determination of ILR obligations*** is approved by the PJM Board of Managers and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year.

Zonal ILR Forecast

The Zonal ILR Forecast is the average of the Zonal Interruptible Load for Reliability (ILR) nominated each of the five Delivery Years prior to the Base Residual Auction for the Delivery Year (for Delivery Years prior to 2012/2013). If five years of ILR history is not available for a Zone that was recently integrated into PJM, an average of the Zonal incremental load subject to mandatory interruption by EDC in the two years prior to the Base Residual Auction will be used as an estimated ILR for the Zone. Zonal Active Load Management (ALM) data will be used in place of Zonal ILR nominated data when Zonal ILR nominated data for the prior Delivery Years does not exist. A market based methodology will be considered for implementation in the future based on RPM experience.

RTO ILR Forecast

The RTO ILR Forecast is the sum of the Zonal ILR Forecasts.

$$ILRForecast_{RTO} = \sum ZonalILRForecasts_{inRTO}$$

An LDA ILR Forecast is the sum of the appropriate Zonal ILR Forecasts.

$$ILRForecast_{LDA} = \sum ZonalILRForecast_{Sin\ appropriatezones}$$

The Forecast RTO/Zonal ILR Obligation in unforced capacity terms equals the RTO/Zonal ILR Forecast * Demand Resource Factor* Forecast Pool Requirement, less the unforced capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region/Zone.

Posting of ILR Obligations

An initial posting of the Forecast RTO/Zonal ILR Obligation without the adjustments related to FRR Entities' Demand Resources committed to their FRR Capacity Plans is posted by February 1 prior to the Base Residual Auction for the Delivery Year (for Delivery Years prior to 2012/2013). A later posting of the Forecast RTO/Zonal ILR Obligation with the adjustments related to FRR Entities' Demand Resource committed to their FRR Capacity Plans will be made shortly after the approval of FRR Capacity Plans for the RPM Auction Delivery Year.

7.3 Unforced Capacity Obligations

7.3.1 Determination of Unforced Capacity Obligations

Unforced Capacity Obligations are obligations for load to be served during the delivery year in unforced capacity terms. However, since RPM auction participants are not bidding in the demand for UCAP in the RPM process, the reliability requirement is forecasted on an aggregate basis prior to the clearing of the RPM Auctions as an input into the clearing process.

In the Reliability Pricing Model, unforced capacity obligations are determined for the RTO and Zones as a result of the Base Residual Auction and Second Incremental Auction prior to 2012/2013 and the Base Residual Auction and all Incremental Auctions effective 2012/2013.

The following parameters, discussed in detail below, are values used in the determination of Unforced Capacity Obligations:

- Peak Load Forecasts
- Forecast Pool Requirement (FPR)

7.3.2 Base Unforced Capacity Obligations

A Base RTO Unforced Capacity Obligation is determined after the clearing of the Base Residual Auction and is posted with the Base Residual Auction results. The Base RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the Base Residual Auction plus the Forecast RTO Interruptible Load for Reliability (ILR) Obligation prior to 2012/2013 (plus RTO Short-Term Resource Procurement Target for 2012/2013 and beyond).

$$BaseRTOUnforcedCapacityObligation = UnforcedCapacityObligation_{inBRA} + ForecastRTOILRObligation$$

$$BaseRTOUnforcedCapacityObligation = UnforcedCapacityObligation_{inBRA} + Short-TermResourceProcurementTarget$$

RTO Unforced Capacity Obligation satisfied in Base Residual Auction is used to determine the Base Zonal RPM Scaling Factors for use in determining Base Zonal Unforced Capacity Obligation.

Base Zonal Unforced Capacity Obligation

Zonal Unforced Capacity Obligations are determined based on an allocation of the RTO Unforced Capacity Obligation based on zonal peak load forecasts and zonal ILR obligations. As a result of the RPM Auction clearing process, additional resources above those required to meet the IRM may be procured and allocated to the zones. Since resource requirements in the constrained zones may be higher than those required based on IRM (FPR) these requirements affect the clearing price in the zones but not the allocation of RTO obligations to zones.

A Base Zonal Unforced Capacity Obligation is determined for each zone and is equal to the (Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement) + Forecast Zonal ILR Obligation (for Delivery Years prior to 2012/2013 or the Zonal Short Term Resource Procurement Target for Delivery Years 2012/2013 and beyond).

$$BaseZonalCapObligation = (ZonalNormalizedSummerPeak-4yr \times BaseZonalRPMScalingFactor \times FPR) + ForecastZonalILRObligation$$

$$BaseZonalCapObligation = (ZonalNormalizedSummerPeak-4yr \times BaseZonalRPMScalingFactor \times FPR) + ZonalShort-TermResourceProcurementTarget$$

Base Zonal Unforced Capacity Obligations are posted with the Base Residual Auction clearing results.

7.3.3 Final Zonal Unforced Capacity Obligations

Prior to the 2009/2010 Delivery Year:

The Final RTO Unforced Capacity Obligation is determined after the clearing of the Second Incremental Auction and is posted with the Second Incremental Auction results. The Final RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the Base Residual Auction and the Second Incremental Auction plus the Forecast RTO Interruptible Load for Reliability (ILR) Obligation.

$$FinalRTOUnforcedCapObligation = UnforcedCapObligation_{BRAand2ndIA} + ForecastRTOILRObligation$$

If a Second Incremental Auction is not conducted, the Final RTO Unforced Capacity Obligation is equal to the Base RTO Unforced Capacity Obligation.

A zone's percentage allocation of the obligation satisfied in the Second Incremental Auction will be zero if the Final Zonal Peak Load Forecast is less than the Preliminary Zonal Peak Load Forecast. If the Final Zonal Peak Load Forecast is greater than the Preliminary Peak Load Forecast, the zone's percentage allocation will be (Final Zonal Peak Load Forecast – Preliminary Zonal Peak Load Forecast) divided by the Sum of (Final Zonal Peak Load Forecast – Preliminary Zonal Peak Load Forecast) for all zones with Final Zonal Peak Load Forecast greater than the Preliminary Peak Load Forecast. The Preliminary Zonal Peak Load Forecast and the Final Zonal Peak Load Forecast in this equation are reduced by the Preliminary or Final Peak Load Forecasts of the FRR Entities in the Zones respectively.

The Final Zonal Unforced Capacity Obligation is determined for each zone and is equal to the Base Zonal Unforced Capacity Obligation plus the RTO unforced capacity obligation satisfied in the Second Incremental Auction * zone's percentage allocation of the obligation satisfied in the Second Incremental Auction.

$$FinalZonalUnforcedCapObligation = BaseZonalUnforcedCapObligation + (SecondIncAuctionUnforcedCapObligation \times ZonePercentAllocation_{2ndIA})$$

If a Second Incremental Auction is not conducted, the Final Zonal Unforced Capacity Obligation is equal to the Base Zonal Unforced Capacity Obligation.

Prior to the 2009/2010 Delivery Year, the ***Final Zonal Unforced Capacity Obligations*** are posted with the Second Incremental Auction results.

Effective with the 2009/2010 Delivery Year through 2011/2012 Delivery Year:

The Final RTO Unforced Capacity Obligation is determined after the clearing of the Third Incremental Auction for the Delivery Year. The Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through the Base Residual Auction and the Second Incremental Auction plus the Forecast RTO Interruptible Load for Reliability (ILR) Obligation. The RTO unforced capacity obligation satisfied through a Base Residual Auction and Second Incremental Auction is equal to the total unforced capacity committed (cleared MWs and make-whole MWs) as a result of the Base Residual and Second Incremental Auction.

$$FinalRTOUnforcedCapObligation = UnforcedCapObligation_{BRAand2ndIA} + ForecastRTOILRObligation$$

The Final Zonal Unforced Capacity Obligation is determined for each zone and is equal to zonal allocation of the RTO unforced capacity obligation satisfied through the Base Residual Auction and Second Incremental Auction plus the Zonal Forecast ILR Obligation. The RTO unforced capacity obligation satisfied through a Base Residual Auction and Second Incremental Auction is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load Forecasts.

$$FinalZonalUnforcedCapObligation = ZonalAllocationofRTOUCAPObligationSatisfiedinBRAand2ndIA + ZonalForecastILRObligation$$

For the 2009/2010 and 2011/2012 Delivery Year, the ***Final Zonal Unforced Capacity Obligations*** are posted after the clearing of the Third Incremental Auction.

Effective with the 2012/2013 Delivery Year:

The Final RTO Unforced Capacity Obligation is determined after the clearing of the final Incremental Auction for the Delivery Year. The Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year. The RTO unforced capacity obligation through all RPM Auctions is equal to the total MWs cleared in PJM Buy Bids in RPM Auctions less the total MWs cleared in PJM Sell Offers in RPM Auctions.

$$FinalRTOUnforcedCapObligation = SumofPJMBuyBidMWsCleared - SumofPJMSellOffersCleared$$

The Final Zonal Unforced Capacity Obligation is determined for each zone and is equal to zonal allocation of the Final RTO Unforced Capacity Obligation. The Final RTO Unforced Capacity Obligation is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load Forecasts.

$$FinalZonalUnforcedCapOblig = (ZonalFinalPeakLoadForecast / RTOFinalPeakLoadForecast) * FinalRTOUCAPC$$

Effective with the 2012/2013 Delivery Year, the ***Final Zonal Unforced Capacity Obligations*** are posted after the clearing of the final Incremental Auction for the Delivery Year.

7.4 RPM Zonal Scaling Factors

RPM Zonal Scaling Factors are calculated as a result of RPM Auctions and are constant for the Delivery Year. The following RPM Zonal Scaling Factors are determined:

- Base Zonal Scaling Factors – determined for each zone after the clearing of the Base Residual Auction
- Final Zonal Scaling Factors – determined for each zone by February 1stprior to the start of the Delivery Year (for Delivery Years prior to 2012/2013), determined for each zone two weeks after the final Incremental Auction (for Delivery Years 2012/13 and beyond).

These scaling factors account for (1) load growth from a prior-year summer to the Delivery Year; (2) any excess resources procured in the Base Residual Auction above those required to exactly meet the FPR requirements; and (3) ILR Forecast Obligation values.

The following parameters are values used in the determination of RPM Zonal Scaling Factors:

- RTO Unforced Capacity Obligation (Base & Final)
- Zonal Peak Load Forecasts (Preliminary & Final)
- Forecast Pool Requirement (FPR)
- Zonal Weather Normalized Summer Peaks

The purpose of RPM Zonal Scaling Factors is to determine the LSE Daily UCAP Obligations in the zones from the Daily Obligation Peak Loads.

7.4.1 Zonal Weather Normalized Summer Peaks

To account for the load growth from a prior-year summer to each Delivery Year, PJM determines Zonal Weather Normalized Summer Peaks by October 31 prior to the start of the Delivery Year. The Zonal Weather Normalized Summer Peaks are calculated in accordance with the ***Load Data Systems Manual (M-19)***.

The RTO Weather Normalized Summer Peak is the sum of the Zonal Weather Normalized Coincident Summer Peaks.

The Electric Distribution Company (EDC) is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer prior to the Delivery Year and providing to PJM an Obligation Peak Load allocation for each eRPM defined "area" within their zone by December 31 prior to the start of the Delivery Year. *See Reliability Assurance Agreement Schedule 8, Section A* for the limitations in the netting of Non-Retail Behind the Meter Generation.

7.4.2 Base Zonal RPM Scaling Factor

A Base Zonal RPM Scaling Factor is determined for each zone and is equal to the [(Preliminary Zonal Peak Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year[15])* ((RTO

[15] For the 2007/2008-2010/2011 Delivery Years, the Zonal Weather Normalized Summer Peak for the summer 2006 will be used to establish Base Zonal RPM Scaling Factors.

Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement))]. Zonal peak load is adjusted for peak loads of zone/areas that elected FRR option.

$$BaseZonalRPMScalingFactor = [(\frac{PrelimZonalPeakLoadForecast)^{s}}{NormalizedSummerPeak - 4yr}) \times (\frac{RTOUnforcedCapacityObligation_{BRA}}{RTOPreliminaryPeakLoadForecasts \times FPR})$$

Base Zonal RPM Scaling Factors are posted with the Base Residual Auction results.

7.4.3 Final Zonal RPM Scaling Factor

The Final Zonal RPM Scaling Factors are used in determining an LSE's Daily Unforced Capacity Obligation. A Final Zonal RPM Scaling Factor for a zone is equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Peak for the summer prior to the Delivery Year).

$$FinalZonalRPMScalingFactor = \frac{FinalZonalUnforcedCapacityObligation}{FPR \times ZonalWeatherNormalizedPeak - 1yr}$$

7.5 Obligation Peak Load

Obligation Peak Load is the peak load value on which LSEs' Unforced Capacity Obligations are based. Each PJM Electric Distribution Company (EDC) is responsible for allocating its normalized previous summer's peak to each customer in the zone (both retail and wholesale). The process used by the EDC to determine these Peak Load Contributions is based on rules negotiated with its regulators. LSE Obligation Peak Load represents the summation of Peak Load Contributions for each of an LSE's customers.

- The Obligation Peak Load allocation for a zone is constant and effective for the entire Delivery Year.
- The EDC is also responsible for allocating the Obligation Peak Load for a zone/area among end-use customers by calculating Peak Load Contributions (i.e., "capacity tickets") for each end-use customer by December 31 prior to the start of the Delivery Year.
- The EDC must make Peak Load Contribution information available to LSEs by December 31 prior to the start of the Delivery Year.

7.6 Daily Unforced Capacity Obligations

The EDC is responsible for uploading Obligation Peak Load data into eRPM for every LSE serving load in their zone/area during the Delivery Year. The file upload must be performed in accordance with eRPM's file format specifications and by the file upload deadline (36 hours before the start of the operating day).

- The daily sum of all the LSEs' Obligation Peak Load data in a zone/area must equal the EDC's Obligation Peak Load allocation to the zone/area.
- A Daily Obligation Peak Load Scaling Factor will be used to scale the uploaded LSE Obligation Peak Load values to the fixed Obligation Peak Load Allocation of the zone/area in the event that the Obligation Peak Load values uploaded by the EDC do not exactly sum to the Annual Obligation Peak Load Allocation for the zone/area.

$$DailyOblPkLoadScalingFactor = \frac{\text{Annual Zone Area Obligation Peak Load Allocation}}{\sum \text{Zone Area Obligation Peak Load Uploads}}$$

- The daily sum of the Obligation Peak Load data for all areas in a zone must equal the Zonal Weather Normalized Summer Peak for the summer prior to the Delivery Year.
- The Daily Unforced Capacity Obligation of an LSE in a zone/area equals the LSE's Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement.

$$DailyUnforcedCapObligation = ObligationPeakLoad \times FinalZonalRPMScalingFactor \times FPR$$

- During the Delivery Year, the Daily Unforced Capacity Obligation of an LSE is locked 36 hours before the start of the operating day.

7.7 Process for Determining Load Obligations

The process that was described in the previous sections is illustrated below.

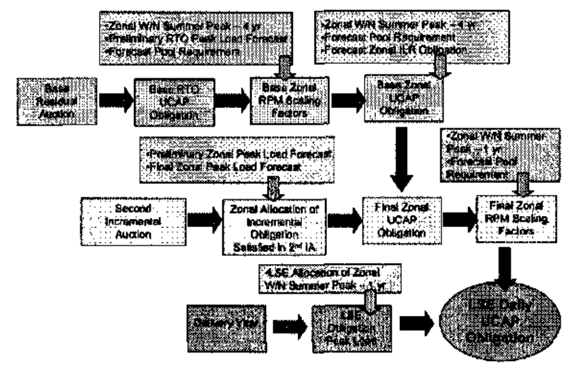


Exhibit 3: Process for determining Load Obligations (applicable to Delivery Years prior to 2012/2013)

7.8 Treatment of Non-Zone Load

Non-Zone Load is the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

The following are business rules that apply to Treatment of Non-Zone Load:

- Non-Zone Load may be Non-Zone Network Load (Tariff 1.27B) that is charged a Network Integration Transmission Service (NITS) charge (Tariff Attachment H-A) or other load that may be 'grandfathered' from the NITS charge.

- PJM forecasts the Preliminary Non-Zone Load for the RPM Delivery Year and includes it in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load of the Zone from which the Non-Zone Load is served, by February 1 prior to the Base Residual Auction.
- Non-Zone Load cannot be served in a Delivery Year using resources committed to RPM if it is not included in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load prior to the RPM Base Residual Auction for the Delivery Year.
- PJM forecasts the final Non-Zone Load for the RPM Delivery Year and includes it in the Final RTO Forecast Peak Load and the Final Zonal Forecast Peak Load that is posted by February 28 prior to the Second Incremental Auction.
- EDC that is responsible to determine the Obligation Peak Loads for the Zone will also establish the Obligation Peak Load associated with the Non-Zone Load by December 31 prior to the start of the Delivery Year.
- Non-Zone load will be modeled as a defined "area" in the zone from which it is served in the eRPM system.

The LSE serving the Non-Zone Load will be assessed a Daily Unforced Capacity Obligation and will be responsible to pay an RPM Locational Reliability Charge.

Section 8: Resource Performance Assessments

Welcome to the *Resource Performance Assessments* section of the PJM Manual for the *PJM Capacity Market*. In this section, you will find the following information:

- An overview description of the resource performance assessments (see "Overview of Resource Performance Assessments")
- The business rules for determining RPM commitment compliance (see "RPM Commitment Compliance")
- The business rules for determining generating unit peak-hour availability (see "Generating Unit Peak-Hour Availability")
- The business rules for determining load management event compliance (see "Load Management Event Compliance")
- The business rules for determining load management test compliance (see "Load Management Test Compliance"
- The business rules for replacement resources ("see "Replacement Resources")

8.1 Overview of Resource Performance Assessments

The PJM Capacity Market is designed to ensure that capacity market prices are consistent with system reliability metrics. All LSEs must satisfy their capacity obligation either through the RPM or through the FRR Alternative. If a resource receives capacity payments, or in the case of FRR Alternative, is committed to directly satisfy load obligation requirements, there is an expectation that the resource will honor their commitments and provide reliability services when required. The following performance assessments provide the means to assess whether or not a resource honored their commitments and provided the expected reliability services during the Delivery Year.

- RPM Commitment Compliance
- Generating Unit Peak-Hour Period Availability
- Summer/Winter Capability Testing
- Peak Season Maintenance (PSM) Compliance
- Load Management Compliance
- Load Management Test Compliance
- Measurement & Verification (M &V) Audit (see Manual 18-B)

Collectively, the performance assessments provide consumers, who have paid for a high level of reliability through their capacity market payments, with reasonable assurance that the resources committed to RPM or FRR Alternative will perform at adequate levels during the Delivery Year. Since failure to perform in a performance assessment results in deficiency or penalty charges, resource providers are incented to ensure that their committed resources perform during the Delivery Year in order to limit their exposure to deficiency or penalty charges.

A resource will have an RPM Resource Commitment if the resource cleared or received make-whole payments through an RPM Auction or if the unit was specified as a replacement resource. A resource will have an FRR Capacity Plan commitment if the unit was included in an FRR Capacity Plan. Portions of the resource that do not have an RPM Resource Commitment or FRR Capacity Plan Commitment during the Delivery Year are not subject to resource performance assessments and the associated deficiency/penalty charges.

The performance assessments are not applicable to all types of resources committed to RPM or FRR Alternative. The following matrix provides an overview of the applicability of resource performance assessments.

Assessment	Generation (except Hydro, Wind & Solar)	Hydro	Wind & Solar Generation	DR	ILR	EE	QTU
RPM Commitment Compliance	X	X	X	X		X	X
Peak-Hour Period Availability	X	X					
Summer/Winter Capability Testing	X	X (Annual)					
PSM Compliance	X						
Load Management Event Compliance				X	X		
Load Management Test Compliance				X	X		
M&V Audit						X	

8.2 RPM Commitment Compliance

A resource committed to RPM is expected to be able to deliver unforced capacity during the Delivery Year that is equal to or greater than the unforced capacity committed through RPM Auctions or through the specification of replacement capacity. RPM Commitment Compliance is evaluated daily during the Delivery year on a resource-specific basis to determine if a party satisfied their Daily RPM Resource Commitments on their generation resources, demand resources, and Qualifying Transmission Upgrades (QTUs).

A resource or portion of a resource committed to the FRR Alternative is not subject an RPM Commitment Compliance. Instead of a unit-specific commitment compliance, FRR Entities are subject to daily unforced capacity obligation compliance.

8.2.1 Generation

A generation resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Unit cancellations and delays – A planned generation is cancelled or delayed and does not commence Interconnection Service prior to the start of the Delivery Year.
- Unit deratings and retirements – The generation resource is derated (through a Capacity Modification decrease) prior to or during the Delivery year. (Retirements result in derating the installed capacity value of a unit to zero MWs through a Capacity Modification decrease in the eRPM system).
- EFORd increases – The final Effective EFORd for a generation resource during the Delivery Year is greater than the Sell Offer EFORds submitted in cleared offers in RPM Auctions for the Delivery Year.

During the Delivery Year, failure to meet generation resource commitments will be determined by comparing a party's Daily RPM Generation Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Generation Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM Generation Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(1-Effective EFORd).

$$DailyRPMResourcePostion = (DailyICAPOwned - DailyFRRCapPlanCommitments - DailyUnofferedICAP) \times (1 - EffectiveEFORd)$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity and the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a specific unit is calculated as Daily RPM Resource Commitments minus Daily RPM Generation Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage = DailyRPMResourceCommitments - DailyRPMGenerationResourcePosition$$

8.2.2 Demand Resources:

A demand resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Load management program cancellation or delay– The load management program(s) associated with the planned demand resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.
- Decrease in nominated value of demand resource – The final nominated value of the demand resource during the Delivery Year is less than the nominated value of the

demand resource used in cleared offers in RPM Auctions for the Delivery Year due to a decrease in the peak load contributions (i.e., capacity tickets) of end-use customers providing the actual load response.

- Failure to have enough sites registered and approved in the eLRS system prior to the start of the Delivery Year to support the nominated value of the demand resource committed for such Delivery Year. Effective with the 2014/2015 DY, the sites registered and approved in the eLRS must be the same resource product type (limited, extended summer, or annual) as the demand resource committed.
- Decrease in the DR Factor or Forecast Pool Requirement - The final UCAP value of the demand resource during the Delivery Year is less than the UCAP value committed in the auction due to the final DR Factor or final FPR for the Delivery Year being less than the DR Factor or FPR that was used in RPM Auction for which the demand resource cleared.

During the Delivery Year, failure to meet demand resource commitments will be determined by comparing a party's Daily RPM Demand Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Demand Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily Nominated DR Value – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP) * DR Factor * Forecast Pool Requirement.

$$DailyRPMPosition_{DR} = (DailyNominatedDRValue - DailyFRRCapacityPlanCommitments - DailyUnofferedICAP) \times DRFactor \times FPR$$

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such demand resource in RPM Auctions to decreases/increase of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a specific demand resource is calculated as Daily RPM Resource Commitments minus Daily RPM Demand Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{DR} = DailyRPMResourceCommitments - DailyRPMDemandResourcePosition$$

Existing Demand Resources that offered and cleared in Base Residual Auction or Second Incremental Auction for Delivery Years prior to 2012/2013 Delivery Year or existing demand resources that offered and cleared in Base Residual Auction, First Incremental Auction, or Second Incremental Auction for 2012/2013 Delivery Year and beyond can receive relief from deficiency charges if they failed to meet their RPM Resource Commitments due to a decrease in Peak Load Contributions (i.e., "capacity ticket(s)") that were due to the permanent departure of load from the transmission system (e.g., plant closure, efficiency gains, or similar reasons) that was relied upon for load response. The resource provider of the existing Demand Resource must provide PJM with all information deemed necessary by PJM to assess the merits of the request for relief.

Beginning with 2012/2013 Delivery Year, request for relief from deficiency charges must be made no later than two weeks in advance of the opening of the of the Third Incremental Auction. Prior to 2012/2013 Delivery Year, request for relief from deficiency charges must be made no later than two weeks after the posting of results of the Third Incremental Auction.

Failure to maintain Demand Resources will not permit relief. If relief from deficiency charges is granted, the resource provider will receive a reduction in their RPM Auction Credits and a reduction in their RPM Resource Commitments. Any reduction in Auction Credits is factored into the calculation of the Final Zonal Capacity Price. There is no relief from deficiency charges for existing Demand Resources that offered and cleared in a First or Third Incremental Auction for Delivery Years prior to 2012/2013 DY or for existing Demand Resources that offered and cleared in a Third Incremental Auction for 2012/2013 Delivery Year and beyond.

8.2.3 Energy Efficiency Resources:

An EE resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Energy efficiency installation cancellation or delay– The energy efficiency installation(s) associated with the planned EE Resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.
- Decrease in nominated value of EE Resource – The final nominated value of the energy efficiency resource during the Delivery Year is less than the nominated value of the energy efficiency resource used in cleared offers in RPM Auctions for the Delivery Year due to a change in number of planned installations associated with the planned EE Resource, change in EDC loss factor, or change due to post-installation measurement and verification activities, or reduction in nominated value due to failure to meet the precision standard requirement for measurement and verification activities in accordance with the PJM Manual for Energy Efficiency Measurement & Verification.

During the Delivery Year, failure to meet EE Resource commitments will be determined by comparing a party's Daily RPM EE Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM EE Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM EE Resource Position for a specific EE resource is equal to the (Daily Nominated EE Value – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP) * DR Factor * Forecast Pool Requirement)..

$$DailyRPMPosition_{EE} = (DailyNominatedEEValue - DailyFRRCapacityPlanCommitments - DailyUnofferedICAP) \times DRFactor \times FPR$$

A party's Daily RPM Resource Commitments for a specific EE resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such EE resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a specific EE resource is calculated as Daily RPM Resource Commitments minus Daily RPM EE Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{EE} = DailyRPMResourceCommitments - DailyRPMEEResourcePosition$$

8.2.4 Qualifying Transmission Upgrade (QTU):

A provider of a Qualifying Transmission Upgrade may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Upgrade cancellations and delays– A qualifying transmission upgrade is cancelled or delayed and does not commence Interconnection Service prior to the start of the Delivery Year.

During the Delivery Year, failure to meet qualifying transmission upgrade commitments will be determined by comparing a party's Daily RPM QTU Position to their Daily RPM Resource Commitments for such upgrade. If a party's Daily RPM QTU Position is less than their Daily RPM Resource Commitments for such upgrade on a delivery day, a Transmission Upgrade Delay Penalty will be assessed on the RPM Commitment Shortage.

A party's Daily RPM QTU Position for a Qualifying Transmission Upgrade is equal to the approved incremental import capability value into the Sink LDA from a Source LDA for such upgrade.

A party's Daily RPM Resource Commitments for a specific Qualifying Transmission Upgrade are calculated by adding the sum of any UCAP Cleared plus UCAP Make whole for such qualifying transmission upgrade in RPM Auctions to decreases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a Qualifying Transmission Upgrade is calculated as Daily RPM Resource Commitments minus Daily RPM QTU Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{QTU} = DailyRPMResourceCommitments - DailyRPMQTUPosition$$

8.3 Commitment Level Used in Peak-Hour Period Availability (PHPA), Summer/Winter Capability Tests, and PSM Compliance

Since the RPM Resource Commitments or FRR Capacity Plan Commitments on a unit can vary daily during the delivery year, a Total Unit ICAP Commitment Amount is calculated for each unit and used as the basis for assessing the performance of a unit for peak-hour period availability, summer/winter capability tests, and PSM compliance.

Since replacement resources can be specified anytime during the Delivery Year, the Total Unit ICAP Commitment Amount is not finalized until after the conclusion of the Delivery Year.

The Total Unit ICAP Commitment Amount on a specific unit is equal to the lesser of (a) the Unit Average Daily ICAP Commitment Amount for the Delivery Year or (b) maximum Summer Net Dependable Rating of the Unit during the Delivery Year.

$$TotalUnitICAPCommitment = \text{Lessof}(UnitAvgDailyICAPCommitment, \text{Max}(SummerNetDependableRating))$$

The Unit Average Daily ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the (sum of all Daily RPM Resource Commitments on such unit for the Delivery Year divided by one minus the Effective EFORd plus the sum of all Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 days (or 366 days).

$$UnitAvgDailyICAPCommitment_{unit} = \frac{(\sum DailyRPMResourceCommitments_{unit}/(1 - EffectiveEFORd_{unit})) + \sum Daily\ FRRCap\ Plan\ Commitments_{unit}}{365\ days\ (or\ 366\ days)}$$

Since a single unit can have both RPM Commitments and FRR Capacity Plan Commitments during the Delivery Year, a Unit Average Daily FRR ICAP Commitment Amount and Unit

Average Daily RPM ICAP Commitment Amount for the Delivery Year is calculated for each unit.

The Unit Average Daily FRR ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of all Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 days (or 366 days).

$$UnitAverageDailyFRRICAPCommitmentAmount = \frac{DailyFRRCapacityPlanCommitments_{forDY}}{365days(or366days)}$$

The Unit Average Daily RPM ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the Total Unit ICAP Commitment Amount less the Unit Average Daily FRR ICAP Commitment Amount.

$$UnitAverageDailyRPMICAPCommitment_{GenResource} = TotalUnitICAPCommitment - UnitAverageDailyFRRICAPCommitment$$

Since a single unit can be committed by multiple parties, a Provider's Average Daily FRR ICAP Commitment Amount, Provider's Average Daily RPM ICAP Commitment Amount, and Provider's Share of Total Unit ICAP Commitment Amount for each unit is calculated in order for PJM to allocate any unit shortfalls calculated for peak-hour period availability, summer/winter capability testing, and PSM compliance.

A Provider's Average Daily FRR ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of the Provider's Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 (or 366 days).

$$Provider'sAverageDailyFRRICAPCommitmentAmountfor_{GenResource} = \frac{Provider'sDailyFRRCapacityPlanCommitments_{forGenResourceforDY}}{365days(or366days)}$$

A Provider's Average Daily RPM ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of the Provider's Daily RPM Resource Commitments on such unit the Delivery Year divided by the sum of all Daily RPM Resource Commitments on such unit for the Delivery Year, multiplied by the Unit Average Daily RPM ICAP Commitment Amount.

$$Provider's\ AvgDailyRPMICAPCommitment = (\sum Provider's\ Daily\ RPMCommitments / \sum Total\ Daily\ RPMResourceCommitments) * Unit\ Avg\ DailyICAPcommitment$$

A Provider's Share of the Total Unit ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the Provider's Average Daily FRR ICAP Commitment Amount plus the Provider's Average Daily RPM ICAP Commitment Amount.

$$Provider'sShareofTotalUnitICAPCommitment_{GenResource} = Provider'sAverageDailyFRRICAPCommitment + Provider'sAvgDailyRPMICAPCommitment$$

8.4 Generating Unit Peak-Hour Period Availability

The Generating Unit Peak-Hour Period Availability (PHPA) metric provides a means to assess whether committed generation resources are available at expected levels during critical peak periods, and credits or charges resource providers to the extent that they exceed or fall short of that expected availability. The metric provides generation owners an added incentive to ensure that their capacity resources are available when they are most needed, and provide loads greater assurance that their payments for capacity will help maintain peak-hour period reliability.

The Generating Unit-Peak-Hour Period Availability metric is applicable to all capacity resources committed to serve load either under Reliability Pricing Model or Fixed Resource Requirement Alternative. It is not applicable to wind and solar generation.

PJM will directly measure generation availability performance during peak load periods. The peak hour periods are defined based on the summer and winter operating periods when high demand conditions are likely to occur and therefore generation performance is most critical to maintaining system reliability. The peak hour periods include: The hour ending 15:00 local prevailing time (LPT) through the hour ending 19:00 LPT on any day during the calendar months of June through August that is not a Saturday, Sunday, or a federal holiday, and the hour ending 8:00 LPT through the hour ending 9:00 LPT and the hour ending 19:00 LPT through the hour ending 20:00 LPT on any day during the calendar months of January and February that is not a Saturday, Sunday, or a federal holiday. The total number of hours is approximately 500, and can vary from year to year.

Generating Unit Peak-Hour Period Availability is measured by calculating a Peak-Period Equivalent Forced Outage Rate (EFORp) and the corresponding Peak Period Capacity Available (PCAP) for a generation resource. The PCAP of a unit is compared to a unit's Target Unforced Capacity (TCAP), which is based on a unit's Equivalent Demand Forced Outage Rate-5 (EFORd-5), to assess whether or not a unit fell short of or exceeded its expected availability during the defined peak-hour periods.

8.4.1 Peak-Period Equivalent Forced Outage Rate (EFORp)

Peak-Period Equivalent Forced Outage Rate Peak (EFORp) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate during the defined peak hour periods. The EFORp is based on actual outage data during the Delivery Year.

The Peak-Period Equivalent Forced Outage Rate (EFORp) is determined by using the following sets of hours from the defined peak hour periods:

- Forced outage hours when needed (outage hours exclude Outside Management Control (OMC) events),
- Forced partial outage hours when needed (outage hours exclude OMC events), and
- Service hours.

The ***"outage hours when needed"*** shall be determined by PJM by identifying hours during which the real-time LMP would have exceeded the cost-based offer for the unit or when PJM would have (absent the outage) called the unit for operating reserves, taking into account the unit's operating constraints.

EFORp is the sum of forced outage hours when needed plus equivalent forced partial outage hours when needed, divided by service hours plus forced outage hours when needed.

$$EFORp = \frac{(ForcedOutageWhenNeeded + EquivalentForcedPartialOutageHoursWhenNeeded)}{(ServiceHours + ForcedOutageHoursWhenNeeded)}$$

Prior to 2009/10 Delivery Year, if the service hours of a unit are less than 50 hours during the defined peak hour period periods, an EFORd calculated based on outage data that covers the entire Delivery Year will be used in place of EFORp. Effective 2009/10 Delivery Year, if the service hours of a unit are less than 50 hours during the defined peak hour periods, the EFORp will be the lesser of the EFORd calculated based on outage data that covers the entire Delivery Year or the calculated EFORp based on peak hour period outage data.

In the calculation of the EFORp for a specific unit the following considerations are made:

- If a summer/winter capability test resulted in a partial forced outage that was entered by PJM in eGADs, the partial forced outage will not be considered in the calculation of the unit's EFORp.
- During the time period that a unit is delayed or retired, forced outages are not reported on the unit. As a result, performance of the unit during the time it is delayed or retired is not considered in the calculation of the unit's EFORp.
- For a single-fueled, natural gas-fired unit, forced outages during the winter peak-hour period will not be used in determining the unit's EFORp (or EFORd for generation units with service hours below 50 hours) if the resource provider can demonstrate that such failure was due to non-availability of gas to supply the unit as a result of events that were Outside of Management Control (OMC). The PJM eGADs Manual provides guidelines for the application of OMC codes. Lack of fuel in the cases where the operator of the unit is not in control of contracts, supply lines, or delivery of fuels is considered an OMC event. Whereas, lack of fuel in the case where an operator elected to contract for fuels where the fuel can be interrupted as part of a fuel cost-saving measure is under management control and is not considered an OMC event.

An estimate of each unit's EFORp will be posted to the eRPM system within three calendar months after the end of the summer period.

8.4.2 Peak Period Capacity Available (PCAP)

The Peak Period Capacity Available (PCAP) for a unit represents the actual availability of the committed portion of the unit during the defined peak-hour periods. PCAP is calculated by multiplying the unit's Total Unit ICAP Commitment Amount times one minus the unit's EFORp.

$$PCAP = TotalUnitICAPCommitment \times (1.0 - EFORp)$$

8.4.3 Equivalent Demand Forced Outage Rate (EFORd-5)

Equivalent Demand Forced Outage Rate (EFORd-5) is an EFORd based on 5 years of outage history that provides the basis for a unit's expected availability during the peak-hour periods.

EFORd-5 is an index that is calculated in a manner similar to the EFORd that is the basis for a unit's UCAP value for the Delivery Year, except the EFORd-5 is determined using five years instead of one year of outage data. The index is calculated using five years of Generator Availability Data System (GADS) outage data excluding OMC events through September 30 prior to the Delivery Year. If a generating unit does not have a full five years of history, the EFORd-5 will be calculated using the class average EFORd and the available history as described in Reliability Assurance Agreement, Schedule 5, Section C. For a new generating unit, the class average EFORd will be used as the EFORd-5. The class average EFORds that are used by PJM to calculate a unit's EFORd-5 are posted to the PJM website by November 30 prior to the Delivery Year.

PJM will post the ***EFORd-5*** that is effective for the Delivery Year to the eRPM system by November 30 prior to the Delivery Year.

8.4.4 Target Unforced Capacity (TCAP)

The Target Unforced Capacity (TCAP) for a unit represents the expected availability of the committed portion of the unit during the defined peak-hour periods. TCAP is calculated as the Total Unit ICAP Commitment Amount times one minus the unit's EFORd-5

$$TCAP = TotalUnitICAPCommitment \times (1.0 - EFORd - 5)$$

8.4.5 Peak-Hour Period Capacity Shortfall

The PCAP value of a unit is compared with the TCAP value of a unit to determine if a unit fell short of or exceeded its expected availability during the defined peak-hour periods. The Unit Peak-Hour Period Capacity Shortfall is equal to the TCAP minus the PCAP for such unit.

$$UnitPeakHourPeriodCapShortfall = TCAP - PCAP$$

A positive Unit Peak-Hour Period Capacity Shortfall indicates a shortfall in meeting a unit's expected availability (underperformance) and a negative Unit Peak-Hour Period Capacity Shortfall indicates that the unit exceeded its expected availability (over performance).

There are limitations on the amount of positive Unit Peak-Hour Period Capacity Shortfall that may be calculated for a specific unit. The limitations include the following:

- A Unit Peak-Hour Period Capacity Shortfall is limited, on a unit specific basis, to 50% of the Total Unit ICAP Commitment Amount * (1-Effective EFORd).
- If the 50% limitation is triggered in a Delivery Year, the limit will increase to 75% in the following Delivery Year.
- If the 75% limitation is triggered in a Delivery Year, the limit will increase to 100% in the following Delivery Year.
- The 50% limit will be reinstated after 3 years of good performance.

If portions of the unit were committed by multiple Resource Providers, the Unit Peak-Hour Period Capacity Shortfall for the unit is allocated to Resource Providers based on the provider's pro-rata share of the Total Unit ICAP Commitment Amount.

For a Resource Provider, the net of their Unit Peak-Hour Period Capacity Shortfalls in an LDA across committed units in an LDA are determined.

The netting of Unit Peak-Hour Period Capacity Shortfalls in an LDA is performed across committed units within a single account in eRPM. There is no netting of shortfalls performed across multiple accounts in eRPM.

The net Peak-Hour Period Capacity Shortfall in an LDA may be adjusted by a Provider's Net Eligible Available PHPA Shortfall in an LDA (i.e., Provider's Net PHPA Replacement Capacity in a LDA) as explained in Section 8.4.5.1.

A Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA will be separated into an Adjusted Net Peak Hour Period Capacity Shortfall in an LDA for RPM Resource Commitments and an Adjusted Net Peak Hour Period Capacity Shortfall in an LDA for FRR Capacity Plan Commitments as explained in Section 8.4.5.1.

Preliminary EFORp estimates (based on summer peak hours) for committed units and estimates of a Resource Provider's Net Peak-Hour Period Capacity Shortfall for RPM Resource Commitments in an LDA and Net Peak-Hour Period Capacity Shortfall for FRR Resource Commitments in an LDA will also be provided through the eRPM System in November of the Delivery Year. Such estimates do not consider any adjustment for a Provider's Net Eligible Available PHPA Shortfall in an LDA.

The Adjusted Net Peak-Hour Period Capacity Shortfall in an LDA is applied to each day in the Delivery Year. A Resource Provider with a positive Adjusted Net Peak-Hour Period Capacity Shortfall in an LDA will be assessed a Peak-Hour Period Availability Charge retroactively for each day in the Delivery Year.

8.4.5.1 Use of Excess Available Capacity in Peak-Hour Period Availability Assessment

Effective with the 2009/2010 Delivery Year, excess available capacity (i.e. uncommitted capacity) in a party's portfolio that satisfies the capacity resource obligations of a committed resource may be used to help cure or offset a party's shortfall for peak hour period availability.

<u>Calculation of Eligible Available Capacity (EAC) for Individual Units</u>

PJM will determine the Eligible Available Capacity (EAC) for each generation resource. A unit's EAC represents the amount of the unit's available capacity for the DY that met the capacity resource obligations by (1) offering into the DA Energy Market (if available) (2) satisfying summer and winter capability test requirements (i.e., test to their committed ICAP level) and (3) entering outages into eDart and GADS.

PJM will determine the Daily EAC for a unit for each day of the Delivery Year and calculate the resource's Average Daily EAC for the entire Delivery Year.

- For a unit that (1) passed Summer and Winter Capability Tests; or (2) failed their Summer or Winter Capability Test, but for which the owner/operator entered a partial forced outage in the eGADS system for the difference between the claimed summer or winter ICAP rating and the test result. (Essentially these are units that will not be assessed Rating Test Failure Charges.)

  Daily EAC = Lesser of (Daily Minimum Hourly ECOMAX in DA Energy Market, Daily Summer Net Dependable Rating of Unit) – Lesser of (Daily ICAP Commitment MWs, Daily Summer Net Dependable Rating) – Daily Unoffered ICAP MWs

  Where:

  Daily Minimum Hourly ECOMAX in the DA Energy Market is determined from the price based offer submitted in eMarkets. If no price offer is available then the schedule of the cheapest cost schedule will be used. Hourly ECOMAX values can be viewed on the Unit Schedule Hourly tab in eMarkets.

Daily Summer Net Dependable Rating is the daily summer ICAP rating of the unit that is based on approved Capacity Modifications for the unit in the eRPM system.

Daily ICAP Commitment MWs = Sum of unit's Daily RPM Commitments in UCAP/(1 – Final EFORd for DY) + Sum of unit's Daily FRR Capacity Plan Commitments in ICAP]

Daily Unoffered ICAP MWs represents the total amount of ICAP MWs that were not offered from the unit by RPM entities in RPM Auctions for the Delivery Year. Daily Unoffered ICAP MWs does not include the Unoffered MWs of an FRR Entity.

- For a unit that failed their Summer or Winter Capability Test and the owner/operator failed to enter a partial forced outage in the eGADS system for the difference between their claimed summer or winter ICAP rating and their test result (Essentially these are units that have the potential to be assessed Rating Test Failure Charges):

Daily EAC = Lesser of (Daily Minimum Hourly ECOMAX in DA Energy Market, Daily Summer Net Dependable Rating of Unit, Test Result) – Lesser of (Daily ICAP Commitment MWs, Daily Summer Net Dependable Rating) – Daily Unoffered ICAP MWs

Where:

Daily Minimum Hourly ECOMAX, Daily Summer Net Dependable Rating of Unit, Daily ICAP commitment MWs and Daily Unoffered ICAP MWs are defined above.

For June 1 – Oct 31, the Test Result will be the unit's Summer Test Result. From November 1 – May 31, the Test Result will be the unit's Winter Test Result. For Hydro Units, the Test Result will be the hyrdo unit's annual test result.

- If a negative Daily EAC is calculated, a zero Daily EAC will be used in the calculation of the Average Daily EAC.
- A unit's Average Daily EAC for the delivery year is equal to the [Sum of the Daily EAC for the Delivery Year]/Number of Days in the Delivery Year.

Allocation of a Unit's Average Daily EAC to Multiple Providers

If portions of the unit are committed by multiple resource providers, the unit's Average Daily EAC is allocated to resource provider's that had available capacity during the Delivery Year to determine a Provider's Share of Average Daily EAC. The pro-rata allocation will be based on the provider's Average Daily Available ICAP MWs on such unit for the entire Delivery Year.

- The Provider's Daily Available ICAP on a unit is captured from the eRPM system and is based on the provider's Daily ICAP Owned, Daily Unoffered ICAP, Daily RPM Resource Commitments, and Daily FRR Capacity Plan Commitments. If a negative Daily Available ICAP value is calculated, a zero Daily Available ICAP will be used in the calculation of the Provider's Average Daily Available ICAP for the Delivery Year.
- For a provider, Daily Available ICAP = Daily ICAP Owned – Daily Unoffered ICAP – (Daily RPM Resource Commitments/(1 – Final DY EFORd) – Daily FRR Capacity Plan Commitments

Where:

Daily Unoffered ICAP MWs does not include the Unoffered MWs of an FRR Entity.

- A provider's Average Daily Available ICAP for the Delivery Year is equal to the [Sum of the provider's Daily Available ICAP for the Delivery Year]/Number of Days in the Delivery Year.

Calculation of a Provider's Net Eligible Available PHPA Shortfall in LDA (i.e., Provider's Net PHPA Replacement Capacity in LDA)

PJM will calculate the Provider's share of Peak Period Capacity Available (PCAP) for the eligible available capacity portion of such unit (i.e., share of Eligible Available PCAP) as Provider's Share of Average Daily EAC *(1 – EFORp).

For each provider, PJM will determine a Provider's Net Eligible Available PHPA Shortfall in an LDA (which represents the Provider's Net PHPA Replacement Capacity in an LDA) by summing the Provider's share of Eligible Available PCAP values for all units in an LDA within a provider's RPM account. Netting is performed across a single eRPM account only. PJM will not net values across a provider's multiple eRPM accounts. The Eligible Available PHPA Shortfall (or Resource Provider's Net PHPA Replacement Capacity in an LDA) will be represented as a negative value in the eRPM system indicating excess or overperformance.

A Provider's Net Eligible Available PHPA Shortfall in an LDA (i.e., Provider's Net PHPA Replacement Capacity in a LDA) is used to reduce a party' positive Net Peak Hour Period Capacity Shortfall in an LDA in their single RPM account. A Provider's Net Eligible Available PHPA Shortfall in an LDA may not be used to reduce a party's negative Net Peak Hour Period Capacity Shortfall in an LDA. Please see Manual 18, Section 8 for details on how a party's Net Peak Hour Period Capacity Shortfall in an LDA is calculated.

Calculation of a Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA

When a Provider's Net Peak Hour Period Capacity Shortfall in an LDA is a positive value, a Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA is equal to the provider's Net Peak Hour Period Capacity Shortfall in the LDA minus the provider's absolute value of Net Eligible Available PHPA Shortfall in an LDA; however, if the calculated value is negative, the Adjusted Net Peak Hour Period Capacity Shortfall in an LDA will be set to zero. When a Provider's Net Peak Hour Period Capacity Shortfall in an LDA is zero or negative, the Adjusted Net Peak Hour Period Capacity is equal to the Provider's Net Peak Hour Period Capacity Shortfall in an LDA.

Allocation of a Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA between RPM and FRR Commitments

A Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA will be separated into an Adjusted Net Peak Hour Period Capacity Shortfall in an LDA for RPM Resource Commitments and an Adjusted Net Peak Hour Period Capacity Shortfall in an LDA for FRR Capacity Plan Commitments.

- A Provider's Adjusted Net Peak Hour Period Capacity Shortfall in LDA for RPM Resource Commitments = provider's Adjusted Net Peak Hour Period Capacity Shortfall in LDA*provider's Net Average Daily RPM ICAP Commitment Amount in LDA/provider's Net Share of Total Unit ICAP Commitment Amount in LDA.

- A Provider's Adjusted Net Peak Hour Period Capacity Shortfall in LDA for FRR Commitments = provider's Adjusted Net Peak Hour Period Capacity Shortfall in LDA*provider's Net Average Daily FRR ICAP Commitment Amount in LDA/provider's Net Share of Total Unit ICAP Commitment Amount in LDA.

8.4.6 Summer/Winter Capability Testing

During the Delivery Year, generation owners are responsible to perform Summer/Winter Net Capability Verification (i.e, Capability Testing) as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) and submit test results through the eGADs system. As described in M-21, as an alternative to performing the Winter Net Verification, data collected during the summer verification window may be used to satisfy winter test requirements after adjustment to appropriate ambient winter conditions. The purpose of the summer/winter net capability verification is to demonstrate that the unit can achieve the claimed summer/winter net dependable rating of the unit. PJM will use the results of the summer/winter net capability testing to assess whether a unit that was committed to RPM or FRR Alternative was able to achieve at least the Total Unit ICAP Commitment Amount in the summer/winter capability test

A Net Capability Test must be performed during both the Summer and the Winter testing periods. The Summer test period begins the first day of June and ends the last day of August. The Winter test period begins the first day of December and ends on the last day of February. Alternatively, data collected during the summer verification window may be used to satisfy winter test requirements after adjustment to appropriate ambient winter conditions. Hydro generation can be tested any time during the Delivery Year, but is only required to perform net capability verification once per year. If the entire unit is on a forced or planned outage during the entire summer or winter testing period, the unit is expected to submit an out-of-period capability test when the outage ends.

An unlimited number of tests may be performed on the unit during each testing period. If none of the tests certify full delivery of the Total Unit ICAP Commitment Amount, those parties with RPM Resource Commitments and FRR Capacity Plan Commitments from such unit may be subject to Generation Resource Rating Test Failure Charges. Intermittent generation is exempted from the summer/winter capability testing requirement and will not be assessed any Generation Resource Rating Test Failure Charges.

The unit's installed capacity shortfall for the testing period is determined by the test that resulted in the highest installed capacity rating (i.e., the highest Corrected Net Test Capacity as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21)). The Unit ICAP Shortfall for the testing period is equal to the Total Unit ICAP Commitment Amount minus the highest installed capacity rating achieved in the capability test.

A positive shortfall indicates a failure to certify the Total Unit ICAP Commitment Amount during the testing period. A negative shortfall indicates that the Total Unit ICAP Commitment Amount was exceeded during the testing period.

The following business rules apply in the determination of the Unit ICAP Shortfall:

- If a unit is on a partial outage during the test, the amount of the partial outage is added to the highest installed capacity rating in the test to determine the Unit ICAP Shortfall for the summer or winter test period.

- The Unit ICAP Shortfall for the summer testing period will be applied daily for the months of June through November of the Delivery Year. The Unit ICAP Shortfall for the winter testing period will be applied daily for the months of December through May of the Delivery Year. If the Unit ICAP Shortfall as a result of the winter testing period is less than the Unit ICAP Shortfall as a result of the summer testing period, the Unit ICAP Shortfall as a result of the summer testing period will be applied daily for the months of December through May of the Delivery Year.
- If the entire unit is on a forced or planned outage from June 1 to December 1 of the Delivery Year, a Unit ICAP Shortfall for the summer testing period is not calculated.
- If the entire unit is on a forced or planned outage from December 1 – May 31 of the Delivery Year, the Unit ICAP Shortfall for the winter testing period is the calculated Unit ICAP Shortfall for the summer testing period.
- If the winter rating on a unit is less than the summer rating on the unit and the Total Unit ICAP Commitment Amount is greater than the winter rating, the Unit ICAP Shortfall for the winter testing period will be calculated as the winter rating of the unit (instead of the Total Unit ICAP Commitment Amount) minus the highest installed capacity rating achieved in a winter capability test.
- If a unit is exempt from the winter net capability verification requirement (in accordance with ***Section 6 of PJM Manual 10 – Pre-Scheduling Operations***), the Unit ICAP Shortfall that is calculated as a result of a summer capability test would also apply for the months of December through May of the Delivery Year.
- In the case of hydro generation, the Unit ICAP Shortfall that is calculated as a result of the single capability test submitted is applied for the entire Delivery Year.
- If a daily RPM commitment compliance shortage on a unit occurs due to a unit delay, derating, or retirement during the Delivery Year, the Daily Unit ICAP Shortfall will be reduced by the portion of the daily RPM commitment compliance shortage (in UCAP) due to the unit delay, derating, or retirement divided by one minus the unit's Effective EFORd for the Delivery Year. The Daily Unit ICAP Shortfall for the unit will not be reduced to a value less than zero.

If portions of the unit were committed by multiple Resource Providers, the Daily Unit ICAP Shortfall is allocated to the Resource Providers based on the provider's pro-rata share of the unit's Total Unit ICAP Commitment Amount.

A Provider's Daily ICAP Shortfall for a unit is equal to the Daily Unit ICAP Shortfall times the Provider's Share of Total Unit ICAP Commitment Amount divided by Total Unit ICAP Commitment Amount.

$$\text{Provider's}\,DailyICAPShortfall_{GenResource} = \frac{DailyUnitICAPShortfall \times \text{Provider's Share of}\,TotalUnitICAPCommitment}{TotalUnitICAPCommitment}$$

If a Resource Provider has both RPM Resource Commitments and FRR Capacity Plan Commitments on the unit, the Provider's Daily ICAP Shortfall for such unit will be separated into a Daily ICAP Shortfall for RPM Resource Commitments and Daily ICAP Shortfall for FRR Capacity Plan Commitments.

A Resource Provider's Daily ICAP Shortfall for RPM Resource Commitments is equal to the Provider's Daily ICAP Shortfall times the Provider's Average Daily RPM ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$Provider'sDailyICAPShortfall_{RPMResourceCommitments} = \frac{Provider'sDailyUnitICAPShortfall \times Provider's\ AverageDailyRPMICAPCommitment}{Provider's\ Share\ of\ TotalUnitICAPCommitment}$$

A Resource Provider's Daily ICAP Shortfall for FRR Capacity Plan Commitments is equal to the Provider's Daily ICAP Shortfall times the Provider's Average Daily FRR ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$Provider'sDailyICAPShortfall_{forFRRCapPlanCommitments} = \frac{Provider's\ Daily\ Unit\ ICAP\ Shortfall \times Provider'sAverageDailyFRRICAPCommitment}{Provider'sShareofTotalUnitICAPCommitment}$$

A Resource Provider with a positive Daily ICAP Shortfall will be assessed The Generation Resource Rating Test Failure Charge.

8.4.7 Peak Season Maintenance (PSM) Compliance

To preserve and maintain the reliability of the PJM Region and to recognize the impact of planned outages and maintenance outages during the Peak Season, PJM will perform a Peak Season Maintenance (PSM) Compliance assessment on generation resources committed to the RPM or FRR Alternative. A Resource Provider will be assessed a Peak Season Maintenance (PSM) Compliance Penalty Charge in accordance with ***Attachment DD of the Open Access Transmission Tariff,*** if the provider committed a generation resource to the RPM or FRR Alternative and such resource was not available due to a planned or maintenance outage that occurred during the Peak Season without the approval of PJM. Hydro resources and intermittent resources are exempt from peak-season maintenance compliance assessment and will not be assessed any PSM Compliance Charges.

The Peak Season is defined as the weeks containing the 24^{th} through 36^{th} Wednesdays of the calendar year. All weeks start on a Monday and end on Sunday, except the week with the 36^{th} Wednesday, which ends on a Friday.

If the Summer Net Dependable Rating of the unit on the peak season day minus the amount of capacity that was out-of-service on a planned or maintenance outage on a peak season day without the approval of PJM is less than the Total Unit ICAP Commitment Amount, a PSM Compliance Penalty Charge will be assessed to those parties that have RPM Resource Commitments or FRR Capacity Plan Commitments for such unit.

The Daily Unit PSM Compliance Shortfall is equal to Total Unit ICAP Commitment Amount minus (Summer Net Dependable Rating on peak season day minus the amount of capacity out-of-service on unapproved planned or maintenance outage on a peak season day).

$$DailyUnitPSMComplianceShortfall = TotalUnitICAPCommitment - (SummerNetDependableRating - AmountofCapacityOutofService)$$

If a daily RPM commitment compliance shortage occurs due to a derating during the peak season, the Daily Unit PSM Compliance Shortfall will be reduced by the portion of the daily RPM commitment compliance shortage (in UCAP) due to the derating divided by one minus

the unit's Effective EFORd for the Delivery Year. The Daily Unit PSM Compliance Shortfall will not be reduced to a value less than zero.

If portions of the unit were committed by multiple Resource Providers, the Daily Unit PSM Compliance Shortfall (MW) is allocated to the Resource Providers based on the provider's pro-rata share of the Total Unit ICAP Commitment Amount.

The Provider's Daily PSM Compliance Shortfall is equal to the Daily Unit PSM Compliance Shortfall times the Provider's Share of the Total Unit ICAP Commitment Amount divided by the Total Unit ICAP Commitment Amount.

$$Provider'sDailyPSMComplianceShortfall = \frac{DailyUnitPSMComplianceShortfall \times Provider'sShareofTotalUnitICAPCommitment}{TotalUnitICAPCommitment}$$

If a Resource Provider has both RPM Resource Commitments and FRR Capacity Plan Commitments on the unit, their Daily PSM Compliance Shortfall will be separated into a Daily PSM Compliance Shortfall for RPM Resource Commitments and Daily PSM Compliance Shortfall for FRR Capacity Plan Commitments.

A Resource Provider's Daily PSM Shortfall for RPM Resource Commitments is equal to the provider's Daily PSM Shortfall times the Provider's Average Daily RPM ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$Provider'sDailyPSMShortfall_{RPMResourceCommitments} = Provider'sDailyPSMShortfall \times Provider'sAvgDailyRPMICAPCommitment / Provider'sShareofTotalUnitICAPCommitment$$

A Resource Provider's Daily PSM Shortfall for FRR Capacity Plan Commitments is equal to the Provider's Daily PSM Shortfall times the Provider's Average Daily FRR ICAP Commitment Amount divided by the Party's Share of the Total Unit ICAP Commitment Amount.

$$Provider'sDailyPSMShortfall_{FRRCapPlanCommitments} = Provider'sDailyPSMShortfall \times Provider'sAvgDailyFRRICAPCommitment / Provider'sShareofTotalUnitICAPCommitment$$

8.5 Load Management Event Compliance

Compliance is the process utilized to review resource performance during PJM-initiated Load Management events. The process establishes potential under/over compliance values for each Load Management Resource, both Demand Resources and ILR Resources.

Compliance is evaluated separately by event in each Zone for Demand Resources and ILR resources dispatched by PJM. Effective with the 2014/2105 Delivery Year, to the extent a demand resource (i.e., registration) cannot respond another demand resource of a different resource product type in the same geographic location defined by PJM dispatch instructions with the same designated lead time and comparable capacity commitment may be substituted. Any demand resource used as a substitute during an event will have the same obligation to respond to future event(s) as if it did not respond to such event. Resource providers are responsible for the submittal of compliance information to PJM through the Load Response system for each PJM initiated Load Management event during the compliance period.

PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews.

Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place.

8.5.1 Measuring Event Compliance

PJM verifies Load Management Event Compliance on an end-use customer basis by reviewing the data submitted by the resource provider through the Load Response system. Like the determination of Nominated Values, Compliance is measured differently for each type of Load Management program.

Compliance for Direct Load Control (DLC) programs will consider only the transmission of the control signal. Resource providers are required to report the time period (during the Load Management event) that the control signal was started and stopped. Failure to start the signal by the start of the event and continue the signal for the duration of the event will result in a deficiency for that end-use customer.

Compliance for Firm Service Level (FSL) customers will be determined by comparing actual load during the event to the nominated firm service level. Resource providers must submit load data for all hours of the event and test day and for all days required for PJM to calculate compliance through the Load Response system.

Compliance for Guaranteed Load Drop (GLD) customers will be determined by comparing actual load dropped during the event to the nominated amount of load drop. Resource providers must submit load data for all hours of the event and test day and for all days required for PJM to calculate compliance. Comparison loads must be developed from the guidelines included in **Attachment A of *PJM Manual M-19 Load Data Analysis*,** and note which method was employed.

Load Management customers may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for the incremental load drop below zero.

Compliance is averaged over the full hours of a Load Management event, for each end-use customer or DLC program to determine a Resource Compliance Position for the Load Management event for each dispatched registration. Compliance data is netted for all registrations in the Load Response system that were dispatched.

The actual load reduction values for sites registered as both DR and ILR for the same Delivery Year are allocated pro-rata across the two registrations based on the unforced capacity commitment in such registrations on the day of the event. The allocated load reduction values will then be compared to the unforced capacity commitments on the day of *the event to determine compliance on a DR and ILR registration level.*

Resource Compliance Position for a registration is determined as the Nominated Load Reduction Value reported in the Load Response system minus the actual load reduction, where the Nominated Load Reduction Value is capped at the RPM/FRR Commitment for such registration on the day of the event. If multiple registrations are linked to a committed Demand Resource in the eRPM system, the RPM/FRR Commitment for such Demand Resource is allocated to the registrations pro-rata based on the nominated load reduction value of the registrations.

Resource Compliance Positions for a registration that are positive indicate that the registration undercomplied during the event. Resource Compliance Positions that are negative indicate that the registration overcomplied during the event.

8.5.2 Load Management Event Compliance Allocation

For each Interruptible Load for Reliability (ILR) provider, compliance data will be totaled over all ILR registrations dispatched by zone, to determine the ILR Provider's actual zonal load reduction for the event.

For each Demand Resource (DR) provider, compliance data will be totaled over all Demand Resource registrations dispatched by zone, to determine the DR Provider's actual zonal load reduction for the event.

Provider that committed both Demand Resources and ILR resources for a Delivery Year will have their DR and ILR compliance data totaled over all DR registrations and ILR registrations dispatched, by zone to determine the DR Provider's actual zone load reduction for the event.

For any Load Management event where the actual load reduction value achieved by a resource provider in a zone is less than the provider's RPM/FRR Resource Commitments in that zone on the day of the event, the zonal *under-compliance MWs will be allocated back to* the registration level on an under-compliance ratio share. Registrations that were compliant (or over-compliant) in the zone will not be allocated a portion of the zonal under-compliance.

For any Load Management event where the actual zonal load reduction value achieved by a *resource provider in a zone is greater than the provider's RPM/FRR Resource Commitments* in that zone on the day of the event, the over-compliance will be allocated back to the registration level on an over-compliance ratio share. Registrations that were not over-compliant or did not have a commitment in the zone will not be allocated a portion of the over-compliance.

Following the allocation, under-compliant registrations will be subject to a Load Management Event Penalty Charge. Over-compliant registrations may be eligible to receive a Load Management Penalty Charge Allocation.

8.6 Load Management Test Compliance

Effective starting with the 2009/10 Delivery Year, DR and ILR Resource providers are subject to Load Management Test Compliance.

If a registration for an ILR resource or a Limited Demand Resource is not dispatched by PJM for a Load Management Event prior to August 15th of the Delivery Year, then such registration must demonstrate that it was tested simultaneously with other non-dispatched ILR or Limited DR registrations in the zone for a one-hour period during any hour when a PJM Load Management Event may be called between June 1 and September 30th of the *Delivery Year. If a registration for an ILR resource or a Limited Demand Resource is* dispatched by a PJMfor a Load Management Event between August 16th and September 30th of the Delivery Year, no load management test is required for such registration. If a registration for a ILR resource or a Limited Demand Resource is dispatched by a PJM-initiated Load Management Event between June 1and September 30th of the Delivery Year , load management test compliance will not be evaluated and Load Management Test Failure Charges will not be assessed for such registration.

If a registration for a Annual Demand Resource is not dispatched by PJM for a Load Management Event in a Delivery Year, then such registration must demonstrate that it was tested simultaneously with other non-dispatched Annual Demand Resource registrations in the zone for a one-hour period during any hour when a PJM Load Management Event may be called during June through October or the following May of the Delivery Year. If a registration for a Annual Demand Resource is dispatched by PJM for a Load Management Event during the Delivery Year, then no test will be required for such registration and no Load Management Test Failure Charges will be assessed for such registration.

If a registration for a Extended Summer Demand Resource is not dispatched by PJM for a Load Management Event during June through October or the following May in a Delivery Year, then such registration must demonstrate that it was tested simultaneously with other non-dispatched Extended Summer Demand Resource registrations in the zone for a one-hour period during any hour when a PJM Load Management Event may be called during June through October or the following May of the Delivery Year. If a registration for a Extended Summer Demand Resource is dispatched by PJM for a Load Management Event during June through October or the following May of the Delivery Year, then no test will be required for such registration and no Load Management Test Failure Charges will be assessed for such registration.

For those registrations required to test, all of the provider's registrations of the same product type and same zone must test at the same time for a one hour period during any hour when a PJM-initiated load management event for such product type may be called:

- ILR and Limited DR: 12:00 PM EPT to 8:00 PM EPT
- Extended Summer DR and Annual DR: 10:00 AM EPT to 10:00 PM EPT

The test must be conducted on a non-holiday weekday during the following testing periods:

- ILR and Limited DR: June 1 through September 30th of the Delivery Year
- Extended Summer DR and Annual DR: June 1 through October 31 and May of the Delivery Year

The resource provider must notify PJM of the intent to test 48 hours in advance of the test. A notification of intent to test (or retest) must be submitted in the eLRs system. If a resource provider failed to provide the required load reduction in a zone by less than 25% of their Summer Average RPM Commitment in the zone, the resource provider may conduct a retest of the subset of resources (i.e., end-use customer sites) in the zone that failed the initial test or a subset of resources that failed the test where the CSP notifies PJM of each end use customer that will not be retested at least 48 hours prior to conducting the retest. If the CSP elects to not retest a subset of end use customers that failed the test, such end use customer(s) will maintain the compliance result achieved in the initial test. Retesting must be performed at the same time of day and under approximately the same weather conditions. Any resource affiliated with a failed resource must also participate in the retest even if the resource passed the initial test, unless the CSP elects to maintain the compliance result achieved in the test for such failed resource through advanced notification to PJM as mentioned above. If a resource and its affiliate both failed the test then such resources must either be included in the retest or excluded from the retest with the necessary advanced

notification to PJM. Affiliated resources are resources that have any ability to shift load and are owned or controlled by the same entity. If a resource provider failed to provide the required load reduction in a zone by more than 25% of their Summer Average RPM Commitment in the zone, retesting only a subset of the resources that failed the initial test is not permitted.

A Provider's Summer Average RPM Commitment in a zone is equal to the daily average of the provider's total RPM/FRR resource commitments (for ILR and DR) from June 1st through September 30th of the Delivery Year.

Multiple tests may be conducted; however, only one test result may be submitted for each end-use customer site in the Load Response System for compliance evaluation. Test data must be submitted in the Load Response System no later than November 14th of the Delivery Year for ILR/Limited DR product type. Test data must be submitted on or after June 1 and no later than July 14th after the Delivery Year for the Annual DR and Extended Summer DR product types. Load Management test compliance will be measured in the same manner as load management event compliance. A resource provider with a positive net testing shortfall in a zone will be assessed a Zonal Load Management Test Failure Charge.

Load Management test compliance will be measured in the same manner as load management event compliance; however, for purposes of Load Management test compliance the Resource Compliance Position for a registration considers the Summer Average RPM/FRR Commitment as opposed to the RPM/FRR Commitment on the day of the event.

Resource Compliance Position for a registration for a test is determined as the Nominated Load Reduction Value reported in the Load Response system minus the actual load reduction, where the Nominated Load Reduction Value is capped at the Summer Average RPM/FRR Commitment for such registration.

Summer Average RPM/FRR Commitment for a Demand Resource is the daily average of the RPM/FRR resource commitments for such Demand Resource from June 1st through September 30th of the Delivery Year. If multiple registrations are linked to a committed Demand Resource in the eRPM system, the Summer Average RPM/FRR Commitment for such Demand Resource is allocated to the registrations pro-rata based on the nominated load reduction value of the registrations.

Summer Average RPM Commitment for an ILR registration is the Nominated Load Reduction Value for such registration.

For any Load Management test, a provider's net testing shortfall in a zone is calculated as the provider's Summer Average RPM/FRR Resource Commitments in such zone minus the actual zonal load reduction value achieved by the provider in such zone. A resource provider with a positive net testing shortfall in a zone (i.e., undercompliance MWs in zone) will be assessed a Zonal Load Management Test Failure Charge.

8.7 Replacement Resources

Participants may specify replacement resources in order to avoid or reduce performance assessment shortfalls and the associated deficiency/penalty charges.

Replacement capacity for generation resources, Demand Resources, Energy Efficiency Resources, or Qualifying Transmission Upgrades committed to RPM may be specified via the eRPM system by entering a "Replacement Capacity" transaction after the EFORd for the Delivery Year has been locked in the eRPM system (November 30 prior to the Delivery Year), but before the start of the Delivery Day.

Through the "Replacement Capacity" transaction functionality in eRPM, PJM will provide participants with a list of the available capacity for each generation or demand resource in their portfolio as well as a list of cleared buy bids from any Incremental Auction via the eRPM system and a list of resources with RPM Resource Commitments. Participants will have the ability to match a generation, Demand Resource, Energy Efficiency Resource or Qualifying Transmission Upgrade resource committed to RPM that they would like to replace with available capacity from a generation resource, demand resource, cleared buy bids in an Incremental Auction, or from Locational UCAP transactions. Available capacity from an EE Resource may be used as replacement capacity only for another EE Resource in the EE Resource Provider's account.

The following are business rules that apply to Replacement Resources for Resources Committed to RPM:

- The start date and end date of the replacement must be specified.
- A Replacement Resource used to reduce a Demand Resource commitment shall be specified for no less than the balance of the Delivery Year. An available Demand Resource may only be used as a Replacement Resource when the start date of the Replacement Capacity transaction is from June 1 through September 30th unless the Demand Resource can demonstrate through the prior summer's event or test compliance data that the Demand Resource met both its Summer Average RPM Commitment and the new daily RPM commitment level that would result if the Replacement Capacity transaction was approved.
- The desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced and the replacement resource must be specified. The change in Daily RPM Resource Commitments cannot result in a negative value for the Daily RPM Resource Commitments for the resource being replaced.
- The replacement resource must be located in the same LDA as the resource that is being replaced or reside in the Sink LDA of the Qualifying Transmission Upgrade being replaced.
- Resources located in a constrained LDA can serve as replacement capacity for a generation resource located in a less constrained parent LDA.
- The replacement resource must have the same or better temporal availability characteristics as the resource that is being replaced. For example, Annual Resource commitments can only be replaced by available capacity from an Annual Resource or cleared Buy Bids for Annual Capacity or Locational UCAP originating from an Annual Resource; Extended Summer DR commitments can be replaced by

available capacity from an Annual Resource or Extended Summer DR, or cleared Buy Bids for Annual or Extended Summer Capacity or Locational UCAP originating from an Annual Resource or Extended Summer DR; and Limited DR commitments can be replaced by available capacity from an Annual Resource, Extended Summer DR or Limited DR, or cleared Buy Bids for Annual, Extended Summer or Limited Capacity or Locational UCAP originating from an Annual Resource, Extended Summer DR or Limited DR.

- If a generation, demand, or EE resource is used as replacement capacity, a decrease in the Daily RPM Resource Commitments for the resource that is being replaced will result and a corresponding increase in the Daily RPM Resource Commitments for the replacement generation, demand, or EE resource will result during the time period specified for replacement. A change in the Daily RPM Resource Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.
- If cleared buy bids from an Incremental Auction or Locational UCAP transactions are used as replacement capacity, a decrease in the Daily RPM Commitments for the resource that is being replaced will result during the time period specified for replacement. A change in the Daily RPM Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

Replacement resources for generation, QTU, Energy Efficiency Resources, or Demand Resources committed to FRR Capacity Plan are specified by an FRR Entity through the update of the FRR Entity's FRR Capacity Plan prior to the start of the Delivery Day. FRR Entities may update their FRR Capacity Plan to reduce the FRR Capacity Plan Commitment on the resource being replaced and increase the FRR Capacity Plan Commitment on a replacement resource. The change in the Daily FRR Capacity Plan Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

8.7.1 Excess ILR MW Credits

Beginning with the 2009/2010 Delivery Year, but prior to the 2012/2013 Delivery Year, if the Certified ILR Obligation, adjusted for any ILR resources that withdraw prior to the start of the Delivery Year, exceeds the Forecast ILR Obligation for the LDA, the excess will be allocated to LSEs that are charged a Locational Reliability Charge, provided the amount does not exceed the ratio (MW) of increase in load charges (due to higher Certified ILR) divided by Final Zonal ILR Price within the LDA.

These "Excess ILR MW Credits" shall be allocated based on the Daily Unforced Capacity Obligation of Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year.

8.7.2 Excess Commitment Credits

Beginning with the 2010/2011 Delivery Year, LSEs may receive credits when Reliability Requirements decrease resulting in an excess capacity.

For 2010/2011 and 2011/2012, the Excess Capacity Credits will be any excess of PJM Reliability Requirement used for BRA over the PJM Reliability Requirement based on the load forecast updated for the Third Incremental Auction. For Delivery Years beginning with 2012/2013, the Excess Capacity Credits will be the PJM Sell Offers in the Scheduled Incremental Auctions that do not clear less the PJM Buy Bids in Incremental Auctions that do not clear. The Excess Capacity Credits in PJM will be allocated to LDAs pro rata based on the reduction in LDA peak load forecast from BRA to the time of Third Incremental Auction, provided the amount allocated does not exceed the reduction in the corresponding LDA Reliability Requirement. There will not be an allocation to LDA with an increase in load forecast.

The amount allocated to LDA will be further allocated to LSEs that are charged a Locational Reliability Charge, based on the Daily Unforced Capacity Obligation of the LSEs as of June 1 of the Delivery Year, and the credits will be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

Section 9: Settlements

Welcome to the *Delivery Year Activity* section of the PJM Manual for the *PJM Capacity Market*. In this section, you will find the following information:

- The business rules for the deficiency and penalty charges in RPM (see "Deficiency and Penalty Charges")
- The business rules for Locational Reliability Charges (see "Locational Reliability Charges"
- The business rules for RPM auction credits and charges (see "Auction Credits and Charges")

9.1 Deficiency and Penalty Charges

9.1.1 Peak-Hour Period Availability Charge

The Peak-Hour Period Availability Charge shall be equal to the Daily Peak-Hour Period Availability Charge Rate * Net Peak Period Capacity Shortfall in an LDA.

$$PeakHourPeriodAvailabilityCharge = DailyPeakHourPeriodAvailability\ Charge\ Rate \times NetPeakPeriodCapShortfall$$

The Daily Peak-Hour Period Availability Charge Rate applied to the Net Peak Period Capacity Shortfalls for RPM Resource Commitments in an LDA is equal to the a party's Weighted Average Resource Clearing Price in an LDA ($/MW-day).

$$DailyPeakHourPeriodAvailabilityChargeRate_{RPM} = WeightedAvgResourceClearingPrice_{inLDA}$$

A party's Weighted Average Resource Clearing Price in an LDA is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by a party's cleared and make-whole MWs in the LDA.

In the case where a Party's Weighted Average Resource Clearing Price in an LDA is equal to $0/MW-day, a PJM Weighted Average Resource Clearing Price in an LDA will be used.

The PJM Weighted Average Resource Clearing Price in an LDA is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by the total cleared and make-whole MWs in the LDA.

Prior to March 27, 2009, The Daily Peak-Hour Period Availability Charge Rate applied to Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in an LDA is equal to the Net Cost of New Entry in an LDA.

$$DailyPeakHourPeriodAvailabilityChargeRate_{FRR} = NetCostOfNewEntry_{inLDA}$$

Starting March 27, 2009, the Daily Peak-Hour Period Availability Charge Rate applied to Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in an LDA is equal to the weighted average of the resource clearing prices across all RPM auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

9.1.2 Allocation of Peak-Hour Period Availability Charges

The Peak-Hour Period Availability Charges for RPM Resource Commitments are allocated to those Resource Providers that have a negative Net Peak Period Capacity Shortfalls for RPM Resource Commitments in an LDA. The amount allocated to these Resource Providers is capped at their Net Peak Capacity Shortfall in the LDA times the Daily Peak-Hour Period Availability Charge Rate.

The Peak-Hour Period Availability Charges for FRR Resource Commitments are allocated to those Resource Providers that have a negative Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in an LDA. The amount allocated to these Resource Providers is capped at their Net Peak Capacity Shortfall in LDA times the Daily Peak-Hour Period Availability Charge Rate.

Any remaining balance of Peak-Hour Period Availability Charges is allocated to LSEs who were assessed a Locational Reliability Charge and FRR Alternative LSEs with a resource portfolio that overperformed (i.e., FRR LSEs with negative Net Peak Period Capacity Shortfalls). The Peak-Hour Period Availability Charges are allocated to these LSEs on a pro-rata basis based on their daily unforced capacity obligations.

Peak-Hour Period Availability Charges and Credits are assessed daily and billed retroactively for the entire Delivery Year in the September billing cycle after the conclusion of the Delivery Year.

9.1.3 Capacity Resource Deficiency Charge

The Daily Capacity Resource Deficiency Charge is equal to the Daily Deficiency Rate times the Daily RPM Commitment Shortage for generation resource or Demand Resource.

$$DailyCapResourceDeficiencyCharge = DailyDeficiencyRate \times DailyRPMCommitmentShortage$$

Prior to March 27, 2009, the Daily Deficiency Rate is equal to the higher of two times a party's Weighted Average Resource Clearing Price for such resource ($/MW-day) or the Net Cost of New Entry in an LDA.

Effective March 27, 2009, the Daily Deficiency Rate ($/MW-day) is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day, a PJM Weighted Average Resource Clearing Price in an LDA will be used.

A party's Weighted Average Resource Clearing Price for such resource is determined by calculating the weighted average of resource clearing prices for such resource across all RPM Auctions, weighted by a party's cleared and make-whole MWs for such resource.

The PJM Weighted Average Resource Clearing Price in an LDA is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by the total cleared and make-whole MWs in the LDA.

Daily Capacity Resource Deficiency Charges are assessed daily and billed monthly.

9.1.4 Transmission Upgrade Delay Penalty Charge

The Daily Transmission Upgrade Delay Penalty Charge is equal to the QTU Delay Penalty Rate times the Daily RPM Commitment Shortage for the QTU.

$$DailyTransUpgradeDelayPenaltyCharge = QTUDelayPenaltyRate \times DailyRPMCommitmentShortage$$

The QTU Delay Penalty Rate is equal to the higher of two times the Locational Price Adder of the LDA into which the QTU is cleared or Net CONE less the Resource Clearing Price in the LDA from which the CETL was increased.

Transmission Upgrade Delay Penalty Charges are assessed daily and billed weekly.

9.1.5 Generation Resource Rating Test Failure Charge

The Daily Generation Resource Rating Test Failure Charge shall be equal to the Daily Deficiency Rate times the Daily ICAP Shortfall times (1 – Effective EFORd) for a generation resource.

$$GenerationResourceRatingTestFailureCharge = DailyDeficiencyRate \times DailyICAPShortfall \times (1 - EffectiveEFORd)$$

Prior to March 27, 2009, the Daily Deficiency Rate applied to a Daily ICAP Shortfall for RPM Resource Commitments is equal to the higher of two times a party's Weighted Average Resource Clearing Price for such resource ($/MW-day) or the Net Cost of New Entry in an LDA.

Effective March 27, 2009, the Daily Deficiency Rate applied to a Daily ICAP Shortfall for RPM Resource Commitments is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day, a PJM Weighted Average Resource Clearing Price in an LDA will be used.

Prior to March 27, 2009, the Daily Deficiency Rate applied to a Daily ICAP Shortfall for FRR Resource Commitments is equal to the Net Cost of New Entry in an LDA.

Effective March 27, 2009, the Daily Deficiency Rate applied to a Daily ICAP Shortfall for FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

Generation Resource Rating Test Failure Charges are assessed daily for the entire Delivery Year and are billed retroactively for the entire Delivery Year in the June billing cycle after the conclusion of the Delivery Year.

9.1.6 Peak Season Maintenance Compliance Penalty Charge

The Daily PSM Compliance Penalty Charge is equal to the Daily Deficiency Rate times the Daily PSM Compliance Shortfall times (1- Effective EFORd) for a generation resource.

$$PSMCompliancePenaltyCharge = DailyDeficiencyRate \times DailyPSMComplianceShortfall \times (1 - EffectiveEFORd)$$

Prior to March 27, 2009, the Daily Deficiency Rate applied to a PSM Compliance Shortfall for RPM Resource Commitments is equal to the higher of two times a party's Weighted

Average Resource Clearing Price in an LDA ($/MW-day) or the Net Cost of New Entry in an LDA.

Effective March 27, 2009, the Daily Deficiency Rate applied to a PSM Compliance Shortfall for RPM Resource Commitments is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day, a PJM Weighted Average Resource Clearing Price in an LDA will be used.

Prior to March 27, 2009, the Daily Deficiency Rate applied to a PSM Compliance Shortfall for FRR Resource Commitments is equal to the Net Cost of New Entry in an LDA.

Effective March 27, 2009, the Daily Deficiency Rate applied to a PSM Compliance Shortfall for FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

PSM Compliance Penalty Charges are assessed each day during the peak season that the resource was out-of-service on an unapproved planned or maintenance outage and billed retroactively in the June billing cycle after the conclusion of the Delivery Year.

9.1.7 Load Management Test Failure Charge

The Daily Load Management Test Failure Charge is equal to the test under compliance MWs in the zone times the LM Test Failure Charge Rate.

$$LoadManagementTestFailureCharge = UnderComplianceMW \times DailyLMTestFailureChargeRate$$

A Provider's Under-Compliance MWs in a zone will be reduced by the summer average of the provider's Daily RPM Commitment Shortages in a zone for all their Demand Resources.

The Daily Load Management Test Failure Charge Rate is equal to the Provider's Weighted Daily Revenue Rate in such zone plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate in such zone, or $20/MW-day.) In the case where a Provider's Weighted Daily Revenue Rate in such zone is $0/MW-day, a PJM Weighted Daily Revenue Rate in such zone will be used.

Load Management Test Failure Charges are assessed daily and billed monthly (or otherwise in accordance with customary PJM billing practices in effect at the time); provided, however that a lump sum payment may be required to reflect amounts due, as a result of the testing failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

9.1.8 Allocation of Deficiency and Penalty Charges

The Daily Capacity Resource Deficiency Charges, Daily Transmission Upgrade Delay Penalties, Daily Generation Resource Rating Test Failure Charges, and Daily Peak Season Maintenance Compliance Penalty Charges, and Load Management Test Failure Charges are distributed on a pro-rata basis to LSEs who were charged a Daily Locational Reliability Charge for the day in order to compensate for resource adequacy that was not delivered.

Daily Capacity Resource Deficiency Charges, Daily Transmission Upgrade Delay Penalties, Daily Generation Resource Rating Test Failure Charges, and Daily Peak Season Maintenance Compliance Penalty Charges, and Load Management Test Failure Charges are allocated on a pro-rata basis to LSEs based on their daily unforced capacity obligation.

9.1.9 Demand Resource and ILR Compliance Penalty Charge

Penalties and rewards are assessed for PJM-initiated events on an event basis, following a compliance review.

A Demand Resource and ILR (Load Management) Compliance Penalty Charge is assessed to those Providers that under-complied during an event. The Load Management Compliance Charge is equal to the under-compliance MW times the Load Management Zonal Compliance Penalty Rate.

$$LoadManagementCompliancePenaltyCharge = UnderComplianceMW \times LMCompliancePenaltyRate$$

Prior to the 2009/2010 Delivery Year, the Load Management Zonal Compliance Penalty Rate per MW-event is one-fifth of the annual revenue rate ($/MW-year) applicable to the Demand Resource or ILR resource. Effective with the 2009/2010 Delivery Year through 2011/2012 Delivery Year, the Load Management Zonal Compliance Penalty Rate per MW-event is equal to the lesser of (one divided by the actual number events during the summer period for the dispatched registrations in such zone, or 0.50) * a Provider's Weighted Annual Revenue Rate in such zone. In the case where a Provider's Weighted Annual Revenue Rate is equal to $0/MW-day, a PJM Weighted Annual Revenue Rate in such zone will be used.

Effective with the 2012/2013 Delivery Year, the LM Compliance Charge for an event for dispatched registrations in a zone is assessed daily and initially billed in the third billing month after the event occurs (e.g., June events will be initially included in the September bill issued in October). The initial billing for a LM event will reflect the amounts due from the start of the Delivery Year to the last day that it is reflected in the initial billing. The remaining charges for such LM event will be assessed daily and billed monthly through the remainder of the Delivery Year. The Daily Load Management Zonal Compliance Penalty Rate per MW-event is equal to the lesser of (one divided by the actual number of events during the summer period for the dispatched registrations in such zone, or 0.50) * Provider's Weighted Daily Revenue Rate in such zone for the dispatched registrations. In the case where a Provider's Daily Revenue Rate in such zone for the dispatched registrations is equal to $0/MW-day, a PJM Weighted Daily Revenue Rate applicable to the dispatched registrations in such zone will be used.

Effective with the 2014/2015 Delivery Year, the LM Compliance Charge for an event for dispatched registrations in a zone for the on-peak period (which includes all hours for which a Limited Demand Resource would be expected to respond) is equal to the lesser of (one divided by the actual number of events during the Delivery Year for the dispatched registrations in such zone, or 0.50) * Provider's Weighted Daily Revenue Rate in such zone for the dispatched registrations, multiplied by the net under-compliance in such on-peak period for the dispatched registrations. In the case where a Provider's Weighted Daily Revenue Rate in such zone for the dispatched registrations is equal to $0/MW-day, a PJM

Weighted Daily Revenue Rate applicable to dispatched registrations in such zone will be used.

The LM Compliance Charge for an event for dispatched registrations in a zone for the off-peak period (which includes all hours for which a Annual Demand Resource and Extended Summer Demand Resource would be expected to respond, but does not include hours in on-peak period) is equal to 1/52 times * Provider's Weighted Daily Revenue Rate in such zone for the dispatched registrations, multiplied by the net under-compliance in such off-peak period for dispatched registrations. In the case where a Provider's Weighted Daily Revenue Rate in such zone for the dispatched registrations is equal to $0/MW-day, a PJM Weighted Daily Revenue Rate applicable to the dispatched registrations in such zone will be used.

If a Load Management Event is comprised of both an on-peak and off-peak period, then such LM Compliance Charge for such event will be the higher of the LM Compliance Charge calculated based on the rate applied for the on-peak period or LM Compliance Charge calculated based on the rate applied for off-peak period.

A Provider's Under-Compliance MWs in a zone for an event will be reduced by the total amount of a Provider's Daily RPM Commitment Shortages in a zone for all their Demand Resources on the day of the event.

The total Load Management Zonal Compliance Deficiency Penalties assessed to the Provider in a Delivery Year is capped at the annual revenue the provider's Demand Resources or ILR resources would receive.

Prior to the 2012/2013 Delivery Year, the Demand Resource and ILR Compliance Penalty Charges collected from LM Providers are allocated the third billing month after the event occurs (e.g., June events will be included in the September bill, which is issued in October) on a pro-rata basis to those LM Providers that provided load reductions in excess of the amount obligated. Effective with the 2012/2013 Delivery Year, the initial allocation will reflect the credits due for such LM event from the start of the Delivery Year to the last day that is reflected in the initial billing. The remaining LM compliance credits for such event will be assessed daily and billed monthly through the remainder of the Delivery Year. The total event allocation to each over-performing Provider shall not exceed for each committed Demand Resource or ILR resource the volume of excess MWs provided by the Demand Resource or ILR resource during a single event times 1/5 of the daily revenue rate received by the Demand Resource or ILR resource dispatched.

Prior to the 2012/2013 Delivery Year, any Demand Resource and ILR Compliance Penalty Charges not allocated to over-performing Providers are instead allocated to all LSEs in the RTO based on the LSE's average Daily Unforced Capacity Obligation during the month the PJM-initiated Load Management event occurred. Effective with the 2012/2013 Delivery Year, the allocation of the balance of Daily Demand Resource and ILR Compliance Penalty Charges to LSEs in the RTO is based on the LSE's Daily Unforced Capacity Obligation.

Any LM compliance credits to LSEs will have the same bill timing as LM compliance credits to over-performing providers.

9.1.10 Emergency Procedures Charges

The Emergency Procedures Charges outlined in ***Schedule 14 of the Reliability Assurance Agreement*** for refusal to comply or failure to employ all reasonable efforts to comply will remain in effect, and will be assessed in addition to any penalty described here.

9.2 Locational Reliability Charges

9.2.1 Calculation of Locational Reliability Charges

All LSEs pay a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a zone times the applicable Final Zonal Capacity Price.

$$\textit{Locational Reliability Charge} = \textit{DailyUnforced Capacity Obligation} \times \textit{Final Zonal Capacity Price}$$

Each LSE that serves load in a PJM Zone or load outside PJM using PJM resources (Non-Zone Network Load) during the Delivery Year is responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a Zone times the applicable Final Zonal Capacity Price for that Delivery Year.

Locational Reliability Charges are calculated daily and billed monthly during the Delivery Year.

9.3 Auction Credits and Charges

9.3.1 Calculation of Auction Credits

Each generation, demand, or Qualified Transmission Upgrade resource provider that clears a Sell Offer in an RPM Auction will receive an Auction Credit equal to the MW amount that cleared for the resource times the applicable resource's clearing price in the applicable auction.

$$\textit{RPM Auction Credits} = \textit{MWCleared}_{\text{in LDA}} \times \textit{ResourceClearingPrice}_{\text{in LDA}}$$

The PJM Generation Deactivation Credits received by units with Reliability Must Run (RMR) contracts will be reduced by the Auction Credits received by the RMR unit in a RPM Auction.

If resource provider cannot provide Demand Resource data on individual LDA basis in a Zone with multiple LDAs, Demand Resources will be paid a Weighted Zonal Resource Clearing Price. The Weighted Zonal Resource Clearing Price for a Zone that includes non-overlapping LDAs is the weighted average of the Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Resources Cleared (including make-whole MWs) in each such LDA. If the Zone has a smaller LDA within a larger LDA then the Weighted Zonal Resource Clearing Price is calculated using the smaller LDA and the remaining portion of the larger LDA.

Auction Credits are be calculated daily and billed monthly during the Delivery Year.

9.3.2 Calculation of Auction Charges

Each resource provider that clears a Buy Bid in the First or Third Incremental Auction will receive an Auction Charge (referred to as Resource Substitution Charge in OATT) equal to the MW amount that cleared in the LDA times the Resource Clearing Price in the LDA in the applicable Incremental Auction.

$$RPM\,Auction\,Charges = MWCleared_{in\,LDA} \times ResourceClearingPrice_{in\,LDA}$$

Auction Charges are calculated daily and billed monthly during the Delivery Year.

9.3.3 Resource Make-Whole Credit

Resource Make-Whole Credit is paid to the marginal resource in an RPM auction as appropriate to ensure the seller is paid the sell offer MW times the sell offer price. Resource Make-Whole Credit is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the RPM Auction.

$$Resourcemake-WholeCredit = (MinMW\,Offered - ClearedMW) \times ResourceClearingPrice_{in\,LDA}$$

Resource Make-Whole Credits from the First or Third Incremental Auctions are charged to all cleared buy bids on a pro-rata basis based on the MWs cleared in such auction.

9.3.4 Capacity Transfer Rights Credit

Each Zonal Capacity Transfer Rights (CTRs) owner will receive a daily Zonal CTR Credit equal to the Zonal CTRs owned multiplied by the Zonal CTR Settlement Rate. Zonal CTRs owned include the Zonal CTRs allocated to an LSE and the results of any CTR transfers. The Zonal CTR Settlement Rate is the Total Economic Value of CTRs in Zone ($/day) as a result of the Base Residual Auction and Second Incremental Auction divided by the total Zonal CTRs (MWs) allocated to LSEs.

$$ZonalCTRCredit = ZonalCTRsOwned \times ZonalCTRSettlementRate$$

Each Incremental CTR owner will receive a daily Incremental CTR Credit equal to the Incremental CTRs owned multiplied by the Zonal Incremental CTR Credit Rate. Credits will be calculated daily and billed monthly during the Delivery Year.

$$IncrementalCTRCredit = IncrementalCTRsOwned \times ZonalIncrementalCTRCreditRate$$

CTR Credits will be calculated daily and billed monthly during the Delivery Year.

9.3.5 Auction Specific MW Transaction Credits and Charges

The Seller of an Auction Specific Capacity Transaction will receive a charge equal to the transaction amount (in MW) times the price associated with the transaction. The price associated with the transaction is a weighted average of the Resource Clearing Prices of the resource-specific, auction-specific Cleared MWs identified in the transaction.

$$SellerCharge = TransactionAmount \times WeightedAverageResourceClearingPrice$$

The Buyer of an Auction Specific MW Transaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction.

$$BuyerCredit = TransactionAmount \times WeightedAverageResourceClearingPrice$$

Charges and Credits for Auction Specific MW Transactions are calculated daily and billed monthly for the duration of the transaction during the Delivery Year.

9.3.6 Interruptible Load for Reliability Credits

Each Interruptible for Load Reliability (ILR) resource provider will receive an ILR Credit equal to the zonal MW amount certified for the ILR resource times the Final Zonal ILR Price.

$$ILRReliabilityCredits = ZonalMWsCertified \times FinalZonalILRPrice$$

ILR Reliability Credits are calculated daily and billed monthly during the Delivery Year.

9.3.7 Capacity Export Charges and Credits

Capacity Export Charge = Export Reserved Capacity * (Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported - Final Zonal Capacity Price for the Zone in which the resource designated for the export is located)

Where, Export Reserved Capacity = Reserved Capacity of Long-Term Firm Transmission Service used for the export.

Capacity Export Credit = Export Customer's Allocated Share * (Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported - the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located)

Where,

Export Customer's Allocated Share = (Unforced Capacity imported) * [Export Reserved Capacity / (Export Reserved Capacity + Unforced Capacity Obligations of all LSEs in the Zone)]

Unforced Capacity imported = Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located =

[(Export Reserved Capacity + Unforced Capacity Obligations of all LSEs in the Zone) – (Unforced Capacity cleared in the Zone) – (ILR)] *

(Ratio, as determined by PJM, of the CETL from the Zone in which the resource designated for export is located to the total CETL into the export interface Zone).

The revenues collected from Capacity Export Charge less the credit provided will be distributed to the LSEs in the export-interface Zone that were assessed Locational Reliability Charge for the delivery year (RPM LSEs) based on their Daily Unforced Capacity Obligations.

Section 10: eRPM

Welcome to the *eRPM* section of the PJM Manual for the *PJM Capacity Market*. In this section, you will find the following information:

- A description of the PJM eRPM Auction system (see "PJM eRPM Overview").

10.1 Overview

PJM eRPM is an Internet application that allows Market Participants to participate in PJM's RPM Auctions and view load and obligation data. Figure 9.1 presents a conceptual view of the RPM auction subsystems.

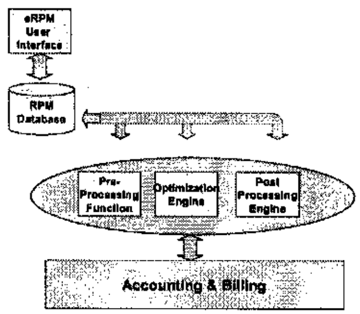


Exhibit 4: RPM Auction Subsystems

The Market User Interface (MUI) allows market participants to:

- Maintain their resource portfolio by increasing or decreasing their installed capacity values for generation, demand resources, and energy efficiency resources via Capacity Modifications, Demand Resource Modifications, and Energy Efficiency Modifications.
- Report Unit Specific Bilateral Transactions with a counterparty
- Report Auction Specific MW Transactions with a counterparty
- Report Locational UCAP Transactions
- Report Cleared Buy Bid Transactions
- Submit Resource Offers to sell capacity into an RPM auction
- Submit replacements for RPM Auction Commitments
- View Auction Results
- View load and obligation data
- View deficiency data related to RPM Auction Commitments

All data entered into the MUI is validated and entered into the RPM database by the MUI.

The RPM auction subsystem consists of the following three components:

- *Pre-processing Function* – performs all activities necessary to setup Auctions, including specifying the Planning Year Parameters as inputs into the solution and evaluating submitted resource offers.
- *Optimization Engine* – performs auction clearing process to ensure the most economical capacity threshold is met. Assigns unit commitments based on the entered offers, demand curves, and specific planning year parameters.
- *Post-processing Function* – ensures that the appropriate data items are transferred to the RPM auction database for posting on the MUI and ensures the results are transferred to the accounting and billing subsystems.

Section 11: Fixed Resource Requirement Alternative

Welcome to the *Fixed Resource Requirement Alternative* section of the PJM Manual for the *PJM Capacity Markets*. In this section, you will find the following information:

- An overview of the Fixed Resource Requirement Alternative (see "Overview of the Fixed Resource Requirement Alternative")
- The business rules for determining Load Obligations in FRR (see "Load Obligations")
- The business rules for creating the Capacity Plan in FRR (see "Capacity Plan")
- The business rules for supply resources in the FRR Alternative (see "Supply Resources in the FRR Alternative"
- The business rules for locational constraints in the FRR Alternative (see "Locational Constraints in the FRR Alternative")
- The conditions on sales by FRR Entities (see "Conditions on Sales by FRR Entities")
- The business rules for Delivery Year Activity (see "Deliver Year Activity")
- The business rules for the calculation of deficiency charges and penalties (see "Deficiency Charges and Penalties")
- The business rules for the allocation of deficiency charges (see "Allocation of Deficiency Charges")
- The business rules for Auction Specific MW Transactions (see "Auction Specific MW Transactions"

11.1 Overview

11.1.1 Definition and Purpose of Fixed Resource Requirement Alternative

The purpose of the Fixed Resource Requirement (FRR) Alternative is to provide a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

The FRR Alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Base Residual Auctions and the Incremental Auctions; however, such LSE is required to submit a FRR Capacity Plan to satisfy the unforced capacity obligation for all loads in an FRR Service Area, including all expected load growth in the FRR Service Area.

An LSE serving load in an FRR Service Area under the FRR Alternative does not pay an RPM Locational Reliability Charge. The portions of capacity resources included in an LSE's FRR Capacity Plan do not receive any RPM Resource Clearing Prices.

11.1.2 Implementation of the FRR Alternative

Implementation of the FRR Alternative starts with the 2007/2008 Delivery Year. PJM's Planning Period is defined as an annual period from June 1 to May 31. The Delivery Year is the Planning Period for which resources are being committed and for which a constant load

obligation for the entire PJM region exists. For example, the 2007/2008 Delivery Year corresponds to the June 1, 2007-May 31, 2008 Planning Period.

The Transition Period of FRR Alternative takes place during the 2007/2008 through 2010/2011 Delivery Years. The following Transition Timetable for FRR activities applies for the 2007/2008 through 2010/2011 Delivery Years.

FRR Activity	2007/2008	2008/2009	2009/2010	2010/2011
Post Parameters for DY	02/02/07	02/02/07	02/02/07	10/26/07
Election of FRR Alternative starting with DY	02/16/07	02/16/07	07/31/07	11/16/07
Submittal of FRR Capacity Plan	03/02/07	03/02/07	08/31/07	12/17/07
Post Final PJM Region/Zonal Peak Load Forecasts	Already posted on 02/02/07	Already posted on 02/02/07	01/31/09	01/31/10
Final EFORd fixed for DY	Posted to eCapacity by 01/02/07	11/30/07	11/28/08	11/30/09

The steady-state condition of FRR Alternative begins with the 2011/2012 Delivery Year. Unless otherwise specified, the rules and timeframes presented throughout this Manual are for the steady-state condition of FRR Alternative.

11.1.3 Participation in the FRR Alternative

An LSE may participate in the Fixed Resource Requirement (FRR) Alternative and avoid *participation in RPM, only if the LSE meets the eligibility requirements* of the Fixed Resource Requirement (FRR) Alternative as defined in Schedule 8.1 of the Reliability Assurance Agreement (RAA).

To elect the FRR Alternative, an LSE must notify PJM of such election in writing at least two months before the conduct of the Base Residual Auction (BRA) for the first Delivery Year that such election is to be effective.

The election of the FRR Alternative shall be for a minimum term of five consecutive Delivery Years.

The written election notification must provide adequate information to demonstrate that the LSE meets the eligibility requirements of the FRR Alternative and that the FRR Service Area identified to be served by the LSE under the FRR Alternative complies with the meaning of an FRR Service Area as defined in the RAA. The written election must also indicate whether or not the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such capacity resources in any RPM Auctions or as replacement resources in RPM or whether the LSE intends to serve load in another area under RPM.

Within ten business days of the receipt of the written election notification, PJM will validate that the LSE meets the eligibility requirements of the FRR Alternative. PJM will also request confirmation from the EDC that the identified FRR Service Area is metered and complies with the meaning of an FRR Service Area as defined in the RAA. PJM will (1) notify such LSE in writing that its election of the FRR Alternative is valid and the appropriate modifications to the eRPM database have been completed to allow the LSE to submit a FRR Capacity Plan through the eRPM system or (2) notify an LSE in writing that its election of the FRR Alternative is invalid since it did not meet the eligibility requirements of the FRR Alternative or that the identified FRR Service Area does not comply with the meaning of an FRR Service Area as defined in the RAA.[16]

If PJM has provided written notice to an LSE that its election of the FRR Alternative is invalid, the LSE will be required to serve its load under the RPM for the Delivery Year such election was to be effective.

If PJM has provided written notice to an LSE that its election of the FRR Alternative is valid, an LSE must submit its initial FRR Capacity Plan through the eRPM system[17] at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year that such election is to be effective.

An LSE may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum term of five consecutive Delivery Years. Written notice of such termination must be provided to PJM no later than two months prior to the Base Residual Auction (BRA) for such Delivery Year.

An LSE that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

In the event of a State Regulatory Structural Change as defined in the RAA, an LSE may elect or terminate its election of the FRR Alternative effective as to any Delivery Year by providing written notice to PJM of the election or termination of FRR Alternative. The written notice shall be provided in good faith as soon as the LSE becomes aware of such State Regulatory Change, but no later than two months prior to the BRA for such Delivery Year.

To facilitate the election and notices required by the FRR Alternative, the following information shall be posted by PJM by February 1 prior to the conduct of RPM's Base Residual Auction for the Delivery Year:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Interruptible Load for Reliability (ILR) Forecasts for each modeled LDA (Prior to 2012/13 DY)
- Short-Term Resource Procurement Target (2012/13 Delivery Year and beyond)

[16] For the 2007/2008-2009/2010 Delivery Years, PJM will validate the election of the FRR Alternative and provide notice to the LSE within five business days of the election.

[17] For the 2007/2008 – 2009/2010 Delivery Years, FRR Capacity Plans will need to be submitted manually via an Excel spreadsheet to rpm_hotline@pjm.com. With the written notice to the LSE that their election of the FRR Alternative is valid, PJM will provide Excel spreadsheets for the 2007/2008-2009/2010 Delivery Years that are specific to the LSE electing the FRR Capacity Plan.

- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd
- Forecast Pool Requirement (FPR)
- Demand Resource (DR) Factor
- Reliability Requirements of the PJM Region and each modeled LDA
- Variable Resource Requirement (VRR) Curves of the PJM Region and each modeled LDA
- CETO and CETL values for each modeled LDA
- Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements for the PJM Region and each Modeled LDA (for the 2014/2015 Delivery Year and beyond)
- Transmission Upgrades projected to be in service for the Delivery Year
- Cost of New Entry (CONE) for the PJM Region and each modeled LDA
- Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
- Base Zonal FRR Scaling Factor
- Percentage of Internal Resources Required in an LDA
- Deadline for FRR Capacity Plan Submittal
- Auction Credit Rate
- LSEs electing the FRR Alternative will be subject to the same credit requirements as suppliers of resources into the RPM auctions, to the extent that they submit as part of their FRR Capacity Plan any resources for which credit would be required if offered into an RPM auction.
- Any credit provided by an LSE to satisfy its credit requirements under the FRR Alternative must be established prior to the deadline for submitting the FRR Capacity Plan.

11.2 Load Obligations

Similar to RPM load obligations, FRR load obligations are calculated in two steps. First, prior to the RPM Base Residual Auction based on Preliminary Zonal Peak Load Forecast; then prior to the Third Incremental Auction[18] based on the Final Zonal Peak Load Forecast. Base and Final Zonal FRR Scaling Factors and Forecast Pool Requirement are used in calculating the FRR Entity Unforced Capacity Obligations.

[18] Calculated prior to the Second Incremental Auction for Delivery Years prior to 2012/13 Delivery Year.

11.2.1 Preliminary Unforced Capacity Obligation

PJM will notify the Electric Distribution Company (EDC) that an election of the FRR Alternative was made by an LSE in their zone within two business days of the receipt of the written election notification.

An approved FRR Service Area will become a defined "area" within a zone in the eRPM system.

Only one LSE shall be responsible for serving the entire load in an FRR Service Area.

The Electric Distribution Company (EDC) is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year and providing to PJM a Base Obligation Peak Load allocation for the FRR Service Area(s) in their zone within five business days of the receipt of notice of an FRR Service Area within their zone.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area in a zone equals the LSE's Base Obligation Peak Load in the zone/area * the Base Zonal FRR Scaling Factor * the Forecast Pool Requirement.

The Base Zonal FRR Scaling Factor is equal to Preliminary Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year.[19] The Base Zonal FRR Scaling Factor is posted by February 1 three years prior to the Delivery Year.

The EDC is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer one year prior to the Delivery Year and providing to PJM a Final Obligation Peak Load allocation for the FRR Service Area(s) in their zone by December 31 prior to the start of the Delivery Year.[20]

The Final Zonal FRR Scaling Factor is equal to Final Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the summer one year prior to the Delivery Year. The Final FRR Zonal Scaling Factor is posted by PJM by February 1 prior to the Delivery Year.

The following parameters used in the determination of FRR load obligations are determined in accordance with Section 2 of this manual: Preliminary and Final Zonal Peak Load Forecasts, Zonal Weather Normalized Summer Peaks, Forecast Pool Requirement (FPR), Installed Reserve Margin (IRM), and Pool-wide Average EFORd.

11.2.2 Treatment of Non-Zone Load

Treatment of Non-Zone Load is similar to the treatment under RPM. The FRR Alternative is available to an LSE serving Non-Zone Load if the LSE meets the eligibility and election requirements of the FRR Alternative.

[19] For the 2007/2008 – 2010/2011 Delivery Years, the Base Zonal FRR Scaling Factor is equal to the Preliminary Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the 2006 Summer period.

[20] For the 2007/2008-2010/2011 Delivery Years, the Base Obligation Peak Load is based on the FRR Service Area's allocation of the 2006 Weather Normalized Summer Peak.

Non-Zone Load is the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

Non-Zone Load may be Non-Zone Network Load (Tariff 1.27B) that is charged a Network Integration Transmission Service (NITS) charge (Tariff Attachment H-A) or other load that may be 'grandfathered' from the NITS charge.

PJM forecasts the Preliminary Non-Zone Load for the RPM Delivery Year and includes it in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load of the Zone from which the Non-Zone Load is served, by February 1 prior to the Base Residual Auction.

To serve Non-Zone Load in a Delivery Year under the Fixed Resource Requirement Alternative, the Non-Zone Load should be included in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load prior to the RPM Base Residual Auction for the Delivery Year. In addition, the LSE must satisfy the eligibility and election requirements of the FRR Alternative.

PJM forecasts the final forecast of the Non-Zone Load and includes it in the Final RTO Forecast Peak Load and the Final Zonal Forecast Peak Load that is posted one month prior to the Third Incremental Auction.[21]

EDC that is responsible to determine the Obligation Peak Loads for the Zone will also establish the Obligation Peak Load associated with the Non-Zone Load by December 31 prior to the start of the Delivery Year.

The LSE serving the Non-Zone Load under the FRR Alternative will be responsible to commit resources in their FRR Capacity Plan to cover the non-zone load.

11.2.3 Unauthorized Load Transfer Charge

A Single-Customer LSE, who is typically a large customer serving load at one or more locations, may be eligible to elect the FRR Alternative. Such an election is subject to some restrictions related to his commitment to serve the load. The following rules and penalty charges apply:

- A Single-Customer LSE[22] that elected the FRR Alternative shall be assessed an Unauthorized Load Transfer Charge if that LSE's end-use customer terminates its service from such LSE and (1) obtains service from a party that has not elected the FRR Alternative or (2) obtains service from a party that has elected the FRR Alternative but the Single Customer LSE did not transfer sufficient capacity resources to cover the unforced capacity obligation related to the end-use customer.
- The Unauthorized Load Transfer Charge shall equal two times the Cost of New Entry * Daily Unforced Capacity Obligation related to the end-use customer for the remaining duration of the period for which the Single-Customer LSE elected the FRR Alternative.

[21] Prior to 2012/13 Delivery Year, the Final RTO and Zonal Peak Load Forecasts posted by February 28 prior to the Second Incremental Auction.

[22] A Single-Customer LSE eligibility is defined in Schedule 8.1 the Reliability Assurance Agreement.

- Unauthorized Load Transfer Charges are allocated on a pro-rata basis to all other LSEs (including RPM LSEs) in the RTO based on their Daily Unforced Capacity obligations.

11.2.4 Annexation & Switching of Load

The following business rules address the annexation of service territory by a Public Power Entity and load switching between FRR Entity and RPM LSEs. If an LSE that is a Public Power Entity annexes service territory to include new customers on sites where no load had previously existed, the incremental load will be treated as unanticipated load growth, and the LSE must commit additional resources to cover the additional load obligation associated with this annexed load.

If an LSE that is a Public Power Entity annexes service territory and the load was already included in the Base Residual Auction, the LSE cannot cover the incremental load obligation using the excess of resources from their FRR Capacity Plan. Instead, the LSE will pay the RPM Locational Reliability Charge for this incremental load obligation (including any additional demand curve obligation) since RPM process has already procured capacity resources to cover this load. The charges collected from the LSE will be used to pay capacity resources that that cleared in the Base Residual Auction for that LDA.

If an LSE that is a Public Power Entity annexes service territory and the Base Residual Auction was not held, the LSE must commit resources to cover this incremental load obligation in its FRR Capacity Plan.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE after the Base Residual Auction, the shifted load will be considered as unanticipated load growth for purposes of determining whether to hold the RPM Second Incremental Auction. If a Second Incremental Auction is held, the FRR LSE will have a must offer requirement for sufficient capacity to meet the load obligation of the shifted load. If no Second Incremental Auction is held, the FRR LSE may sell its excess capacity into RPM Auction or bilaterally.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE and the Base Residual Auction has not been conducted for a Delivery Year, the FRR LSE should no longer commit capacity resources for the shifted load in its FRR Capacity Plan. PJM will include the shifted load in the future Base Residual Auctions.

11.3 Capacity Plan

The most important requirement in electing FRR Alternative is for the FRR Entity to commit Capacity Resources to meet their daily unforced capacity obligations, any applicable Percentage of Internal Resources Required in an LDA, plus any additional threshold if the FRR Entity plans to sell capacity. Failure to commit the required resources would result in FRR Commitment Insufficiency Charge and ineligibility to continue the FRR Alternative. An FRR Capacity Plan is the long-term plan for the commitment of Capacity Resources to satisfy the daily zonal unforced capacity obligations of an LSE that has elected the FRR Alternative in an FRR Service Area and any applicable Percentage of Internal Resources Required in a Locational Deliverability Area (LDA).

If the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such a resource in any RPM Auctions or as a replacement resource in RPM, the LSE must also maintain a Threshold Quantity in its FRR Capacity Plan prior to the Delivery Year.

The Threshold Quantity is equal to the Preliminary Daily Unforced Capacity Obligation plus the lesser of (a) 0.03 * Preliminary Daily Unforced Capacity Obligation or (b) 450 MW.

An LSE must submit an initial FRR Capacity Plan at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year by demonstrating that it has sufficient capacity resources in its FRR resource portfolio in eRPM to satisfy[23]:

- LSE's Preliminary Daily Unforced Capacity Obligations by zone for its FRR Service Area;
- any applicable Percentage of Internal Resources Required in LDA;
- the Minimum Annual Resource Requirement and Minimum Extended Summer Resource Requirement; and
- Threshold Quantity, if applicable.

If the initial FRR Capacity Plan does not satisfy the LSE's Preliminary Daily Zonal Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted Deadline for FRR Capacity Plan Submittal, the LSE's election of the FRR Alternative will not be approved by PJM. The LSE will be required to serve its entire load in the FRR Service Area under the RPM for the Delivery Year such election was to be effective.

An LSE must annually demonstrate through the eRPM system no later than one month prior to the Base Residual Auction for each succeeding Delivery Year that it has extended the commitment of sufficient capacity resources to satisfy:

- LSE's Preliminary Daily Unforced Capacity Obligations by zone for its FRR Service Area;
- any applicable Percentage of Internal Resources Required in LDA;
- the Minimum Annual Resource Requirement and Minimum Extended Summer Resource Requirement; and
- Threshold Quantity, if applicable.

If the FRR Capacity Plan for a succeeding Delivery Year does not satisfy the LSE's Preliminary Daily Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted Deadline for FRR Capacity Plan Submittal, the LSE will be assessed an FRR Commitment Insufficiency Charge for any shortage of unforced capacity in meeting the Percentages of Internal Resources Required in LDA or the Preliminary Daily Unforced Capacity Obligations (including any Threshold Quantity) for any remainder of the minimum term of the FRR election. The FRR Commitment Insufficiency Charge in a zone is equal to two times the Cost of New Entry ($/MW-Year) in the zone times the shortage of unforced capacity resources in meeting the obligation. The shortage is defined as the shortage in meeting the Percentage of Internal Resources Required in LDA plus any additional shortage in meeting the Preliminary Daily Unforced Capacity Obligation including any Threshold Quantity Requirement. The shortage amount identified in the first delivery year that this charge is to

[23] For the 2007/2008 – 2009/2010 Delivery Years, FRR Capacity Plans will need to be submitted manually via an Excel spreadsheet torpm_hotline@pjm.com.

be assessed is to be applied in the remaining delivery years that the charge is to be assessed.

FRR Commitment Insufficiency Charges are allocated on a pro-rata basis to all other LSEs (including RPM LSEs) in the RTO based on their Daily Unforced Capacity obligations.

Existing generation, planned generation, bilateral contracts for unit-specific capacity resources, existing demand resources, planned demand resources, and energy efficiency resources may be used in the FRR Capacity Plan if these products meet the requirements specified in the PJM Agreements and Business Rules.

Existing generation that is located outside of the PJM market footprint may be used in the FRR Capacity Plan if the external generation meets the requirements specified in PJM Agreements and Section 4 of this manual.

At the FRR Entity's election, the UCAP MW quantity of generation resources that are committed to the initial FRR Capacity Plan will be determined using the lower of the generation resources' EFORd calculated based on outage data for the 12 months ending September 30th prior to the Base Residual Auction or the 5 Year Average EFORd based on outage data for the 12 months ending September 30th prior to the Base residual Auction.

At the FRR Entity's election and only for the purposes of evaluation of the initial FRR Capacity Plan, the 5 Year Average EFORd for a generation resource having an effective EFORd of 25% or higher may be recalculated excluding outage data for the most recent one year period.

The EFORd applied to the Final FRR Capacity Plan evaluated prior to the Delivery Year will be determined by PJM using the forced outage data for the 12 months ending September 30th prior to the Delivery Year.

Qualifying Transmission Upgrades may be used to reduce the Percentage of Internal Resources Required in an LDA for the FRR LSE if the Qualifying Transmission Upgrade meets the requirements specified in the PJM Agreements and Section 4 of this manual.

A capacity resource used in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit-specific.

An LSE's FRR Capacity Plan for the Delivery Year shall not include any capacity resource that cleared in any RPM Auction for such Delivery Year.

Any capacity resource that was not offered or offered but did not clear in any RPM Auction for such Delivery Year may be included in an FRR Capacity Plan.

An LSE's FRR Capacity Plan for the Delivery Year may include resources that are committed for less than a full Delivery Year; however, the FRR Capacity Plan in aggregate must satisfy all obligations for the Delivery Year.

If an LSE has committed capacity to meet a Threshold Quantity, the LSE shall maintain such resources until the Delivery Year's Final Unforced Capacity Obligation and final requirements (Percentage of Internal Resources Required in LDA, Minimum Annual Resource Requirement, and Minimum Extended Summer Resource Requirements) are known. The LSE may use such resources during the Delivery Year to meet any increased capacity obligation resulting from an increase in Final Obligation Peak Load from Base Obligation Peak Load, or sell the resources to another FRR Entity in PJM or to an External Party.

All generation resources that have a FRR Capacity Plan Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources must be registered to participate in the Full Program Option of the Emergency Load Response Program and thus be available for dispatch during PJM-declared emergency event.

11.4 Supply Resources in the FRR Alternative

The supply resources available and the qualification requirements for use in FRR Capacity Plans are very similar to RPM resources.

11.4.1 Resource Portfolio

An FRR Entity must specify through the eRPM system, before the FRR Capacity Plan Submittal Deadline, the amounts of installed capacity from resources in their eRPM resource portfolio that are being committed to their FRR Capacity Plan for the Delivery Year.

A party's Daily Generation Resource Position is calculated dynamically by the eRPM system for each unit and is equal to the Daily ICAP Owned on a unit multiplied by one minus the unit's Effective EFORd.

The Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

The Installed Capacity (ICAP) Value of a unit is based on the summer net dependable rating of the unit as determined in accordance with PJM's Rules and Procedures for the Determination of Generating Capability.

The EFORd of a unit is based on forced outage data from an October through September period.

If a unit does not have a full one-year history of forced outage data, the EFORd will be calculated using class average EFORd and the available history as described in the Reliability Assurance Agreement, Schedule 5, Section B.

New units are initially assigned a class average EFORd.

The class average EFORds that are used by PJM to calculate a unit's EFORd are posted to the PJM website by November 30 prior to the Delivery Year.

The Effective EFORd is the EFORd that is effective for the delivery day in the eRPM system.

Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the eRPM system.

During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year.

The EFORd that is effective for the Delivery Year is considered locked in the eRPM system by November 30 prior to the execution of the Third Incremental Auction.

A unit that is in a party's Generation Resource portfolio in eRPM may be committed to FRR Capacity Plan if the party has Daily Available ICAP to commit from the unit for the entire term of the commitment specified in the FRR Capacity Plan.[24] If the party's Daily Available

[24] The term of the resource's commitment to the FRR Capacity Plan may be less than a Delivery Year.

ICAP for the unit varies for the term of the commitment specified in the FRR Capacity Plan, only the minimum Daily Available ICAP may be committed for the term of the commitment specified in the FRR Capacity Plan.

For a party, the Daily Available ICAP to commit on a unit is equal to Daily ICAP Owned - (Daily RPM Resource Commitments/(1-Effective EFORd)) – Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity, approved locational UCAP transactions, and the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific generating unit are equal to the total amount of installed capacity that was committed from the unit for the FRR Capacity Plan.

A party's Daily FRR Generation Resource Position for a specific unit is calculated by multiplying the Daily FRR Capacity Plan Commitments by (1-Effective EFORd).

An LSE's Daily Total FRR Generation Resource Position is calculated by summing the Daily FRR Generation Resource Positions of all units in their resource portfolio in eRPM.

An LSE's Daily LDA FRR Generation Resource Position is calculated by summing the Daily FRR Generation Resource Positions of all units in the LDA.

A party's Daily Nominated DR Value for a specific demand resource is equal to the Daily Nominated DR Value as determined by party's "Provisionally Approved" or "Approved" DR Modifications.

A party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the eRPM system and is equal to the Daily Nominated DR Value * DR Factor * Forecast Pool Requirement.

A Demand Resource that is in a party's Demand Resource portfolio may be committed to the FRR Capacity Plan, if there is Daily Available ICAP to commit from the Demand Resource for the entire term of the commitment specified in the FRR Capacity Plan.

For a party, the Daily Available ICAP for a specific demand resource is equal to the resource's Daily Nominated DR Value ((Daily RPM Resource Commitments/(DR Factor *Forecast Pool Requirement)) – Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such demand resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources, approved unit specific transactions for cleared capacity, and approved locational UCAP transactions.

A party's Daily FRR Capacity Plan Commitments for a specific demand resource are equal to the total amount of Nominated DR that was committed from the Demand Resource for the FRR Capacity Plan.

A party's Daily FRR Demand Resource Position for a specific demand resource is equal to Daily FRR Capacity Plan Commitments* DR Factor* Forecast Pool Requirement.

A LSE's Daily Total FRR Demand Resource Position is equal to the sum of the Daily FRR Demand Resource Position of all demand resources in their resource portfolio in eRPM.

A LSE's Daily LDA FRR Demand Resource Position is calculated by summing the Daily FRR Demand Resource Positions of all demand resources in the LDA.

A party's Daily FRR Capacity Plan Commitments for a specific EE Resource are equal to the total amount of Nominated EE that was committed from the EE Resource for the FRR Capacity Plan.

A party's Daily FRR EE Resource Position for a specific EE Resource is equal to Daily FRR Capacity Plan Commitments* DR Factor* Forecast Pool Requirement.

A LSE's Daily Total FRR EE Resource Position is equal to the sum of the Daily FRR EE Resource Position of all EE resources in their resource portfolio in eRPM.

A LSE's Daily LDA FRR EE Resource Position is calculated by summing the Daily FRR EE Resource Positions of all EE resources in the LDA.

An LSE's Daily Total FRR Resource Position is calculated by summing the Daily FRR Generation Resource Positions, Daily FRR Demand Resource Positions, and Daily FRR EE Resource Positions of all resources in their eRPM resource portfolio.

After the FRR Capacity Plan Submittal Deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Preliminary Unforced Capacity Obligation to determine if the LSE has satisfied their Preliminary Unforced Capacity Obligation for the entire Delivery Year.

After the FRR Capacity Plan Submittal Deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Threshold Quantity, if applicable, to determine if the LSE has satisfied their Daily Threshold Quantity for the entire Delivery Year.

During the Delivery Year, an LSE's Daily Total FRR Resource Position is compared to their Daily Final Unforced Capacity Obligation to determine if a Capacity Resource Deficiency Charge is to be assessed.

An LSE's Daily LDA FRR Resource Position is calculated by summing the Daily LDA FRR Generation Resource Positions, Daily LDA FRR Demand Resource Positions, and Daily LDA FRR EE Resource Positions of all resources in their RPM resource portfolio.

After the FRR Capacity Plan Submittal Deadline, an LSE's Daily LDA FRR Resource Position is compared to Amount of Internal Resources Required in the LDA to determine if the LSE has satisfied the Percentage of Internal Resources Required in the LDA for the entire Delivery Year.

During the Delivery Year, an LSE's Daily LDA FRR Resource Position is compared to the Amount of Internal Resources Required in the LDA to determine if a Capacity Resource Deficiency Charge is to be assessed.

11.4.2 Existing Generation

Existing generation located within the PJM region or outside the PJM region is eligible to be committed to the FRR Capacity Plan if it meets the requirements set forth in Section 4 of this manual.

11.4.3 Planned Generation

Planned generation located within the PJM region or outside the PJM region is eligible to be committed to the FRR Capacity Plan if it meets the requirements set forth in Section 4 of this manual.

11.4.4 Capacity Modifications (Cap Mods)

RPM Business Rules regarding Capacity Modifications in Section 4 of this manual apply to the FRR Alternative.

CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and "Provisionally Approved" in the eRPM system in order for the CAP MODs to be considered in a party's Daily Generation Resource Position and the calculation of Available ICAP to commit to the FRR Capacity Plan.

If the status of a "Provisionally Approved" CAP Mod changes to "Denied" or "PJM Withdrawn" all bilateral transactions for the unit will be changed from "Approved" to "Denied". There will be no change to any party's RPM Resource Commitments; however, there may be a change to a party's FRR Capacity Commitments.

11.4.5 Bilateral Unit-Specific Transactions

RPM Business Rules regarding Bilateral Unit-Specific Transactions in Section 4 of this manual apply to the FRR Alternative.

Available or Unoffered Installed capacity purchased through a bilateral unit-specific transaction that is reported via PJM's eRPM system may be committed to an FRR Capacity Plan.

All unit-specific bilateral transactions that are in the "Provisionally Approved" or "Approved" status in the eRPM system will be considered in a party's Daily Generation Resource Position and the calculation of Daily Available ICAP to commit.

The Capacity Export Charge and Credit described in Section 4: Supply Resources in the Reliability Pricing Model, under BILATERAL TRANSACTIONS and in Section 9: Settlements are applicable to resources owned by FRR Entities also.

11.4.6 Qualified Transmission Upgrade

A Qualified Transmission Upgrade may be included in an LSE's FRR Capacity Plan. Such a transmission upgrade must be approved and assigned an incremental import capability value into the constrained LDA by the PJM Planning Department at least 45 days prior to deadline for submitting the initial FRR Capacity Plan for the Delivery Year.

An approved Qualified Transmission Upgrade may be used to reduce the Amount of Internal Capacity Required in the LDA for the FRR LSE.

The planned transmission upgrade in-service date must be on or before the start of the Delivery Year.

At a minimum, a facilities study agreement must be executed for the proposed transmission upgrade, in order for approval to be granted and the transmission upgrade must conform to all applicable standards of the PJM Regional Transmission Expansion Planning Process.

If a Qualified Transmission Upgrade is not completed by the start of the Delivery Year, the LSE who included the upgrade as part of their FRR Capacity Plan for the Delivery Year shall provide a replacement in the form of an equivalent amount of capacity resource capability within the applicable LDA by the start of the delivery Year. If replacement capacity is not provided, a Capacity Resource Deficiency Charge may apply.

11.4.7 Load Management Products

A Load Management program (e.g., Direct Load Control, Firm Service Level, or Guaranteed Load Drop program) is eligible to be committed as a Demand Resource (DR) to the FRR Capacity Plan, if the program meets the requirements specified in the Load Data Systems Manual (M-19) and Section 4.3.1 of this manual.

Providers of Planned Demand Resources must also provide a timeline including the milestones, which demonstrates to PJM's satisfaction that the Planned Demand Resources will be available for the start of the Delivery Year, 15 business days prior to a Base Residual Auction, First or Second Incremental Auction. PJM may verify the provider's adherence to the timetable at any time including, but not limited to, 30 days prior to the First and Third Incremental auctions.

The UCAP value of a Demand Resource is the Nominated DR Value * DR Factor * Forecast Pool Requirement. (The DR Factor was formerly known as the ALM Factor).

The Nominated DR Value for a Demand Resource cannot exceed the maximum value determined in accordance with the ***Load Data Systems Manual (M-19)***.

For existing Demand Resources, the maximum load reduction (used in determining the Nominated DR Value) is based on the Peak Load Contributions in place at the time of the submittal of the Load Management Certification upload.

A resource provider who has FRR Capacity Plan Commitments for their demand resource must provide (or contract with another party to provide) the following during the Delivery Year:

Supplemental status reports, detailing Load Management availability, as requested by PJM System Operations in accordance with the PJM Manuals;

After each PJM-initiated Load Management event, customer-specific compliance and verification information within 45 days after the end of the month in which the event occurred, in accordance with Load Data Systems Manual (M-19);

Load drop estimates for all Load Management events (whether initiated by PJM or the resource provider) at the end of each season, in accordance with the Load Data Systems Manual (M-19).

A resource provider who has FRR Capacity Plan Commitments for their demand resource will be subject to the Load Management Event Compliance and Load Management Test Compliance in accordance with Section 8 of this manual.

11.4.8 Demand Resource Modifications (DR MODs)

RPM Business Rules for DR MODs in Section 4 of this manual apply to the FRR Alternative.

DR MODs must be in a "Provisionally Approved" or "Approved" status in order for the DR MOD to be considered in a party's Demand Resource Position and in the calculation of Available ICAP to commit to the FRR Capacity Plan.

Once all approved registrations for relevant Delivery Year have been received by PJM, a DR MOD increase/decrease for the Demand Resource will be entered by PJM in eRPM if the nominated value of the Demand Resource in a zone/area increases/decreases due to an increase/decrease in Peak Load Contribution values and/or due to changes in EDC Loss Factors. This DR MOD will be submitted and approved by PJM in the eRPM system in order to be reflected in a party's Demand Resource position for the relevant Delivery Year. A DR Mod decrease may result in the reduction of FRR Capacity Plan Commitments.

11.5 Energy Efficiency Resources

An EE Resource may commit to an FRR Capacity Plan for a maximum of up to four consecutive Delivery Years. The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year. The time period of Energy Efficiency installations and their associated eligibility, in addition to the modeling of EE Resources in the PJM Capacity Market, is presented in ***PJM Manual 18B: Energy Efficiency Measurement &Verification,***

An EE Resource must meet the following minimum requirements:

- Submit Initial Measurement &Verification (M&V) Plan no later than 30 days prior to the FRR Capacity Plan submittal in which the EE Resource is initially committed
- Submit Updated M&V Plan no later than 30 days prior to next FRR Capacity Plan submittal in which EE Resource is subsequently committed
- Establish credit with PJM Credit Department prior to FRR Capacity Plan submittal (for planned EE Resources)
- Submit Energy Efficiency Resource Modification (EE MOD) in eRPM system
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed
- Submit Updated Post-Installation M&V Reports no later than business 15 days prior to each subsequent Delivery Year that the EE Resource is committed
- Permit Post- Installation M&V Audit(s) by PJM or Independent Third Party.

PJM Manual 18B: Energy Efficiency Measurement & Verification establishes the requirements for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports, and the M&V Audit.

11.5.1 Energy Efficiency Modifications (EE MODs)

RPM Business Rules for EE MODs in Section 4 of this manual apply to the FRR Alternative.

EE MODs must be in a "Provisionally Approved" or "Approved" status in order for the EE MOD to be considered in a party's EE Resource Position and in the calculation of Available ICAP to commit to the FRR Capacity Plan.

An EE MOD may be required prior to the Delivery Year to reflect the final Nominated EE Value of an EE Resource for the Delivery Year. An EE MOD decrease may result in the reduction of FRR Capacity Plan Commitments.

11.6 Locational Constraints in the FRR Alternative

As discussed in Section 2 locational constraints may require modeling constrained Locational Deliverability Areas (LDAs) separately. Locational Constraints are used to define the minimum Percentage of Internal Resources Required for a constrained LDA in the FRR Capacity Plan.

The constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year will be posted on the PJM website by February 1 prior to the commencement of the Base Residual Auction for that Delivery Year.

An LDA has a limited import capability to import resources from outside the LDA. In RPM these imported resources are considered in clearing the auction in an LDA and the auction results would reflect the effect of the imports in reducing the LDA clearing price. Similar to RPM Entities, FRR Entities are provided the benefit of import capability by allowing them to include some resources from outside the LDA in their Capacity Plan. The minimum Percentage of Internal Resources Required in a constrained LDA for the Delivery Year will be posted by February 1 prior to the commencement of the RPM Base Residual Auction for such Delivery Year. This Percentage of Internal Resources Required in an LDA is used to determine the Amount of Internal Resources Required (UCAP MWs) by the FRR LSE in the LDA. An approved Qualified Transmission Upgrade may be used to reduce the Amount of Internal Capacity Required in the LDA for the FRR LSE. An LSE must include enough capacity resource in its FRR Capacity Plan to satisfy the Amount of Internal Resources Required in the LDA. These capacity resources must be physically located in the LDA in which the FRR Service Area is located in order to satisfy this requirement.

The LDA Reliability Requirement is the projected internal capacity in the LDA plus the Capacity Emergency Transfer Objective (CETO) for the Delivery Year, as determined by the RTEP process. The internal resource requirement in an LDA is the LDA Reliability Requirement less the Capacity Emergency Transfer Limit (CETL) for the Delivery Year, as determined by the RTEP process. This internal resource requirement is expressed as a percentage of the Unforced Capacity Obligation based on Preliminary LDA/Zonal Peak Load Forecast multiplied by FPR to determine the Amount of Internal Resources (UCAP MWs) Required by the FRR LSE in the LDA.

Capacity Transfer Rights (CTRs) are implicitly allocated to the FRR LSE in the determination of the Percentage of Internal Resources Required in an LDA. An FRR LSE will not be eligible for any explicit CTRs.

11.7 Conditions on Sales by FRR Entities

If an FRR LSE has not satisfied a Threshold Quantity, they may not offer to sell capacity in excess of the amount needed to satisfy Preliminary/Final Daily Unforced Capacity Obligation bilaterally into RPM or in RPM Auctions; however, they may offer to sell such excess capacity to an External Party (i.e., delist) or to an FRR Entity. If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the amount needed to satisfy their Threshold Quantity bilaterally into RPM or in RPM Auctions up to a Sales Cap Amount. The Sales Cap and other rules related to sales by FRR Entities are shown below:

- The Sales Cap Amount is equal to the lesser of (a) [(0.25 * Preliminary Unforced Capacity Obligation or (b) 1300 MW.
- If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the Preliminary/Final Daily Unforced Capacity Obligation to an External Party (i.e., delist) or to another FRR Entity. In order for this type of sale to proceed, the Seller's FRR Capacity Commitments on the unit must be reduced.
- Sell offers in RPM Auctions and bilateral unit-specific transactions will be subject to offer and bilateral transaction checks to ensure that the seller does not violate any "Conditions on Sales by FRR Entities".
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" will be rejected.

If an FRR LSE serves load under the FRR Alternative and additional load under the RPM, the LSE may self-supply capacity resources in RPM Auctions and avoid the requirement to satisfy a Threshold Quantity; however, the MW amount of their sell offer(s) may not exceed a Self-Supply Offer Cap Amount.

- The Self-Supply Offer Cap Amount is the lesser of (a) 0.25 * (FRR Preliminary Daily Unforced Capacity Obligation + RPM Expected UCAP Obligation) or (b) 200 MW.
- An LSE's RPM Expected UCAP Obligation in a Zone is equal to the LSE's allocation of the Zonal Weather Normalized Summer Peak for summer four years prior to the Delivery Year (i.e., an Obligation Peak Load) * (Preliminary Zonal Peak Load Forecast/Zonal Weather Normalized Summer Peak for summer four years prior to Delivery Year) * Forecast Pool Requirement.

11.8 Delivery Year Activity

11.8.1 Final Daily Unforced Capacity Obligation

The Final Daily Unforced Capacity Obligation of an LSE in a zone equals the LSE's Final Obligation Peak Load in the zone * the Final Zonal FRR Scaling Factor * the Forecast Pool Requirement. Effective 2012/2013, the Forecast Pool Requirement updated for the RPM Third Incremental Auction will be used.

A reduction in the Daily Unforced Capacity Obligation is applicable in the case of annexation of service territory where the FRR load is acquired by a party that has not elected FRR alternative.

11.9 Deficiency Charges & Penalties

11.9.1 FRR Capacity Resource Deficiency Charges

An LSE participating in the FRR Capacity Plan Alternative will pay a FRR Capacity Resource Deficiency Charge in the delivery year for any shortage of resources to meet the Final Daily Unforced Capacity Obligation and the Amount of Internal Resources Required in an LDA.

A shortage/excess of resources to meet the Amount of Internal Resources Required in an LDA is calculated by comparing an LSE's Daily LDA FRR Resource Position to the Amount of Internal Resources Required in an LDA. If the Daily LDA FRR Resource Position is less than the Amount of Internal Resources Required in an LDA, a FRR Capacity Resource Deficiency Charge for this shortage will be assessed.

A shortage/excess of resources to meet the Final Daily Unforced Capacity Obligation is calculated by comparing an LSE's Daily Total FRR Resource Position to their Final Daily Unforced Capacity Obligation. If the Daily Total FRR Resource Position is less than Final Daily Unforced Capacity Obligation, a deficiency charge for this shortage less the shortage calculated for failure to satisfy the Amount of Internal Resources Required in the LDA will be assessed.

Shortages in meeting the Minimum Annual Resource Requirement in an LDA and the Minimum Extended Summer Resource Requirement in an LDA are calculated separately.

A shortage of Annual Resources to meet the Final Daily Minimum Annual Resource Requirement in an LDA is calculated by comparing the total Annual Resources in an LDA that comprise the LSE's Daily Total FRR Resource Position to their Final Daily Minimum Annual Resource Requirement in an LDA. If the total amount of Annual Resources in an LDA that comprise the Daily Total FRR Resource Position is less than Final Daily Minimum Annual Resource Requirement in an LDA, a deficiency charge for this shortage will be assessed (starting with the 2014/2015 Delivery Year).

A shortage of in the total amount of Annual Resources and Extended Summer Demand Resources in an LDA to meet the Final Daily Minimum Extended Summer Resource Requirement in an LDA is calculated by comparing the total Annual Resources and Extended Summer Demand Resources in an LDA that comprise the LSE's Daily Total FRR Resource Position to their Final Daily Minimum Extended Summer Resource Requirement in an LDA. If the total amount of Annual Resources and Extended Summer Demand Resources that comprise the Daily Total FRR Resource Position is less than Final Daily Minimum Extended Summer Resource Requirement in an LDA, a deficiency charge for this shortage will be assessed (starting with the 2014/2015 Delivery Year).

The FRR Capacity Resource Deficiency Charge is equal to 1.2 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such zone, weight-averaged for the Delivery Year based on the prices established and the quantities cleared in such auctions, multiplied by the shortage.

FRR Capacity Resource Deficiency Charges are assessed daily and billed monthly.

11.9.2 Transmission Upgrade Delay

If a Qualifying Transmission Upgrade is not completed by the start of the Delivery Year and the upgrade was not replaced with an equivalent amount of Capacity Resources in the LDA into which the import capability was to be increased, then the Amount of Internal Capacity Resources Required in an LDA will be increased and the LSE may be assessed a FRR Capacity Resource Deficiency Charge.

11.9.3 Peak-Hour Period Availability Charge

All generation resources that have FRR Capacity Plan Commitments are subject to the Generating Unit Peak Period Availability Measure.

RPM Business Rules regarding the Generation Unit Peak Period Availability Measure and Peak-Hour Availability Charge in Section 8 of this manual apply to the FRR Alternative.

11.9.4 Generation Resource Rating Test Failure Charge

All generation resources that have FRR Capacity Plan Commitments are subject to Capacity Testing for both the Summer and Winter Periods.

RPM Business Rules regarding the Capacity Testing and Generation Resource Rating Test Failure Charges apply to the FRR Alternative. Peak Season Maintenance Compliance Penalty Charge.

11.9.5 Peak Season Maintenance Compliance Penalty Charge

All generation resources that have FRR Capacity Plan Commitments are subject to Peak Season Maintenance Compliance.

RPM Business Rules regarding the Peak Season Maintenance Compliance Penalty Charges apply to the FRR Alternative.

11.9.6 Load Management Event Compliance Penalties

LSEs that have committed Demand Resources to their FRR Capacity Plan are subject to a compliance check performed after each PJM-initiated Load Management event that occurs during the months June through September.

Please refer to Section 8 of this manual for details on Load Management Event Compliance.

11.9.7 Load Management Test Compliance

Effective 2009/10 Delivery Year, DR and ILR Resource providers are required to simultaneously test all of their committed DR and certified ILR resources in a zone if no PJM-initiated load management event is called by PJM during the Delivery Year.

Please see Section 8 of this manual for details on Load Management Test Compliance.

11.10 Allocation of Deficiency Charges

The Daily FRR Capacity Resource Deficiency Charges, FRR Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, and Peak Season Maintenance Compliance Penalty Charges, and Load Management Test Failure Charges are distributed on a pro-rata basis to the LSEs in the RTO that were charged an RPM Locational Reliability Charge.

Daily Capacity Resource Deficiency Charges, Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, and Peak Season Maintenance Compliance Penalty Charges, and Load Management Test Failure Charges are allocated on a pro-rata basis to RPM LSEs based on their daily unforced capacity obligation.

11.11 Auction Specific MW Transactions

11.11.1 Auction Specific MW Transactions

LSEs that elect the FRR Alternative may report Auction Specific MWTransactions if they have cleared capacity in RPM Auctions through the eRPM system.

Approved Auction Specific MW Transactions do not contribute to the Sales Cap Amount for RPM Auctions described in the FRR Business Rules.

Appendix A: Glossary of Terms

Welcome to the *Glossary of Terms* section of the PJM Manual for the *Capacity Market*. In this section, you will find the following information:

Glossary of Terms

Active Load Management (ALM) – prior to the implementation of RPM, the term that referred to end-use customer load which can be interrupted at the request of PJM.

Adjusted Zonal Capacity Prices – are the results of the Second Incremental Auction. Preliminary Zonal Capacity Prices that result from the Base Residual Auction are adjusted to account for the procurement in the 2nd Incremental Auction for the RTO.

Auction Specific MW Transactions – are transactions reported to PJM via eRPM between a buyer and seller that report the transfer of physical MW between the buyer and seller using the eRPM system and PJM settlement process. Auction Specific MW Transactions are not eligible to be offered in an RPM auction Auction Specific MW Transactions are settled at the weighted average Resource Clearing Price of the MW supplying the transaction.

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 Control Area under specified system conditions.

Base LDA Unforced Capacity Obligation – is equal to the sum of the Base Zonal Unforced Capacity Obligations for all the zones in an LDA and is the result of the clearing of the Base Residual Auction.

Base Offer Segment – is the sell offer segment that may be offered as either a single price quantity for the capacity of the resource or divided into up to ten (10) offer blocks with varying price-quantity pairs that represent various output levels of the resource. The Base Offer Segment will consist of block segments at the specified price-quantity pairs.

Base Residual Auction (BRA) – allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

Base RTO Unforced Capacity Obligation – determined after the clearing of the BRA and is posted with the BRA results. The Base RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the BRA plus the Forecast RTO Interruptible Load for Reliability (ILR) Obligation.

Base Unforced Capacity Imported into an LDA – is equal to the Base LDA Unforced Capacity Obligation less the LDAs Unforced Capacity cleared in the Base Residual Auction less the LDA Forecast ILR Obligation. This value is used to determine the maximum total amount of Capacity Transfer Rights that are allocated into an LDA in the Base Residual Auction for the Delivery Year.

Base Zonal RPM Scaling Factor – is determined for each zone and is equal to the [(Preliminary Zonal Peak Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Years) * ((RTO

Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement))]. Base Zonal RPM Scaling Factors are posted with the Base Residual Auction results.

Base Zonal Unforced Capacity Obligation – determined for each zone and is equal to the (Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement) + Forecast Zonal ILR Obligation. Base Zonal Unforced Capacity Obligations are posted with the Base Residual Auction clearing results.

Behind the Meter Generation – a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of Interconnection. Behind the Meter Generation may not include at any time any portion of a generating unit's capacity that is designated as a Capacity Resource or any portion of the output of a generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market at any time.

Bilateral Market – provides LSEs the opportunity to hedge the Locational Reliability Charge determined through the BRA and Second Incremental Auction. The bilateral market also provides resource providers an opportunity to cover any auction commitment shortages.

Bilateral Unit-Specific Transaction – transaction that enables reporting of the transfer of ownership of a specified amount of installed capacity from a specific unit from one party to another.

Capacity Modification (Cap Mod) – transaction that enables generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in eRPM, or the request an MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

Capacity Resources – includes megawatts of net capacity from existing or planned generation capacity resources or load reduction capability provided by Demand Resources or ILR in the PJM Region.

Capacity Emergency Transfer Limit (CETL) – the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Objective (CETO) – the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency.

Capacity Transfer Rights (CTR) – rights used to allocate the economic value of transmission import capability that exists into a constrained LDA. Serve to offset a portion of the Locational Price Adder charged to load in constrained LDAs.

Control Area – electric power system or combination of electric power systems bounded by interconnection metering and telemetering to which a common generation control scheme is applied in order to:

(a) Match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s) with the load within the electric power system(s)

(b) Maintain scheduled interchange with other Control Areas

(c) Maintain the frequency of the electric power system(s)

(d) Maintain power flows on transmission facilities within appropriate limits to preserve reliability

(e) Provide sufficient generating capacity to maintain operating reserves.

Cost of New Entry (CONE) – Levelized annual cost in ICAP $/MW-Day of a reference combustion turbine to be built in a specific location.

CTR Settlement Rate – The CTR Settlement Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of the Base Residual Auction and Second Incremental Auction divided by the Total CTR MWs allocated to LSEs in the zone.

Daily Unforced Capacity Obligation - of equals the LSE's Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement for an LSE in a zone/area.

Daily Capacity Resource Deficiency Charge – assessed to party when the Daily RPM Resource Position of its resource is less than the Daily RPM Resource Commitment for such resource on a delivery day. This charge is applicable to generation resource, Demand Resource, or Qualified Transmission Upgrade.

Delivery Year – Planning period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2007/2008 Delivery Year corresponds to the June 1, 2007 – May 31, 2008 Planning Period.

Demand Resource – a resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.

Demand Resource Factor (DR Factor) – used to determine the reliability benefit of demand resource products and to assign an appropriate value to demand resource products. The DR Factor is calculated by PJM and is approved and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year.

Demand Resource Modification (DR Mods) – transaction used by PJM to track an increase or decrease of the nominated value of the Demand Resource in a party's resource portfolio in eRPM.

Electric Cooperative – an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distribution Company (EDC) – PJM Member that owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Control Area.

Emergency – an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety

of persons or property; a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scare fuel; or a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End Use Customer – a member that is a retail end-user of electricity within the PJM region.

Equivalent Demand Forced Outage Rate (EFORd) – is a measure of the probability that generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate. See Generator Resource Performance Indices Manual (M-22) for equation.

Equivalent Demand Forced Outage Rate (EFORd-5) – is EFORd determined based on five years of outage data through September 30 prior to the Delivery Year. This is an index similar to EFORd that is the basis for a unit's UCAP value for the Delivery Year, and it does not include the events that are outside management control (OMC events). The index is calculated using Generator Availability Data System (GADS) data in PJM. If a generating unit does not have a full 5 years of history, the EFORd-5 will be calculated using class average EFORd and the available history as described in Reliability Assurance Agreement, Schedule 5, Section C. The class average EFORd will be used for a new generating unit. The class average EFORds that are used by PJM to calculate a unit's EFORd-5 are posted to the PJM website by November 30 prior to the Delivery Year.

Effective EFORd – the most recently calculated EFORd that has been bridged to the eRPM system. During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year. This is the basis for a unit's UCAP value, and it does not include the events that are outside management control (OMC events).

EFORd Offer Segment – is the sell offer segment that specifies an installed capacity MW quantity not to exceed the product of the resource's summer net capability of installed capacity and the potential increase in EFORd as determined in accordance with Section 6.7 (d) (iii) of Attachment DD of the PJM Tariff. A seller may specify a single EFORd Offer Segment for their ownership portion of a specific resource.

Peak-Period Equivalent Forced Outage Rate Peak (EFORp) – is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate during seasonal peak periods. Currently there are two sets of seasonal peak periods. The Summer peak period is defined as June through August non-holiday weekdays from 1400 to 1900. The Winter peak period is defined as January through February non-holiday weekdays from 0700 to 0900 and 1800 to 2000.

Facilities Study Agreement (FSA) – is the agreement that must be executed by a Generation and/or Transmission Interconnection Customer to authorize PJM to proceed with an Interconnection Facilities Study. Refer to PJM OATT section 36.6 for Generation Interconnection projects and OATT section 41.5 for Transmission Interconnection projects.

FERC – Federal Energy Regulatory Commission or any successor federal agency, commission or department.

Final RTO Unforced Capacity Obligation –Effective with the 2012/2013 Delivery Year, the Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year. The RTO unforced capacity obligation through all RPM Auctions is equal to the total MWS cleared in PJM Buy Bids in RPM Auctions less the total MWs cleared in PJM Sell Offers in RPM Auctions.

Final Zonal Capacity Prices – are the capacity prices assessed to RPM Load Serving Entities through the RPM Locational Reliability Charge. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined by PJM after the Third Incremental Auction. Final Zonal Capacity Prices reflect the final price adjustments that may be necessary to account for any granted requests for relief from Capacity Resource Deficiency Charges due to permanent departure of load.

Final Zonal RPM Scaling Factors – used in determining an LSE's Daily Unforced Capacity Obligation. A Final Zonal RPM Scaling Factor for a zone is equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Peak for the summer prior to the Delivery Year). The Final Zonal RPM Scaling Factors are posted February 1st prior to the start of the Delivery Years prior to 2012/2013, or two weeks following the final Incremental Auction starting 2012/2013.

Final Zonal Unforced Capacity Obligation – Effective with the 2012/2013 Delivery Year, the Final Zonal Unforced Capacity Obligation is equal to the zonal allocation of the Final RTO Unforced Capacity Obligation and is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load Forecasts. The Final Zonal UCAP Obligations are determined after the clearing of the final Incremental Auction for the Delivery Year.

Firm Transmission Service – transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement (FRR) – an alternative method for a Party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

FRR Capacity Plan – a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR alternative.

FRR Service Area – the service territory of an IOU as recognized by state law, rule, or order; the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to and regularly reported to the Office of Interconnection or an EDC who agrees to aggregate the meters' load data for the FRR Service Area and regularly report the information to the Office of Interconnection or for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within the area excluding the load of Single-Customer LSEs that are FRR Entities. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Areas is defined as all customers physically connected to transmission or distribution facilities of the Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Forecast Pool Requirement (FPR) – the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region.

Incremental Capacity Transfer Rights – allocated to transmission expansion projects associated with new generation interconnection that were required to meet PJM Deliverability requirements and to Merchant Transmission Expansion projects and are applicable to all such projects that have gone through the PJM interconnection process since the beginning of the PJM RTEPP in 1999. Such incremental Capacity Transfer Rights allocation is based on the incremental increase in import capability across a Locational Constraint that is caused by the transmission facility upgrade.

Installed Reserve Margin (IRM) – used to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. The IRM is determined by PJM in accordance with the PJM Reserve Requirements Manual (M-20). The IRM is approved and posted prior to its use in an RPM Auction for the Delivery Year.

Interruptible Load for Reliability (ILR) Zonal/RTO Forecast – the average of the Zonal ILR nominated each of the five Delivery Years prior to the BRA for the Delivery Year. If five years of ILR history is not available for a Zone that was recently integrated into PJM, an average of the Zonal incremental ldoalaod subject to mandatory interruption by EDC in the two years prior to the BRA will be sued as an estimated ILR for the Zone. Zonal Active Load Management (ALM) data will be used in place of Zonal ILR nominated data when Zonal ILR nominated data for the prior Delivery Years does not exist. The RTO ILR Forecast is the sum of the Zonal ILR Forecasts. A market based methodology will be considered for implementation in the future based on RPM experience. The Forecast Zonal/RTO ILR Obligation is determined by PJM in accordance with the Load Data Systems Manual (M-19) by February 1 prior to its use in the BRA for the Delivery Year.

Flexible Self-Scheduled Resources – are resources specified by an LSE in the Base Residual Auction to provide a mechanism to manage quantity uncertainty related to the Variable Resource Requirement. For each resource-specific sell offer, the LSE must designate a flexible self-scheduling flag as well as an offer price that will be utilized in the market clearing in the event the resource is not needed to cover a specified percentage of the LSE's capacity obligation. Flexible self-scheduled resources will automatically clear the auction if they are needed to supply the LSE's resulting capacity obligation.

Full Requirements Service – wholesale service to supply all of the power needs of a LSE to serve end-users within the PJM Region that are not satisfied by its own generation facilities.

Generation Capacity Resource – a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of the Reliability Assurance Agreement. A generation resource may be an existing or planned Generation Resource.

Generation Owner – a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility is not sufficient to qualify a Member as a Generation Owner.

Generator Forced Outage – an immediate reduction in output or capacity or 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, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions does not constitute a Generator Forced Outage.

Generator Maintenance Outage – the scheduled removal from service of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage.

Generator Planned Outage – the scheduled removal from service of a generating unit for inspection, maintenance or repair with the approval of the office of the Interconnection.

Installed Capacity (ICAP) – value based on the summer net dependable rating of the unit as determined in accordance with PJM's Rules and Procedures of the Determination of Generating Capacity.

Incremental Auctions – Allow for an incremental procurement of resource commitments to satisfy an *increase in the region's unforced capacity obligation due to a load forecast* increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.

Interconnection Service Agreement (ISA) – an agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection.

Interruptible Load for Reliability (ILR) – a resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with PJM Standards that is certified by PJM no later than three months prior to a Delivery Year. Known as **ILR Resource.**

Investor Owned Utility (IOU) – an entity with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Load Management – is the ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

Load Serving Entity (LSE) – any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer that (a) serves end-users within the PJM Control Area, and (b) is granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Control Area.

Locational Constraints – localized capacity import capability limitations that are caused by transmission facility limitations, voltage limitations or stability limitations that are identified for a Delivery Year in the PJM Regional Transmission Expansion Planning Process (RTEPP) prior to each Base Residual Auction. Such Locational Constraints are included in the RPM to recognize and to quantify the locational value of capacity.

Locational Deliverability Area (LDA) – sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Locational Price Adder – an addition to the marginal value of unforced capacity within an LDA as necessary to reflect the price of resources required to relieve the applicable binding locational constraints.

Locational Reliability Charge – Fee applied to each LSE that serves load in PJM during the delivery year. Equal to the LSEs Daily Unforced Capacity Obligation multiplied by the applicable Final Zonal Capacity Price.

Nested LDAs – when an aggregate of Zones, a Zone and its sub-zones are constrained LDAs, the LDAs are referred to as "Nested". When LDAs are nested, the Zonal CTR calculations include allocation of CTRs from RTO to aggregate of Zones as well as CTRs from aggregate of Zones to the Zone.

Net Energy & Ancillary Services (E&AS) Offset – is used to offset the value of Cost of New Entry (CONE) to determine the net value of CONE. This value is calculated using the historical averages of Energy &Ancillary Services revenue data for a reference combustion turbine. During the first three Delivery Years (2007/08, 2008/09, 2009/10), the E&AS Offset is calculated using a historical average of the six most recent calendar years. In the subsequent Delivery Years E&AS Offset is calculated using a historical average of the three most recent calendar years.

New Entry Pricing – is an incentive provided to a Planned Generation Resource where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are capped. This allows Planned Generation Resources to recover the amount of its cost of entry-based offer for up to two additional consecutive years, under certain conditions, and to set the clearing price of all resources within that LDA for all three years.

Nominated DR Value – the nominated value of a Demand Resource or ILR Resource is the value of the maximum load reduction and the process to determine this value is consistent with the process for the determination of the capacity obligation for the customer. Therefore, the maximum load reduction for each resource is adjusted to include system losses.

Non-Retail Behind the Meter Generation – Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Zone Load – the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

Obligation Peak Load – the summation of the weather normalized coincident summer peaks for the previous summer of the end-users for which the Party was responsible on that billing day.

Office of the Interconnection – the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM board.

Partial Requirements Service – wholesale service to supply a specified portion, but not all, of the power needs of a LSE to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Peak Period Capacity Available (PCAP) – Total Unit ICAP Commitment Amount of the generating unit times (1.0 – EFORp).

Percentage Internal Resources Required – for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with physically Capacity Resources located in that LDA.

Planned Demand Resource – a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing a reduction or control on or before the start of the Delivery Year for which the resource is to be committed.

Planned Generation Capacity Resource – a Generation Capacity Resource participating in the generation interconnection process for which Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which the resource is to be committed. A Facilities Study Agreement (FSA) must be executed prior to the BRA for the corresponding Delivery Year and an Interconnection Service Agreement (ISA) must be executed prior to any Incremental Auctions for the corresponding Delivery Year.

Planning Year – Annual period from June 1 to May 31 (also may be referred to as Planning Period).

Pool-Wide Average EFORd – average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all units that are planned to be in service during the delivery year. Determined by PJM and is approved and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. The OMC events are not considered in the EFORd values used to calculate Pool-Wide Average EFORd (this change as a part of RAA was filed with FERC on June 19).

Public Power Entity – any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the above, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrade (QTU) – a proposed enhancement or addition to the Transmission System that will increase the Capacity Emergency Transfer Limit (CETL) into an LDA by a megawatt quantity certified by PJM. A Qualified Transmission Upgrade is scheduled to be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction. Prior to the conduct of the Base Residual Auction for such Delivery Year, a Facilities Study Agreement (FSA) must be executed.

Regional Transmission Expansion Planning Process (RTEPP) – is PJM's comprehensive annual process that examines the three interrelated components of electric power system reliability: load, generation, and transmission. The RTEP Process employs a range of planning study tools and methodologies to analyze and assess each component to ensure that reliability remains firm. The RTEP Process is designed to meet established reliability criteria, keep markets robust and competitive, and ensure stable operations.

Regional Transmission Owner (RTO) – Each entity that owns, leases, or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce or that provides Transmission that is a party to the PJM Transmission Owners Agreement and PJM Operating Agreement

Reliability Pricing Model (RPM) – is PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Resource Clearing Price – is the clearing price in the Base Residual Auction or Incremental Auctions as determined by optimization algorithm for each auction. The Resource Clearing Price within an LDA is equal to the sum of (1) the marginal value of system capacity; and (2) the Locational Price Adder, if any, for the LDA. The Resource Clearing Price for the Unconstrained Market Area is the marginal value of system capacity. PJM posts the Resource Clearing Prices for all resources that clear in the Base Residual Auction and all Buy Bids and Sell Offers that clear in the Incremental Auctions.

RTO Unforced Capacity Obligation – established in the BRA and is used to determine the Base Zonal RPM Scaling Factors to use in determining Base Zonal Unforced Capacity Obligation.

RTO Weather Normalized Summer Peak – the sum of the Zonal Weather Normalized Summer Coincident Peaks.

Self-Scheduled Resources – are resources specified by a resource provider in the Base Residual Auction to provide a mechanism to guarantee that the resource will clear in the Base Residual Auction. For each resource-specific sell offer, if a resource is designated as self-scheduled by the resource provider, the minimum and maximum MW amounts specified must be equal and the sell offer price will be set to zero. Self-Scheduled resources will be cleared first in the Base Residual Auction, and cannot set the clearing price as the marginal resource, since these resources lack flexibility.

Single-Customer LSE – a Party that serves only retail customers that affiliates of such Party; owns or controls generation facilities located at one or more of the retail customer location(s) that in the aggregate satisfy at least 50% of the Party's Unforced Capacity obligations; and serves retail customers where each location's peak load is at least 10 MW and obligation peak load is at least 25 MW and the sum of all locations is at least 100 MW.

Steady State Period – period of time where the auction schedule follows the proposed three year forward planning dates. The steady-state condition of RPM begins with the 2011/12 Delivery Year.

Target Unforced Capacity (TCAP) – the "target" to measure the peak period availability of capacity from the generator in the Delivery Year and it may be different from the Delivery Year UCAP value of such generator. The TCAP for a unit is calculated as the Total Unit ICAP Commitment Amount times (1 – EFORd-5).

Transition Period – period of time where the auction schedule is compressed in order for the auction schedules to occur before the delivery year. The Transition Period takes place during the 2007/08 through 2010/11 Delivery Years.

Transmission Facilities – facilities within the PJM Region that have been approved by or meet the definition of transmission facilities established by FERC; or have been demonstrated to the satisfaction of the Office of Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve al of the power and transmission customers within the PJM Region.

Transmission Owner – a Member that owns or leases, with rights equivalent to ownership, Transmission Facilities. Taking transmission service is not sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity (UCAP) – installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Weighted Zonal Resource Clearing Price – the average of the Resource Clearing Price of the sub-zones, weighted by the Unforced Capacity of Resources Cleared in each of the sub-zones. This value is used to calculate CTR values on a Zonal basis, when a Zone and its sub-zones are constrained LDAs. This is also used to calculate the Auction Credit to DR on the zonal basis if EDC cannot provide DR data by sub-zones.

Weighted Average Resource Clearing Price – the average of the Resource Clearing Prices that result in all the auctions for a specific Capacity Resource, weighted by the Unforced Capacity cleared for that particular resource. This value is used to determine the Daily Peak-Hour Period Availability Charge Rate for an individual resource.

Variable Resource Requirement Curve (VRR) – defines the maximum price for a given level of Capacity Resource commitment relative to the applicable reliability requirement. VRR Curves are defined for the PJM Region and each of the constrained LDAs within the PJM region.

Zonal Capacity Price – the price of UCAP in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year. Zonal Capacity Prices are calculated in the Base Residual Auction or the Second Incremental Auction clearing process as the sum of (1) the marginal value of system capacity for the PJM Region;(2) the Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA); and (3) an adjustment in the Zone, if required, to account for any resource make-whole payments. *Preliminary Zonal Capacity Prices* are the result of the clearing of the Base Residual Auction. *Adjusted Zonal Capacity Prices* are the result of the clearing of the Second Incremental Auction. *Final Zonal Capacity Prices* are determined after the ILR Resources are cCertified (3 months prior to the Delivery Year).

Zonal CTR Credit Rate (Base and Final) – the rate calculated as a ratio of economic value of CTRs to zonal unforced capacity obligation. These rates are calculated as the Base Zonal CTR Credit Rate after the Base Residual Auction (used to calculate Base Zonal ILR Price) and as the Final CTR Credit Rate adjusted for the results of the Second Incremental Auction (used to calculate Final Zonal ILR Price) Zonal CTR Credit Rate is subtracted from Zonal Capacity Price to estimate Net Load Price. .

Zonal ILR Price (Base and Final) – Zonal ILR Prices are the prices paid the Interruptible Load for Reliability that is certified. These prices are calculated as the Base Zonal ILR Price after the Base Residual Auction and as Final Zonal ILR Price adjusted for the results of the Second Incremental Auction.

Zonal CTR Settlement Rate – a rate calculated as a ratio of economic value of CTRs to total CTRs allocated to LSEs in a zone. This rate is used to settle CTRs by calculating credit for CTRs owned.

Zone – an area within the PJM Region or such areas that may be combined as a result of mergers and acquisitions; or added as a result of the expansion of the boundaries of the PJM Region. A Zone will include any Non-Zone Network Load located outside the PJM Region that is served from inside a particular Zone.

Attachment B: Transition Period

Transition Period

The Transition Period of the RPM takes place during the 2007/2008 through 2010/2011 Delivery Years.

The following Transition Timetable for RPM activities applies for the 2007/2008 through 2010/2011 Delivery Years.

RPM Activity	2007/2008	2008/2009	2009/2010	2010/2011
Data collected by MMU for Preliminary Market Structure Screen (MSS)	01/08/07	03/02/07	06/01/07	09/03/07
Post results of Preliminary MSS	02/02/07	04/02/07	07/02/07	10/01/07
Post Parameters for Delivery Year	02/02/07	02/02/07	02/02/07	10/26/2007
Data Submittal (Avoidable Cost Data, Opportunity Cost, & Projected Market Revenues) to MMU if submitting non-zero sell offer price for resource in LDA or Unconstrained LDA Group that fails Preliminary MSS	02/16/07	05/01/07	08/03/07	11/02/07
MMU to notify Capacity Market Sellers of Market Seller Offer Caps	03/02/07	06/01/07	09/03/07	12/03/07
Base Residual Auction	04/02/07-04/13/07	07/02/07-07/13/07	10/01/07-10/12/07	01/21/08-02/01/08
First Incremental Auction	None Held	None Held	None Held	None Held
Post Final RTO/Zonal Peak Load Forecasts	Same as 02/02/07 posting.	Same as 02/02/07 posting.	02/28/08	02/28/09
Second Incremental Auction	None Held	None Held	04/07/08-04/18/08	04/06/09-04/17/09
Final EFORd fixed for Delivery Year	Posted to eCapacity on 01/29/07	11/30/07	11/28/08	11/30/09
Third Incremental Auction	None Held	01/07/08-01/18/08	01/05/09-01/16/09	01/04/10-01/15/10
ILR Nomination	05/18/07	03/03/08	03/02/09	03/01/10

Exhibit 5: RPM Auction Timeline during the Transition Period

Locational Deliverability Areas during Transition Period

During the Transition Period, Locational Deliverability Areas for Each Transition Delivery Year shall be as follows:

Transition Delivery Year	Locational Deliverability Areas
2007/2008, 2008/2009, 2009/2010	• PJM Mid-Atlantic Region and APS • Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL, and RECO) • Southwestern MAAC (PEPCO & BG&E) • RTO
2010/2011	• All 23 LDAs.
2011/2012 and later	• All 25 LDAs.

Attachment C: Authorization to Self-Schedule Capacity

AUTHORIZATION TO SELF-SCHEDULE CAPACITY

This Authorization to Self-Schedule Capacity ("Authorization") of ________________ ("Owner"), effective this ___ day of ____, 20___, hereby authorizes PJM Interconnection, L.L.C. ("PJM") to self-schedule on its behalf capacity associated with a specific generating unit ________________ ("Unit"), which it will own or control for a portion of the delivery year from June 1 to May 31, 20___ to 20___ ("Delivery Year"), with the following other party or parties owning or controlling the Unit for the balance of such delivery year (if known): ________________________________ ("Other Owners"). Owner states that it will own or control the Unit during the period(s) within the Delivery Year from ___/___/___ to ___/___/___ and any additional periods listed hereafter: ________________________________.

RECITALS:

WHEREAS, PJM Interconnection, L.L.C. ("PJM") is a Regional Transmission Organization ("RTO") that administers the Reliability Pricing Model ("RPM"), a centralized market for obtaining the electric capacity resources necessary to ensure resource adequacy in its control area;

WHEREAS, a capacity resource must remain available for the entire delivery year in order to be eligible to offer its capacity in RPM auctions;

WHEREAS, an owner may seek to sell capacity in an RPM auction associated with a generating unit that such owner owns or controls for only a portion of the delivery year as result of a transaction specific to such unit commencing or terminating within a delivery year;

WHEREAS, PJM, in order to facilitate participation in its auctions of all capacity resources potentially available, permits owners collectively to authorize PJM to self-schedule the Unit on their behalf capacity owned or controlled by such owner for a portion of the delivery year,

AUTHORIZATION

NOW, THEREFORE, Owner authorizes PJM to self-schedule its Unit during the years during which it will own or control the Unit for only a portion of the identified delivery year(s), and acknowledges that it understands and accepts the following terms and conditions of this authorization:

1. Each Owner and Other Owner (i) must submit to the PJM-designated electronic mail address a fully prepared and executed Authorization from the Owner and each Other Owner at least 5 business days prior to the opening of the bidding window of an RPM auction and (ii) must submit as the "seller" into the eRPM electronic interface system a new unit-specific transaction(s) indicating "Self Scheduling Coordinator (SELFSC)" as the "buyer" prior to the opening of the auction bidding window. Owner understands that failure of any Other Owner to satisfy both of these requirements shall preclude a Unit from participation in an RPM auction even where Owner otherwise has otherwise fully complied.

2. Because PJM will use the Unit's current $EFOR_d$ rating in the self-schedule, Owner recognizes that, consequently, the Unit's unforced capacity value may change between the time the Unit is offered into the RPM Auction and the delivery year for which the Unit was self-scheduled.

3. Because PJM will self-schedule the Unit, Owner recognizes that the Unit's offer will always clear an auction and that Owner must accept the applicable clearing price.

4. PJM automatically will transfer to Owner (and each Other Owner) the cleared capacity of the Unit for the portion of the Delivery Year during which it owns or controls the Unit, and that, as the "buyer" in this unit specific transaction, the Owner will for the duration of this period be responsible for any Capacity Resources Deficiency Charges that may be assessed (including those resulting from a reduced $EFOR_d$ rating), and, for the duration of the delivery year, its proportional share of any Peak-Hour Period Availability Charges, Generation Test Resource Rating Test Failure Charges, or Peak Season Maintenance Compliance Penalty Charges that may be assessed under RPM rules.

The undersigned, having been granted eRPM Read/Write Access by Owner and duly authorized to act on Owner's behalf, declares to PJM the authority described here above and intends that PJM may rely upon such declaration even to Owner's detriment.

Signed this ____th day of ______________, 20____

____

Signed by: ____________________
Title: ____________________

Revision History

Revision 13 (11/17/2011):

- Revisions for DEOK integration (Sections 2.3.1, 2.3.4, 3.3.1, and Attachment B)

Revision 12 (05/25/2011):

- Confirming Revisions for FERC Order ER11-2898, accepted on 04/04/2011 and effective 04/18/2011, to include changes for:
    - Requirement to provide meter data on a 24-hour basis during the day on which a Load Management event or performance test occurs and for all hours during any other days as required by PJM to calculate load reduction
    - Avoiding double assessment of a penalty (penalty for both RPM Commitment Compliance and Load Management Event or Test Compliance) for a Demand Resource
    - Modification to the load management retest rules
    - Modification and clarification of the rules for use of Demand Resources as replacement capacity
- Confirming Revisions for FERC Order ER11-1909, accepted on 12/20/2010 and effective on 12/27/2010, to include a change to clarify the definition of an EE Resource to reflect that a project qualifying as an EE Resource is one installed at an end-use customer's retail site.
- Revisions to EFORd used for a generation resource in the initial evaluation of a FRR Entity's FRR Capacity Plan for a Delivery Year as approved by stakeholders at the MRC on August 5, 2010.

Revision 11 (04/28/2011)

- Revisions for ATSI integration (Sections 2.3.1, 2.3.4, 3.3.1, and Attachment B)

Revision 10 (06/01/2010)

- Revisions made to rules for Non Unit-specific Capacity Transactions to clarify that PJM will be the counterparty to all transactions, unless market participants expressly and mutually contract between themselves (or self schedule to themselves). Revisions have been approved at the Markets and Reliability Committee on April 21, 2010 and by FERC (Order ER10-1003 issued on May 5, 2010)
- (Reference: FERC Order ER10-1003)

Revision 9 (03/01/2010)

- Clarifying Revisions
- Conforming Revisions for FERC Order ER10-15, accepted on 11/13/09 and effective 12/01/09, to include changes to Credit Rate Change
- Conforming Revisions for FERC Order ER09-1679 accepted on October 29, 2009 and effective November 1, 2009 to include changes for:
- New Entry Pricing Adjustment

- Removal of Existing EE and DR offer caps
- Allocation of LM Test Failure Charges
- Planned DR Deadline - change to 15 business days
- Excess Commitment Credit for LSEs if cannot sell excess in IA
- Reduction in FRR Obligation when Load Forecast is reduced
- Conforming Revisions for FERC Order ER05-1410 accepted on October 30, 2009 and effective 11/1/09 to include changes to Incremental Auctions design
- Conforming Revisions for FERC Order ER09-412 accepted on November 5, 2009 and effective November 13, 2009, to include changes to the trigger for a Conditional IA only for delay of Backbone Transmission Upgrade
    - Conforming Revisions for ER09-1679 to include changes to Revisions for the automated adjustment to Net CONE
    - Conforming Revisions for FERC Order ER10-366 accepted on January 22, 2010 and effective January 31, 2010, to include changes to
- evaluate the method for creation of additional CONE regions
- Revisions to allow Energy Efficiency Resources to participate in Earlier Deliver Years
    - RPM Incremental Auction Times

Revision 8 (01/01/10)

- Revisions approved by stakeholders at MRC on November 11, 2009
- One CSP Rule (Section 4, p 33)
- Permanent Load Departure (Section 8, p 98)
- Tracking Existing DR (Section 4, pp 30-31)
- Revisions approved by stakeholders at MRC on November 30, 2009 (awaiting FERC approval by February 1, 2010)
- Winter Capacity Test Exemption (Sections 4 & 8, pp 24, 27, 104-105)

Revision 7 (08/18/2009)

- Revision to Section 4 to modify business rules to state that RPM suppliers must confirm the modeling of each of their capacity resources (Zone, LDA, Unit Type, State Location) prior to any RPM auction.
- Revision to Section 5 to modify business rules to state that RPM Auction Results will not be posted until 4pm or later on Friday of Auction Clearing week.

Revision 06 (06/18/2009)

- Revisions to include business rules for Cleared Buy Bid and Locational UCAP transactions.
- Revisions required as a result of the March 26, 2009 FERC Order regarding Reliability Pricing Model

Revision 05 (10/03/2008)

- Revisions regarding Transmission Service for External Resources offering into RPM.

Revision 04 (06/08/2008)

- Incorporate Rules for Capacity Export Charge per FERC Order ER07-1050
- (Effective May 30, 2008)

Revision 03 (04/01/2008)

- Established a Min and Max capacity value for Wind Resources offering into an RPM Auction.

Revision 02 (02/21/2008)

- Revisions made for the following changes:
    - Correct an error in the original posting of this Manual. Remove the word "not" in the End-Use Customer Aggregation section of Section 4 to reflect the fact that aggregation of Interruptible for Load (ILR) Resources is allowed.

Revision 01 (02/03/2008)

- Revisions made for the following changes:
    - Current, Minimum, Maximum Available Capacity Position Definitions.
    - Change Final Zonal RPM Scaling Factors posting date from October 31st to January 5th.
    - Allow for Combined Demand Resources and ILR Resources at the same location.

Revision 00 (06/01/07)

- Manual Created for the Implementation of the Reliability Pricing Model, and the Fixed Resource Requirement Alternative.

PJM Manual 18B:

Energy Efficiency Measurement & Verification

Revision: 01

Effective Date: March 1, 2010

Prepared by

PJM Forward Market Operations

PJM 2010

EXHIBIT IEU 3

PENGAD 800-631-6989

PJM Manual 18B

Energy Efficiency Measurement & Verification

Table of Contents

Approval

Approval Date: 03/01/2010
Effective Date: 03/01/2010

Jeff Bastian, Manager

Capacity Market Operations Department

Current Revision

Revision 01 (03/01/2010)

Revisions approved by stakeholders at MRC on November 11, 2009

- One CSP Rule

Conforming Revisions for FERC Order ER10-366 accepted on January 22, 2010 and effective January 31, 2010, to include changes to

- revisions to allow Energy Efficiency Resources to participate in 2011/2012 Deliver Years

Introduction

Welcome to the PJM Manual for *Energy Efficiency Measurement & Verification*. In this Introduction you will find information about PJM Manuals in general, an overview of this PJM Manual in particular, and information on how to use this manual.

- What you can expect from the PJM Manuals (see "About PJM Manuals").
- What you can expect from this PJM Manual (see "About This Manuals).
- How to use this manual (see "Using This Manual").

About PJM Manuals

The PJM Manuals are the administrative, planning, operating, and accounting procedures of the PJM Interconnection. The manuals are grouped under the following categories:

- Regional Transmission Planning Process
- PJM Energy Market
- Transmission
- Reserve
- Accounting and Billing
- PJM Administration
- Miscellaneous.

About This Manual

The PJM Manual for ***Energy Efficiency Measurement & Verification*** is one of the PJM procedure manuals under the Reserve Manuals category. This manual focuses on the measurement and verification of the Nominated Energy Efficiency Value (i.e., the demand reduction value) of Energy Efficiency (EE) Resources. To demonstrate the Nominated Energy Efficiency Value of an EE Resource, EE Resource Providers must comply with the measurement and verification standards defined in this Manual.

This manual provides the framework for a Measurement and Verification (M&V) Plan for an EE Resource. It serves the following purposes:

- Provide a foundation for an M&V plan utilizing a "best practice" approach, which considers technical accuracy and cost-effectiveness.
- Provide guidance on what is essential for a robust Initial M&V Plan for an EE Resource.
- Describe the components of Initial M&V Plans, Updated M&V Plans and Post-Installation M&V Report Submittals.

This manual also refers to other PJM manuals, which define in detail the operating procedures, obligations, reporting requirements, and accounting procedures established to ensure reliable and efficient capacity market operation.

The PJM Manual for ***Energy Efficiency Measurement & Verification*** consists of several sections and attachments. Both the sections and the attachments are listed in the table of contents beginning on page ii.

PJM used the following reference materials to assist in the development of the PJM Manual for ***Energy Efficiency Measure & Verification***:

- ISO New England Manual for Measurement & Verification of Demand Reduction Value from Demand Resources, Manual M-MVDR, Revision 1, October 2007.
- M&V Guidelines for Federal Energy Projects, Version 3.0, USDOE Federal Energy Management Program, April 2008.
- International Performance Measurement and Verification Protocol: Concepts and Options for Determining Energy and Water Savings, EVO-100000-1-2007.

Intended Audience

The intended audiences for this PJM Manual for Energy Efficiency Measurement & Verification are:

- Applicants to the RAA, OA and OATT Operating Agreement of PJM Interconnection, L.L.C.
- Resource providers and those interested in providing EE Resources that will be made available to provide reliable service to loads within the PJM Region.
- Load Serving Entities (LSEs) for load served in the PJM Region.
- PJM Members
- PJM staff
- Parties that may be responsible for performing a M & V Audit

References

There are other PJM documents that provide both background and detail on specific topics. These documents are the primary source for specific requirements and implementation details. This manual does not replace any of the information in those reference documents. The references for the PJM Manual for *Energy Efficiency Measurement & Verification* are:

- PJM Manual for PJM Capacity Market (M-18)
- Schedule 6 of Reliability Assurance Agreement
- Attachment DD of the Open Access Transmission Tariff

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with the "big picture." Then we present details, procedures or references to procedures found in other PJM manuals.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections and attachments
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions
- Attachments that include additional supporting documents, forms, or tables
- A section at the end detailing all previous revisions of this PJM Manual.

Section 1: Overview of Energy Efficiency

Welcome to the *Overview of Energy Efficiency* section of the PJM Manual for *Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- An overview of Energy Efficiency in the PJM Capacity Market (see "Overview of Energy Efficiency")
- Details regarding eligibility of Energy Efficiency installations in the PJM Capacity Market (see "Energy Efficiency Installations and Eligibility")
- Details regarding modeling Energy Efficiency Resources in the PJM Capacity Market (see "Modeling of EE Resources")

1.1 Overview of Energy Efficiency

An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then-current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of Schedule 6 (section M) of the Reliability Assurance Agreement. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE Performance Hours) that is not reflected in the peak load forecast used for the Base Residual Auction for the Delivery Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Note that dispatchable demand may be offered as a Demand Resource in the PJM Capacity Market, rather than an Energy Efficiency Resource. Examples of EE Resources are efficient lighting, appliance, or air conditioning installations; building insulation or process improvements; and permanent load shifts that are not dispatched based on price or other factors. For an end-use customer site, the PJM Member that offers the Energy Efficiency Resource into the PJM Capacity Market may be different than the PJM Member that offers the Demand Resource into the PJM Capacity Market.

An EE Resource may be used as Capacity Resource in the PJM Capacity Market starting with the 2011/12 Delivery Year. Planned energy efficiency projects will be allowed to offer into Reliability Pricing Model (RPM) Auctions or to be committed in a Fixed Resource Requirement (FRR) Alternative Capacity Plan for up to four consecutive Delivery Years. An EE Resource that clears in an RPM Auction will receive an RPM Auction Credit during the Delivery Year equal to the Resource Clearing Price of the Locational Deliverability Area in which the EE Resource resides times the MW amount cleared.

All of the requirements to offer or commit an EE Resource in the PJM Capacity Market are detailed in PJM Manual for PJM Capacity Market (M-18). One of the major requirements includes the measurement and verification of the EE Resource's Nominated EE Value for the Delivery Year. The Nominated EE Value is the expected average demand (MW) reduction during the defined EE Performance Hours in the Delivery Year. The EE Performance Hours are between the hour ending 15:00 Eastern Prevailing Time (EPT) and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday.

A Measurement & Verification (M&V) Plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource and confirming that the Nominated EE Value is achieved. An EE Resource Provider must submit an Initial Measurement & Verification Plan for the EE Resource no later than 30 days prior to the RPM Auction in which the EE Resource is to be initially offered, or no later than 30 days prior to the submittal of an FRR Capacity Plan in which the EE Resource is to be initially committed.[1] An EE Resource Provider must submit an Updated Measurement & Verification Plan for the EE Resource no later than 30 days prior to the next RPM Auction in which the EE Resource is to be subsequently offered, or no later than 30 days prior to the submittal of the next FRR Capacity Plan in which the EE Resource is to be subsequently committed. Post-installation of the EE Resource, an EE Resource Provider must submit an Initial Post-Installation M&V Report for the EE Resource prior to the first Delivery Year that the EE Resource is committed to RPM or FRR Alternative. An EE Resource Provider must submit Updated Post-Installation M&V Reports prior to each subsequent Delivery Year that the resource is committed. Failure to submit an Updated Post-Installation M&V Report prior to a subsequent Delivery Year or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Final Nominated EE Value equal to zero MWs for the Delivery Year.

The last Post-Installation M&V Report submitted and approved by PJM prior to the Delivery Year that the EE Resource is committed establishes the final Nominated EE Value that is used to measure RPM Commitment Compliance during the Delivery Year. Details regarding RPM Commitment Compliance and the associated penalty for failure to deliver the unforced value of an RPM capacity commitment (i.e., Capacity Resource Deficiency Charge) are provided in PJM Manual for PJM Capacity Market (M-18).

PJM reserves the right to audit the results presented in an Initial or Updated Post-Installation M&V Report. The M&V Audit may be conducted any time, including during the defined EE Performance Hours. If the M&V Audit is performed and results finalized prior to the start of a Delivery Year, the Nominated EE Value confirmed by the Audit becomes the Final Nominated EE Value that is used to measure RPM Commitment Compliance during the Delivery Year. If the M&V Audit is performed and results finalized after the start of a Delivery Year, the Nominated EE Value confirmed by the M&V Audit becomes the basis to determine if any incremental RPM Commitment Compliance Shortfall needs to be assessed retroactively from June 1 of the Delivery Year to May 31 of the Delivery Year.

The PJM Manual *for Energy Efficiency Measurement & Verification* establishes the standards and criteria for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports and the M&V Audit.

1.2 Energy Efficiency Installations & Eligibility

The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year.

Energy Efficiency installations prior to June 2007 are fully reflected in the 2008 peak load forecast used for the 2011/12 Base Residual Auction, thus installations prior to June 2007

[1] Initial M&V Plan deadline for offering an EE Resource for 2012/13 Base Residual Auction or for committing an EE Resource for 2012/13 FRR Capacity Plan is extended until April 15, 2009.

are not eligible to participate in RPM Auctions or be committed in an FRR Capacity Plan for the 2011/12 DY.

Energy Efficiency installations between June 2007 and May 2012 are eligible to participate in RPM Auctions or committed in an FRR Capacity Plan for certain Delivery Years in accordance with the following table:

Installation Period	Fully Installed for Summer	Eligible Delivery Years
June 2007 – May 2008	2008	2011/2012
June 2008 – May 2009	2009	2011/2012, 2012/13
June 2009 – May 2010	2010	2011/2012, 2012/13, 2013/14
June 2010 – May 2011	2011	2011/2012, 2012/13, 2013/14, 2014/15
June 2011 – May 2012	2012	2012/13, 2013/14, 2014/15, 2015/16

Energy Efficiency installations after May 2012 that are installed prior to the Delivery Year are eligible to participate in RPM Auctions or to be committed in an FRR Capacity Plan for the Delivery Year and three subsequent Delivery Years as illustrated in the table below.

Installation Period	Fully Installed for Summer	Eligible Delivery Years
June 2012 – May 2013	2013	2013/14, 2014/15, 2015/16, 2016/17
June 2013 – May 2014	2014	2014/15, 2015/16, 2016/17, 2017/18
June 2014 – May 2015	2015	2015/16, 2016/17, 2017/18, 2018/19
June prior to DY – May prior to DY	DY	DY, DY+1, DY+2, DY +3

1.3 Modeling of an EE Resource in the PJM Capacity Market

An EE Resource must be modeled in the eRPM system in order for the EE Resource to participate in the PJM Capacity Market. An EE Resource modeled in the eRPM system shall be an EE project(s) or portion of EE project(s) that represent the installation of EE during a defined period of time.

Installations during the following defined periods of time must be modeled as separate EE Resources in the eRPM system in order for PJM to keep track of an EE Resource's eligibility.

Installation Period	Eligible Delivery Years
June 2007 – May 2008	2011/2012
June 2008 – May 2009	2011/2012, 2012/13
June 2009 – May 2010	2011/2012, 2012/13, 2013/14
June 2010 – May 2011	2011/2012, 2012/13, 2013/14, 2014/15
June 2011 – May 2012	2012/13, 2013/14, 2014/15, 2015/16
June 2012 – May 2013	2013/14, 2014/15, 2015/16, 2016/17
June 2013 – May 2014	2014/15, 2015/16, 2016/17, 2017/18
June 2014 – May 2015	2015/16, 2016/17, 2017/18, 2018/19
June prior to DY – May prior to DY	DY, DY+1, DY+2, DY +3

A Resource Provider may create a single EE Resource that represents all EE installations during the defined installation period or create multiple EE Resources to represent different types of EE projects that are being installed during the same installation period. For example:

Resource Name	Installation Period	Eligible Delivery Years
XYZ_EE Lighting_J11M12	June 2011 – May 2012	2012/13, 2013/14, 2014/15, 2015/16
XYZ_EE A/C_J11M12	June 2011 – May 2012	2012/13, 2013/14, 2014/15, 2015/16
XYZ_EE Lighting_J12M13	June 2012 – May 2013	2013/14, 2014/15, 2015/16, 2016/17
XYZ_EE A/C_J12M13	June 2012 – May 2013	2013/14, 2014/15, 2015/16, 2016/17

A distinct name must be established for each EE Resource. At least two weeks prior to the initial offering of an EE Resource in an RPM Auction or initial committal of an EE Resource in an FRR Capacity Plan, the EE Resource Provider shall contact PJM at rpm_hotline@pjm.com to establish the name of the EE Resource and to request PJM to model the EE Resource in the RPM system database. Once the EE Resource is modeled in the RPM system database, the EE Resource may be used in an Energy Efficiency Modification (EE MOD) Transaction in the eRPM system.

An EE Resource is initially established in the account of an EE Resource Provider in the eRPM system through the submittal and approval of an EE Modification (EE MOD) transaction. Subsequent increases or decreases in the Nominated EE Value of an EE Resource are also accomplished through an EE Modification transaction in the eRPM system. Details regarding EE Modifications are provided in PJM Manual for PJM Capacity Market (M-18) and the eRPM User Guide.

1.4 Increase in the Nominated EE Value of EE Resource

After an EE Resource is initially offered and cleared in a RPM Auction, the Nominated EE Value of the EE Resource may increase due to additional installations planned during the defined installation period. The increase in the Nominated EE Value may be offered into a subsequent Incremental Auction for the same Delivery Year for which the EE resource was originally offered and cleared. In this case, an Updated M&V Plan documenting the increase in the Nominated EE Value of the EE Resource must be submitted 30 days prior to the Incremental Auction.

1.5 Early Completion of EE Installations

If any of the installations that make up an EE Resource are to be completed prior to the defined installation period for the EE Resource, the EE Resource may be eligible to participate in an Incremental Auction for the prior Delivery Year. However, that resource would still only be eligible for four consecutive years of RPM revenue.

Section 2: Overview of M&V Plan

Welcome to the *Overview of M&V Plan* section of the PJM Manual for *Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- The description of a M&V Plan for an EE Resource (see "Description of M&V Plan")
- The general requirements of an M&V Plan for an EE Resource (see "General Requirements of M&V Plan")

2.1 Description of M&V Plan

The Measurement and Verification (M&V) Plan is a document that defines project-specific M&V methods and techniques that will be used to determine and verify the Nominated EE Value (i.e., the demand reduction) resulting from an EE Resource. A single M&V Plan may be submitted to cover multiple EE Resources. The single M&V Plan must clearly document the Nominated EE Value of each EE Resource covered in the M&V Plan.

In addition to providing accurate and conservative methods to calculate the Nominated EE Value, a good M&V Plan is clear, consistent, and repeatable. All the assumptions, procedures, and data for the M&V Plan should be recorded properly so that they may be easily referenced and verified by others. The data included should be sufficient for a third party to audit the M&V procedures and verify the Nominated EE Value of an EE Resource.

M&V activities include, but are not limited to, site surveys, demand and energy measurements, metering of key variables, data analyses, calculations, and quality assurance procedures. All of these key components need to be adequately detailed in the M&V Plan.

2.2 General Requirements of M&V Plan

An M&V Plan submitted to PJM must include:

(1) A summary of the methodologies used to determine the Nominated EE Value.

(2) A description of why the methodology or combination of methodologies selected is the most appropriate, relative for its project.

(3) A description of any variables that affect the project's electrical demand (such as outside temperature, time of day, process changes, occupancy, etc.) that will be measured or monitored and used in the determination of the Nominated EE Value during the defined EE Performance Hours.

(4) All substantive assumptions for the project's Nominated EE Value, including but not limited to, baseline demand consumption, post- installation demand consumption, process changes, and measure life.

(5) Specifications of the equipment or types of equipment for projects being installed and/or modified. The information may include, but is not limited to, engineering analysis utilized to specify equipment, program design measures

and or practices, or applications of equipment, measure or practice relative to end use or processes in the facility.

If one or more of the variables that will be measured or monitored and/or assumptions that will be used in the determination of the EE Resource's Nominated EE Value during the defined EE Performance Hours are not known at the time the EE Resource Provider submits its Initial M&V Plan to PJM for review and approval, the EE Resource Provider may provide alternative information and/or forecasts and indicate the portion of the Nominated EE Value associated with such measurement and monitoring variables and/or assumptions and explain the basis for such forecasts.

The M&V Plan may also include the following:

(1) References to engineering best practices in the Measurement and Verification literature, reference reports, or state of the art techniques to demonstrate that its proposed Measurement and Verification approach is appropriate for the Energy Efficiency Resource type and will produce an accurate and reliable Nominated EE Values.

(2) A description of the technical capabilities of its project team and subcontractors to implement its proposed methodology.

Section 3: M&V Plan Components

Welcome to the Initial M&V Plan section of the *PJM Manual for Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- Required components of the Initial M&V Plan (see "Initial M&V Plan Components")
- Required components of an Updated M&V Plan (see "Updated M&V Plan Components")

3.1 Initial M & V Plan Components

The following are the Project Level and Measurement Level Components that are required to be contained in the Initial M&V Plan. Each Project Level and Measurement Level Component includes a description of the required information.

3.1.1 Project Level Components

The project level components lay the groundwork for obtaining information about the project and provide a shared understanding about its objectives, sponsorship, costs, benefits, timeframes, resources and mandate. All of the Project-level Components of the M&V Plan should be complete in the Initial M&V Plan.

3.1.2 Project Description/Executive Summary

- Company name
- Project name
- Submission date
- Company address and contact information
- Project goals
- Energy Efficiency Application – how it reduces demand during defined EE Performance Hours
- Applicable Energy Efficiency or performance standards (i.e., building codes, appliance standards, or other relevant standards that are in effect at the time of the installation, as known at the time of commitment)
- Anticipated energy, demand and cost savings for each EE application and total anticipated savings
- Anticipated costs for Measurement and Verification
- Location of EE Resource (Transmission zone)
- Anticipated Nominated EE Value of EE Resource

3.1.3 Schedule

- *Timeline for EE installation and Measurement and Verification activities.*

3.2 Measurement Level Components

The measurement level components define the measurement and verification process(es) selected and provide detailed rationale for the selection. The following measurement level components must be included in the Initial M&V Plan. The information submitted in these components should be refined, when appropriate, with each Updated M&V Plan submittal.

3.2.1 Measurement Description

- Specific details about each EE project
- Demand, Energy, & Cost Savings to be claimed
- Rationale for selected form of measurement

3.2.2 Equipment Specifications and Documentation

- History of equipment to be replaced or modified
- Equipment standards

3.2.3 Measurement and Verification Approach

- Measurement and Verification Option
- General description of approach
- Monitoring parameters and variables
- Monitoring interval and period
- Measurement equipment specifications
- Measurement data collection and management
- Data validation, editing and estimating plan
- Accuracy of Monitoring and Verification method
- Savings uncertainty and confidence level
- Factors most uncertain or difficult to quantify

3.2.4 Assumptions

- Baseline and post-installation assumptions that affect demand and energy consumption (building occupancy schedules, equipment efficiencies, equipment operating strategies, load shapes, weather data, etc.)

3.2.5 Measurement and Verification Activities: Baseline Period

- Who will do M&V Activities
- List of activities before and after installation
- List of variables affecting demand and energy consumption and how they will be quantified
- Critical baseline condition factors

3.2.6 Measurement and Verification Activities: Post-Installation Period

- List of variables affecting energy consumption, variance from baseline case, and how they will be quantified
- Evidence that proper equipment/systems were installed, are operating correctly, and have the potential to generate the predicted savings (verification methods include surveys, inspections, spot measurements, and short-term metering.).
- New equipment surveys
- Critical post-installation condition factors
- Activities to ensure equipment operating as intended

3.2.7 Calculations & Adjustments

- Equations, calculations and analysis procedures for baseline and post-installation demand and energy consumption
- How performance models will be developed
- Description of population(s)
- Sample size calculations
- Method of sampling
- How demand and energy savings will be calculated
- How adjustments will be made

3.2.8 Metering Plan

- Who will provide and maintain metering equipment
- Specifications of metering equipment, accuracy, calibration procedures
- How data will be collected, maintained and reported
- Accuracy and quality assurance procedures

3.3 Updated M&V Plan Components

An Updated M&V Plan must include any updates to the Project Level & Measurement Level Components that were included in the Initial M&V Plan or prior Updated M&V Plan.

The Updated M&V Plan must include:

- Cover page with list of changes/updates contained in the Updated M&V Plan
- Details of any changes between the prior M&V Plan, including any changes to the project status, and any changes to the demand and energy savings
- Updated/refined Nominated EE Value calculations, including any baseline adjustments performed.

Section 4: Post-Installation M&V Report Components

Welcome to the *Post-Installation M&V Report Components* section of the PJM Manual for *Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- Required components of the Initial Post-Installation M&V Report submittals (see "Initial Post-Installation M&V Report Components")
- Required components of the Updated Post-Installation M&V Report submittals (see "Updated Post-Installation M&V Report Components")

4.1 Initial Post-Installation M&V Report Components

Post-installation measurement and verification activities are conducted to ensure that proper equipment/systems were installed, are operating correctly, and have the potential to generate the Nominated EE Value of the EE Resource. Verification methods include surveys, inspections, spot measurements, and short-term metering.

An Initial Post-Installation M&V Report must include any updates to the Project Level & Measurement Level Components that were included in the prior Updated M&V Plan.

The Initial Post-Installation Report should include:

- Cover page with list of changes/updates contained in the Initial Post-Installation M&V Report
- Details of any changes between the prior Updated M&V Plan and as-built conditions, and any changes to the estimated demand and energy savings
- Detailed list of installed equipment
- Documentation of all post-installation verification activities (verifying that the equipment/systems were installed and are operating)
- Documentation of performance measurements conducted to validate the Nominated EE Value of the EE Resource (if applicable in accordance with the approved M&V Plan)
- Detail any changes to the Nominated EE Value of the EE Resource

4.2 Updated Post-Installation M&V Report Components

An Updated Post-Installation M&V Report should include any updates to the Initial Post-Installation Report or a prior Updated Post-Installation Report.

The Updated Post-Installation Report should include:

- Cover page with list of changes/updates contained in the Updated Post-Installation M&V Report
- Documentation of all post-installation verification activities (verifying that the equipment/systems are still installed and operating)

- Documentation of performance measurements conducted to validate the Nominated EE Value of the EE Resource (if applicable in accordance with the approved M&V Plan)
- Detail any changes to the Nominated EE Value of the EE Resource.

Section 5: Submission and Approval Process

Welcome to the *Submission and Approval Process* section of the PJM Manual for the PJM Manual for *Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- Submittal requirements and deadlines for the Initial M&V Plan, Updated M&V Plans, and Post-Installation M&V Reports (see "Submittal Requirements")
- Description of PJM approval process for Initial M&V Plan, Updated M&V Plans, and Post-Installation M&V Reports (see "PJM Approval Process")

5.1 Submittal Requirements

5.1.1 Initial Measurement and Verification Plan

The EE Resource Provider must submit an Initial Measurement & Verification (M&V) Plan for the EE Resource via e-mail to the RPM Hotline at rpm_hotline@pjm.com, no later than 30 days prior to the RPM Auction in which the EE Resource is to be initially offered, or no later than 30 days prior to the submittal of an FRR Capacity Plan in which the EE Resource is to be initially committed.[2]

PJM or an independent third party will review the content of the M&V Plan, and will notify the EE Resource Provider within 10 days of receipt of the Initial M&V Plan whether or not approval of the Initial M&V Plan is granted. If approval is granted, the EE Resource Provider will be permitted to offer the EE Resource into the RPM Auction.

5.1.2 Updated Measurement and Verification Plans

The EE Resource Provider must submit an Updated Measurement & Verification (M&V) Plan for the EE Resource via e-mail to the RPM Hotline at rpm_hotline@pjm.com, no later than 30 days prior to each of the next RPM Auctions in which the EE Resource is to be subsequently offered, or no later than 30 days prior to the each of the next FRR Capacity Plan submittals in which the EE Resource is to be subsequently committed. If an Updated M&V Plan is not submitted prior to the subsequent RPM Auction or FRR Capacity Plan Submittal, the EE Resource will not be permitted to offer the EE Resource into the RPM Auction or commit the EE Resource in an FRR Capacity Plan for the relevant Delivery Year and subsequent Delivery Years.

PJM or an independent third party will review the content of an Updated M&V Plan, and will notify the EE Resource Provider within 10 days of receipt of the Updated M&V Plan and indicate whether or not approval of the Updated M&V Plan is granted. If approval is granted, the EE Resource Provider will be permitted to offer the EE Resource into the RPM Auction or commit the EE Resource in an FRR Capacity Plan for the relevant Delivery Year.

[2] Initial M&V Plan deadline for offering an EE Resource for 2012/13 Base Residual Auction or for committing an EE Resource for 2012/13 FRR Capacity Plan is extended until April 15, 2009.

5.1.3 Initial Post-Installation Measurement and Verification Report

Post-installation of the EE Resource, the EE Resource Provider must submit an Initial Post-Installation M&V Report for the EE Resource via e-mail to the RPM Hotline at rpm_hotline@pjm.com, no later than 15 business days prior to the first Delivery Year that the EE Resource is committed to RPM or FRR Alternative.

PJM or an independent third party will review the content of the Initial Post-Installation M&V Report, and will approve the Final Nominated EE Value for the EE Resource for the first Delivery Year that the EE Resource is committed.

Failure to submit an Initial Post-Installation M&V Report will result in a Final Nominated EE Value equal to zero MWs.

The Final Nominated EE Value will be reflected in the eRPM system and used in determining the final unforced capacity value of the EE Resource for the Delivery Year. If the final unforced capacity value of the EE Resource is greater than its RPM Resource Commitments, the available capacity from the EE Resource may be used as replacement capacity for another EE Resource in the EE Resource Provider's account.

RPM deficiency penalties may result if the final unforced capacity value of the EE Resource is less than the unforced capacity commitment associated with that EE Resource. Details regarding RPM Commitment Compliance and associated failure to deliver the unforced value of an RPM capacity commitment (i.e., Capacity Resource Deficiency Charge) are provided in PJM Manual for PJM Capacity Market (M-18). FRR deficiency penalties may result if a reduction in the unforced capacity value of the EE Resource causes the FRR Entity to no longer have sufficient unforced capacity committed in its FRR Capacity Plan to meet its Final Unforced Capacity Obligation for the Delivery Year. Details regarding FRR Capacity Resource Deficiency Charges are also provided in PJM Manual for PJM Capacity Market (M-18).

5.1.4 Updated Post-Installation Measurement and Verification Reports

The EE Resource Provider must submit an Updated Post-Installation M&V Report for the EE Resource via e-mail to the RPM Hotline at rpm_hotline@pjm.com, no later than 15 business days prior to each of the subsequent Delivery Years that the EE Resource is committed to RPM or FRR Alternative.

PJM or an independent third party will review the content of the Updated Post-Installation M&V Report, and will approve the Final Nominated EE Value for the EE Resource for the relevant Delivery Year that the EE Resource is committed.

If the EE Resource Provider ***fails*** to submit an Updated Post-Installation M&V Report for a Delivery Year or if the submitted Updated Post-Installation M&V Report fails to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan, the Final Nominated EE Value will equal zero MWs for the Delivery Year.

The Final Nominated EE Value will be reflected in the eRPM system and used in determining the final unforced capacity value of the EE Resource for the relevant Delivery Year.

RPM deficiency penalties may result if the final unforced capacity value of the EE Resource is less than the unforced capacity commitment associated with that EE resource. Details regarding RPM Commitment Compliance and associated failure to deliver the unforced value of an RPM capacity commitment (i.e., Capacity Resource Deficiency Charge) are provided in PJM Manual for PJM Capacity Market (M-18). FRR deficiency penalties may result if a reduction in the unforced capacity value of the EE Resource causes the FRR Entity to no longer have sufficient unforced capacity committed in its FRR Capacity Plan to meet its Final Unforced Capacity Obligation for the Delivery Year. Details regarding FRR Capacity Resource Deficiency Charges are also provided in PJM Manual for PJM Capacity Market (M-18).

5.2 PJM Approval Process

5.2.1 Initial Measurement and Verification Plan

Upon receipt of an Initial Measurement and Verification Plan, PJM or an independent third party will review the contents of the plan to ensure that the requirements for the Project Level and Measurement Level Components of the Initial M&V Plan were adequately satisfied and the EE Resource meets the criteria for offering an Energy Efficiency Resource into an RPM Auction or committing an Energy Efficiency Resource in an FRR Capacity Plan.

Within 10 days of receipt of the Initial Measurement and Verification Plan, PJM will notify the EE Resource Provider and indicate whether or not the Initial Measurement and Verification Plan is approved or denied.

PJM may deny entry into an RPM Auction or deny inclusion of the EE Resource in an FRR Capacity Plan if the submitted Initial M&V Plan falls short of meeting the requirements.

If an Initial M&V plan is denied, PJM will provide a list of the areas in the Initial M&V Plan that were not adequate to the EE Resource Provider. Initial M&V Plans that are denied by PJM may be corrected and resubmitted no later than 15 days prior to the RPM Auction, or no later than 15 days prior to the submittal of an FRR Capacity Plan. If time does not permit, Initial M&V Plans that are denied by PJM may be corrected and resubmitted for a consideration in a subsequent RPM Auction.

Alternately, PJM may approve a reduced Nominated EE Value based on the Initial M&V Plan and allow entry into the RPM Auction or use of the EE Resource in an FRR Capacity Plan.

5.2.2 Updated Measurement and Verification Plans

Upon receipt of an Updated Measurement and Verification Plan, PJM or an independent third party will review the contents of the plan to determine if the requirements of an Updated M&V Plan were met.

Within 10 days of receipt of the Updated Measurement and Verification Plan, PJM will notify the EE Resource Provider and indicate whether or not the Updated Measurement and Verification Plan is approved or denied.

PJM may deny entry into a subsequent RPM Auction or deny use of the EE Resource in an FRR Capacity Plan if the submitted Updated M&V Plan falls short of meeting the requirements of an Updated M&V Plan.

If an Updated M&V Plan is denied, PJM will provide a list of the areas in the Updated M&V Plan that were not adequate to the EE Resource Provider. Updated M&V Plans that are denied by PJM may be corrected and resubmitted no later than 15 days prior to the RPM Auction, or no later than 15 days prior to the submittal of an FRR Capacity Plan. If time does not permit, Updated M&V Plans that are denied by PJM may be corrected and resubmitted for a consideration in a subsequent RPM Auction for the same Delivery Year.

Alternately, PJM may approve a reduced Nominated EE Value based on the Updated M&V Plan and allow entry into the RPM Auction or use of the EE Resource in an FRR Capacity Plan.

5.2.3 Post-Installation M&V Reports

Upon receipt of an Initial or Updated Post-Installation M&V Report, PJM or an independent third party will review the contents of the report to determine if the requirements of an Initial or Updated Post-Installation Report were met and approve the Final Nominated EE Value for the Delivery Year. If the Initial or Updated Post-Installation M&V Report is not submitted or if the submitted Initial or Updated Post-Installation M&V Report fails to demonstrate post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan, the approved Final Nominated EE Value will be zero MWs for the relevant Delivery Year.

Section 6: M&V Audit Process

Welcome to the *M&V Audit Process* section of the PJM Manual for the PJM Manual for *Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- An overview of the M&V Audit (see "Overview of the M&V Audit")
- A description of the measurement and verification audit process requirements for an EE Resource Provider (see "M&V Audit Process Requirements").
- Details regarding the M&V Audit Charge (see "M&V Audit Charge")

6.1 Overview of the M&V Audit

PJM or an independent third-party (as directed by PJM) may conduct an audit, at the EE Resource Provider's expense, of the energy efficiency installation prior to or during the Delivery Year. The M&V Audit may be conducted any time, including during the defined EE Performance Hours. If the M&V Audit is performed and results finalized prior to the start of a Delivery Year, the Nominated EE Value confirmed by the Audit becomes the Final Nominated EE Value that is used to measure RPM Commitment Compliance during the Delivery Year. If the M&V Audit is performed and results finalized after the start of a Delivery Year, the Nominated EE Value confirmed by the M&V Audit becomes the basis to determine if any Incremental RPM Commitment Compliance Shortfall needs to be assessed retroactively from June 1 of the Delivery Year to May 31 of the Delivery Year.

6.2 M&V Audit Process Requirements

(1) The EE Resource Provider shall cooperate in any and all unannounced audits or tests of a project conducted by PJM or an independent third-party to verify its compliance with the requirements in this Manual. These audits may be conducted on a periodic basis, or at the PJM's discretion should PJM have a reason to suspect a deficiency in the Resource Provider's compliance with any of the requirements in this Manual. On site audits will be coordinated with the EE Resource Provider and scheduled during normal business hours.

(2) The EE Resource Provider shall allow PJM or an independent third-party to audit testing and calibration records, and order and witness the testing of metering and measurement equipment installed pursuant to the EE project's approved M&V Plan.

(3) The EE Resource Provider shall allow PJM or an independent third-party to audit any tracking databases used to track when and where the energy efficiency technology was installed.

(4) The EE Resource Provider will be responsible for all expenses associated with installing, maintaining, calibrating and testing the metering, data recording and measurement equipment installed pursuant to the project's approved M&V Plan.

(5) PJM may accept an audit conducted by the State if the M&V meets all the PJM requirements. The determination will be made case by case basis.

Alternatively, the data provided by the State audit may be used to reduce the cost of PJM audit.

6.3 M&V Audit Charge

PJM will provide documentation regarding the cost of the audit no later than two months after the completion of the audit. PJM will assess an M&V Audit Charge to an EE Resource Provider no later than the third billing month after the completion of audit.

Section 7: Measurement and Verification Methodologies

Welcome to the *Measurement and Verification Methodologies* section of the PJM Manual for *Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- A description of the acceptable measurement and verification methodologies (see "Acceptable Measurement and Verification Methodologies").
- A description of other acceptable methodological techniques (see "Other Acceptable Methodological Techniques").

The following options are considered acceptable Measurement and Verification methodologies:

7.1 Option A: Partially Measured Retrofit Isolation/Stipulated Measurement

Option A may involve an equipment specific retrofit or replacement, new installation or a system level Measurement and Verification assessment. The approach is intended for measures where either performance factors (such as lighting wattage) or operational factors (such as operating hours) can be measured on a spot or short-term basis during baseline establishment and post-installation periods, or for measures for which a measured proxy variable can, in combination with well-established algorithms and/or stipulated factors, can provide an accurate estimate of the Nominated EE Value.

Option A methodology consists of the following:

(1) The factors, parameters and/or variables not measured can be stipulated based on assumptions, analysis of historical data, or manufacturer's data. If a stipulated factor is subject to change over the EE Performance Hours, the EE Resource Provider shall describe how the changes will be factored into the calculation of the Nominated EE Value.

(2) Measuring a variable other than electrical demand (MW) and using that variable in the calculation of the demand reduction value. Measurements can include short-term or long-term end-use metering of a variable such as current (amperage) and voltage to calculate demand, equipment operating status (on/off), equipment operating times, equipment quantities (i.e., number of units installed, cubic feet of insulation installed) or facilities served where the Nominated EE Value per facility is constant.

(3) An established correlation between the metered/monitored proxy variable and electrical demand (MW). The EE Resource Provider may establish the correlation by conducting short-term monitoring or a series of spot measurements of both stipulated parameters, and correlating the data sets (e.g., by performing a regression analysis) to determine the functional relationship between the two parameters.

(4) Engineering correlations may also be specified using documented engineering algorithms or as part of an engineering simulation.

(5) Equipment manufacturer's data, equipment data compiled by a recognized industry group or equipment data compiled as part of a State-sponsored demand side management program (i.e., lighting fixture wattage tables) may be used in combination with the other measurements, variables or factors as described above to calculate Nominated EE Value. Data from a manufacturer must be determined in a manner consistent with standards established by a recognized United States government agency or national recognized industrial manufacturing association.

7.2 Option B: Retrofit Isolation/Metered Equipment

Option B involves a retrofit or system-level Measurement and Verification assessment. The approach is intended for retrofits with performance factors and operational factors that can be measured at the component or system level using interval electrical demand meters, as defined in the Measurement Equipment Specifications Section of this Manual, installed on the affected end-use.

Option B methodology consists of the following:

(1) Spot or short-term electrical demand measurements can only be used when variations in operations are not expected to change over the commitment years.

(2) When temporal variations are expected, electrical demand measurements must be made over a period of time sufficient to represent performance during the EE Performance Hours and across the commitment years of the resource.

(3) This method may be more appropriate when the electrical loads to be impacted by the project are small relative to the building load, a facility does not currently have whole-premise interval metering, or if end-use electrical demand data can be readily obtained from a building energy management or control system.

(4) The EE Resource Provider must take into consideration any interactive effects that may alter electrical loads on other end-use equipment being monitored.

7.3 Option C: Whole Facility/Regression

Option C estimates Nominated EE Values by analyzing the overall energy use in a facility and identifying the impact of the implemented measure on total building or facility energy use patterns. The evaluation of whole-building or facility level metered data is completed using techniques ranging from simple billing comparison to multivariate regression analysis.

Option C methodology consists of the following:

(1) Nominated EE Value is measured using whole-premise interval meters.

(2) Option C is appropriate for measures that cannot be measured directly, such as insulation or other building envelope measures.

(3) Option C should not be used if the Nominated EE Value is expected to be small relative to the total facility load, due to the small "signal-to-noise ratio".

7.4 Option D: Calibrated Simulation

Option D involves calibrated computer simulation models of component or whole building demand and energy consumption to determine measure demand and energy savings. Engineering simulation models (such as DOE-2) can model both residential buildings (homes, apartments and condominiums) as well as more complex commercial buildings. Operational simulations can be used for industrial processes that take into account the specifics of the process addressed by the energy efficiency actions.

Both engineering and operational simulations are made more powerful by calibrating these methods to actual kW and kWh data from the site or process being examined, even if these data are available for a monitoring period shorter than or different from the required EE Performance Hours. Short-term metering and monitoring are methods that produce data that can be used to adjust engineering simulations.

This approach is generally termed "calibrated engineering simulations." Linking simulation inputs to baseline and post-installation conditions completes the calibration. Characterizing baseline and post-installation conditions may involve metering performance and operating factors both before and after the retrofit. Long-term whole-building demand and energy use data may be used to calibrate the simulation(s).

7.5 Other Acceptable Measurement and Verification Methodologies

The EE Resource Provider may propose alternative methodologies not listed above. The EE Resource Provider proposing alternative methodologies shall demonstrate that the alternative methodologies will be equivalent to one of the accepted methodologies described above, and demonstrate justifiable need for deviation from the acceptable methodologies based on unique project requirements.

In addition to the acceptable methodological approaches described above, several methodological techniques may be applied to one or more of the methods described above. The following describe other acceptable methodological techniques.

Engineering Calculations and Audit Results

The EE Resource Provider may use engineering algorithms to calculate the project's Nominated EE Value during the Performance Hours. Engineering algorithms must be supplemented with data collected on the energy-consuming equipment effected by the measures.

7.5.1 Load Shape Analyses

The EE Resource Provider may use verifiable measure hourly load shapes to calculate a project's Nominated EE Value during the Performance Hours. Measure load shapes must be based on actual metering data, load research, and/or simulation modeling.

Values for monthly or annual energy savings (whether from engineering calculations, analysis of billing data, simulation modeling or other means described in this Manual) can be combined with information on verifiable measure load shapes to produce values for electrical demand reduction (MW) during the Performance Hours. Measure load shapes shall be based on actual metering data, load research (current or historic) and/or simulation modeling.

Section 8: Establishing Baseline Conditions

Welcome to the *Establishing Baseline Conditions* section of the PJM Manual for *Energy Efficiency Measurement and Verification*. In this section, you will find the following information:

- A description of general requirements for all EE Resources on establishing, measuring and reporting baseline (see "Baseline Requirements for All EE Resources").
- A description of requirements for EE Resources involving new construction or major renovations on establishing, measuring and reporting baseline (see "Baseline Requirements for EE Resources involving New Construction or Major Renovations").

The EE Resource Provider shall describe in its M&V Plan the methodology used to determine Baseline Conditions for the equipment or process comprising the EE project. Baseline Conditions are defined as the MW demand of the equipment or process during defined EE Performance Hours, or the demand that would have existed, in the absence of the energy efficiency project.

The EE Resource Provider shall identify in its Measurement and Verification Plan any and all equipment, systems, practices or strategies or type of the aforementioned, whose alteration from its Baseline Condition operation will lead to reduced demand during the Performance Hours.

8.1 Baseline Requirements for All EE Resources

The EE Resource Provider must describe in its Measurement and Verification Plan how it will satisfy each of the applicable requirements listed below.

(1) For projects where the demand reduction results from measures involved variable load equipment or equipment whose operation is time-dependent or weather-dependent, the Baseline Conditions must be calculated for each hour across the Performance Hours.

(2) 'Standard' Baseline: For projects in which equipment (whether failed or not) is replaced by a more efficient equivalent or by an alternative strategy for delivering comparable output, the Baseline Condition shall be the nameplate rating of the equipment meeting the level of efficiency required by applicable State code, Federal product efficiency standard, or standard practice, whichever is most stringent, in place at the time of installation, as known at the time of commitment. If there is no applicable State code or federal standard, then standard practice shall be used as the basis for establishing Baseline Conditions and shall be documented in the M&V Plan.

(3) 'Current Load' Baseline: For projects in which replacement, modification or removal of equipment and controls in systems or buildings are not planned independently of the Energy Efficiency initiative that is being offered into the RPM Auction, the Baseline Condition is the kW load of the existing equipment across the Performance Hours under pre-retrofit conditions.

For eligibility to use the 'Current Load' Baseline Condition:

(a) Document the nature of the project such that it can be reasonably assumed that the replacement, removal or retrofit would not have occurred in the absence of the Energy Efficiency initiative.

(b) Replacement of equipment shall be with equipment that is better than the standards in place at the time of installation, as known at the time of commitment. If there is no applicable State code or federal standard, then standard practice shall be used as the basis for establishing Baseline Conditions and shall be documented in the M&V Plan.

8.2 Requirements for EE Resources Involving New Construction or Major Renovations

For new construction or major renovation Projects, the Baseline Conditions shall be equal to the kW load during the applicable Performance Hours of equipment meeting the level of efficiency required by:

(1) Applicable State code or Federal product efficiency standard, or

(2) Standard practices, provided the EE Resource Provider can document the standard practices in the M&V Plan, if there are no applicable State codes or Federal product efficiency standards.

Section 9: Statistical Significance

Welcome to the *Statistical Significance* section of the PJM Manual for *Energy Efficiency Measurement and Verification*. In this section, you will find the following information:

- An overview of the requirements to meet statistical significance (see "Overview of Statistical Significance").
- A description of the requirements for statistical sampling (see "Statistical Sampling").

9.1 Overview of Statistical Significance

The EE Resource Provider must describe in its Measurement and Verification Plan how it will meet or exceed the statistical precision and accuracy standards specified in this Manual. The M&V Plan must demonstrate that the techniques utilized to calculate sample accuracy and precision comply with the methods described in this Manual. The accuracy requirement needs to include a description of how the Measurement and Verification effort will use methods to mitigate and adjust for the potential types of bias applicable to the methods being used in the Measurement and Verification effort. Where monitoring is specified over the Delivery Years in which EE will be offered, the Measurement and Verification plan must also describe how accuracy and precision will be monitored on the sample during the period.

9.1.1 Requirements

(1) EE Resource Provider shall include in its M&V Plan a description of how Measurement and Verification efforts address accuracy and precision issues as described in this Manual appropriate for the measurement and verification approach being proposed and strategy to calculate the Nominated EE Value.

(2) EE Resource Provider that proposes the use of Measurement and Verification Reference Documents to support estimates including but not *limited to, engineering estimates, load profiles, measure life, and coincidence* factors, shall provide justification for use appropriate to the Measurement and Verification methodology to calculate the Nominated EE Value.

(3) If the Nominated EE Value calculations include an engineering-based direct measurement, measurement of proxy variables or simulations, then the EE Resource Provider shall describe methods to control relevant types of potential bias including, but not limited to: (a) accuracy and calibration of the measurement tools (as described elsewhere in this Manual); (b) measurement error; (c) engineering model bias; (d) modeler bias; (e) deemed parameter bias; (f) meter bias; (g) sensor placement bias; and (h) sample selection bias or non-random selection of equipment and/or circuits to monitor.

(4) If the Nominated EE Value calculations include regression or statistical analyses, then the EE Resource Provider shall describe methods to control relevant types of potential bias including, but not limited to: (a) model misspecification; (b) statistical validity; (c) error in measuring variables; (d)

autocorrelation; (e) heteroscedasticity; (f) collinearity; (g) outlier data points; and (h) missing data.

(5) If the Nominated EE Value calculations include any form of survey or interview data, the EE Resource Provider shall describe methods to control relevant types of potential bias including, but not limited to: (a) construct validity; (b) sampling frame versus population; (c) selection bias (for a sample and for a census attempt where not all sites within the census received usable data); (d) non-response bias; (e) error in measuring variables; (f) sample homogeneity relative to project (external validity); (g) outlier data points; and (h) missing data.

9.2 Statistical Sampling

The demand reduction value during Performance Hours or other key parameters for a project including multiple installations of similar measures and/or facilities may be developed by sampling the total population of all measure installations. Sampling shall meet a **statistical accuracy and precision of no less than one-tailed 90% confidence level (equivalent to two-tailed 80% confidence level) and 10% relative precision** as described below.

9.2.1 General Requirements

If sampling will be conducted, the EE Resource Provider must describe in its M&V Plan each of the following general sampling conditions:

(1) The population to be sampled,

(2) The required sample size in accordance with this Manual,

(3) The planned sample size, plus contingencies for attrition due to metering equipment failure and the like,

(4) All assumptions and calculations for determining the sample size, and

(5) The method for selecting sample points.

9.2.2 Sample Size Requirements

If sampling will be conducted, the EE Resource Provider must describe in its Measurement and Verification Plan how it will satisfy each of the requirements listed below for determining the sample size and sample point.

(1) If the demand reduction value is estimated from one or more samples, the required sample size(s) must be based upon targeting 10% relative precision at a 90% confidence level. If an EE project consists of multiple sites and/or measures, and the EE Resource Provider uses multiple samples to estimate the aggregated demand reduction value during the Performance Hours in each Zone as the sum of all individual measured demand reduction values, the sampling requirements may be met (1) for each sample or combination of samples used, (2) for the combination of all samples, or (3) by using strata as described below.

(2) If the demand reduction value is estimated from a sample drawn from 2 or more strata the overall test sample size must be based upon targeting 10% relative precision with a 90% confidence interval. Strata shall be defined as any subset of the project's population that is based on known information. The concept of strata may include, but is not limited to: programs in a state sponsored demand side management portfolio or subsets of an entire population of affected equipment at a project site that have similar operating characteristics.

(3) All sampling calculations shall incorporate a plan to compensate for potential data loss through:

(a) Over sampling
(b) Sample site replacement in the course of the study,
(c) Demonstration that precision and confidence targets will still be met with a smaller sample size.

(4) The EE Resource Provider shall demonstrate the method for controlling bias in sample selection including, but not limited to random sampling, census or rolling census for each sample and strata used.

(5) The Coefficient of Variation (c.v.) used to derive the required sample size shall be the measured c.v. for the primary measurement including all its error components.

(6) The EE Resource Provider shall demonstrate the method for controlling bias attributed to the c.v. as it relates to sample size determination.

(7) If a c.v. from prior Measurement and Verification or Measurement and Verification Reference Documents is not available for the primary measurement applicable to the segments of sites, installed measures, and/or strategy, then the EE Resource Provider shall use a default value for the initial c.v., not less than 0.5 for homogeneous samples (samples from populations that are uniform with respect to some criteria of classification) and 1.0 for heterogeneous samples (samples from populations that are variable with respect to some criteria of classification), until such time that a c.v. can be estimated from the project sample population.

(8) If a method such as stratified ratio estimation is used to take advantage of supporting information for the population, the c.v. may be adjusted to take account of the added efficiency of the stratification and estimation methodology.

9.2.3 Sample Size Calculation Requirements

The formulas below are illustrative of the calculation of required sample size and precision. Alternative sample size determination shall meet the minimum requirements set forth in the preceding section and be documented in the Measurement and Verification plan.

(1) The EE Resource Provider shall calculate the sample number designed to achieve a precision of 10% using the following equation, utilizing a t value of 1.282, which corresponds to a one-tailed 90% confidence interval of an infinite population, where

n' = number of samples in an infinite population

c.v. = coefficient of variation as set by a default value or where it is known, and

r.p. = relative precision

$$n' = \left\{\frac{1.282 \times c.v.}{r.p.}\right\}^2$$

The sample size (n) for the finite population (N) less than 200 shall be calculated using the following equation, where

n' = number of samples in an infinite population

$$n = \frac{n'}{1 + \frac{n'}{N}}$$

9.3 Sample Size Recalibration Based on Monitoring Data

In the absence of a reliable c.v. the EE Resource Provider may use a default c.v. as described in preceding Section. However, once performance data has been collected, the EE Resource Provider shall demonstrate that the level of precision and accuracy is met in the sampling methodology by calculating the relative precision (r.p.) with a new estimate of c.v.

9.3.1 Sample Recalibration Requirements

(1) The EE Resource Provider shall calculate the relative precision of sampling studies based on the new estimated sample coefficient of variation calculated using the following equations, where:

$\bar{x}$ = sample mean,

s = standard deviation, and

n' = number of samples in an infinite population.

$$c.v. = \frac{s}{\bar{x}}$$

$$r.p. = \frac{1.282 \times c.v}{\sqrt{n'}}$$

(2) In the case where the finite population (N) is less than 200, the relative precision of the sampling study shall be calculated using the following equation, where:

n = number of samples in a finite population, and

N = total number of units in the population

$$r.p. = \sqrt{1 - \frac{n}{N}}\,\frac{1.282 \times c.v}{\sqrt{n}}$$

If a method such as stratified ratio estimation is used to take advantage of supporting information for the population, the estimated c.v. and achieved relative precision may be adjusted to take account of the added efficiency of the stratification and estimation methodology.

9.4 Sampling Over Load Zones

If the EE Resource Provider conducts sampling for a population of similar EE Resources spanning multiple Zones, then the EE Resource Provider must describe in its M&V Plan how it will satisfy each of the requirements listed below:

9.4.1 Requirements

The EE Resource Provider shall demonstrate that the accuracy and precision requirements discussed above apply to the overall population of EE Resources being studied, rather than to the project or projects within each individual Zone.

The EE Resource Provider shall demonstrate the method for controlling any bias attributed to sampling across Zones.

Section 10: Nominated EE Value Calculations

Welcome to the Nominated EE *Value Calculations* section of the PJM Manual for *Energy Efficiency Measurement and Verification*. In this section, you will find the following information:

- An overview of the requirements to determine the Nominated EE Value (see "Overview of Nominated EE Value Calculations").
- A procedure for determining the Nominated EE Value for weather sensitive loads (see "Nominated EE Value for Weather Sensitive Loads").
- A procedure for reducing the Final Nominated EE Value if the EE Resource fails to meet the precision standards (see "Reduction in the Final Nominated EE Value").

10.1 Overview of Nominated EE Value Calculations

As defined in Section 1, the Nominated EE Value is the expected average demand (MW) reduction during the defined EE Performance Hours in the Delivery Year. The EE Performance Hours are between the hour ending 15:00 Eastern Prevailing Time (EPT) and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday. End-user loads have a consumption pattern depending on the type of customer (residential, commercial, industrial, or other), time of day, day of the week, and season. The consumption pattern is analyzed to determine the expected average demand reduction when electrical devices or systems are replaced by more efficient devices or systems. The demand reduction during the EE Performance Hours as a fraction of the gross difference between ratings of the current devices and the more efficient devices can vary significantly depending on the consumption pattern. This fraction is referred to as Coincidence Factor in the M&V process.

When consumption pattern is weather-sensitive (e.g. air conditioning) the determination of average demand reduction may vary significantly depending on the weather conditions (e.g. cool summer or very hot summer). A normalization method is proposed in the case of weather-sensitive load later in this section to ensure that the demand reduction estimate is consistent with the method used for other resources.

The EE Resource Provider shall describe in the M&V Plan how the Nominated EE Value (i.e., the demand reduction) during the EE Performance Hours will be calculated for the EE Resource. The description must include, where applicable, the following factors used in the calculations:

(1) Equations and formulas

(2) Assumptions

(3) Manufacturers equipment specifications

(4) Direct measurement data

(5) Indirect measurement data

(6) Engineering factors, parameters and other variables

If the one or more of the factors listed above are not known or not available at the time the EE Resource Provider submits its Measurement and Verification Plan to PJM, the EE Resource Provider shall describe when the unknown or unavailable factors will be known and available and how the factors will be used in the Nominated EE Value calculations.

The EE Resource Provider must give consideration to the following items in its M&V Plan:

(2) The reported Nominated EE Value shall achieve at least a 10% relative precision at a one-tailed 90% confidence level.

(3) If Baseline Conditions are used in the calculation of the Nominated EE Value, the EE Resource Provider must make adjustments to the Baseline Conditions to reflect operating conditions at the time of the Performance Hours.

(4) Formulas used by the EE Resource Provider to determine the Nominated EE Value shall include any modifying factors, including, but not limited to, Coincidence Factor for the specified EE type and the Performance Hours, realization rate, and equipment failure rate.

(5) If an EE project consists of multiple sites and/or measures, the EE Resource Provider may calculate the aggregated Nominated EE Value during the Performance Hours in each Zone as the sum of all measured demand reduction values, provided that each measured demand reduction value achieves at least a 10% relative precision at a one-tailed 90% confidence level, or the aggregated (EE Resource level) demand reduction value achieves at least a 10% relative precision at a one-tailed 90% confidence level in each Zone.

(6) If sampling will be conducted, the project's aggregated demand reduction value in each Zone must be calculated from the measured data of the sample, and the M&V Plan shall describe how this calculation will be performed.

(7) Any measurement or monitoring equipment of current (amps) and voltage used to calculate electrical demand must include the power factor of the end-uses in the demand (kW) calculations.

10.2 Nominated EE Value for Weather Sensitive Load

If the demand reduction is a function of weather conditions the Nominated EE Value shall be based on the Zonal Weighted Temperature Humidity Index (WTHI) Standard posted by PJM. The Nominated Value shall be calculated using the relationship between average demand reduction measured during the Performance Hours on a day and the WTHI on the day. Alternate approaches may be used with documentation to show that the demand reduction estimate is comparable to the value computed using to the PJM WTHI Standard.

The Zonal WTHI Standard is the mean of the Zonal WTHI values on the days on which PJM peak load occurred in the ten year history. Zonal WTHI is used to determine the demand reduction for Direct Load Control. Use of Zonal WTHI is also consistent with the ambient conditions 'at the time of PJM peak' used to test generation resources. PJM posts on its website updated Zonal WTHI Standards each year.

See Appendix A for an illustration of Zonal WTHI calculation and Demand Reduction calculation for weather sensitive load.

10.3 Reduction in the Final Nominated EE Value

It would be important to meet the specified precision requirement at the aggregate level of the EE Resource to avoid penalties due to reduction in the value. If the final estimate of the Nominated EE value determined in the Post-Installation M&V Report does not meet the 10% precision standard, the estimated value will be reduced to determine the Final Nominated EE Value.

Final Nominated EE Value =

Estimate of Nominated EE Value *(100 – Achieved Precision) / (100 – Standard Precision) =

Estimate of Nominated EE Value * (100 – Achieved Precision) / (100 – 10%) =

Estimate of Nominated EE Value * (100 – Achieved Precision) / 90.

Examples:

Case 1: Standard Precision met.

Estimate of Nominated EE Value = 10 MW.

Achieved Precision = 10% at one-tailed 90% confidence level.

Final Nominated EE Value = 10 * (100 – 10%) / 90 = 10 MW.

Case 2: Standard Precision not met.

Estimate of Nominated EE Value = 10 MW.

Achieved Precision = 12% at one-tailed 90% confidence level.

Final Nominated EE Value = 10 * (100 – 12%) / 90 = 9.8 MW.

Section 11: Measurement and Monitoring

Welcome to the Measurement and Monitoring section of the PJM Manual for *Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- A description of the Measurement and Monitoring details that must be included in the M&V Plan (see "Measurement and Monitoring Requirements").

11.1 Measurement and Monitoring Requirements

The EE Resource Provider shall describe in its M&V Plan the variables that will be measured, monitored, counted, recorded, collected, and maintained to determine the project's Nominated Value.

The EE Resource Provider shall describe in its M&V Plan how each of the variables will be measured, monitored, recorded, collected and maintained.

The EE Resource Provider must describe in its M&V Plan how it will satisfy each of the requirements listed below. When equipment manufacturer, model, serial number and age are not readily available, the EE Resource Provider may propose alternative means of acquiring or estimating the information.

(1) For projects affecting HVAC Systems, the EE Resource Provider must, at a minimum, collect and maintain the following information:

(a) On HVAC equipment: equipment capacity, quantity, manufacturer, model and serial numbers, and age.

(b) On HVAC system controls: location of zones, temperature set-points, control set-points and schedules, and any special control features.

(2) For projects affecting Building Envelope, the EE Resource Provider must, at a minimum, collect, maintain and report on all key variables effecting savings associated with the measures.

(3) For projects affecting Interior or Exterior Lighting Systems, the EE Resource Provider must, at a minimum, collect and maintain the following information: number and types of lamps and ballasts, with nameplate data.

(4) For projects affecting Major Electric Consuming Equipment, the EE Resource Provider must, at a minimum, collect and maintain the following information: equipment capacity, quantity, manufacturer, model and serial numbers and age.

(5) For projects affecting Weather Sensitive Electrical Loads including HVAC, where temperature, humidity or degree-days will be used in the calculation of demand reduction, the EE Resource Provider shall collect and maintain representative site weather data, either measured on-site or obtained for a nearby site, from the National Climatic Data Center ("NCDC"). On-site measurement equipment must satisfy the requirements described in Section 12.

Section 12: Measurement Equipment Specifications

Welcome to the *Measurement Equipment Specifications* section of the PJM Manual for *Energy Efficiency Measurement & Verification*. In this section, you will find the following information:

- A description of the Measurement Equipment Specifications details that must be included in the Measurement and Verification Plan (see "Measurement Equipment Requirements").

12.1 Measurement Equipment Requirements

The EE Resource Provider shall describe, to the most practical extent, in its M&V Plan how each measurement, monitoring and/or data recording device will be installed (including its specific location) and operated to measure, monitor and/or record data from each of the parameters and variables described in the M&V Plan pursuant to Section 12 of this Manual.

The EE Resource Provider must describe in its M&V Plan how it will satisfy each of the requirements listed below:

(1) All solid-state measurement, monitoring and data recording equipment must meet or exceed the relevant standards set by the American National Standard Institute ("ANSI") or equivalent standard.

(2) Measurement, monitoring and data recording equipment that is directly measuring watt-hour, volt-hour, volt-ampere-hours, reactive volt-ampere-hour, and the associated demand components should conform to ANSI or equivalent standards.

(3) Instruments or transducers for the analog or digital measurement of volt, volts-squared, amperes, amperes-squared, phase angle, volt-amperes, watts, and reactive volt-amperes should conform to ANSI or equivalent standards.

(4) Data recorders that are recording pulses from measurement and monitoring devices must utilize a pulse rate within the resolution capabilities of the recorder.

(5) All measurement, monitoring and data recording equipment installed on electric circuits with significant harmonics must meet the relevant standards provided by the Institute of Electrical and Electronics Engineers ("IEEE").

(6) Any measurement or monitoring equipment that directly measures electrical demand (kW) must be a true RMS measurement device with an accuracy of no less than ±2%.

(7) Any measurement or monitoring equipment that directly measures electrical demand from three-phase devices must be installed such that measurements are taken on all three-phases to account for any phase imbalance or an equivalent method that can measure electrical demand using two phases.

(8) Any measurement or monitoring equipment that directly measures electrical demand on circuits with significant harmonics must have a digital sampling rate of at least 2.6 kHz as defined in the relevant IEEE Standards.

(9) (10) (11) Data recorders must be synchronized in time, within an accuracy of +/- 2 minutes per month, with the National Institute of Standards and Technology ("NIST").

(12) All measurement, monitoring and data recording equipment must be calibrated by the EE Resource Provider or its independent calibration contractor in such a way to meet or exceed the International Measurement and Verification Protocol (IPMVP), NIST, or equivalent standard. If a recalibration interval is not specified by its manufacturer, electrical measurement equipment should be recalibrated at least once every two calendar years.

(13) The EE Resource Provider must ensure that all measurement, monitoring and data logging equipment shall be maintained in such a way as to meet or exceed industry and manufacturer standards.

(14) The EE Resource Provider must maintain documentation on all measurement, monitoring and data recording equipment maintenance and calibration activities. Documentation and records must be maintained.

(15) The EE Resource Provider shall provide to PJM, upon request, measurement equipment maintenance, calibration and testing records to demonstrate that the EE Resource Provider's measurement equipment is calibrated and maintained in accordance the requirements described in this Manual.

(16) The EE Resource Provider may propose alternative methods to demonstrate the measurement, monitoring and data recording equipment used in the determination of Nominated Value satisfies the accuracy, calibration and maintenance standards described in the Manual.

(17) Any measurement, monitoring and data recording equipment that sample continuously and integrate values should collect data at a frequency of one hour or less. For devices that only sample "snapshots" or applications susceptible to data aliasing, one should collect data at a frequency of 15 minutes or less.

Appendix A: Illustration of Zonal WTHI and Demand Reduction Calculations

The Zonal WTHI Standards based on 1998-2008 period are shown in the table below for illustration:

Zone	WTHI Standard	Zone	WTHI Standard
AE	83.3	JCPL	82.8
AEP	81.5	METED	82.4
APS	81.1	PECO	83.1
BGE	83.1	PENLC	80.4
COMED	80.4	PEPCO	83.7
DAYTON	81.6	PL	81.5
DLCo	80.4	PS	82.9
DOM	83.5	RECO	82.9
DPL	83.1	UGI	80.4

THI = (TEMPERATURE_F - 0.55 * (1 - RELATIVE_HUMIDITY_PCT/100) * (TEMPERATURE_F - 58.0)).

WTHI = [(4 * Current Day THI)+(Previous Day THI)] / 5

As an example of WTHI calculations, 2007 PJM peak occurred on August 8 when the following weather conditions occurred in BGE Zone:

Maximum THI on August 8: Temperature = 102 F; Relative Humidity = 34%.

THI = 102 – 0.55 * (1 – 34/100) * (102 – 58.0) = 86.03.

Maximum THI on August 7: Temperature = 94; Relative Humidity = 48%.

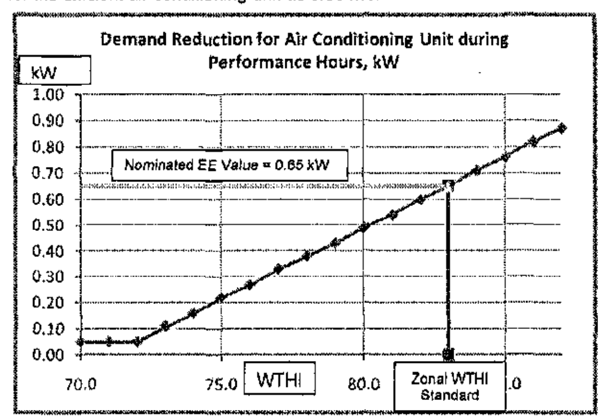
THI = 94 – 0.55 * (1 – 48/100) * (94 – 58.0) = 83.70.

WTHI = [(4 * August 8 WTHI) + (August 7 THI)] / 5 = [(4 * 86.03) + (83.70)] / 5 = 85.56.

The 1998 – 2008 Mean WTHI is calculated in the following table for BGE Zone:

Year	WTHI
1998	83.41
1999	85.78
2000	81.02
2001	84.71
2002	82.42
2003	80.63
2004	79.84
2005	83.52
2006	84.65
2007	85.56
2008	82.81
Mean	**83.12**

The determination of Nominated EE Value at Zonal WTHI Standard is illustrated here. An air conditioning unit was replaced with a more efficient unit. Based on the demand patterns of the two air conditioning units, data on the average demand reduction during the EE Performance Hours was collected for days with WTHI ranging from 70.0 to 87.0. The demand reduction vs. WTHI relationship is as shown below. The demand reduction corresponding to the Zonal WTHI of 83.0 provides an estimate of the Nominated EE Value for the efficient air conditioning unit as 0.65 kW.



Revision History

Revision 00 (04/23/2009)

This is the initial version of the PJM Manual for Energy Efficiency Measurement & Verification.

Exhibit EGD-3

Example of Adjusted Net Benefits (For Illustrative Purposes Only)

A	B	C	D = C - B
Program	Discounted Lifetime Costs	Discounted Lifetime Benefits	Total Discounted Net Lifetime Benefits
Direct Load Control	$4,300,000	$6,000,000	$1,700,000
Appliance Turn-In	$3,300,000	$4,700,000	$1,400,000
Energy Efficient Products	$7,900,000	$11,000,000	$3,100,000
Home Performance	$8,200,000	$11,500,000	$3,300,000
Low-Income	$1,000,000	$1,400,000	$400,000
C&I Energy Efficiency Equipment-Small	$2,300,000	$3,200,000	$900,000
Energy Efficient Buildings-Small	$9,500,000	$13,400,000	$3,900,000
Mercantile Customer	$8,900,000	$12,500,000	$3,600,000
Demand Reduction	$9,400,000	$13,100,000	$3,700,000
C/I Energy Efficient Equipment-Large	$4,000,000	$5,500,000	$1,500,000
Energy Efficient Buildings-Large	$6,200,000	$8,700,000	$2,500,000
Government Tariff Lighting	$900,000	$1,200,000	$300,000
Transmission & Distribution Projects	$300,000	$400,000	$100,000
Total	*$66,200,000*	*$92,600,000*	*$26,400,000*

Adjustments			
Mercantile Projects Pre-3/23/2011	$8,500,000	$12,000,000	$3,500,000
T&D Projects not modified for additional EE benefits	$100,000	$200,000	$100,000
Behavioral Modification Projects that do not demonstrate persistence	$400,000	$600,000	$200,000
Total	*$9,000,000*	*$12,800,000*	*$3,800,000*

Adjusted Discounted Net Lifetime Benefits ***$22,600,000***

Note: All values in the above scenario are illustrative and for the purpose of discussion only. Actual values will be calculated consistent with information as presented in the Company's Annual Portfolio Status Report, with discounted lifetime costs and benefits determined under the Utility Cost Test (UCT), and calculated in line with industry standards.

Exhibit EGD-4

Example of Company Incentive Calculation (For Illustrative Purposes Only)

A	B	C	D	E	F = B*E
Year	Adjusted Net Benefits	Compliance Percentage	Incentive Tier	Incentive Percentage	Company Incentive
2015	$22,600,000	107%	3	7.50%	$1,695,000

IEU-Ohio Ex. 4

EXHIBIT
IEU
4

Working to Perfect the Flow of Energy

PJM Manual 19:

Load Forecasting and Analysis

Revision: 20

Effective Date: June 28, 2012

Prepared by

Resource Adequacy Planning

PJM Manual 19:

Load Forecasting and Analysis

Table of Contents

Table of Exhibits

Approval

Approval Date: 06/28/2012
Effective Date: 06/28/2012

Thomas A. Falin, Manager

Resource Adequacy Planning Department

Current Revision

Revision 20 (06/28/2012)Attachment A updated based on PJM Interconnection, L.L.C., Docket No. ER11-3322 (Capacity measurement and verification). This tariff and RAA update specifically requires GLD to provide reductions below the PLC and aligns any recognized reductions used to determine capacity compliance with add back process.

Introduction

Welcome to the ***PJM Manual for Load Forecasting and Analysis.*** In this Introduction you will find the following information:

- What you can expect from the PJM Manuals in general (see "*About PJM Manuals*").
- What you can expect from this PJM Manual (see "*About This Manual*")
- How to use this manual (see "*Using This Manual*").

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by the PJM Office of the Interconnection for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and billing
- PJM administrative services
- Miscellaneous

For a complete list of all PJM Manuals, go to www.pjm.com and select "Manuals" under the "Documents" pull-down menu.

About This Manual

The ***PJM Manual for Load Forecasting and Analysis*** is one of a series of manuals within the Reserve group of manuals. This manual focuses on load-related topics. This manual describes the data input requirements, the processing performed on the data, computer programs involved in processing the data, and the reports that are produced. It then describes processes used to analyze load data and produce a long-term planning forecast.

The ***PJM Manual for Load Forecasting and Analysis*** consists of four sections. These sections are listed in the table of contents beginning on page ii.

Intended Audience

The intended audiences for the ***PJM Manual for Load Forecasting and Analysis*** are:

Electric Distribution Company (EDC) planners — The EDC planners are responsible for supplying historical load data in the required format, for using coincident peaks to allocate normalized peaks, and for input data verification.

Load Serving Entity (LSE) planners — LSEs use allocated peaks and the Load Management systems to determine their capacity obligations.

PJM staff — PJM is responsible for the calculation of hourly PJM loads, normalizing PJM seasonal peaks, forecasting RTO and zonal peaks for capacity obligations, compiling the PJM Load Forecast Report, and administering Load Management. This information is used in calculating the capacity obligations.

Planning Committee members — The Planning Committee is responsible for the stakeholder review of the peak forecasts and techniques for their determination.

Reliability Assurance Agreement Signatories — The Markets Reliability Committee is involved in the review of rules, methods and parameters associated with Load Forecasting and Analysis.

References

There are several references to other documents that provide background or additional detail. The ***PJM Manual for Load Forecasting and Analysis*** does not replace any information in these reference documents. The following documents are the primary source of specific requirements and implementation details:

- eMTR documentation
- PJM Load Forecast Report
- PJM Manual for Emergency Operations (M-13)
- Reliability Assurance Agreement
- Behind-the-Meter Generation Business Rules (in Manual M-14D)
- Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region

Using This Manual

We believe that explaining concepts is just as important as presenting the procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then, we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections.
- An approval page that lists the required approvals and a brief outline of the current revision.
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions.
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual.
- A section at the end detailing all previous revisions of this PJM manual.

Section 1: Overview

Welcome to the *Overview* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the Load Forecasting and Analysis (see "Overview of Load Forecasting and Analysis")

1.1 Overview of Load Forecasting and Analysis

Load Forecasting and Analysis utilizes the PJM eMTR load data, Load Management, PJM Load Forecast Model, and Weather Normalization and Peak Allocation.

PJM Hourly Load Data — After-the-fact hourly load data are entered by EDCs and used by PJM for deriving seasonal load profiles, weather normalization factors, 1CP zonal load contributions for Network Service billing, charts contained in the PJM Load Forecast Report, and the Monthly Operations Report.

PJM Load Forecast Model — PJM staff produces an independent forecast of monthly and seasonal peak load and load management, for each PJM zone, region, the RTO, and selected combinations of zones. The PJM Load Forecast Report includes tables and charts presenting the results.

Weather Normalization and Peak Allocation — PJM uses approved techniques for weather-normalizing historical summer and winter zonal peaks, and determining RTO unrestricted coincident peaks.

Section 2: PJM Hourly Load Data

Welcome to the *PJM Hourly Load Data* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the historic hourly load data file (see "Load Data Overview")
- Guidelines for reporting load data to PJM (see "Load Data Reporting Business Rules")

2.1 Load Data Overview

Official historic hourly load data for each EDC with revenue-metered tie data reported to PJM are collected via the eMTR application. For EDCs submitting all internal generation, eMTR will calculate a revenue-quality load based on submitted tie and generation meter values. EDCs may accept these values as their reported hourly service territory load, with the option to input data directly through the application's user interface or via uploaded XML files. The entered data are available through eMTR screens, postings on the PJM website, or in several reports produced by the Performance Compliance Department.

[For details on submitting data into eMTR, refer to the information posted on the PJM Website (under "eTools", select "eMTR.")]

Load Data Definitions

Actual Net Metered Interchange: The sum of allocated tie metered values to which the EDC is a party.

Total Internal Generation: The sum of all meter values for non-500kV generators electrically located in the EDC's zone. For PJM Western and Southern regions, 500kV generation will be counted as part of internal generation.

Allocated Mid-Atlantic 500kV Losses: Participant's share of total PJM Mid-Atlantic 500kV losses

Calculated Load = Actual Net Metered Interchange + Total Internal Generation + Allocated 500kV Losses.

2.2 Load Data Reporting Business Rules

As established by the PJM Planning Committee, the following guidelines govern the reporting of load data into the PJM eMTR application:

Data Reporting Responsibility: It will be the responsibility of each PJM electric distribution company (EDC) with fully-metered tie flows to report hourly load data for its metered area(s), regardless of which entity is responsible for serving end-use customers.

For all entities using network transmission service, it will be the responsibility of the signatory to the Network Integration Transmission Service Agreement to ensure that hourly load data are reported to PJM for its customers via PJM eSchedules.

Curtailment Service Providers (CSPs) are responsible for providing information to estimate load management impacts as detailed in Attachment A.

Data Specifications: Load data supplied to eMTR will reflect each entity's total impact to the system, and will therefore need to properly account for system losses and flows. PJM will adjust loads for their assigned share of Extra High Voltage losses. LSEs providing load management impact estimates will adjust loads for system losses. Data are accepted in eMTR in 0.001 MWh increments.

Reporting Schedule: The data for each day should initially be entered within the following ten calendar days, except during peak periods, when the data must be entered daily. PJM contacts EDCs when daily reporting is needed.

Edits to load data should be made by the tenth calendar day of the following month.

PJM will adjust submitted load data, as necessary, to reflect additional load that is determined by PJM after-the-fact, resulting from third-party supply of generator station power requirements.

Failure to report data to PJM in a timely and complete manner will subject responsible parties to Data Submission Charges, as outlined in Schedule 13 of the Reliability Assurance Agreement and the PJM West Reliability Assurance Agreement.

EDC/ CSP Actions:

- *Enter Hourly Load Data* — PJM EDCs submit aggregate hourly load values into eMTR, as required. CSPs provide resource-specific settlements data to quantify Load Management impacts into the eLRS application. (*See Attachment A*).

- *Edit the Data as necessary* — All hourly load value changes for a given month must be entered and edited by the 10th of the following month.

- *Notify the OI of All Changes* — Without this notification, PJM can only determine that changes have been made but cannot readily identify specific changes which were made.

PJM Actions:

- *Allocate Extra High Voltage Losses:* — 500kV losses in the PJM Mid-Atlantic region are calculated as the total 500kV system energy injections minus withdrawals. Hourly 500kV losses are allocated to each PJM Mid-Atlantic EDC with revenue metered tie flows reported to eMTR, in proportion to their real-time load ratio share.

- *Distribute Reports:* — By the 10th of each month, PJM makes reports of load data from the previous month available to the EDCs. These data include a summary Daily

Load Report for each day of the month, showing daily peak loads and the monthly energy total for each LSE and for the PJM RTO. A monthly summary report also is provided.

- *Post Zonal Data:* — PJM will publish zonal load data in an electronic format on a monthly basis.
- *Data Usage:* — PJM uses the hourly load data for operational analysis, for calculating seasonal load factors, developing weather normalization curves, for allocating the PJM weather normalized seasonal peaks, and for preparing various charts and tables in the PJM Load Forecast Report.

Section 3: PJM Load Forecast Model

Welcome to the *PJM Load Forecast Model* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the PJM Load Forecast Model (see "Forecast Model Overview").
- A description of the methodology used to produce the PJM forecast (see "Development of the Forecast").
- A description of the forecast review and approval process (see "Review and Approval the Forecast").

3.1 Forecast Model Overview

The PJM Load Forecast Model produces 15-year monthly forecasts of unrestricted peaks assuming a range of weather conditions for each PJM zone, load deliverability area and the RTO. The model uses anticipated economic growth and historical weather patterns to estimate growth in peak load and energy use. It is used to set the peak loads for capacity obligations, for reliability studies, and to support the Regional Transmission Expansion Plan. Net energy forecasts are used in reporting requirements of FERC and NERC, and for market efficiency studies. The forecast is produced by PJM and released prior to each Planning Period, typically in January.

3.2 Development of the Forecast

The PJM Load Forecast employs econometric multiple regression models to estimate daily peak load for each PJM zone (the non-coincident peak), the zone's contribution to the daily RTO peak (the coincident peak), and monthly net energy for load. Definitions of each model variable are presented in Exhibit 1. The variables included are:

Dependent Variable - Load:

For the non-coincident models, zonal hourly metered load data are supplemented with estimated load drops (as outlined in Attachment A) to obtain unrestricted hourly load. The maximum value for each day is used in the regressions. For the coincident models, the zone's contribution to the daily RTO unrestricted peak load is used in the regressions. For the net energy models, the sum of each day's hourly loads is used in the regressions.

Calendar Effects:

Days of the week, month of the year, holidays, minutes of daylight, and Daylight Savings Time impacts are included in the model using binary variables. Holiday seasonal lighting load is reflected using a trend variable.

Weather Data:

Weather is included in the models using different variables for heating, cooling and shoulder seasons. For the heating season (December, January and February), the Winter Weather Parameter is defined as:

If WIND > 10 mph,

$$WWP = DB - (0.5 * (WIND - 10))$$

If WIND ≤ 10 mph,

$$WWP = DB$$

Where: WIND = Wind velocity, in miles per hour;

WWP = Wind speed adjusted dry bulb temperature;

DB = Dry bulb temperature (°F).

For the cooling season (June, July and August), Temperature-Humidity Index (THI) is used as the weather variable:

If DB ≥ 58,

$$THI = DB - 0.55 * (1 - HUM) * (DB - 58)$$

If DB < 58,

$$THI = DB$$

Where: THI = Temperature humidity index;

DB = Dry bulb temperature (°F);

HUM = Relative Humidity (where 100% = 1).

For shoulder months (March, April, May, September, October and November), the average daily dry bulb temperature serves as the weather variable.

Additionally, measures of heating and cooling degree days are included. These readings are divided into separate morning, afternoon, evening, and night effects, as well as weekends. They are also lagged over three days. Weather data for each PJM zone are calculated according to the mapping presented in Exhibit 2.

Economic Drivers:

Measures of economic and demographic activity are included in the forecast models, representing total U.S., state, or metropolitan areas, depending upon their predictive value. Economic drivers for states and metropolitan areas are assigned to each PJM zone according to the mapping presented in Exhibit 3. Models for each PJM zone share the same general specification.

Load Adjustments:

In cases where a zone has experienced a large, sudden shift in load, a load adjustment dummy (binary) variable may be added to the zone's model specification. The resulting model coefficient must satisfy the following criteria:

- Be explained by an identifiable occurrence (such as the migration of load from another service territory, factory shutdown, or a price shock);
- Be statistically significant;
- Have a sign in the expected direction;
- Have a magnitude, relative to the zone's metered peak, large enough to make a discernable difference in the forecast; and
- Make an appreciable improvement to model fit statistics.

Non-Coincident Base and 90/10 Scenarios

For each PJM zone, a distribution of non-coincident peak (NCP) forecasts is produced using a Monte Carlo simulation process. The weather distributions are developed using observed historical weather data. The simulation process produces a distribution of monthly forecast results by selecting the 12 monthly peak values per forecast year for each weather scenario. For each year, by weather scenario, the maximum daily NCP load for a zone over each season is found. For each zone and year, a distribution of zonal NCP by weather scenario is developed. From this distribution, the median values are used to shape the monthly profile within each season.

The median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

RTO and Coincident Forecasts

To obtain the RTO peak forecast, the solution for each of the zonal coincident peak (CP) models are summed by day and weather scenario to obtain the RTO peak for the day. By weather scenario, the maximum daily RTO value for the season is found. For the RTO, a distribution of the seasonal RTO peak vs. weather scenario is developed. From this distribution, the median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

To determine the final zonal RTO-coincident peak (CP) forecasts, a methodology similar to the process for deriving zonal NCPs is applied. By weather scenario, the maximum daily CP load for a zone over the summer season is found. For each zone a distribution of zonal CP vs. weather scenario is developed. From this distribution the median value is selected. The median zonal CPs are summed and this sum is then used to apportion the forecasted RTO peak to produce the final zonal CP forecasts.

Net Energy for Load Forecasts

For each PJM zone, a distribution of forecasts is produced using a Monte Carlo simulation process. The weather distributions are developed using observed historical weather data. The simulation process produces a distribution of monthly forecast results by summing the daily values per forecast year for each weather scenario.

Load Management, Energy Efficiency, Price Responsive Demand and Behind-the-Meter Generation

PJM incorporates assumptions of load management, energy efficiency, price responsive demand and behind-the-meter generation to supplement the base, unrestricted forecast.

For Demand Resources (DR), forecasted values for each zone equal the amount of DR cleared in Reliability Pricing Model (RPM) auctions. The value cleared in the last auction is held constant for the remainder of the forecast.

For winter Load Management, only estimates of non-weather sensitive (Contractually Interruptible) DR and ILR are used.

The forecasted impact of approved Energy Efficiency programs equals the amount cleared in RPM auctions, and represents accelerated efficiency increases that would not otherwise occur, or would occur at a later time, without the EE program.

The impact of price responsive demand equals the amount subscribed through the RPM process. The amount subscribed for the last RPM auction year is held constant for the remainder of the forecast.

[Note: More information on behind-the-meter generation can be found in the Behind-the-Meter Generation Business Rules in the PJM Manual for Generator Operational Requirements (M-14D) posted on PJM.com.]

3.3 Non-Zone Peak Forecast

For use in the Reliability Pricing Model (RPM), PJM staff develops summer peak forecasts of the recognized non-zone loads. These forecasts are produced separately from the PJM Load Forecast Model, and utilize methods appropriate for each situation. Non-zone forecasted loads are added to the associated PJM zone for RPM purposes only.

3.4 Review of the Forecast

The PJM Load Forecast is reviewed by the Load Analysis Subcommittee and the Planning Committee.

A member of the Planning Committee may submit an appeal (detailing the issue and outlining a solution) for a review of part or all of the forecast, which will be forwarded by the Chair of the Planning Committee to PJM, upon a vote of the Committee.

Calendar Data

Day of week

Variable Name	Type or Formula	Description
Monday	Binary	Day of the Week
Tuesday	Binary	Day of the Week
Wednesday	Binary	Day of the Week
Thursday	Binary	Day of the Week
Friday	Binary	Day of the Week
Saturday	Binary	Day of the Week

Holiday

MartinLutherKingDay	Fuzzy	MLK Day Holiday
PresidentsDay	Fuzzy	President's Day Holiday
GoodFriday	Binary	Good Friday Religious Holiday
MemorialDay	Fuzzy	Memorial Day Holiday
July4th	Fuzzy	Independence Day and surrounding days
LaborDay	Fuzzy	Labor Day Holiday
Thanksgiving	Binary	Thanksgiving Holiday
FridayAfterThanksgiving	Fuzzy	Friday After Thanksgiving Holiday
XMasWkB4	Fuzzy	Week Before Christmas
ChristmasEve	Fuzzy	Christmas Eve (value depends on day of week)
ChristmasDay	Binary	Christmas Day
XMasWk	Fuzzy	Week after Christmas Holiday
NewYearsEve	Fuzzy	New Years Eve(value depends on day of week)
NewYearsDay	Binary	New Years Day Holiday
XMasLights	Trend	Christmas Lights/Retail Operations Trend

Month

January	Binary	Month of the Year
February	Binary	Month of the Year
March	Binary	Month of the Year
April	Binary	Month of the Year
May	Binary	Month of the Year
June	Binary	Month of the Year
July	Binary	Month of the Year
August	Binary	Month of the Year
September	Binary	Month of the Year
October	Binary	Month of the Year
November	Binary	Month of the Year

Notes:
Binary – A variable which has a value of 1 for the indicated characteristic, otherwise the value is 0.
Fuzzy – A variable which has a conditional value for the indicated characteristic, otherwise the value is 0.
Trend - A variable which has a value with increasing then decreasing value for the indicated characteristic, otherwise the value is 0.

Weather Data

Variable Name	Type or Formula	Description
NightHDD	Max(50 - NightWWP[1],0)	Night heating degree days
MornHDD	Max(55 - MornWWP[2],0)	Morning heating degree days
AfterHDD	Max(62 - AftWWP[3],0)	Afternoon heating degree days
EvenHDD	Max(55 - EvenWWP[4],0)	Evening heating degree days
NightCDD	Max(NightTHI[5] - 60,0)	Night cooling degree days
MornCDD	Max(MornTHI[6] - 65,0)	Morning cooling degree days
AfterCDD	Max(AftTHI[7]- 72,0)	Afternoon cooling degree days
EvenCDD	Max(EvenTHI[8]- 65,0)	Evening time cooling degree days
WkEndCDD	WkEnd[9] * CDD[10]	Weekend cooling degree days
WkEndHDD	WkEnd[9] * HDD[11]	Weekend heating degree days
ColdWind	Min(Max(60 - AftTHI[7],0) /20,1) * AvgWind[12]	Wind speed index on cold days
HotWind	Min(Max(AftTHI[7] - 60,0) /15,1) * AvgWind[12]	Wind speed index on hot days
LagHDD	IF (month ≤ 5 or month ≥ 10) THEN .75 * Lag(HDD[11], 1) + .25 * Lag(HDD, 2) ELSE 0	Lagged heating degree days
LagCDD	IF (month ≥ 6 & month ≤ 9) THEN .75 * Lag(CDD[10], 1)+.25*Lag(CDD,2) ELSE 0	Lagged cooling degree days
FuzzyHum	Min(Max(AvgTmp[13]- 60,0) /15,1) * AvgHum[14] Humidity index, triggered at 60 degrees	

Intermediate Calculations:

1 NightWWP	Average of WWP for hours ending 1 through 6	
2 MornWWP	Average of WWP for hours ending 7 through 12	
3 AftWWP	Average of WWP for hours ending 13 through 18	
4 EvenWWP	Average of WWP for hours ending 19 through 24	
5 NightTHI	Average of THI for hours ending 1 through 6	
6 MornTHI	Average of THI for hours ending 7 through 12	
7 AftTHI	Average of THI for hours ending 13 through 18	
8 EvenTHI	Average of THI for hours ending 19 through 24	
9 WkEnd	Weekend Binary	
10 CDD	Max(AvgTmp-65,0)	Cooling degree days
11 HDD	Max(60 - AvgTmp,0)	Heating degree days
12 AvgWind	24 hour average wind speed	
13 AvgTmp	24 hour average temperature (Fahrenheit)	
14 AvgHum	24 hour average humidity (percent)	

Seasonal Weather Variables

S_THI	IF (month ≥ 6 & month ≤ 9) For cooling months, use MaxTHI THEN MaxTHI[15] ELSE 0
W_WWP	IF (month ≤ 2 or month = 12) For heating months, use MinWWP THEN MinWWP[16] ELSE 0
SH_AvgTmp	IF (month = 3, 4, 5, 10 or 11) For shoulder months, use AvgTemp THEN AvgTmp[13] ELSE 0

Intermediate Calculations:
15 MaxTHI Maximum THI over 24 hours
16 MinWWP Minimum WWP over 24 hours

Economic Data

Variable Name	Type or Formula	Description
DailyEconIndex	Convstock(EconIndex)	Economic index quarterly values converted to daily

$$EconIndex = ResWt \ x \ (HH_{y,m}/HH_{base})^{0.47} \ x \ (Pop_{y,m}/Pop_{base})^{026} \ x \ (PInc_{y,m}/PInc_{base})^{027}$$
$$+ ComWt \ x \ (NMEmp_{y,m}/NMEmp_{base})^{0.47} \ x \ (GDP_{y,m}/GDP_{base})^{020} \ x \ (GMP_{y,m}/GMP_{base})^{016} \ x \ (Pop_{y,m}/Pop_{base})^{017}$$
$$+ IndWt \ x \ (GDP_{y,m}/GDP_{base})^{047} \ x \ (GMP_{y,m}/GMP_{base})^{053}$$

Where: ResWt is the residential sector sales percentage to total zonal electric sales in year (y);
HH is the number of households in year (y) and month (m);
Pop is the population in year (y) and month (m);
PInc is the value of total real personal income in year (y) and month (m);
ComWt is the commercial sector sales percentage to total zonal electric sales in year (y);
NMEmp is the number of non-manufacturing employees in the metro area(s) in year (y) and month (m);
GDP is the value of total real gross domestic product in the United States in year (y) and month (m);
GMP is the value of total real gross metropolitan product in the metro area(s) in year (y) and month (m);
IndWt is industrial sector sales percentage to total zonal electric sales in year (y);
And base indexes the base year.

Economic/Weather Data

Econ_HDD	HDD^{11} * DailyEconIndex	Heating Degree Days interacted with economic index
Econ_CDD	CDD^{10} * DailyEconIndex	Cooling Degree Days interacted with economic index

Solar Data

DLSav_EPA2005	Binary	Daylight Savings Time conversion
MinutesDaylight	Minutes	Minutes of daylight at local airport

Load Adjustment

LA_<yy>	Binary	Adjustment for year 20yy forward

Exhibit 1: Model Variable Definitions

Zone	Weather Station	Airport Name	Weight
AE	ACY	Atlantic City International	1
AEP	CMH	Columbus Port Columbus International	0.5
AEP	FWA	Fort Wayne International Airport	0.2
AEP	ROA	Roanoke Regional Airport	0.3
APS	IAD	Washington Dulles	0.3
APS	PIT	Pittsburgh International	0.7
ATSI	CAK	Akron-Canton Regional Airport	0.465
ATSI	CLE	Cleveland Hopkins Airport	0.3
ATSI	TOL	Toledo Express Airport	0.15
ATSI	PIT	Pittsburgh International Airport	0.085
BGE	BWI	Baltimore Washington International	1
COMED	ORD	Chicago O'Hare International	1
DAY	DAY	Cox-Dayton International	1
DEOK	CVG	Cincinnati Northern KY Airport	1
DLCo	PIT	Pittsburgh International	1
DOM	IAD	Washington Dulles	0.3333
DOM	ORF	Norfolk International	0.3333
DOM	RIC	Richmond International	0.3334
DPL	ILG	Wilmington New Castle County Airport	0.7
DPL	WAL	Wallops Island Flight Center	0.3
JCPL	EWR	Newark International	0.75
JCPL	ACY	Atlantic City International	0.25
METED	PHL	Philadelphia International	0.5
METED	ABE	Allentown Lehigh Valley International	0.5
PECO	PHL	Philadelphia International	1
PENLC	ERI	Erie International	0.5
PENLC	IPT	Williamsport Regional	0.5
PEPCO	DCA	Washington Reagan National	1
PL	ABE	Allentown Lehigh Valley International	0.6
PL	IPT	Williamsport Regional	0.4
PS	EWR	Newark International	1
RECO	EWR	Newark International	1
UGI	AVP	Wilkes-Barre Scranton International	1

Exhibit 2: Assignment of Weather Stations to Zones

Zone	State(s)	Metro Area Name(s)
AE	NJ	Atlantic City NJ, Vineland NJ
AEP	OH, WV, VA, IN	Elkhart IN, Fort Wayne IN, South Bend IN, Canton OH, Columbus OH, Kingsport TN, Lynchburg VA, Roanoke VA, Charleston WV, Huntington WV
APS	PA, OH, WV	Hagerstown MD, Morgantown WV
ATSI	PA, OH	Akron OH, Cleveland OH, Mansfield OH, Springfield OH, Toledo OH, Youngstown OH, Pittsburgh PA
BGE	MD	Baltimore MD
COMED	IL	Chicago IL
DAY	OH	Dayton OH
DEOK	OH	Cincinnati OH
DLCO	PA	Pittsburgh PA
DOM	VA	Richmond VA, Virginia Beach VA, Roanoke VA
DPL	DE	Dover DE, Wilmington DE, Salisbury MD
JCPL	NJ	Camden NJ, Edison NJ, Trenton NJ
METED	PA	Allentown/Bethlehem/Easton PA, Reading PA, York PA, Lebanon PA
PECO	PA	Philadelphia PA
PENLC	PA	Erie PA, Altoona PA, Johnstown PA
PEPCO	MD	Washington D.C.
PL	PA	Allentown/Bethlehem/Easton PA, Scranton Wilkes-Barre PA, Harrisburg PA, Lancaster PA, Williamsport PA
PS	NJ	Camden NJ, Edison NJ, Trenton NJ, Newark NJ
RECO	NJ	Newark NJ
UGI	PA	Scranton Wilkes-Barre PA

Exhibit 3: Assignment of Metropolitan Areas and States to Zones

Section 4: Weather Normalization and Coincident Peaks

Welcome to the *Weather Normalization and Coincident Peaks* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the weather normalization process (see "Weather Normalization Overview").
- A description of the weather normalization procedure (see "Weather Normalization Procedure").
- A description of the identification and calculation of PJM unrestricted coincident peaks (see "Peak Load Allocation (5CP)").

4.1 Weather Normalization Overview

PJM performs load studies on summer and winter loads, according to the procedures described below. The Load Analysis Subcommittee reviews the normalizations, and either adopts the resulting values, or Members may challenge the results as anomalous. In the latter situation, alternate analysis will be conducted, until a consensus is reached. After the review process is completed, the results are presented to the Planning Committee. The weather normalized (W/N) peaks are then used by EDCs to determine capacity peak load shares for wholesale and retail customers.

4.2 Weather Normalization Procedure

The standard PJM weather normalization procedure consists of utilizing the PJM Load Forecast Model as described in Section 3 above. After each season, each zonal/RTO NCP and CP model is re-estimated, adding the most recent historical load, weather, and economic data. Then, the Monte Carlo process is run, including historical weather through the just-completed season. From the resulting distribution of results, the median value is selected as the weather normalized seasonal peak. These peaks are then adjusted, as described above in Section 3, to align the zones with the RTO.

4.3 Normalized Peak Appeal Process

Results of the weather-normalization analysis will be reviewed by LAS members. Members will have an opportunity at that point to trigger the following appeal process if, in their judgment, the results of the standard method described above appear inaccurate:

- Any LAS member may request review of any zone's normalized peak, though the primary responsibility resides with the member from the zone in question.
- A request for review will be followed by further analysis, conducted by PJM and LAS members, to identify and quantify the inaccuracy in the weather-normalization of the zone.

- LAS will conduct peer review of all supplemental analysis, and seek a (supermajority) consensus before the issue is presented to the Planning Committee.
- If an adjustment needs to be made to a zonal W/N peak, LAS will forward the proposed zonal W/N peak to the Planning Committee, along with the results of the standard analysis.

The appeals process is designed to address the rare significant miscalculation of a zone's load, and is not intended as a method to "fine tune" the results of the standard method.

EDC/ CSP Actions:

- Enter hourly load data into eMTR, as described in Section 2 of this manual.
- Provide resource-specific settlements data to quantify Load Management impacts into the eLRS application
- Submit voltage reduction and loss of load Load Drop Estimates as described in Attachment A of this manual.
- Participate in review of seasonal load studies, through the Load Analysis Subcommittee.

PJM Actions:

- Obtain weather observations
- Produce voltage reduction load drop estimates, as described in Attachment A of this manual.
- Weather-normalize the zonal RTO-coincident winter and summer peak loads. Provide recommendation to PJM Planning Committee, by its October meeting, to accept the results of the standard normalization procedure, or to use the alternate methodology.
- If necessary, produce analysis to establish alternate estimate of zonal W/N CP Load.

4.4 Peak Load Allocation (5CP)

Zonal weather-normalized RTO-coincident summer peak loads are allocated to the wholesale and retail customers in the zones using EDC-specific methodologies that typically employ the customer's shares of RTO actual peaks. The resulting Peak Load Contributions are then used in the determination of capacity obligations.

PJM establishes and publishes information, referred to as the 5CP, to aid EDCs in the calculation of Peak Load Contributions (also known as "tickets"). For each summer:

- Hourly metered load and load drop estimate data are gathered for the period June 1 through September 30
- RTO unrestricted loads are created by adding load drop estimates to metered load

- From the unrestricted values, the five highest non-holiday weekday RTO unrestricted daily peaks (5CP) are identified

5CP data are typically released in mid-October.

Attachment A: Load Drop Estimate Guidelines

General

Load Drop Estimates (also referred to as addbacks) are produced for three types of occurrences:

1. Curtailment of load for customers registered in the PJM emergency program either as a Load Management resource (Demand Resource and Interruptible Load for Reliability) or an Emergency – Energy Only resource.

2. Voltage Reductions implemented by PJM or an EDC

3. Significant losses of load.

PJM is responsible for producing Load Management/Emergency load drop estimates, from CSP and EDC input into the appropriate PJM system. EDCs are responsible for reporting the estimated impact of voltage reductions (optional) or significant losses of load on their systems.

Load drop estimates are used to construct unrestricted loads used in the PJM Load Forecast Model, weather normalization of PJM seasonal peaks, and to calculate the unrestricted Peak Load Contributions used in formulating capacity obligations.

These rules also apply to Non-Retail Behind-the-Meter Generation as provided in Section G of Schedule 6 to the Reliability Assurance Agreement.

Load Drop Estimates for Load Management Customers

The table below summarizes the requirements for producing load drop estimates for customers registered as a Demand Resource, Interruptible Load for Reliability, or in the Emergency– Energy Only option, or as Economic load response, depending upon the cause of the load curtailment. Following the table are descriptions of the methods used by PJM to calculate load drop estimates for each load management type (Direct Load Control, Firm Service Level, and Guaranteed Load Drop).

Requirements for Production of Load Drop Estimates

Reason for Load Drop		*PJM-Initiated Emergency or CSP-Initiated Test*	*Economic*	*EDC- or CSP-Initiated*
Program Registration	*Emergency Full or Emergency Capacity Only (DR / ILR)*	*Load Drop Estimates must be produced for any interruptions from June 1 through September 30.*	*Load Drop Estimates must be produced for any settled interruptions from June 1 through September 30.*	*No Load Drop Estimates required.*
	Emergency Energy Only	*Load Drop Estimates must be produced for any interruptions during Emergency hours from June 1 through September 30.*	*No Load Drop Estimates required.*	*No Load Drop Estimates required.*
	Economic	*No Load Drop Estimates required.*	*No Load Drop Estimates required.*	*No Load Drop Estimates required.*

Actual Emergency Load Response and Economic Load Response load reductions for Load Management resources registered as Emergency Full or Emergency Capacity Only resources which occur from June 1 through September 30, will be added back for the purpose of calculating peak load for capacity for the following Delivery Year and consistent with the load response recognized for capacity compliance as set forth in the Manual.

Non-Interval Metered Customers Including Direct Load Control

The nominated quantity (MW) of Load Management provided by non-interval metered customers * Loss Factor will be the estimated load drop added back to the zone for a load management emergency or test event. If the resource participates as an economic resource, then the hourly MW settled under the economic program will be used for the load drop that is added back to the zone.

Contractually Interruptible

The estimated load drop for Firm Service Level and Guaranteed Load Drop customers is calculated as follows:

For Guaranteed Load Drop end-use customers, the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the metered load ("Load") and then multiplied by the loss factor ("LF") or (b) the current Delivery Year peak load contribution ("PLC") minus the metered load multiplied by the loss factor ("LF"). A load reduction will only be recognized for capacity compliance if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution. The calculation is represented by:

Minimum of {(comparison load – Load) * LF, PLC – (Load * LF)}

For Firm Service Level end-use customers the current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

PLC – (Load * LF)

Note: When Generation interval meter data is provided to determine test or event compliance, and interval metering on load is available, the interval metered load data should be provided to ensure load drop is below the PLC. It is expected that interval load data will be available for all customers that have a PLC > 0.5 MW. If no interval meter load data exists, such Generation interval meter data multiplied by loss factor will be used as the estimated load drop.

Event Compliance for Guaranteed Load Drop (GLD) Customers

For purposes of determining compliance with a PJM-initiated Load Management event or test for Guaranteed Load Drop customers, several options are available to estimate comparison loads. The method used should result in the best possible estimate of what load level would have occurred in the absence of an emergency or test event.

The CSP will be responsible for supplying all necessary load data to PJM in order to calculate the load reduction for each registered end use customer. PJM will calculate the load drop amount unless otherwise indicated below or approved by PJM. The amount of load data required will depend on the GLD method selected where the minimum amount shall be 24 hours for one full calendar day.

Comparable Day: The customer's actual hourly loads on one of the prior 10 calendar days before the test or emergency event day selected by the CSP which best represents what the load level would have been absent the emergency or test event. The CSP may request use of an alternative day for extenuating circumstances with supporting documentation that clarifies why the alternative day should be utilized. PJM must approve the use of any alternative day. CSP must provide usage data for all 10 days such that PJM may validate an appropriate day was selected.

Same Day (Before/After Event): The customer's average hourly integrated consumption for two full hours prior to notification of an emergency event or prior to one full hour before a test and for two full hours after skipping first full hour after the event or test. This option is appropriate for high load factor customers with no weather sensitivity.

Customer Baseline: The Customer's estimated baseline used to calculate load drops for PJM economic demand resources as defined on the applicable PJM economic registration.

Regression Analysis: The customer's estimated hourly loads from a regression analysis of the customer's actual loads versus weather. This option is appropriate for customers with significant weather sensitivity. The CSP will perform the regression analysis and provide results including supporting information to PJM. The information should include all load and weather data and associated regression statistics used to estimate the load impact on the event or test day.

Generation: The hourly integrated output from a generator used to provide Guaranteed Load Drop. This method may only be utilized if the generation would not have otherwise been deployed on the emergency event or test day and must comply with the provisions contained in the PJM Manuals.

Missing Data

If an end use customer meter malfunctions during a Load Management test, retest or emergency event and the end use customer performed the required load reduction activity and no interval meter data is available to use for purposes of measuring capacity compliance or to determine applicable energy settlements, then PJM may allow CSP one of the following two remedies, otherwise the end use customer will be considered to have taken no load reduction actions during such period:

1. CSP may provide supporting information to quantify the load reduction amount which includes an engineering analysis or meter data from a comparable site that reduced load based on the same actions during a comparable time, or;

2. CSP may perform a separate test for the end use customer(s) to quantify the load reduction that will be used for the test, retest or event time period compliance and, as appropriate, energy settlement(s). The test will need to be performed at comparable time and conditions to when the test, retest or emergency event occurred.

Remedies will only be considered if the CSP and associated metering entity followed Good Utility Practice as outlined in the OATT, no interval load data is available from the EDC, and the CSP can provide supporting information, such as building automation system logs, to verify the load reduction action was taken during the test, retest or emergency event when the meter malfunctioned. CSP must also provide evidence that the meter did malfunction.

PJM must approve any remedy and CSP must meet appropriate load data submission deadline.

Voltage Reduction

Whenever a part of the PJM system experiences a voltage reduction, whether it is PJM- or locally initiated, the distribution companies involved are to estimate its impact on hourly load levels. The estimated impact of a 5% voltage reduction will be 1.7% of the load in the affected area at the time of the voltage reduction. Variances from this guideline are acceptable in cases where a thorough analysis was performed. In such cases, a written explanation of the estimate must accompany the reported values.

Loss of Load

Whenever a part of the PJM system experiences a loss of load event (beyond the level of nominal localized outages), the Distribution Company involved is to estimate its impact on hourly load levels. The method used to estimate the impact of the loss of load event will vary by the circumstances involved, but the outcome of the estimation should represent the best approximation of the actual hourly loads that would have occurred if the loss of load event had not occurred. A written explanation of the loss of load event and how its impact was estimated is to accompany the report.

Attachment B: Direct Load Control Load Research Guidelines

The intention of these guidelines is to ensure that the estimated per-participant impacts of Direct Load Control program reliably represent the amount of load shed, on average, for active program participants.

Curtailment Service Providers with Direct Load Control programs which employ a radio signal may elect to either submit a load research study supporting base per-participant impacts for their program, or utilize the base per-participant impacts contained in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region" report. Providers utilizing other technology must submit a load research study. All Providers must submit switch operability studies once every five years.

Requirements for Provider-Submitted Studies

Study Design

DLC load research studies will be designed to achieve a minimum accuracy of 90% Confidence with 20% error.

Study Detail

Load research studies submitted must present estimated per-participant impacts in a matrix which details average impacts on non-holiday weekdays by hour, for the hours ending 13:00 through 20:00 (PJM Eastern Region) or 8:00 through 21:00 (PJM Western Region), and by weather condition (over a range of local conditions under which it can reasonably be expected that the program will be implemented). Separate matrices must be estimated:

By program (and/or cycling scheme);

By PJM zone.

Switch Operability Rate

In addition to base per-participant impacts, studies submitted to PJM must also include the average switch operability rate, reflecting the percentage of all active switches which both receive the control signal and operate. The switch operability rate must be supplied with the original base impact study, and then updated every five years. Any Provider with a switch operability study older than five years will be given a switch operability rate of 50%.

Utilizing the Deemed Savings Estimates

[Note: The "Deemed Savings Estimates" study report is available on the PJM.com website.]

Eligibility

Load Management Providers with Direct Load Control programs which employ a radio signal may elect to utilize the base per-participant impacts contained in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region" report.

Base Impact Value

Base impacts for air conditioning programs will be established utilizing the aggregate values detailed in Appendix F of the Deemed Savings Estimates report. The Provider must supply the applicable duty cycle strategy (percentage of each hour the unit is interrupted) and an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak). The Provider may opt to customize the base impact by supplying a research study which stratifies its program by A/C usage or connected A/C load. In this case, base impacts will be drawn from the aggregate results presented in Appendix G or H, as appropriate.

Base impacts for water heating programs will be established utilizing the aggregate values detailed in Appendix J. The Provider must supply an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak)

EDCs with base impacts presented in the Deemed Savings report (BGE, JCPL, and PSEG) may elect to use those impacts.

Switch Operability Rate

All Providers utilizing the modeled base per-participant impacts must submit to PJM a switch operability rate study, reflecting the percentage of all active switches which both receive the control signal and operate. This study must be designed to achieve a minimum accuracy of 90% Confidence with 10% error. Any Provider without a switch operability study, or with one older than five years will be given a switch operability rate of 50%.

Revision History

Revision 19 (02/23/2012):

Attachment A changed to update Comparable Day definition, clarify data required if Generation data is used to substantiate load reduction and have PJM perform the compliance calculation.

Revision 18 (11/16/2011)

Section 3: Revisions reflect adoption of Itron, Inc recommendations regarding the economic driver used in the load forecast model. References to the now-defunct Interruptible Load for Reliability option of Load Management were removed.

Revision 17 (07/14/2011)

Attachment A: 24 hour data submission required and additional clarification for use of generation data to substantiate compliance (FERC Docket #: ER11-2898-000, 4/18/11). Also added revisions concerning how add backs are applied to DLC as approved by the MRC.

Revision 16 (04/01/2011)

Section 3: Integrated the description of the net energy forecast model into the general model description.

Revised Exhibits 2 and 3 to reflect updated economic and weather station mappings.

Attachment A: Revised load drop estimate guidelines based on Load Management Task Force proposal approved at November 2010 Markets and Reliability Committee and January 2011 Members Committee. Corresponding tariff language changes were filed with FERC under Docket ER11-2898-000.

Revision 15 (10/01/2009):

Attachment A: Revised load drop estimate guidelines to reflect the FERC-approved business rules. Section 3: added price responsive demand to the adjustments made to the load forecast.

Revision 14 (12/01/2008)

Section 3: Revised load forecast model specification to allow for a load adjustment dummy variable. Clarified the review and approval process for the Load Forecast Report.

Section 4: Revised the Weather Normalization approval process to clarify that Board approval is not required.

Revision 13 (06/01/2008)

A new Exhibit 1 was added, presenting definitions of variables used in the load forecast model. Other exhibits were re-numbered.

Exhibit 2 was revised to reflect a new weather station assignment for the DAY zone.

Section 4: Removed note from Weather Normalization Procedure description (the process is finalized).

Attachment A: Revised to reflect that the guidelines apply to both capacity- and energy-related load drop estimates.

Revision 12 (06/01/2007)

Removed Section 3 and moved content to Manual 18.

Removed Section 7 and moved content to Manual 18.

Revision 11 (06/01/07)

This extensive revision incorporates changes to Load Data Systems due to the implementation of the Reliability Pricing Model (RPM). Sections on Active Load Management and Qualified Interruptible Load have been replaced with a new Load Management section. The Zonal Scaling Factor section reflects a revised calculation. The Load Forecast Model section has been updated for enhancements made to the model specification as well as revised coincident peak forecast method. The Weather Normalization section was revised to reflect that seasonal peaks are now normalized using the load forecast model.

Revision 10 (06/01/06)

- Exhibit 1—Updated to include the new Manual 30: Alternative Collateral Program.
- Section 3—Revised to reflect changes in the handling of outlier observations in weather normalization of seasonal peaks.
- Section 4—Revised to incorporate the addition of the Full Emergency option of Load Response.
- Updated the penalties/rewards section under Compliance.

Revision 09 (01/01/06)

This revision includes a complete revision to Section 6 to detail the PJM-produced load forecast which will be used for capacity and system planning purposes. The previous Section 3 (PJM Load Forecast Report) has been removed since Member input is no longer required for its production.

Revision 08 (06/01/05)

Updated Exhibit 1 to include new PJM Manuals.

This revision includes changes to Section 3 to reflect reporting requirements for sub-Zones. Section 4 was completely revised to reflect a new weather normalization method and revised basis for calculating 5CPs. Section 8 has been modified to reflect revised release dates for Zonal Scaling Factors.

Revision 07 (07/01/04)

This revision includes changes to Section 2, to reflect that 500kV generation will be treated differently in the PJM Western and Southern regions than the Mid-Atlantic Region. Section 4 was revised to reflect that peak load allocation will be impacted for market integration. Section 5 has been modified to reflect that the Active Load Management program has been fully incorporated into the eCapacity application.

Revision 06 (10/01/03)

This revision incorporates a new presentation format. Substantive changes were made to Section 4, to reflect changes in peak normalization procedures. Section 5 and Attachment B were revised to reflect the change in load research requirements for cycling programs to a five year cycle. The previous Section 6 (Forecast Peak Period Load) has been deleted. The section on Qualified Interruptible Load now reflects that it is the same as Active Load Management. New sections have been added for the PJM Entity Forecast and Zonal Scaling Factors. Attachment A includes an additional load drop estimate technique, Customer Baseline. Throughout the document, changes were made to reflect the new committee structure, and the Board of Managers enhanced authority.

Changed all references from "*PJM Interconnection, L.L.C.*" to "*PJM.*"

Changed all references from "the PJM OI" to "PJM."

Renamed Exhibits to consecutive numbering.

Reformatted to new PJM formatting standard.

Renumbered pages to consecutive numbering.

Revision 05 (01/01/03)

This revision contains changes to Section 2, which was revised to reflect that hourly load data are reported through the new eMTR application. Section 5 was revised to clarify wording on existing Active Load Management rules and procedures.

Revision 04 (06/01/02)

This revision contains changes to Section 3, which was revised to reflect a new reporting format for the PJM Load Forecast Report. Section 7 was revised to incorporate firm level customers into the Qualified Interruptible Load program.

Revision 03 (01/01/02)

This revision incorporates changes resulting from the addition of PJM West into the Interconnection. Section 4 was revised to add a description of the peak normalization process for PJM West. Sections 6 (Qualified Interruptible Load) and 7 (Forecast Period Peak Load) were added.

Revision 02 (10/01/00)

This revision contains changes to Section 4 to include a clarification of the weather normalization overview, and revises the summer season weather normalization to reflect the newly adopted PJM summer weather parameter. Also, the removal of Attachment A: Definitions and Abbreviations. Attachment A is being developed into a 'new' PJM Manual for *Definitions and Abbreviations (M-35)*. Attachments B, C, and D have been renamed A, B, and C respectively. Also, changes to the 'new' Attachment A: ALM Load Drop Estimate Guidelines (previously listed as Attachment B) have been in effect since 6/01/00; however, they are now being addressed in this revision.

Revision 01 (06/01/00)

This revision contains changes to Sections 3, 4, and 5, to reflect the influence of retail choice, including the creation of a peak allocation, revamped Active Load Management rules and procedures, and revamped PJM Load Forecast Report. Also, it details a revised weather normalization procedure.

Revision 00 (07/15/97)

This revision is the complete draft of the PJM Manual for Load Data Systems.