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PJM Capacity Market

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Prepared by
PJM Capacity Market Operations

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PJM Manual 18: PJM Capacity Market

Table of Contents

Table of Contents.....	ii
Table of Exhibits	viii
Approval.....	1
Current Revision	1
Introduction	1
ABOUT PJM MANUALS	1
ABOUT THIS MANUAL	1
INTENDED AUDIENCE.....	1
REFERENCES.....	2
USING THIS MANUAL	2
WHAT YOU WILL FIND IN THIS MANUAL.....	2
Section 1: Overview of the PJM Capacity Market	3
1.1 OVERVIEW OF THE PJM CAPACITY MARKET	3
1.2 PARTICIPATION IN THE PJM CAPACITY MARKET.....	4
1.2.1 Participation of Load Serving Entities.....	4
1.2.2 Participation of Resource Providers	4
1.2.3 Participation of PRD Providers	5
1.3 DEFINITION AND PURPOSE OF THE RELIABILITY PRICING MODEL.....	5
1.4 IMPLEMENTATION OF THE RELIABILITY PRICING MODEL	6
Section 2: Resource Adequacy.....	9
2.1 OVERVIEW OF RESOURCE ADEQUACY.....	9
2.1.1 Installed Reserve Margin	9
2.1.2 Peak Load Forecasts.....	9
2.1.3 Pool-wide Average EFORd.....	10
2.1.4 Forecast Pool Requirement	11
2.2 ROLE OF LOAD DELIVERABILITY IN THE RELIABILITY PRICING MODEL	11
2.3 LOCATIONAL CONSTRAINTS IN THE RELIABILITY PRICING MODEL	12
2.3.1 Locational Deliverability Areas.....	13
2.3.2 Constrained Locational Deliverability Areas (LDAs).....	14
2.3.3 Creation of New Locational Deliverability Areas (LDAs)	15
2.3.4 Capacity Import Limits	15
2.4 RELIABILITY REQUIREMENTS.....	17
2.4.1 PJM Region Reliability Requirement	17
2.4.2 Reliability Requirement in Locational Deliverability Areas	18
2.4.3 Minimum Annual/Extended Summer Resource Requirements (2014/2015 – 2016/2017 Delivery Years)	18
2.4.3A Limited Resource Constraint & Sub-Annual Resource Constraint (Effective with 2017/2018 Delivery Year)	19
2.4.4 Adjustments to RPM Auction Parameters for PRD	21
Section 3: Demand in the Reliability Pricing Model.....	22
3.1 OVERVIEW OF DEMAND IN THE RELIABILITY PRICING MODEL	22
3.2 DEFINITION AND PURPOSE OF THE VARIABLE RESOURCE REQUIREMENT	23



3.3 PARAMETERS OF THE VARIABLE RESOURCE REQUIREMENT	23
3.3.1 <i>Cost of New Entry</i>	24
3.3.2 <i>Net Energy and Ancillary Services Offset</i>	24
3.3.3 <i>Net Cost of New Entry</i>	26
3.4 PLOTTING THE VARIABLE RESOURCE REQUIREMENT CURVE	26
3.4.1 <i>Plotting the Variable Resource Requirement Curves</i>	29
3.5 DEMAND CURVES IN THE INCREMENTAL AUCTIONS	30
Section 3A: Integration of Price Responsive Demand	33
3A.1 OVERVIEW OF PRICE RESPONSIVE DEMAND IN PJM CAPACITY MARKET	33
3A.2 TRANSITION PERIOD	35
3A.3 ELIGIBILITY REQUIREMENTS OF PRICE RESPONSIVE DEMAND	36
3A.4 PRD PLAN REQUIREMENTS	37
3A.4.1 <i>PRD Plan Submission & Approval Process</i>	37
3A.4.2 <i>Required Components of a PRD Plan</i>	38
3A.4.2.1 <i>Verification of Retail Rate Structure with LSE</i>	40
3A.4.2.2 <i>Verification of Contractual Arrangement with PRD Provider</i>	40
3A.4.2.3 <i>PRD Election Requirements</i>	41
3A.5 REGISTRATION OF PRICE RESPONSIVE DEMAND	42
3A.6 PERFORMANCE REQUIREMENTS OF PRICE RESPONSIVE DEMAND	43
3A.6.1 <i>PRD Commitment Compliance</i>	43
3A.6.2 <i>Maximum Emergency Event Compliance</i>	43
3A.6.3 <i>PRD Test Compliance</i>	45
3A.7 PRD BILATERALS	47
Section 4: Supply Resources in the Reliability Pricing Model	48
4.1 OVERVIEW OF SUPPLY IN THE RELIABILITY PRICING MODEL	48
4.2 GENERATION RESOURCES	49
4.2.1 <i>Existing Generation Resources - Internal</i>	49
4.2.2 <i>Existing Generation Resources - External</i>	49
4.2.3 <i>Planned Generation Resources - Internal</i>	51
4.2.4 <i>Planned Generation Resources – External</i>	52
4.2.5 <i>Equivalent Demand Forced Outage Rate (EFORd)</i>	53
4.2.6 <i>Capacity Modifications (CAP Mods)</i>	54
4.3 LOAD MANAGEMENT PRODUCTS	55
4.3.1 <i>Requirements of Load Management Products in RPM</i>	55
4.3.2 <i>Types of Load Management Programs</i>	58
4.3.3 <i>Demand Resources</i>	58
4.3.4 <i>Demand Resource Modifications (DR Mods)</i>	60
4.3.5 <i>Pre-Emergency and Emergency Load Response Registration</i>	60
4.3.6 <i>End-Use Customer Aggregation</i>	61
4.3.7 <i>Determination of Nominated Values for Load Management</i>	62
4.3.8 <i>Determination of the UCAP Value of Load Management</i>	63
4.3.9 <i>Load Reduction Reporting</i>	63
4.3.10 <i>Maintenance Outage Reporting for Annual Demand Resource</i>	64
4.4 ENERGY EFFICIENCY RESOURCES	65
4.4.1 <i>Determination of Nominated Value of EE Resource</i>	67
4.4.2 <i>Determination of the UCAP Value of EE Resource</i>	67
4.4.3 <i>Energy Efficiency Resource Modifications (EE MODs)</i>	68
4.5 QUALIFIED TRANSMISSION UPGRADES	68
4.6 BILATERAL TRANSACTIONS	69
4.6.1 <i>Unit-Specific Bilateral Transactions</i>	69
4.6.2 <i>Entering Unit-Specific Bilateral Transactions</i>	70
4.6.3 <i>Exporting a Generation Resource</i>	72



4.6.4 Importing an External Generation Resource	73
4.6.5 Treatment of Unit-Specific Capacity Transactions that Start/End Mid-Delivery Year	73
4.6.6 Auction Specific MW Transactions	74
4.6.7 Cleared Buy Bid Transactions	75
4.6.8 Locational Unforced Capacity (UCAP) Transactions.....	76
4.7 RESOURCE PORTFOLIO	77
4.7.1 Resource Position for Generation Resources	77
4.7.2 Resource Position for Demand Resources	79
4.7.3 Resource Position for Energy Efficiency Resources	80
4.7.4 Resource Position for Qualified Transmission Upgrades	82
4.8 CREDIT REQUIREMENTS	82
4.8.1 RPM Credit Limit.....	83
4.8.2 RPM Credit Requirement.....	84
4.8.3 Auction Credit Rate.....	85
4.8.4 Credit-Limited Offers in RPM Auctions	87
4.8.5 Price Responsive Demand Credit Requirement.....	88
Section 5: RPM Auctions	94
5.1 OVERVIEW OF RPM AUCTIONS	94
5.2 RPM AUCTION TIMELINE	95
5.3 RPM AUCTION PARAMETERS	97
5.3.1 Resource-Specific Sell Offer Requirements	98
5.3.2 Flexible Self Scheduling	101
5.3.3 New Entry Pricing	102
5.3.4 Sell Offer Caps.....	103
5.3.5 Minimum Offer Price Rule (MOPR)	105
5.3.6 Qualified Transmission Upgrade Sell Offer Requirements.....	107
5.4 BUY BIDS IN RPM.....	108
5.5 ENERGY MARKET OFFER REQUIREMENTS	108
5.6 BASE RESIDUAL AUCTION.....	108
5.6.1 Participation in the Base Residual Auction	108
5.6.2 Auction Clearing Mechanism – Base Residual Auction.....	110
5.6.3 Resource Make-Whole Payments in the Base Residual Auction.....	111
5.6.4 Posting of Base Residual Auction Results	111
5.7 INCREMENTAL AUCTIONS.....	111
5.7.1 Participation in the Incremental Auctions	112
5.7.2 Timing of the Incremental Auctions	114
5.7.3 Resource Make-Whole Payments in Incremental Auctions	114
5.7.4 Allocation of Costs in Incremental Auctions	115
5.7.5 Auction Clearing Mechanism – Incremental Auctions	115
5.7.6 Posting of Incremental Auction Results.....	116
5.8 AUCTION CLEARING RESULTS.....	117
5.8.1 Zonal Capacity Prices.....	117
5.8.3 CTR Credit Rates.....	119
5.8.4 CTR Settlement Rates.....	119
5.9 RELIABILITY BACKSTOP	119
Section 6: Capacity Transfer Rights.....	121
6.1 DEFINITION AND PURPOSE OF CAPACITY TRANSFER RIGHTS	121
6.1.1 Capacity Transfer Rights	122
6.1.2 Participant-Funded Project Incremental Capacity Transfer Rights	123
6.1.3 Incremental Capacity Transfer Rights Associated with Incremental Rights-Eligible Required Transmission Enhancements.....	123
6.2 DETERMINATION OF CAPACITY TRANSFER RIGHTS.....	125



6.3 ALLOCATION OF CAPACITY TRANSFER RIGHTS	125
6.4 CAPACITY TRANSFER RIGHTS CREDITS	126
6.5 CAPACITY TRANSFER RIGHTS TRANSFERS	126
Section 7: Load Obligations	127
7.1 OVERVIEW OF LOAD OBLIGATIONS	127
7.2 UNFORCED CAPACITY OBLIGATIONS	127
7.2.1 <i>Determination of Unforced Capacity Obligations</i>	127
7.2.2 <i>Base Unforced Capacity Obligations</i>	128
7.2.3 <i>Final Zonal Unforced Capacity Obligations</i>	128
7.3 RPM ZONAL SCALING FACTORS	129
7.3.1 <i>Zonal Weather Normalized Summer Peaks</i>	129
7.3.2 <i>Base Zonal RPM Scaling Factor</i>	130
7.3.3 <i>Final Zonal RPM Scaling Factor</i>	130
7.4 OBLIGATION PEAK LOAD	130
7.5 DAILY UNFORCED CAPACITY OBLIGATIONS	130
7.6 PROCESS FOR DETERMINING LOAD OBLIGATIONS	131
7.7 TREATMENT OF NON-ZONE LOAD	132
Section 8: Resource Performance Assessments	133
8.1 OVERVIEW OF RESOURCE PERFORMANCE ASSESSMENTS	133
8.2 RPM COMMITMENT COMPLIANCE	135
8.2.1 <i>Generation</i>	135
8.2.2 <i>Demand Resources</i>	136
8.2.3 <i>Energy Efficiency Resources</i>	137
8.2.4 <i>Qualifying Transmission Upgrade (QTU)</i>	138
8.3 COMMITMENT LEVEL USED IN PEAK-HOUR PERIOD AVAILABILITY (PHPA), SUMMER/WINTER CAPABILITY TESTS, AND PSM COMPLIANCE	138
8.4 GENERATING UNIT PEAK-HOUR PERIOD AVAILABILITY	140
8.4.1 <i>Peak-Period Equivalent Forced Outage Rate (EFORp)</i>	140
8.4.2 <i>Peak Period Capacity Available (PCAP)</i>	142
8.4.3 <i>Equivalent Demand Forced Outage Rate (EFORD-5)</i>	142
8.4.4 <i>Target Unforced Capacity (TCAP)</i>	142
8.4.5 <i>Peak-Hour Period Capacity Shortfall</i>	142
8.4.5.1 <i>Use of Excess Available Capacity in Peak-Hour Period Availability Assessment</i>	143
8.4.6 <i>Summer/Winter Capability Testing</i>	146
8.4.7 <i>Peak Season Maintenance (PSM) Compliance</i>	153
8.5 LOAD MANAGEMENT EVENT COMPLIANCE	154
8.5.1 <i>Measuring Event Compliance</i>	155
8.5.2 <i>Load Management Event Compliance Allocation</i>	156
8.6 LOAD MANAGEMENT TEST COMPLIANCE	157
8.7 REPLACEMENT RESOURCES	159
8.7.1 <i>Excess Commitment Credits</i>	161
8.8 DEMAND RESPONSE (DR) TRANSITION PROVISION FOR 2012/2013-2014/2015 DELIVERY YEARS	162
Section 9: Settlements	164
9.1 DEFICIENCY AND PENALTY CHARGES	164
9.1.1 <i>Peak-Hour Period Availability Charge</i>	164
9.1.2 <i>Allocation of Peak-Hour Period Availability Charges</i>	165
9.1.3 <i>Capacity Resource Deficiency Charge</i>	165
9.1.4 <i>Transmission Upgrade Delay Penalty Charge</i>	166
9.1.5 <i>Generation Resource Rating Test Failure Charge</i>	166
9.1.6 <i>Peak Season Maintenance Compliance Penalty Charge</i>	167
9.1.7 <i>Load Management Test Failure Charge</i>	167
9.1.8 <i>Allocation of Deficiency and Penalty Charges</i>	168



9.1.9 Demand Resource Compliance Penalty Charge.....	168
9.1.10 Emergency Procedures Charges.....	170
9.2 LOCATIONAL RELIABILITY CHARGES.....	172
9.2.1 Calculation of Locational Reliability Charges.....	172
9.3 AUCTION CREDITS AND CHARGES.....	172
9.3.1 Calculation of Auction Credits.....	172
9.3.2 Calculation of Auction Charges.....	172
9.3.3 Resource Make-Whole Credit.....	173
9.3.4 Capacity Transfer Rights Credit.....	173
9.3.5 Auction Specific MW Transaction Credits and Charges.....	173
9.3.6 Capacity Export Charges and Credits.....	174
9.4 DR TRANSITION PROVISION CREDITS AND CHARGES (2012/2013 – 2014/2015 DELIVERY YEARS)....	174
9.4.1 DR Transition Credit.....	174
9.4.2 Alternate DR Transition Credit.....	175
9.5 PENALTIES FOR NON-PERFORMANCE OF PRICE RESPONSIVE DEMAND.....	175
9.5.1 PRD Commitment Compliance Penalty & Credits.....	175
9.5.2 PRD Maximum Emergency Event Compliance Penalty & Credits.....	176
9.5.3 PRD Test Failure Charges & Credits.....	177
9.5.4 LSE PRD Credit.....	177
Section 10: eRPM.....	179
10.1 OVERVIEW.....	179
Section 11: Fixed Resource Requirement Alternative.....	181
11.1 OVERVIEW.....	181
11.1.1 Definition and Purpose of Fixed Resource Requirement Alternative.....	181
11.1.2 Implementation of the FRR Alternative.....	182
11.1.3 Participation in the FRR Alternative.....	182
11.2 LOAD OBLIGATIONS.....	184
11.2.1 Preliminary Unforced Capacity Obligation.....	184
11.2.2 Treatment of Non-Zone Load.....	185
11.2.3 Annexation & Switching of Load.....	186
11.3 CAPACITY PLAN.....	186
11.4 SUPPLY RESOURCES IN THE FRR ALTERNATIVE.....	189
11.4.1 Resource Portfolio.....	189
11.4.2 Existing Generation.....	192
11.4.3 Planned Generation.....	193
11.4.4 Capacity Modifications (Cap Mods).....	193
11.4.5 Bilateral Unit-Specific Transactions.....	193
11.4.6 Qualified Transmission Upgrade.....	193
11.4.7 Load Management Products.....	194
11.4.8 Demand Resource Modifications (DR MODs).....	195
11.5 ENERGY EFFICIENCY RESOURCES.....	195
11.5.1 Energy Efficiency Modifications (EE MODs).....	196
11.6 LOCATIONAL CONSTRAINTS IN THE FRR ALTERNATIVE.....	196
11.7 CONDITIONS ON SALES BY FRR ENTITIES.....	197
11.8 DELIVERY YEAR ACTIVITY.....	197
11.8.1 Final Daily Unforced Capacity Obligation.....	197
11.9 DEFICIENCY CHARGES & PENALTIES.....	198
11.9.1 FRR Capacity Resource Deficiency Charges.....	198
11.9.2 Transmission Upgrade Delay.....	199
11.9.3 Peak-Hour Period Availability Charge.....	199
11.9.4 Generation Resource Rating Test Failure Charge.....	199
11.9.5 Peak Season Maintenance Compliance Penalty Charge.....	199



11.9.6 Load Management Event Compliance Penalties.....	199
11.9.7 Load Management Test Compliance.....	199
11.10 ALLOCATION OF DEFICIENCY CHARGES.....	201
11.11 AUCTION SPECIFIC MW TRANSACTIONS.....	201
11.11.1 Auction Specific MW Transactions.....	202
Attachment A: Glossary of Terms.....	203
Attachment B: Authorization to Self-Schedule Capacity.....	214
Attachment C: Demand Resource Sell Offer Plan.....	216
Attachment D: Demand Resource Officer Certification Form.....	221
Revision History.....	222



Table of Exhibits

EXHIBIT 1: ILLUSTRATIVE EXAMPLE OF A VARIABLE RESOURCE REQUIREMENT CURVE	29
EXHIBIT 2: RPM AUCTION TIMELINE	97
EXHIBIT 3: PROCESS FOR DETERMINING LOAD OBLIGATIONS	131
EXHIBIT 4: RPM AUCTION SUBSYSTEMS.....	179



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Current Revision

Revision [287](#) ([01/22/2015](#))

- Conforming revisions for FERC Order ER15-623 (i.e., Capacity Performance filing), accepted on 06/09/2015 and effective April 1, 2015 to better ensure that committed resources will perform when called upon to meet the reliability needs of the PJM Region.
- ~~Conforming revisions for FERC Order ER14-2940, accepted on 11/28/2014 and effective 12/01/2014, to revise the shape of Variable Resource Requirement Curve, the gross Cost of New Entry values, and the methodology to determine Net Energy and Ancillary Services Revenue Offset and Net Cost of New Entry. (Sections 3.3.1, 3.3.2, 3.3.3, 3.4, & 3.4.1)~~



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, price responsive demand 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.



Effective with the 2018/2019 Delivery Year, the capacity market design is enhanced to recognize two product types for capacity resources, Capacity Performance and Base Capacity, to ensure that capacity resources committed to meet the PJM Region's reliability and resource adequacy needs will deliver the promised energy and reserves when called upon in emergencies. The Base Capacity product-type will be phased out such that all capacity resources used to meet the PJM Region's reliability and resource adequacy needs will be the Capacity Performance product-type effective with the 2020/2021 Delivery Year.

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 Incremental Auctions 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 resources](#) 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.

1.2.3 Participation of PRD Providers

Starting with the 2016/2017 Delivery Year, PRD Providers may participate in PJM's Capacity Market, either in PJM's Reliability Pricing Model or the Fixed Resource Requirement Alternative. A PRD Provider is a PJM Member that is (1) a LSE that provides PRD; or (2) an entity without direct load serving responsibilities that has entered contractual arrangements with end-use customers served by a LSE that satisfy the eligibility criteria for PRD as specified in this Manual.

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,



Energy Efficiency Resources and planned and existing Demand Resources 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 and PRD 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.
- *Incremental Auctions* – At least 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 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. [Deferred short-term resource procurement applies prior to 2018/2019 Delivery Year.](#)
- 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 2012/2013 Delivery Year corresponds to the June 1, 2012 - May 31, 2013 Planning Period.

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

The steady-state condition of the RPM began 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.

[1.5 Transition to Capacity Performance](#)



Effective with the 2018/2019 Delivery Year¹, PJM will procure two capacity product types through RPM Auctions, Capacity Performance and Base Capacity. The Base Capacity product-type will be phased out such that only resources that meet the requirements of the Capacity Performance product-type will be used to meet the PJM Region's reliability and resource adequacy needs effective with the 2020/2021 Delivery Year.

For a capacity resource to qualify as a Capacity Performance product type, the resource must be capable of sustained, predictable operation that allows the resource to be available throughout the entire Delivery Year to provide energy and reserves whenever PJM determines an emergency condition exists. For a capacity resource to qualify as a Base Capacity product type the resource is not expected to be capable of sustained, predictable operation that allows the resource to be available throughout the entire Delivery Year; however, the resource must provide enhanced assurance to provide energy and reserves during hot weather operations. Since Base Capacity Resources do not provide the same availability and reliability benefit as Capacity Performance Resources, constraints are imposed on the quantity of Base Capacity Resources that can be procured in RPM Auctions for the 2018/2019 and 2019/2020 Delivery Years.

Internal and external generation resources that can qualify as Capacity Performance product type, Demand Resources that meet Capacity Performance DR product type requirements, Energy Efficiency resources that provide permanent, continuous load reduction during both summer and winter peak seasons in accordance with the Capacity Performance EE product type requirements, Capacity Storage Resources, and Qualifying Transmission Upgrades are eligible to offer as the Capacity Performance product-type. Resources that clear and have a Capacity Performance Commitment are obligated to deliver energy during the relevant Delivery Year as scheduled and/or dispatched by PJM during Performance Assessment Hours and are subject to Non-Performance Assessment Charge for failure to meet this obligation, unless such resource was excused.

Internal and external generation resources, Capacity Storage Resources, Demand Resources that meet Base Capacity DR product type requirements, Energy Efficiency Resources which only provide permanent, continuous load reduction during the months of June through August are eligible to offer as the Base Capacity product type for the 2018/2019 and 2019/2020 Delivery Years. Resources that clear and have a Base Capacity Commitment are obligated to provide energy output to PJM if called during Performance Assessment Hours occurring in calendar months of June through September of the relevant Delivery Year, including any necessary recall of such capacity and energy from service to areas outside the PJM Region, are subject to Non-Performance Assessment Charge for failure to meet this obligation, unless such resource was excused.

Capacity Performance Transition Incremental Auctions will be conducted to procure a percentage of the PJM Region's Reliability Requirement as Capacity Performance Generation Resources on a voluntary basis for the 2016/2017 and 2017/2018 Delivery

¹ For FRR Entities, Capacity Performance and Base Capacity resources are effective for the 2019/2020 Delivery Year. Limited DR, Extended Summer DR, and Annual Resources remain effective for FRR Entities through the 2018/2019 Delivery Year. Capacity Performance Resources are solely effective for 2020/2021 Delivery Year.



Years. The 2016/2017 Capacity Performance Transitional Incremental Auction will be held in late July 2015 and the 2017/2018 Capacity Performance Transitional Incremental Auction will be held in early August 2015. Business Rules specific to the Capacity Performance Transitional Incremental Auctions are posted on the [pjm website](#).



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.

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

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*.

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), Capacity Import Limits, 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. Prior to the 2018/2019 Delivery Year, the Pool-Wide Average EFORd will does 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 $(1 + \text{Installed Reserve Margin}) \times (1 - \text{Pool-wide Average EFORD})$.²

$$\text{ForecastPoolRequirement (FPR)} = (1 + \text{InstalledReserveMargin}) * (1 - \text{PoolWideAverageEFORD})$$

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: PJM Region Transmission Planning Process , 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.

Effective with the 2017/2018 Delivery, the Reliability Pricing Model recognizes locational constraints that limit the delivery of generation capacity to PJM from areas outside of PJM (i.e., Capacity Import Limits). The Capacity Import Limit Calculation Procedure is performed by PJM to establish the amount of power that can be reliably transferred to PJM from defined regions external to PJM. For more details regarding Capacity Import Limit Calculation Procedure, please see **Manual 14B: PJM Region Transmission Planning Process, Attachment G.11, PJM Capacity Import Limit Calculation Procedure.**

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. 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 intra-PJM 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 within the PJM region.

Effective with the 2017/2018 Delivery Year, locational constraints are expanded to include Capacity Import Limits to recognize the transfer limitations on the delivery of external generation capacity to the PJM region and quantify the locational value of capacity located outside the PJM region.



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.

Effective with the 2017/2018 Delivery Year, a region-wide Capacity Import Limit and Capacity Import Limits for external source zones are posted by February 1 prior to their use in the Base Residual Auction for the Delivery year and posted one month prior to their 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 27 sub-regions referred to as Locational Deliverability Areas for evaluating the locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

The 27 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 => ATSI => **Cleveland**

RTO => Western PJM => **DEOK**

RTO => Western PJM => **EKPC**

RTO => Dominion

RTO => **MAAC**

RTO => MAAC => **WMAAC**

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

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

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

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 => EMAAC => **RECO**

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) 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.

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.



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 B: 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 1.15⁴ 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 Capacity Import Limits

Effective with the 2017/2018 Delivery Year, Capacity Import Limits for the PJM Region and for each of several external source zones will be implemented in each RPM auction as locational constraints that limit the delivery of capacity from areas outside of PJM. The Capacity Import Limits for the PJM Region and each external source zone are determined by PJM in accordance with **Manual 14B: PJM Region Transmission Planning Process, Attachment G.11, PJM Capacity Import Limit Calculation Procedure**. External source zones are identified in Manual 14B and are groupings of one or more balancing authority areas that may need to be periodically modified based on changing system patterns or operational data, as well as changes in RTO/ISO membership. The initial Capacity Import Limit implementation employs five external source zones:

Northern Zone: NYISO & ISONE

Western Tier 1 Zone: MISO East, MISO West & OVEC

Western Tier 2 Zone: MISO Central & MISO South

Southern Tier 1 Zone: TVA & LGEE

Southern Tier 2 Zone: VACAR (non-PJM)

The Capacity Import Limit for the PJM Region and Capacity Import Limits for each external source zone are determined for each Delivery Year, posted with the RPM Auction planning parameters, and implemented as locational constraints in the RPM Auction clearing process. The Capacity Import Limit for the PJM region represents the maximum amount of external capacity that can be cleared in the RPM Auctions for such Delivery Year. The Capacity Import Limit for an external source zone represents the maximum amount of external capacity located in the external source zone that can be cleared in RPM Auctions for such Delivery Year. If the Capacity Import Limit for the PJM Region or for an external source zone binds in the auction clearing process, the resource clearing price for external generation resources located in the external source zone will be lower than the resource clearing price for resources located in the unconstrained area of the PJM region.

External generation resources offering into RPM Auctions will be subject to the Capacity Import Limits unless a Capacity Market Seller of external generation requests an exception demonstrating that the external resource meets all of the three requirements described below. A resource that requests an exception and demonstrates that it meets all three of

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



these requirements by no later than five business days prior to the commencement of the auction offer period will not be subject to the Capacity Import Limits, and will be modeled in the unconstrained area of the PJM region for the MWs granted in the exception request and will receive the resource clearing price of the unconstrained area of the PJM region for such MWs granted if the resource clears in the auction. A Capacity Import Limit exception request must be submitted to PJM via rpm_hotline@pjm.com no later than five business days prior to the commencement of the offer period for the relevant RPM Auction. To qualify for an exception to the Capacity Import Limits, the external generation resource must meet the following requirements:

- (1) The external resource, at the time the exception is requested, is pseudo-tied or committed to be pseudo-tied by the start of the auction Delivery Year.⁵
- (2) The external resource, at the time the exception is requested, has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM.
- (3) The external resource, by written commitment of the Market Seller, is subject to a capacity must offer requirement under the same obligations imposed to internal generation resources by section 6.6 of Attachment DD of the OATT to offer into RPM Auctions.

In order to satisfy these requirements, a Market Seller must submit the following documentation with their exception request for an external resource: (1) a signed PJM Capacity Import Limit Exception Officer Certification Form (2) an executed External Resource Must Offer Agreement; and (3) an executed Reimbursement Agreement if the external resource is not pseudo-tied at the time the exception is requested. The PJM Capacity Import Limit Exception Officer Certification Form specifies that the signing officer certifies for the MWs of installed capacity specified for such external resource that (1) long-term firm transmission service has been confirmed on the complete transmission path from the external resource into PJM for the relevant Delivery Year; (2) the external resource meets or will meet prior to the Delivery Year that the CIL exception is requested all applicable requirements to be pseudo-tied; and (3) a separate written commitment has been executed to offer all unforced capacity of the external resource into RPM Auctions under the same terms, and subject to the same conditions and exceptions, as set forth for internal generation resources by section 6.6 of Attachment DD of PJM Tariff. The External Must Offer Agreement specifies that the Market Seller agrees to offer all unforced capacity of the external resource (associated with the installed capacity MWs specified in the PJM Capacity Import Limit Officer Certification Form) into RPM Auctions under the same terms, and subject to the same conditions and exceptions, as set forth for internal capacity resources by section 6.6 of Attachment DD of PJM Tariff. The Reimbursement Agreement specifies that the Market Seller agrees to reimburse PJM for the actual cost of determining and effectuating any modifications to the network model needed to accommodate the pseudo-tie of the external resource. Templates of the PJM Capacity Import Limit Exception Officer Certification Form, External Resource Must Offer Agreement, and Reimbursement Agreement are posted on the PJM website.

⁵ For the purposes of an external generation resource offering as Capacity Performance Resource into the 2016/2017 or 2017/2018 Transition Incremental Auction, the resource must be reasonably expected to be pseudo-tied by the start of the relevant Delivery Year.



The total MW quantity of exceptions granted for a Delivery Year in an external source zone plus the Capacity Import Limit for the external source zone may not exceed the total MW quantity of confirmed Network External Designated Transmission Service on such interface. The total MW quantity of exceptions granted for a Delivery Year across all external source zones plus the region-wide Capacity Import Limit may not exceed the total MW quantity of confirmed Network External Designated Transmission Service for all interfaces. PJM will grant qualified exception requests but reduce the region-wide CIL and/or CILs for external source zones by the quantity necessary to ensure the total quantity of confirmed Network External Designated Transmission Service on interface(s) is not exceeded. PJM shall post the updated CILs, aggregate MW quantities of exception requests granted by external source zones, and the MWs of confirmed Network External Designated Transmission Service for external interfaces no later than two (2) business days prior to the commencement of the offer period for the RPM Auction.

Effective with the 2018/2019 Delivery Year, only external generation resources requesting an exception and meeting the exception requirements will be permitted to offer as a Capacity Performance product in RPM Auctions. For the 2018/2019 and 2019/2010 Delivery Years, external generation resources that have not requested an exception and met the exception requirements may only offer as a Base Capacity product and will be subject to the Capacity Import 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. Reliability Requirements for the region and for any affected LDA are further adjusted for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

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, and less any necessary adjustment for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

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

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, and less any necessary adjustment for PRD proposed in an approved PRD Plan or committed in any RPM Auction for PRD located in the LDA.

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

2.4.3 Minimum Annual/Extended Summer Resource Requirements (2014/2015 – 2016/2017 Delivery Years)

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 Sub-Annual 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 Sub-Annual 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 Sub-Annual Reliability Target (formerly known as the Extended Summer Demand 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)***.

2.4.3A Limited Resource Constraint & Sub-Annual Resource Constraint (Effective ~~with~~for the 2017/2018 Delivery Year)

~~Starting with~~ Effective for the 2017/2018 Delivery Year, the greater reliability value associated with the less limited demand resource products are recognized by establishing and enforcing a maximum requirement on the commitment of less limited products. The Limited Resource Constraints set the maximum level of Limited Resources to be procured in RPM Auctions for the Delivery Year. The Sub-Annual Resource Constraints set the maximum level of Limited Demand Resources and Extended Summer Demand Resources to be procured in RPM Auctions for the Delivery Year.

Limited Resource Constraints and Sub-Annual Resource Constraints are established for the RTO and each modeled LDA and the auction clearing process can select Annual Resources or Extended Summer DR in out of merit order, if necessary, to enforce Limited Resource Constraints or Sub-Annual Resource Constraints. In those cases where one or both of the resource constraints bind in the auction solution, Limited Demand Resources and/or Extended Summer Demand Resources selected will receive a decrement to the system marginal price of capacity (in addition to any locational price adder(s) received to resolve locational constraints).

For the RTO, the Limited Resource Constraint is equal to the Limited Demand Resource Reliability Target for the RTO in unforced capacity minus the Short-term Resource Procurement Target for the RTO. For an LDA, the Limited Resource Constraint is equal to the Limited Demand Resource Reliability Requirement for the LDA in unforced capacity minus the Short-term Resource Procurement Target for the LDA. 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)***.



For the RTO, the Sub-Annual Resource Constraint is the equal to the Sub-Annual Resource Reliability Target for the RTO minus the Short-term Resource Procurement Target for the RTO. For an LDA, the Sub-Annual Resource Constraint is equal to the Sub-Annual Resource Reliability Target for the LDA minus the Short-term Resource Procurement Target for the LDA. The Sub-Annual Reliability Target (formerly known as the Extended Summer Demand 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)***.

2.4.3B Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint (2018/2019 & 2019/2020 Delivery Years)

Effective for the 2018/2019 and 2019/2020 Delivery Years, the greater reliability value associated with Capacity Performance Resources are recognized by establishing and enforcing a maximum requirement on the commitment of less-available resources. The Base Capacity Demand Resource Constraints set the maximum level of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources to be procured in RPM Auctions for the Delivery Year. The Base Capacity Resource Constraints set the maximum level of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources, and Base Capacity Generation Resources to be procured in RPM Auctions for the Delivery Year.

Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints are established for the PJM Region and each modeled LDA and the auction clearing process can select Base Capacity Generation Resources and Capacity Performance Resources in out of merit order, if necessary, to enforce Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints. In those cases where one or both of the resource constraints bind in the auction solution, Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources, and/or Base Capacity Generation Resources selected will receive a decrement to the system marginal price of capacity (in addition to any locational price adder(s) received to resolve locational constraints).

The Base Capacity Demand Resource Constraint for PJM Region or LDA is expressed as a reliability target percentage of the forecasted peak load of the PJM Region/LDA and is converted to unforced capacity by multiplying the target percentage times the RTO/LDA forecasted peak load reduced by the amount of forecasted peak load served under FRR Alternative, times the Forecast Pool Requirement. The Base Capacity Demand Resource Constraint for the PJM Region or an LDA is the maximum unforced capacity amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, determined by PJM to be consistent with the maintenance of reliability as more fully described in the ***PJM Manual for Reserve Requirements (M-20)***.

The Base Capacity Resource Constraint for PJM Region or LDA is expressed as a reliability target percentage of the forecasted peak load of the PJM Region/LDA and is converted to unforced capacity by multiplying the target percentage times the RTO/LDA forecasted peak load reduced by the amount of forecasted peak load served under FRR Alternative, times (one minus pool-wide average EFORd). The Base Capacity Resource Constraint for the PJM Region or an LDA is the maximum unforced capacity amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency, and Base Capacity Generation



Resources, determined by PJM to be consistent with the maintenance of reliability as more fully described in the *PJM Manual for Reserve Requirements (M-20)*.

2.4.4 Adjustments to RPM Auction Parameters for PRD

After PRD Providers propose PRD commitments in their PRD Plans, and PJM reviews and accepts those commitments, PJM will use the resulting PRD values to reduce the reliability requirement to be satisfied for the region and for any affected Zones (or sub-Zonal LDAs). The reliability requirement will be reduced by the quantity of UCAP that would have been procured on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The Reliability Requirement of the RTO and each affected LDA will be reduced by a quantity equal to the Nominal PRD Value multiplied by the FPR. These reliability requirement reductions will be considered in the development of the RTO/LDA Variable Resource Requirement Curves, RTO/LDA Minimum Annual Resource Requirements and RTO/LDA Minimum Extended Summer Resource Requirements (2014-2015-2016/2017 Delivery Years), ~~and~~ Limited Resource Constraints and Sub-Annual Resource Constraints (~~effective with 2017/2018 Delivery Years~~), and Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints (effective for 2018/2019 and 2019/2020 Delivery Years.)

Section 3: Demand in the Reliability Pricing Model

Welcome to the *Demand in the Reliability Pricing Model* section of the **PJM Capacity Market Manual**. 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. A demand curve is defined in advance of each RPM 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 Nominal PRD Value and PRD Reservation Prices that have been elected

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 Short Term Resource Procurement Target), Cost of New Entry, and Net Energy & Ancillary Services (E&AS) Revenue Offset. Effective with the 2018/2019 Delivery Year, the Short Term Resource Procurement Target is eliminated and not considered in the development of the Variable Resource Requirement Curve for the PJM Region.

For each LDA, the LDA Variable Resource Requirement Curve is based on a target level (i.e., the LDA Reliability Requirement less the LDA Short Term Resource Procurement Target), Cost of New Entry, and Net E&AS Revenue Offset. Effective with the 2018/2019 Delivery Year, the LDA Short Term Resource Procurement Target is eliminated and not considered in the development of the LDA Variable Resource Requirement Curve.

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 Short Term Resource Procurement



Target or the LDA Reliability Requirement less the LDA Short Term Resource Procurement Target, 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 (CONE) (in ICAP terms) is determined in accordance with Attachment DD of the Open Access Transmission Tariff (OATT), Section 5.10 (a) (iv). The Reference Resource is a combustion turbine (CT) generating station, configured with two General Electric Frame 7FA turbines as defined in the OATT.

For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Cost of New Entry for the PJM Region and each modeled LDA shall be the respective value used in the Base Residual Auction for such Delivery Year and LDA.

The gross Cost of New Entry values for the following four CONE Areas for the 2018/2019 Delivery Year are specified in the OATT, Section 5.10 (a) (iv)(A). :

- (1) AE, DPL, JCPL, PECO, PSEG, RECO (“CONE Area 1”);
- (2) BGE, PEPCO (“CONE Area 2”);
- (3) AEP, APS, COMED, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion (“CONE Area 3”); and
- (4) METED, PENELEC, PPL (“CONE Area 4”).

Effective for the 2018/2019 Delivery Year, the gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the four CONE Areas.

For the 2019/2020 Delivery Year, the gross CONE values specified in the OATT for the 2018/2019 Delivery Year shall be adjusted to reflect changes in generating plant construction costs based on changes in the applicable United States Bureau of Labor Statistics (BLS) Composite Index to establish the CONE values used in the development of the Variable Resource Requirement Curves for the PJM Region and the modeled LDAs for all RPM Auctions for the 2019/2020 Delivery Year.

The applicable BLS Composite Index for a Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Index for Construction Materials and Components (weighted 50%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 30%). The Quarterly Census of Employment and Wages for Utility System Construction will be based on the state of New Jersey for CONE Area 1, Maryland for CONE Area 2, Ohio for CONE Area 3, and Pennsylvania for CONE Area 4. For subsequent Delivery Years, the Benchmark CONE values will be the CONE values used in the development of the Variable Resource Requirement Curves for the prior Delivery Year. The applicable BLS Composite Index for the Delivery Year will be applied to the Benchmark CONE values to establish the CONE values used in the development of the Variable Resource Requirement Curves for the PJM Region and the modeled LDAs for all RPM Auctions for such Delivery Year.

3.3.2 Net Energy and Ancillary Services Offset



Pursuant to Attachment DD, Section 5.10(a)(v and vi) of the PJM Tariff, PJM determines a Net Energy and Ancillary Services (E&AS) Revenue Offset for the PJM Region and for each Zone.

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is (a) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the Base Residual Auction for such Delivery Year plus (b) an assumed value for ancillary services revenues (\$/MW-year) as set forth in the OATT.

The annual average of energy revenues for the PJM Region is based on (1) heat rate and other characteristics of such Reference Resource; (2) daily natural gas prices averaged across the fuel pricing points specified in the table below; (3) assumed variable operation and maintenance expenses for such Reference Resource as set forth in the OATT; (4) actual PJM hourly average LMP prices recorded in the PJM Region during such period; and (5) an assumption that the Reference Resource would be dispatched for both Day-Ahead and Real-Time Energy Markets on Peak-Hour Dispatch basis.

For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, PJM will employ for the purposes of developing the RTO and modeled LDA VRR Curves for such Delivery Years the same calculated values of RTO and modeled LDA Net E&AS Revenue Offsets that were used in the BRA for such Delivery Year.

For the 2018/2019 and subsequent Delivery Years, the Net E&AS Revenue Offset for each Zone for a Delivery Year is determined using the same procedures and methods used to determine the Net E&AS Revenue Offset for the PJM Region; provided, however, that (1) actual hourly average LMPs for such Zone shall be used in place of the PJM Region hourly average LMPs; and (2) daily natural gas prices at the fuel pricing points specified in the table below.

The fuel pricing point used for the purpose of establishing the Net E&AS Offset for each Zone is provided in the table below.

Zone	Fuel Pricing Point
AE, BGE, DPL, PEPCO, PSEG, & RECO	Transco-Z6 (non-NY)
COMED	Chicago Citygates
JCPL, METED, PECO, & PPL	TETCO M3
DOM	Transco-Z5 (non-WGL)
AEP, APS, ATSI, DAY, DEOK, DUQ, & EKPC	Columbia-APP
PENELEC	Dominion-NORTH

Peak-Hour Dispatch means, for purposes of calculating the energy revenues in the Energy and Ancillary Services Revenue Offset, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to



generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

3.3.3 Net Cost of New Entry

The Net Cost of New Entry (Net CONE) for the PJM Region is the gross Cost of New Entry for the PJM Region minus the Net E&AS Revenue Offset for the PJM Region.

For the 2015/2016, 2016/2017, and 2017/2018 Delivery Year, the Net CONE for a modeled LDA shall be the Net CONE used for such modeled LDA in the Base Residual Auction for such Delivery Year.

Effective with the 2018/2019 Delivery Year, PJM shall determine the Net Cost of New Entry for each Zone that comprises the modeled LDA. The Net Cost of New Entry for a Zone is the applicable gross Cost of Net Entry value for such Zone minus the Net E&AS Revenue Offset for such Zone. The Net Cost of New Entry for a modeled LDA shall be the average of the Net CONE values of all zones within the modeled LDA.

3.4 Plotting the Variable Resource Requirement Curve

For the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, 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 the greater of [the Cost of New Entry or 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

Basis for Price at Point a:

$$\frac{\text{Greater of } [CONE \text{ or } 1.5(CONE - E \& AS)]}{1 - \text{Pool Wide EFORD}}$$

Basis for Quantity at Point a:

$$\left[\text{RelReq} \frac{(100\% + IRM - 3\%)}{(100\% + IRM)} \right] - \text{Short - Term Resource Procurement Target}$$



- (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.

Basis for Price at Point b:

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

Basis for Quantity at Point b:

$$\left[Rel\ Re\ q \frac{(100\% + IRM + 1\%)}{(100\% + IRM)} \right] - \frac{Short - Term\ Resource}{Procurement\ Target}$$

- (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.

Basis for Price at Point c:

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

Basis for Quantity at Point c:

$$\left[Rel\ Re\ q \frac{(100\% + IRM + 5\%)}{(100\% + IRM)} \right] - \frac{Short - Term\ Resource}{Procurement\ Target}$$

For the 2018/2019 Delivery Year and subsequent Delivery Years, 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 the greater of [the Cost of New Entry or 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 0.2%) divided by (100% plus approved IRM %)] ~~minus the RTO Short-Term Resource Procurement Target~~

Basis for Price at Point a:

$$\frac{\text{Greater of } [CONE \text{ or } 1.5(CONE - E \& AS)]}{1 - \text{Pool Wide EFORD}}$$

Basis for Quantity at Point a:

$$\left[\text{Rel Req} \frac{(100\% + IRM - 0.2\%)}{(100\% + IRM)} \right]$$

- (b) The price is equal to 0.75 times 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 2.9%) divided by (100% plus approved IRM%)] ~~minus the RTO Short Term Resource Procurement Target.~~

Basis for Price at Point b:

$$\frac{[0.75(CONE - E \& AS)]}{1 - \text{Pool Wide EFORD}}$$

Basis for Quantity at Point b:

$$\left[\text{Rel Req} \frac{(100\% + IRM + 2.9\%)}{(100\% + IRM)} \right]$$

- (c) The price is equal to zero and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 8.8%) divided by (100% plus approved IRM %)] ~~minus the RTO Short Term Resource Procurement Target.~~

Basis for Price at Point c: \$0/MW-day

Basis for Quantity at Point c:

$$\left[\text{Rel Req} \frac{(100\% + IRM + 8.8\%)}{(100\% + IRM)} \right]$$

3.4.1 Plotting the Variable Resource Requirement Curves

The graph below illustrates the process for plotting the Variable Resource Requirement curves for Delivery Years prior to 2018/2019 Delivery Year. The VRR Curve is plotted by combining a horizontal line from the y-axis to point (a), a straight line connecting points (a) and (b), a straight line connecting points (b) and (c), and a vertical line from point (c) to the x-axis.

:

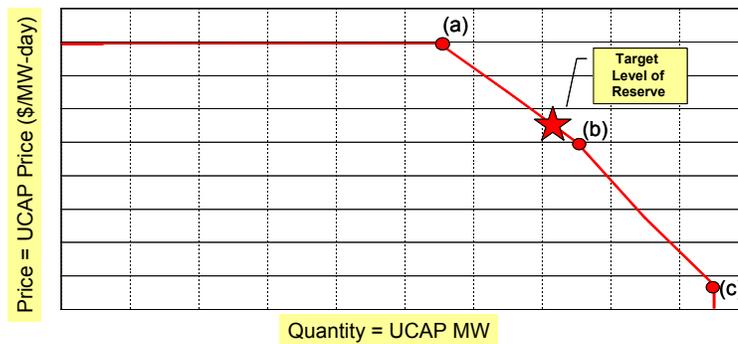


Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve

Effective with the 2018/2019 Delivery Year, the VRR Curve is plotted by combining a horizontal line from the y-axis to point (a), a straight line connecting points (a) and (b), a straight line connecting points (b) and (c). The price associated with point (c) is \$0/MW-day; therefore, no vertical line is needed to connect point (c) to the x-axis.

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 the Zones associated with such LDA shall be substituted for the RTO Short-Term Resource Procurement Target~~ and the FRR adjustments will be for the FRR Entities in the LDA.

Beginning with the 2018/2019 Delivery Year and continuing no later than for every fourth Delivery Year thereafter, PJM will perform a review of the shape of the Variable Resource Requirement Curve, CONE values, and Energy & Ancillary Services methodology, and any FERC approved changes resulting from this review will be incorporated into the appropriate BRA Auctions.

The Variable Resource Requirement Curve will be further adjusted to reflect the impact of any PRD that is proposed in a PRD Plan and that is reviewed and accepted by PJM. To reflect accepted PRD Plans, the Variable Resource Requirement Curve will be shifted leftward along the horizontal axis by a quantity equal to the Nominal PRD Value multiplied



by the FPR. This quantity represents the quantity of Unforced Capacity that would have been procured in the RTO on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The curve will be shifted leftward in this manner only for those portions of the curve that are at or above the PRD Reservation Price, since the PRD load can be excluded only if the auction clears at or above that price. The Variable Resource Requirement Curve for each LDA in which the PRD resides (including the RTO curve) will be shifted in the exact same manner.

3.5 Demand Curves in the Incremental Auctions

The First, Second and Third 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 ([effective prior to 2018/2019 Delivery Year](#)). 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:

- [Effective prior to the 2018/2019 Delivery Year](#), 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 of that curve in a MW amount equal to the positive quantity. [Prior to the 2018/2019 Delivery Year](#), 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). Effective with the 2018/2019 Delivery Year, 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 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.

Prior to each Incremental Auction conducted for the 2014/2015, 2015/2016 and 2016/2017 Delivery Years, 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.

Starting with the 2017/2018 Delivery Year, prior to each Incremental Auction for the 2017/2018 Delivery Year, PJM will calculate an updated Limited Resource Constraint and a Sub-Annual Resource Constraint for the RTO and each LDA. If PJM is procuring additional capacity in the Incremental Auction then PJM will determine the portion of a PJM buy bid that may be satisfied by Limited Demand Resources and/or Extended Summer Demand Resource based on the difference between the updated Limited Resource Constraint and the updated Sub-Annual Resource Constraint minus the amount of previously procured capacity from Limited Demand Resources and Extended Summer Demand Resources. If PJM is seeking to release capacity in the auction, this difference will determine the minimum amount of Extended Summer and/or Limited DR that PJM will attempt to release.

Effective for the 2018/2019 and 2019/2020 Delivery Year, prior to each Incremental Auction, PJM will calculate an updated Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint for the RTO and each LDA. If PJM is procuring additional capacity in the Incremental Auction then PJM will determine the portion of a PJM buy bid that may be satisfied by Base Capacity Demand Resources. Base Capacity Energy Efficiency Resources and/or Base Capacity Generation Resources based on the difference



between the updated Base Capacity Demand Resource Constraint and the updated Base Capacity Resource Constraint minus the amount of previously procured capacity from Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources, and Base Capacity Generation Resources. If PJM is seeking to release capacity in the auction, this difference will determine the minimum amount of Base Capacity Resources and/or Base Capacity Demand Resources, and/or Base Capacity Energy Efficiency Resources that PJM will attempt 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 3A: Integration of Price Responsive Demand

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

- An overview of Price Responsive Demand in PJM Capacity Market (see “Overview of Price Responsive Demand in PJM Capacity Market”)
- The transition period for price responsive demand (see “Transition Period”)
- The eligibility requirements for price responsive demand participation in PJM Capacity Market (see “Eligibility Requirements for Price Responsive Demand”)
- The PRD Plan requirements (see “PRD Plan Requirements”)

3A.1 Overview of Price Responsive Demand in PJM Capacity Market

The development and implementation of dynamic and time-differentiated retail rates, together with utility investment in advanced metering infrastructure (AMI) has led an increasing quantity of load in PJM to be responsive to changing wholesale prices. Through enabling technology and behavioral changes, consumers modify their demand as prices change without being centrally dispatched by PJM or bidding demand reductions into the PJM markets. Given the linkage between dynamic retail rate structures and wholesale prices, this price responsiveness is predictable and needs to be accounted for in the wholesale market design and operations. This predictable reduction in consumption in response to changing wholesale prices is known as Price Responsive Demand (PRD).

Although Price Responsive Demand is not directly dispatchable by PJM, automated retail customer response to real time energy prices signals can produce a predictable demand curve as a function of real time energy price. Prices typically increase during capacity emergencies and as a consequence demand drops. Price Responsive Demand will therefore be able to reduce the installed capacity required to meet Loss of Load Expectation (LOLE) based reliability standards.

PRD is provided by a PJM Member that represents retail customers that have the capability to reduce load in response to price. PJM Member acting on behalf of such retail customers for the purpose of providing PRD is referred to as the PRD Provider. A PRD Provider for a given retail customer may be the customer’s retail Load Serving Entity (LSE). However, PRD may also be provided in the PJM markets by an entity such as an Electric Distribution Company (EDC), or Curtailment Service Provider (CSP) that does not have direct responsibility for serving the retail load but meets all of the eligibility requirements for providing PRD.

In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of Price Responsive Demand that will reduce its consumption in response to real time energy price during a Delivery Year.

In order to commit PRD for a Delivery Year, a PRD Provider must submit a PRD Plan in advance of the Base Residual Auction or Third Incremental Auction for such Delivery Year that demonstrates to PJM’s satisfaction that the maximum nominated amount of price responsive demand will be available by the start of the Delivery Year. Additional PRD may participate in the Third Incremental Auction only in the event, and to the extent that the LDA



final peak load forecast for the Delivery Year increases relative to the LDA preliminary peak load forecast used for the Base Residual Auction.

A PRD Provider that is committing PRD in Base Residual Auction or Third Incremental Auction must also submit a PRD election in the eRPM system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices (\$/MW-day). The PRD election by PRD Providers will result in a change in the shape of the RTO/LDA VRR Curves used in the RPM Auctions. Based on the PRD elections and Resource Clearing Price in the RPM Auction, PJM will determine the Nominal PRD Value committed by each PRD Provider. Those PRD Providers that elected to provide PRD at reservation prices equal to or less than the Resource Clearing Price will have the corresponding value of PRD committed in the RPM Auction.

A PRD Provider that is committing PRD which is associated with load being served under the Fixed Resource Requirement Alternative is not required to submit a PRD election. The FRR Entity's Preliminary Daily Unforced Capacity Obligation to be satisfied in the FRR Entity's initial submittal of their FRR Capacity Plan for the Delivery Year will be reduced by the Nominal PRD Value associated with their FRR load that was approved by PJM in advance of the BRA, multiplied by the BRA Forecast Pool Requirement. The Final Daily Unforced Capacity Obligation of the FRR Entity that must be satisfied in the FRR Entity's FRR Capacity Plan for the Delivery Year will be reduced by the total Nominal PRD Value associated with their FRR load that was approved by PJM in advance of the Base Residual Auction and Third Incremental Auction for the Delivery Year, multiplied by the final Forecast Pool Requirement. The approval of the PRD Provider's PRD Plan associated with the FRR load shall establish a firm commitment of the PRD Provider to the PJM approved sub-zonal/zonal Nominal PRD Value.

Once committed in a Base Residual Auction, Third Incremental Auction or committed for load served under the FRR Alternative, Price Responsive Demand may not be uncommitted or replaced by available capacity resources or Excess Commitment Credits. However, a PRD Provider may transfer the PRD obligation to another PRD Provider bilaterally.

A PRD Provider with a committed sub-zonal/zonal Nominal PRD Value through an RPM Auction or through the FRR Alternative will be required to register sub-zonal/zonal PRD prior to the start of the Delivery Year to satisfy their PRD commitment. Failure to register enough price responsive loads to meet their sub-zonal/zonal PRD commitment prior to the start of the Delivery Year or failure to maintain enough price responsive loads to meet their sub-zonal/zonal PRD commitment throughout the Delivery Year will result in a PRD Commitment Compliance Penalty.

A PRD Provider will also be subject to performance compliance during Maximum Emergency Events during the Delivery Year. Failure to comply during Maximum Emergency Events will result in a PRD Maximum Emergency Event Compliance Penalty. If PJM does not declare a Maximum Generation Emergency during the Delivery Year that requires the zonal PRD to reduce to the zonal MESL, then the zonal registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency Event may be called during June through October or the following May of the relevant Delivery Year. Failure of the zonal registered PRD to reduce to the zonal MESL in a test will result in a PRD Test Failure Charge.

An LSE serving PRD in RPM registered by a PRD Provider will receive a Daily PRD Credit (\$/MW-day) during the Delivery Year. The Daily PRD Credit may offset the Daily Locational



Reliability Charges (\$/day) that are assessed to the LSE serving such PRD during the Delivery Year. A FRR Entity serving PRD under the FRR Alternative will not be eligible to receive a Daily PRD Credit (\$/MW-day) during the Delivery Year.

3A.2 Transition Period

The maximum quantity of PRD that can be committed in the RTO through RPM Auctions for a Delivery Year is capped during the transition period (2016/2017 – 2018/2019) Delivery Years) as follows:

<u>2016/2017 Delivery Year</u>	<u>2017/2018 Delivery Year</u>	<u>2018/2019 Delivery Year</u>	<u>2019/2020 Delivery Year & future Delivery Years</u>
<u>2,500 MW</u>	<u>3,500 MW</u>	<u>4,000 MW</u>	<u>No Cap</u>

Although there is a limit on the amount of PRD that may be committed to PJM through RPM Auctions during the transition period, there is no limit on the amount of PRD that can be reflected in the Day-ahead and Real-time Energy Markets.

PRD will be committed in the Base Residual Auction based on the most economical BRA PRD elections. If, as a result of the initial clearing of the BRA, the total PRD commitments exceed the RTO cap for the transition Delivery Year, PJM will ensure that the total PRD commitments in a zone (or sub-zonal LDA) do not exceed a zonal (or sub-zonal LDA) allocation of the RTO cap. The RTO cap is allocated to the zones (or sub-zonal LDA) pro-rata based on the Preliminary Zonal (or Sub-Zonal LDA) Peak Load Forecast less zonal (or sub-zonal LDA) forecasted peak load to be served under the FRR Alternative. Unused portions of a zonal (or sub-zonal LDA) allocation will be assigned to other zones (or sub-zonal LDAs) in which the initial PRD committed amount exceeded the zonal (or sub-zonal) allocation. Such assignments will be based on committing the most economical BRA PRD elections in such other zones (or sub-zonal LDAs).

PRD will be committed in the Third Incremental Auction based on the most economical Third IA PRD elections. If, as a result of the initial clearing of the Third IA, the total PRD commitments in the BRA and Third IA exceed the RTO cap for the transition Delivery Year, PJM will ensure that the total BRA and Third IA PRD commitments in a zone (or sub-zonal LDA) do not exceed a zonal (or sub-zonal LDA) allocation of the RTO cap. The RTO cap is allocated to the zones (or sub-zonal LDA) pro-rata based on the Preliminary Zonal (or Sub-Zonal LDA) Peak Load Forecast less zonal (or sub-zonal LDA) forecasted peak load to be served under the FRR Alternative. Unused portions of a zonal (or sub-zonal LDA) allocation will be assigned to other zones (or sub-zonal LDAs) in which the initial total (BRA and Third IA) PRD committed amount exceeded the zonal (or sub-zonal) allocation. Such assignments will be based on committing the most economical Third IA PRD elections in such other zones (or sub-zonal LDAs).

During the transition period, annual reviews will be conducted to inform the market of the impact of Price Responsive Demand.



3A.3 Eligibility Requirements of Price Responsive Demand

In order for load to be eligible to be considered as Price Responsive Demand, the end-use customer load must be:

- served under a dynamic retail rate structure with an LSE or subject to a contractual arrangement with a PRD Provider where such rate or compensation arrangement can change on an hourly basis, is linked to or based upon a PJM real-time LMP trigger at a substation location within a transmission zone as electrically close as practical to the applicable load, and results in predictable response to varying wholesale electricity prices;
- subject to advanced metering capable of recording electricity consumption at an interval of one hour or less; and
- subject to Supervisory Control as defined in the Reliability Assurance Agreement to curtail the demand should PJM declare an emergency condition.

Supervisory Control of customer load registered as Price Responsive Demand is required on the part of the PRD Provider consistent with any Relevant Electric Retail Regulatory Authority (RERRA) requirements. RERRA shall have the meaning specified in the PJM Operating Agreement. To the extent load was not already reduced, the PRD Provider is required to have the remote capability to decrease the load at each location contained in the PRD Registration to the required service level when a PJM Maximum Emergency event has been declared and the LMP at the applicable location has exceeded the level at which the load has committed to reduce. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to Real Time LMPs for the PRD Curves that are submitted in the PJM Energy Market. Automation of load response to LMP trigger without manual intervention is required to be PRD.

However, PRD Providers may request an exception to the automation requirement for end-use customers that are a single site, a single location and a single end-use customer with supervisory control over processes with which load reduction would be accomplished. In this case, the end use customer site is eligible for this specific exception from standard automation requirement, but the end-use customer is still required to respond within 15 minutes to Real Time LMPs for the PRD Curves that are submitted in the PJM Energy Market.

The customer load must be on a dynamic retail rate structure with an LSE or subject to a contractual arrangement with a PRD Provider that results in retail charges or credits to the end use customer that are linked to or based on the Real Time LMP. Multiple retail rates or contractual arrangements could qualify for this requirement, such as a structure where the retail charge or credit to the end-use customer is greater than or equal to the Real-time LMP, or applies only when the Real Time LMP exceeds a preset threshold. Dynamic retail rate structures, based on PJM Real-time LMP, that qualify as Price Responsive Demand may include:

- Critical Peak Pricing that allows retail rates to rise when the wholesale market price exceeds a threshold level;
- Critical Peak Rebate pricing which provides bill credits to consumers who reduce their usage below a baseline quantity during periods when the wholesale market price exceeds a threshold level; or
- Real-Time Pricing based on LMP.



3A.4 PRD Plan Requirements

3A.4.1 PRD Plan Submission & Approval Process

A PRD Provider that wishes to nominate PRD load for a Delivery Year's Base Residual Auction or nominate PRD to reduce an FRR Entity's preliminary unforced capacity obligation must submit a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 immediately prior to the Delivery Year's Base Residual Auction. Additional PRD may be nominated in an LDA in the Third Incremental Auction in the event and to the extent that the LDA final peak load forecast used in Third Incremental Auction increases relative to LDA preliminary peak load forecast used in the Base Residual Auction. Nomination of additional PRD load in an LDA for a Delivery Year's Third Incremental Auction when LDA peak load forecast increases may be made by submitting a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 immediately prior to the Delivery Year's Third Incremental Auction. Nomination of additional PRD for use in reducing an FRR Entity's final unforced capacity obligation for the Delivery Year may also be made by submitting a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 prior to the Delivery Year's Third Incremental Auction.

Once received by PJM, the PRD Provider will receive an email confirmation that their plan has been received and will be reviewed by PJM. PJM will review the content to ensure the PRD Plan contains all the necessary detail and information. PJM will notify the PRD Provider within 10 days of receipt of the PRD Plan and indicate whether or not the PRD Plan is approved or rejected. Any submitted plan that is incomplete or falls short of meeting the informational requirements of a PRD Plan by such January 15 deadline shall be rejected.

A PRD Provider must submit a PRD Plan no later than January 1, prior to a Base Residual Auction or Third Incremental Auction if the PRD Provider wants PJM to conduct an advance review of their PRD Plan. PJM will review the content of the PRD Plan and will notify the PRD Provider within 10 days of receipt of the PRD Plan if the submitted PRD Plan is approved or rejected. If the PRD Plan is rejected, PJM will provide to the PRD Provider a list of the areas in the PRD Plan that were not adequate. PRD Plans that are denied by PJM in an advance review may be corrected and resubmitted no later than January 15, prior to the Base Residual Auction or Third Incremental Auction. Alternately, PJM may approve a lower maximum Nominal PRD Value supported by the PRD Plan.

To help a PRD Provider prepare and submit a PRD Plan by the January 15 deadline, the following information will be made available:

- Prior year summer weather normalized zonal peak loads posted by PJM by October 31. The summer weather normalized zonal peak loads will be developed from hourly metered zonal loads that include add backs due to demand response and price responsive demand in accordance with PJM Manual 19, Load Forecasting and Analysis.
- Customer PLCs developed and made available by EDCs based on prior year summer weather normalized Zonal peak loads by December 31.
- Zonal Scaling Factors (Ratio of Delivery Year Zonal Peak Load Forecast to prior year summer weather normalized Zonal peak load) posted by PJM by January first week.



3A.4.2 Required Components of a PRD Plan

The PRD Plan is a document submitted by the PRD Provider that defines and provides data to support a PRD Provider's maximum Nominal PRD Value in a Zone or sub-zone LDA (for example, if nominating PRD in DPL South or PS North). The PRD plan must identify any methods and techniques that will be used to determine and verify the quantity of load consumed at varying wholesale price levels. A single PRD Plan may be submitted to cover multiple Sub-zone/Zone locations, provided that the price-demand curves are submitted on a Sub-zone/Zone level. All of the assumptions, procedures, and data for the PRD Plan should be clearly documented. The data included should be sufficient for a third party to audit the procedures and verify the PRD Provider's maximum Nominal PRD Value in a Sub-zone/Zone.

The PRD Plan must detail the price responsive characteristic of the customer load at a zonal or sub-zonal LDA (for example, if load is in PSEG-North or DPL-South) level. If known, the PRD Plan should detail the price responsive characteristics at a substation level. The price responsive characteristic of such customer loads must be provided in terms of the quantity of load that will continue to consume at various levels of price.

The Expected Peak Load Value of PRD is the expected contribution of such PRD Provider's price responsive load to the Delivery Year's Zonal Peak Load Forecast if such load were not to be reduced in response to price. The substation/sub-zonal/zonal Expected Peak Load Values of PRD will be aggregated to determine the Zonal/LDA Expected Peak Load Value of PRD quantity for the PRD Provider in such Zone/LDA.

The Maximum Emergency Service Level (MESL) is the level to which the price-responsive load will be reduced during the Delivery Year when a Maximum Emergency Event is declared. The quantity of load that will be consumed at a price equal to the applicable energy market offer cap to the relevant delivery year represents the MESL. The locational MESL quantities (at substation/sub-zonal/zonal) will be aggregated to determine the Zone/LDA MESL quantity for the PRD Provider in such Zone/LDA.

For the purposes of the PRD Plan, the PRD Provider's Nominal PRD Value for a Zone/LDA is the difference between the PRD Provider's Zonal/LDA Expected Peak Load Value of PRD and MESL for such Zone/LDA.

A Price Responsive Demand (PRD) Plan submitted to PJM must include:

- Company name
- Submission date
- Company address and contact information
- Indication of whether price responsive demand is being nominated for an RPM Auction or for use in reducing an FRR Entity's unforced capacity obligation
- Location of Price Responsive Demand by applicable electrical location within a transmission zone (i.e., PNODE), if available at the time of submittal of PRD Plan, or by Sub-zone/Zone. At the time of the submittal of PRD Plan, the PRD Provider may provide data at the smallest LDA level, but the PRD Provider is required to provide final locational detail (i.e., PNODE) prior to Delivery Year.
- Expected Peak Load Value of PRD by applicable electrical location, if available, or by Sub-zone/Zone



- Maximum Emergency Service Level (MESL) of Price Responsive Demand by applicable electrical location, if available, or by Sub-zone/Zone
- Nominal PRD Value by applicable electrical location, if available, or by Sub-zone/Zone. The smallest increment that may be submitted for a Sub-zone/Zone is .1 MW.
- PRD Reservation Price, elected by PRD Provider as defined in section 3A.4.2.3
- Price-Demand curves at the applicable electrical location, (PNODE)/Sub-zone/Zone level, detailing the base electricity consumption level as well as the decreasing consumption levels (i.e., demand levels) at increasing wholesale energy prices (i.e., real-time LMPs).
- A description of the methodologies, analysis, or pilot programs used to determine the Expected Peak Load Value of PRD, Maximum Emergency Service Level (MESL) value, and Price-Demand Curves
- Specifications of the equipment used to meet the advanced metering and supervisory control requirements, including a project plan and timeline with the milestones that demonstrates that the AMI and supervisory control will be available and operational for the start of the Delivery Year.
- If the PRD Provider is an LSE, documentation, conforming to **Section 3A.4.2.2** below, verifying that the LSE has Relevant Electric Retail Regulatory Authority (“RERRA”) approval:
 - (a) Where LSE is under the jurisdiction of a RERRA, documentation verifying that the RERRA has approved the LSE’s PRD Program including the time varying rate structure required to implement the program.
 - (b) Whether or not the LSE is under the jurisdiction of a RERRA, documentation verifying that such rate conforms to PRD implementation standards as specified in the PJM RAA, PJM Operating Agreement, PJM OATT and PJM Manuals.
- If the PRD Provider is not a LSE, documentation conformation to **Section 3A.4.2.3** below, verifying that the contractual arrangement with relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements and adheres to PRD implementation standards as specified in PJM RAA, PJM Operating Agreement, PJM OATT and PJM Manuals.
- AMI is required in support of the PRD installation:
 - (a) In jurisdictions where the PRD program is under the jurisdiction of a RERRA, the PRD Provider shall use the AMI infrastructure in conformance with RERRA requirements. Furthermore, the AMI system shall be designed to allow for full implementation of PRD including metering reading requirements, supervisory control requirements, and all other requirements developed under the PJM RAA, PJM Operating Agreements, OATT and PJM Manuals.
 - (b) In jurisdictions where PRD Provider is not required to obtain RERRA approval for the PRD program, the PRD Provider shall use an automated metering infrastructure that effects the needed operational requirements for



PRD. Furthermore, the metering infrastructure shall be designed to allow for full implementation of PRD including meter reading requirements, supervisory control requirements, and all other requirements developed under the PJM RAA, PJM Operating Agreements, OATT and PJM Manuals.

- (c) The meter utilized to measure consumption for the purpose of retail billing shall also be the meter utilized to measure consumption for the purpose of PRD participation.

3A.4.2.1 Verification of Retail Rate Structure with LSE

Before PJM will approve a LSE's PRD Plan, PJM will require that the LSE verify that it has received Relevant Electric Retail Regulatory Authority ("RERRA") approval of its time-varying retail rate structure for the referenced load. An LSE that seeks to assert that the RERRA approves or conditionally approves (which condition the LSE asserts has been met) its time varying retail rate structure for the referenced load, shall provide to PJM, within ten (10) business days of PJM's request, either: (a) an order, resolution or ordinance of the RERRA, approving or conditionally approving (which condition the LSE asserts has been met) the LSE's time varying retail rate structure for the referenced load, or (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to existence of a RERRA order, resolution or ordinance approving or conditionally approving (which condition the RERRA legal counsel or the LSE asserts has been met) the LSE's time varying retail rate structure for the referenced load. If the LSE fails to provide the required documentation to PJM within the referenced ten business days, PJM shall reject the LSE's PRD Plan.

In RERRA jurisdictions where a LSE is not required by the RERRA to seek approval from the RERRA for its time varying retail rate structure for the referenced load, the LSE shall provide to PJM, within ten (10) business days of PJM's request, an opinion of either the LSE's legal counsel or the RERRA's legal counsel attesting that the LSE does not need to obtain approval from the RERRA for the LSE's time varying retail rate structure for the referenced load, and that the LSE's time-varying retail rate structure for the referenced load adheres to any guidelines established by the RERRA. If the LSE fails to provide the required documentation to PJM within the ten business days, PJM shall reject the LSE's PRD Plan.

3A.4.2.2 Verification of Contractual Arrangement with PRD Provider

In the case where the PRD Provider is not a LSE, PJM will require the PRD Provider to provide documentation, within (10) business days of PJM's request, that verifies that their contractual arrangement with the relevant end-use customers establishing a time-varying retail rate structure that conforms any RERRA requirements and adheres to PRD implementation standards specified in the PJM RAA, PJM Operating Agreement, PJM OATT or PJM Manuals. The PRD Provider shall provide to PJM, within ten (10) business days of PJM's request, copies of their applicable contracts with end-use customers capable of reducing load in response to price (including any proposed contracts). If the PRD Provider fails to provide any of the required documentation, including but not limited to end-use customer contracts within the ten business days, PJM shall reject the PRD Provider's PRD Plan.

In RERRA jurisdictions where a PRD Provider is not required by the RERRA to seek approval from the RERRA for its contractual arrangement for the referenced load, the PRD



Provider shall provide to PJM, within ten (10) business days of PJM's request, an opinion of either the PRD Provider's legal counsel or the RERRA's legal counsel attesting that the PRD Provider does not need to obtain approval from the RERRA for the PRD Provider's contractual arrangement for the referenced load, and that the PRD Provider's contractual arrangement for the referenced load adheres to any guidelines established by the RERRA. If the PRD Provider fails to provide the required documentation within the ten business days, PJM shall reject the PRD Provider's PRD Plan.

3A.4.2.3 PRD Election Requirements

A PRD Provider that is nominating PRD for an RPM Auction must also submit a PRD election (indicating the Sub-zonal/Zonal Nominal PRD Value to be provided at different reservation prices) in the eRPM system by January 15, prior to the Base Residual Auction or Third Incremental Auction for the relevant Delivery Year.

A PRD election must include:

Zonal/Sub-zonal Nominal PRD Value (MW) and Reservation Price (\$/MW-day) pair(s) that meet the following requirements.

- (a) Up to ten quantity(MW)-price(\$/MW-day) pair segments for a zone/sub-zone may be submitted
- (b) A minimum and maximum Nominal PRD Value quantity must be submitted for each segment
- (c) The smallest increment that may be submitted for a Nominal PRD Value MW quantity is 0.1 MW.
- (d) The sum of the maximum Nominal PRD Values in the segments must not exceed the sub-zonal/zonal Nominal PRD Value requested for approval by PJM in the PRD Provider's PRD Plan. If PJM approves a lower sub-zonal/zonal Nominal PRD Value than the requested value in their PRD Plan, the PRD Provider will be asked to resubmit their PRD election such that the maximum Nominal PRD Values in the segments does not exceed the final sub-zonal/zonal Nominal PRD Value approved by PJM.
- (e) A Reservation Price submitted in a segment must be equal to or greater than \$0/MW-day. If a PRD Provider does not submit a reservation price for a segment, the reservation price will default to \$0/MW-day. A PRD Provider is willing to commit the Nominal PRD level specified in a segment if the RPM Auction Resource Clearing Price applicable to Annual Resources in the zone/sub-zone is equal to or greater than the Reservation Price specified in such segment.
- (f) The PRD Provider is willing to accept the commitment of any amount of Nominal PRD Value equal to or greater than the minimum MW amount quantity specified in a segment and equal to or less than the maximum MW amount quantity specified in a segment.
- (g) If a PRD Provider's PRD Plan is not approved by PJM, the PRD Provider's Election will be rejected by PJM and not considered in the RPM Auction clearing.



Upon posting of the RPM Auction Results, PJM will notify the PRD Provider via the eRPM system of their sub-zonal/zonal committed Nominal PRD Value. Upon notification by PJM, the PRD Provider has a binding commitment to provide sub-zonal/zonal PRD at the committed level during the relevant Delivery Year.

3A.5 Registration of Price Responsive Demand

A PRD Provider will be required to register price responsive load in eLRS system prior to the start of the Delivery Year and maintain the registration of enough price responsive load in a zone/sub-zone throughout the Delivery Year to satisfy their zonal/sub-zonal PRD commitments.

Only load that meets all the eligibility requirements of PRD can be registered as PRD. The registration of price responsive load must be identified at the substation location within a transmission zone as electrically close as practical to the applicable load (i.e., PNODE).

If during the Delivery Year, the load no longer meets all the eligibility requirements of PRD, the PRD Provider must terminate the initial registration on the date the load no longer meets the eligibility requirements. The PRD Provider may also register new customers throughout the Delivery Year to cover loss of PRD load when customers drop out of the PRD Provider's program.

End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Delivery Year, (i) be registered as Economic Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Sell Offer in any RPM Auction; (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider.

An individual site registration must be submitted for each end-use customer site that is price responsive and has a peak load contribution equal to or greater than 10 KW. The site registration must identify the LSE serving the load at the site, the EDC, PLC, MESL, EDC-assigned loss factor, PNODE, and whether the load is being served by the LSE under the RPM or the FRR Alternative. The MESL in the registration represents the load level that the site is committing to be at during a Maximum Emergency Event.

An aggregate registration may be submitted to aggregate end-use customer sites that have peak load contributions below 10 KW provided such aggregate registration must represent end-use customers served by the same Load Serving Entity under RPM or FRR Alternative and located at the same PNODE.

PJM will receive data to validate the PLC calculation of any EDC who is also an LSE that has registered PRD for a given year.

The Nominal PRD Value calculated for a registration is equal to the $[\text{PLC} * \text{Final Zonal Peak Load Forecast} // \text{Prior Summer Weather Normalized Zonal Coincident Peak}] - [\text{MESL in the registration} * \text{EDC-assigned loss factor}]$.

PJM will aggregate the Nominal PRD Values of effective, approved registrations in a zone/sub-zone to determine the PRD Provider's actual Daily Nominal PRD Value in zone/sub-zone for each day during the Delivery Year.

The deadline for the submittal of a PRD registration in the eLRS system is one day before the tenth business day prior to the start date that a PRD registration is effective so that adequate time is provided for the EDC and LSE to confirm the registration data. During the



Delivery Year, if the load identified in the approved PRD registration will no longer meet the PRD eligibility requirements, a request to terminate the PRD registration on the last day that such load meets the PRD eligibility requirements must be submitted in eLRS within two business days prior to the date that the PRD registration is to terminate. A PRD registration must be in an approved status by the start date of the registration and be effective on the delivery day in order for such registration to be counted towards meeting the PRD Provider's committed sub-zonal/zonal Nominal PRD Value for the relevant delivery day.

For a PRD Provider, the MW amount of PRD that is currently registered by the PRD Provider at the time of PRD Plan submittal may be considered as Existing PRD and not be subject to a Price Responsive Demand Credit Requirement.

3A.6 Performance Requirements of Price Responsive Demand

Once a PRD Provider commits PRD for the Delivery Year, the PRD Provider will be subject to both daily commitment compliance during the Delivery Year and event compliance during Maximum Emergency Events during the Delivery Year. In the absence of a Maximum Emergency Event during the relevant Delivery Year that required a PRD registration to respond, such registration would be required to test during the Delivery Year.

A PRD Provider cannot use replacement capacity to reduce a MW shortfall for PRD commitment compliance, failure to perform during a Maximum Emergency Event, or failure to perform during a test. However, a PRD provider may register additional price responsive demand throughout the Delivery Year to cure a daily commitment compliance shortfall or avoid additional event compliance shortfalls. In addition, a PRD Provider may transfer the obligation to provide PRD to another PRD provider through a bilateral transaction.

3A.6.1 PRD Commitment Compliance

A PRD Provider must register enough PRD prior to the start of the Delivery Year and maintain enough Price Responsive Demand registrations throughout the Delivery Year to satisfy their sub-zonal/zonal PRD commitment for RPM or FRR.

PRD commitment compliance will be evaluated on a daily basis throughout the Delivery Year. PJM will determine the actual Daily Nominal PRD Value of the PRD Provider in a Sub-Zone/Zone for RPM or FRR based on the registration information provided in the eLRS system. If a PRD Provider's actual Daily Nominal PRD Value in a Sub-Zone/Zone for RPM is less than their committed Nominal PRD Value in Sub-Zone/Zone for RPM, the PRD Provider will be subject to a Daily PRD Commitment Compliance Penalty in the Sub-zone/Zone for the MW shortfall. If a PRD Provider's actual Daily Nominal PRD Value in a Sub-Zone/Zone for FRR is less than their committed Nominal PRD Value in Sub-Zone/Zone for FRR, the PRD Provider will be subject to a Daily PRD Commitment Compliance Penalty in the Sub-zone/Zone for the MW shortfall.

3A.6.2 Maximum Emergency Event Compliance

Sub-zonal/zonal committed PRD is required to reduce to a level based on the sub-zonal/zonal MESL in the registration system upon PJM declaration of a Maximum Emergency Event during that Delivery Year. During the Delivery Year, PRD Providers for which committed Price Responsive Demand does not respond consistent with the sub-



zonal/zonal commitment during emergency conditions will be subject to a PRD Maximum Emergency Event Compliance Penalty.

The performance of Price Responsive Demand will be measured and verified whenever PJM declares a Maximum Emergency Event in sub-zone/zone. PRD Providers are responsible for the submittal to PJM of all meter information required to complete this measurement and verification for each PJM Maximum Emergency Event during the Delivery Year. PJM requires that actual metered data at the end-use customer site for all hours during the PJM Maximum Emergency Event be submitted to PJM via the eLRS system within 60 days of the event, with accountability if for failure to do so. PJM's review of the PRD Provider's performance and the calculation of a net MW shortfall in a sub-zone/zone for a Maximum Emergency Event are to be completed by the PJM and any resulting PRD Maximum Emergency Event Compliance Penalties billed by the later of (i) third billing month following the Maximum Emergency Event or (ii) the month of December of the Delivery Year.

Compliance is measured for a PRD registration upon declaration of a PJM Maximum Emergency Event in same sub-zone/zone of such PRD registration and when the PRD Curve associated with such registration in the PJM Energy Market has a price point at or below the highest Real-Time LMP recorded during the Maximum Emergency Event.

The MW shortfall for a PRD registration = highest hourly integrated metered load for end-use customer(s) associated with the registration – adjusted MESL of the registration.

If the PRD Provider failed to submit actual metered data for the end-use customer site for all hours during the PJM Maximum Emergency Event, the MW shortfall for such registration for the Maximum Emergency Event will be equal to the Expected Peak Load Value of the registration minus the adjusted MESL of the registration.

The MW shortfall for a PRD registration will be capped at the PRD commitment level (MW) for such registration on the day of the event. The PRD Provider's committed Zonal (or Sub-Zonal LDA) Nominal PRD Value on the day of the event is allocated to the PRD Provider's registrations in the zone (or sub-zonal LDA) pro-rata based on the Nominal PRD Value of the registrations to determine the PRD commitment level for such registrations.

For event compliance, the MESL of the registration is adjusted to account for the fact that actual load can be greater than the PJM 50/50 load forecast during an emergency event. The MESL in the registration will be multiplied by the higher of 1.0 or (the ratio of the actual non-PRD zonal load at the time of RTO unrestricted peak for the Delivery Year to the non-PRD final zonal peak load forecast for the Delivery Year.)

The adjusted MESL for a registration shall equal the MESL reported in the registration * service level adjustment factor.

The service level adjustment factor = higher of 1.0 or (actual zonal load – actual total PRD load in zone/ (Final Zonal Peak Load Forecast-final total Zonal Expected Peak Load Value of PRD in Zone), where:

Actual zonal load is equal to the actual unrestricted zonal peak load at the time of the RTO peak.

Actual total PRD load in zone is the hourly integrated metered load for all end-use customers' registered to meet a PRD commitment for RPM or FRR Alternative at the time of the RTO unrestricted peak for the Delivery Year plus any add-backs for PRD in accordance



with Manual 19: Load Forecast and Analysis. The final total Zonal Expected Peak Load Value of PRD in the zone is equal to the sum of the Zonal Expected Peak Load Values as determined from approved PRD registrations that are effective on the day of the RTO unrestricted peak for the Delivery Year

A single service level adjustment factor applies for each zone and is used in the measuring compliance for all Maximum Emergency Events during the Delivery Year. The service level adjustment factor must be greater than or equal to 1.0.

The event compliance evaluation for a registration is completed for every, full clock hour for which the Maximum Emergency Event was in effect. In addition, for any partial clock hours during which the Event was in effect, at the PRD Provider's option, PJM will verify either that the load was reduced to the adjusted MESL level within 15 minutes of the emergency procedures notification regardless of the response rate submitted in the associated PRD Curve in the PJM Energy Market, or that the hourly integrated value of the load was at or below the adjusted MESL. If not verified, the MW shortfall for the partial clock hour will be equal to the hourly integrated load for the whole hour minus the adjusted MESL.

The highest of MW shortfalls calculated for each hour in the Maximum Emergency Event will be the MW shortfall for the registration for the Maximum Emergency Event. A positive MW shortfall for the registration represents under-compliance for the Maximum Emergency Event. A negative MW shortfall for the registration represents over-compliance for the Maximum Emergency Event.

The MW shortfalls of the PRD Provider's PRD registrations in a sub-zone/zone that were expected to respond are aggregated to determine a PRD Provider's sub-zonal/zonal net shortfall during a Maximum Emergency Event.

If the PRD Provider registered PRD to satisfy RPM PRD commitments and PRD to satisfy FRR PRD commitments, the PRD Provider's sub-zonal/zonal net shortfall for a Maximum Emergency Event will be allocated into a net shortfall for RPM and a net shortfall for FRR based on the percentage of the total under-compliance MWs in the sub-zone/zone due to under-compliance MWs of registrations tied to RPM versus FRR.

The PRD Provider's sub-zonal/zonal net shortfall for RPM for a Maximum Emergency Event may be reduced by the amount of daily MW shortfall for RPM commitment compliance if the PRD Provider is assessed a Daily PRD Commitment Compliance Penalty on the day of the Maximum Emergency Event.

The PRD Provider's sub-zonal/zonal net shortfall for FRR for a Maximum Emergency Event may be reduced by the amount of daily MW shortfall for FRR commitment compliance if the PRD Provider is assessed a Daily PRD Commitment Compliance Penalty on the day of the Maximum Emergency Event.

3A.6.3 PRD Test Compliance

If PJM does not declare during the relevant Delivery Year a Maximum Generation Emergency in zone that requires the registered PRD to reduce to the Maximum Emergency Service Level then such registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency may be called during June through October or the following May of the relevant Delivery Year. If a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum



Emergency Service Level is called during the relevant Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registrations.

All PRD registrations in a zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies PJM 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election.

Multiple tests may be conducted; however only one test result may be submitted for each end-use customer site in eLRS for test compliance evaluation. Test data must be submitted in eLRS on or after June 1 and no later than July 14th after the Delivery Year.

Testing compliance is measured for a PRD registration in a manner similar to event compliance.

The MW testing shortfall for a PRD registration = hourly integrated metered load for end-use customer(s) associated with the registration during test – adjusted MESL of the registration.

The MW shortfall for a PRD registration will be capped at the PRD commitment level (MW) for such registration on the day of the test. The PRD Provider's committed Zonal (or Sub-Zonal LDA) Nominal PRD Value on the day of the test is allocated to the PRD Provider's registrations in the zone (or sub-zonal LDA) pro-rata based on the Nominal PRD Value of the registrations to determine the PRD commitment level for such registrations.

The adjusted MESL for a registration shall equal the MESL reported in the registration * service level adjustment factor. The same zonal service level adjustment factors that would be calculated for event compliance are used for test compliance.

Positive MW shortfalls represent underperformance for a PRD registration. Negative MW shortfalls represent over performance for a PRD registration.

The test compliance results of the PRD Provider's PRD registrations in a zone that were expected to test are aggregated to determine a PRD Provider's net zonal testing shortfall.

If the PRD Provider registered PRD to satisfy RPM PRD commitments and PRD to satisfy FRR PRD commitments, the PRD Provider's net zonal testing shortfall will be allocated into a net zonal testing shortfall for RPM and a net zonal testing shortfall for FRR based on the percentage of the total under-compliance MWs in the zone due to under-compliance MWs of registrations tied to RPM versus FRR.

The PRD Provider's net testing shortfall in a zone for RPM shall be reduced by the PRD Provider's summer daily average of the MW shortfalls for RPM PRD commitment compliance. Any remaining positive net testing shortfall in the zone for RPM will be assessed a PRD Test Failure Charge.



The PRD Provider's net testing shortfall in a zone for FRR shall be reduced by the PRD Provider's summer daily average of the MW shortfalls for FRR PRD commitment compliance. Any remaining positive net testing shortfall in the zone for FRR will be assessed a PRD Test Failure Charge.

3A.7 PRD Bilaterals

A PRD Provider may transfer the obligation to provide PRD bilaterally to another PRD Provider during the Delivery Year.

The following are the business rules that apply to PRD bilateral transactions:

- PRD bilateral transactions must be reported in the eRPM system.
- Both parties of the PRD transaction must confirm the transfer of a PRD commitment from the seller (transferor) to the buyer (transferee) via the eRPM system prior to the start date of the transaction.
- PRD bilateral transactions must be in the "Approved" status by the start date of the transaction or the status of such transaction will be changed to "PJM Withdrawn".
- The smallest increment of committed Nominal PRD Value that may be transferred is 0.1 MW.
- PRD transactions must specify:
 - start and end data for the transaction
 - the amount of Nominal PRD Value (in MW) to be transferred
 - the sub-zone/zone in which the Nominal PRD Value to be transferred was committed
 - whether the Nominal PRD Value to be transferred was committed to RPM or the FRR Alternative
 - the RPM Auction (BRA or Third IA) for which the Nominal PRD Value to be transferred was committed (if committed to RPM)
- The eRPM system will validate that the Seller has the committed Nominal PRD Value in the sub-zone/zone to transfer for the term of the transaction.
- To the extent that the Nominal PRD Value to be transferred has a Price Responsive Demand Credit Requirement, the Buyer must have sufficient credit in place prior to PJM approving the PRD transaction.
- As a result of an approved PRD transaction, the buyer that is assuming the seller's PRD commitment and obligations will be subject to PRD performance requirements to the extent of such transfer and for the term of the transaction.
- The seller shall be relieved of its PRD commitment and any Price Responsive Demand Credit Requirements for the Nominal PRD Value transferred for the term of the transaction.



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 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, energy efficiency resources, and aggregate resources:

- Zone assignment
- LDA assignment
- Unit Location by State (generation resources only)
- Unit Type (generation resources only)

Product Type (Annual, Extended Summer, Limited for 2014/2015-2017/2018 Delivery Years)

Capacity Performance assignment (whether the resource is able to submit a Capacity Performance offer segment, effective for 2018/2019 Delivery Year)

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 [for a Delivery Year prior to the 2019/2020 Delivery Year](#).⁶
- Effective with the 2019/2020 Delivery Year, at a minimum, a Facilities Study Agreement has been executed for planned generation resources greater than 20 MWs and an Impact Study Agreement has been executed for planned generation resources less than or equal to 20 MWs.
- 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.

⁶ 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.

- 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.

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 the required System Impact Study Agreement or Facilities 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 [for a Delivery Year prior to 2019/2020 Delivery Year](#).
- [Effective with the 2019/2020 Delivery Year, at a minimum, a functionally equivalent Facilities Study Agreement has been executed for a planned unit greater than 20 MWs and a functionally equivalent Impact Study Agreement has been executed for planned generation resources less than or equal to 20 MWs.](#)
- 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.
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- 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.***

Effective with the 2018/2019 Delivery Year, the EFORd based on forced outage data from an October through September period prior to the Delivery Year will be based on all forced outage data and not exclude forced outage data for Outside Management Control events.



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 Interconnection 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 IMM 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:

- **Aa Demand Resource (DR)** offered into the Base Residual Auction or an Incremental Auction and paid the Resource Clearing Price.

4.3.1 Requirements of Load Management Products in RPM

In order to offer a Demand Resource in an RPM Auction, a demand resource provider must submit no later than 15 business days prior to the RPM Auction a Demand Resource Sell Offer Plan (DR Sell Offer Plan) in accordance with Attachment C of this Manual. Actual deadline date for a DR Sell Offer Plan for an RPM Auction is provided in the RPM Auction Schedule posted on the PJM website. A demand resource provider with a PJM approved DR Sell Offer Plan for the RPM Auction will be permitted to offer their Demand Resource(s) into such RPM Auction, provided the additional demand resource requirements in section 4.3.3 are met.

Demand resources that clear in an RPM Auction will have an RPM Resource Commitment for the relevant Delivery Year. Effective with the 2018/2019 Delivery Year, an RPM Resource Commitment will be further classified as a Base or Capacity Performance depending on how the Demand Resource offers and clears in an RPM Auction. Demand resources that are committed to an FRR Capacity Plan will have an FRR Capacity Plan Commitments for the relevant Delivery Year. Effective with the 2019/2020 Delivery Year, the FRR Capacity Plan Commitment will be further classified as Base or Capacity Performance depending on how the Demand Resource was committed by the FRR Entity in the FRR Capacity Plan. A resource provider who has RPM Resource Commitments or FRR Capacity Plan Commitments for their demand resource must meet the following requirements:

- Must be registered in the Pre-Emergency or Emergency Load Response Program (see more detail below in the Pre-Emergency and Emergency Load Response Registration section) prior to the start of the relevant Delivery Year.



- Have the capability to retrieve electronic messages from PJM which notify curtailment service providers of a load management event in accordance with PJM Manual 1: Control Center and Data Exchange Requirements.
- 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.
- Provide 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**.
- Provide accurate estimates of the amount of energy that will be reduced in direct response to PJM dispatch of demand response during the Delivery Year (see more detail in the Load Reduction Reporting section)

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 (Effective through 2017/2018 Delivery Year for RPM and through 2018/2019 Delivery Year for FRR Entities)** – 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 – 2017/2018 Delivery Years for RPM and 2014/2015-2018/2019 Delivery Years for FRR Entities)** – 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 – 2017/2018 Delivery Years for RPM and 2014/2015-2018/2019 Delivery Years for FRR Entities)** – 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.



- Base Capacity DR (Effective 2018/2019 – 2019/2020 Delivery Year) – Base Capacity DR is available for unlimited number of interruptions during June through September in the Delivery Year and will be capable of maintaining such interruption for at least a 10 hour duration between the hours of 10:00 AM to 10:00 PM Eastern Prevailing Time.
- Capacity Performance DR (Effective 2018-2019 Delivery Year) – Capacity Performance DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption 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. Effective with the 2015/2016 Delivery Year, load management will be required to fully respond within 30 minutes of notification unless an exception request for 60 or 120 minutes notification time is approved by PJM. If qualified for one of the following exceptions, then CSP shall elect either 60 minute or 120 minute lead time based on the resources physical capability to provide the load reduction:
 - The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process; or
 - Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes; or
 - On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or
 - The Demand Resource is comprised of mass market residential customers or similarly situated mass market small commercial customers which collectively cannot be notified of a Load Management event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.
 - The intent of these exemptions is to accommodate resources with legitimate, physical reasons as to why the load reduction cannot be achieved in the default, 30 minute notification time period and require up to 120 minutes to fully provide the load reduction. CSP must provide additional data and information within three business days of PJM request to substantiate the request for a longer lead time (60 or 120 minutes). PJM will make its determination within ten business days of receiving such additional information regarding the appropriate lead time for the registration.
- 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***.

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 three notification periods:

- 30 Minute Lead Time – Load management which must be fully implemented in 30 minutes or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.
- 60 Minute Lead Time – Load management which requires more than 30 minutes but no more than one hour, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.
- 120 Minute 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 those MWs on a demand resource identified in a pre-registration process in the eRPM system prior to the RPM Auction. The Nominated DR Values (in MWs) associated with end-use customer sites that the Curtailment Service Provider (CSP) has under contract for the current Delivery Year (i.e., end-use customer sites registered in PJM eLRS system for the current Delivery Year)⁷ and that the CSP intends to

⁷ For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM eLRS system for the subsequent Delivery Year may also be considered as existing DR

have under contract for the auction Delivery Year are considered Existing MWs. A CSP may request an adjustment to the Nominated DR Value (in MWs) associated with an end-use customer site and used in the determination of a CSP's Existing MWs if the following three criteria are satisfied:

- The original Nominated DR Value for the end-use customer was determined based on one registration in eLRS.
- The peak load contribution (PLC) reported in the eLRS registration for the end-use customer is at least 2 MW lower than it should have been due to an anomaly. An anomaly is a condition at the end-use customer site that resulted in significantly low usage that is not expected to occur in the future, such as a lighting strike or a major mechanical failure to an end use device.
- The CSP provides supporting information including historical load data to support an adjustment to the Nominated DR Value for the end-use customer.

A CSP request for an adjustment to the Nominated DR Value of an end-use customer and supporting information must be submitted via email to rpm_hotline@pjm.com at least five business days prior to the opening of the pre-registration window in the eRPM system for an RPM Auction. PJM will notify the CSP of the approval or rejection of their request prior to the opening of the pre-registration window in the eRPM system for an RPM Auction.

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 are those MWs on a demand resource that the CSP intends to offer in the RPM Auction in excess of the CSP's Existing MWs on such demand resource.

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 [product-specific](#) 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

provided the registrations are in "Confirmed" status by specified deadlines established by PJM and communicated to CSPs in advance of the DR Sell Offer Plan submittal deadline.



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. 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 or Capacity Only Option 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 Pre-Emergency and Emergency Load Response Registration

Pre-Emergency and Emergency Load Response Registration is the process of providing the following information through the submittal of a Pre-Emergency or Emergency Load Response registration into PJM's Load Response system (eLRS). As part of this process, 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 (Demand Resource Name if applicable)
- Load Management product type for customer site (Limited DR, Extended Summer DR, or Annual Summer DR.) (Effective with the 2014/2015 – 2017/2018 Delivery Years for RPM and 2014/2015-2018/2019 Delivery Years for FRR Entities and Base DR or Capacity Performance DR (Effective with 2018/2019 Delivery Year for RPM and 2019/2020 Delivery Year for FRR Entities))
- 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 must register customers in the Full Program Option or as a Capacity Only Option of the Emergency Load Response or Pre-Emergency Load Response Program.

The Full Program and Capacity Only Option enable a resource provider that has approved registrations for the Delivery Year prior to the applicable registration deadline to receive capacity credits, in the form of RPM Auction Credits, if the resource provider cleared their demand resource in an RPM Auction, for that Delivery Year. Full Program Option resource providers may claim an energy settlement for a PJM-initiated Load Management Event. Capacity Only resource providers may not claim an energy settlement for a PJM-initiated Load Management Event for Capacity Only registrations.

Customer sites registered in the Energy Only 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 for 2014/2015-2017/2018 Delivery Years for RPM and 2014/2015-2018/2019 Delivery Years for FRR Entities, Base or Capacity Performance for 2018/2019 and 2019/2020 Delivery Years for RPM and for 2019/2020 Delivery Year for FRR Entities) as the committed Demand Resource. Effective with the 2020/2021 Delivery Year, a provider with RPM or FRR Resource Commitments for their Demand Resource must register customer sites that are the Capacity Performance product-type.

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

4.3.6 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 (or sub-zonal LDA)

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 registration process.

4.3.7 Determination of Nominated Values for Load Management

Once an end-use customer is registered in the Pre- Emergency or Emergency Load Response Program (Full Program Option 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 a 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 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 ~~SCP methodology~~ [Electric Distribution Company](#).

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

$$\text{Nominated Value of FSL} = \text{PLC} - (\text{FL} * \text{LossF})$$

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.

$$\text{Nominated Value of GLD} = \text{GLD} (\text{LossF})$$

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.

$$\text{Nominated Value of DLC} = PPI * Cust * LossF$$

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**.

4.3.8 Determination of the UCAP Value of Load Management

Prior to 2018/2019 Delivery Year, the 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). Effective with the 2018/2019 Delivery Year, the unforced capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the Forecast Pool Requirement.

$UCAP\text{valueofLoadManagementProduct} = \text{NominatedValue} \times DR\text{Factor} \times FPR$ (Prior to 2018/2019 Delivery Year)

$UCAP\text{valueofLoadManagementProduct} = \text{NominatedValue} \times FPR$ (Effective 2018/2019 Delivery Year)

4.3.9 Load Reduction Reporting

PJM requires an accurate estimate of the amount of energy that will be reduced in direct response to PJM dispatch of Pre-Emergency and Emergency Demand Response capacity resources. This information will be used by PJM to determine the amount of DR resources to dispatch during a pre-emergency or emergency event. The Curtailment Service Provider



will contact DR resources, as necessary, to determine a reasonably accurate load reduction capability. The CSP will analyze and review the load reduction capability on a periodic basis to ensure it is reasonably accurate before it is provided to PJM.

Load Reduction Capability

The Load Reduction Capability provided by the CSP should represent the expected future incremental load reduction of energy that will be provided by the DR resources if dispatched by PJM under pre-emergency or emergency conditions. The Load Reduction Capability should only include energy load reductions expected to occur if a pre-emergency or emergency DR event is declared. This is independent of the committed capacity MW on the registration(s) and represents the operational expectations regarding the ability to reduce load for the specific time period. The Load Reduction Capability should not include load reductions that have already occurred or are already planned such as the following:

- Planned or unplanned outages at the facility
- Load reductions based on high expected prices, peak shaving or existing contract provisions

PJM will adjust, downward, the reported Load Reduction Capability values to account for any real time or day ahead economic market dispatch that has been assigned to the registered location(s) by PJM. The difference between the Load Reduction Capability and any economic dispatch reductions will indicate the estimated load reductions still available and able to respond to a PJM call for Pre-Emergency or Emergency DR.

Reporting

Curtailment Service Providers that have active Full Program Option or Capacity Only registrations shall provide PJM the Load Reduction Capability by zone by lead time on a monthly basis, to be submitted by the last business day of a given month and effective on the first business day of the following month. During the months of June through September, CSPs will provide any updates to this information for each day by no later than 4 p.m. on the day prior to the operating day.

On days for which a Maximum Emergency Generation/Load Management Alert or Action has been issued as communicated through the PJM ALL CALL and/or published on eDATA emergency messages, the Curtailment Service Provider shall on an hourly basis provide any updates to their information for the remaining hours of the day beginning at 10 a.m. and continuing until 7 p.m.

The Curtailment Service Provider shall submit the information electronically to the appropriate PJM system.

4.3.10 Maintenance Outage Reporting for Annual Demand Resource

An annual product ([prior to 2018/2019 Delivery Year](#)) and Capacity Performance product ([effective 2018/2019 Delivery Year](#)) Pre-Emergency or Emergency Load Response registration may request a maintenance outage during the months of October through April. The maintenance is defined as:

- maintenance to a device or generator used to reduce load at the end use customer location that cannot be reasonably scheduled outside of the annual product availability window, or



- maintenance of a CSP's system used to dispatch DR, but such maintenance shall be limited to no more than two times per quarter, shall not exceed one day in duration, and shall be on a Saturday or Sunday.

The outage request must be submitted at least four business days before the requested start date in the appropriate PJM system and will be evaluated on a first come first served basis. If a request is submitted less than four business days in advance, PJM may approve the request up to one day prior to operating day. The maintenance outage must be between one and thirty days and an extension may be requested during an approved outage at least four business days before the beginning of the extension period. PJM may deny a maintenance outage request if the outage is expected to create reliability issues. A maintenance outage denied by PJM may be resubmitted by the CSP to request another time period for the outage. CSPs should make a best effort not to request outages during weekday annual product availability hours for the months of January and February. A CSP may cancel maintenance outage at any time and the associated registration(s) will be required to respond to a PJM-initiated Load Management Event and shall be measured for event compliance if the event starts after PJM receives the cancellation. PJM may cancel a previously approved maintenance outage one day prior to the start of the outage for reliability concerns.

A registration associated with an approved maintenance outage that is in effect during a PJM- initiated Load Management event will not be considered as dispatched for such an event.

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 Hours⁸) 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.

The EE Performance Hours are defined as the hours 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.

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;

⁸The 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.



- 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 dispatchable⁹.

An Existing EE Resource is defined as an EE Resource with a PJM approved Post-Installation Measurement & Verification (M&V) Report. A Planned EE 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 [applicable product-specific Resource Clearing Price of the Locational Deliverability Area in which the EE Resource resides. Prior to 2018/2019 Delivery Year, all EE Resources are treated as Annual product type and will receive an Annual Resource Clearing Price. Effective for the 2018/2019 and 2019/2020 Delivery Year, Base Capacity EE Resources will receive a Base Capacity DR/EE Resource Clearing Price and Capacity Performance EE Resources will receive a Capacity Performance Resource Clearing Price. Effective with the 2020/2021 Delivery Year, all EE Resources must be the Capacity Performance product type and will receive a Capacity Performance Resource Clearing Price.](#)

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.

⁹ Dispatchable demand may be offered as a Demand Resource in the PJM Capacity Market.



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. Effective for the 2018/2019 Delivery Year, EE Resources that qualify as a Capacity Performance product type shall also have an expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and hour ending 9:00 EPT, and between the hour ending 19:00 EPT and hour ending 20:00 EPT, that is not less than the Nominated EE Value determined during the defined EE Performance Hours. If the Nominated EE Value determined during the defined EE Performance hours is greater than the expected average demand during the defined winter hours, the expected demand during the defined winter hours will be the Nominated EE Value of the Capacity Performance EE Resource. 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

Prior to 2018/2019 Delivery Year, 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. Effective with the 2018/2019 Delivery Year, the Unforced Capacity (UCAP) value of an Energy Efficiency Resource is equal to the Nominated EE Value of the EE Resource multiplied by the Forecast Pool Requirement.

UCAP value of EE Resource = Nominated EE Value × DR Factor × FPR (Prior to 2018/2019 Delivery Year)

UCAP value of EE Resource = Nominated EE Value × FPR (Effective with 2018/2019 Delivery Year)



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 [of the appropriate product type \(Annual product type prior to 2018/2019 Delivery Year and Capacity Performance product type effective with the 2018/2019 Delivery Year\)](#) 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 [Auction Specific MW 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 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



- [The product-type applicable to the MWs cleared \(Base Generation, Base DR/EE, or Capacity Performance\) \(Effective for the 2018/2019 and 2019/2020 Delivery Year\). Starting 2020/2021 Delivery Year, the product-type applicable to the MWs cleared can only be Capacity Performance.](#)
- 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:

- [An Aggregate Resource may not be specified as a unit transacted in a Unit-specific transaction.](#)
- 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 [of the specified product-type \(effective 2018/2019 Delivery Year\)](#) 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 [applicable product-specific](#) Auction Credit for the specified number of UCAP MW from the Seller to the Buyer. In addition, the [applicable product-specific](#) RPM Resource Commitment for the specified number of UCAP MWs is also transferred from the Seller to the Buyer.
- The Seller in a unit-specific transaction for cleared capacity will indemnify PJM Settlement, the LLC, and the Members for any failure by the Buyer 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 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 all Incremental Auctions. 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 Long-Term Firm Transmission Service is reserved from export source to export interface.

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 B 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 RPM auction 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 the Delivery 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, aggregate resource), Auction Type (Base, First, Second, Third, ~~or~~ Conditional, or Transitional), Product Type for 2018/2019 & 2019/2020 Delivery Year (Base Generation, Base DR/EE or Capacity Performance) 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 must be reported on an annual basis prior to each Delivery Year, therefore, the start and end date of the transaction must correspond to a Delivery Year.
- 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, [product-type \(Limited, Extended Summer, or Annual for 2014/2015-2017/2018 Delivery Year,](#)

Base Generation, Base DR/EE or Capacity Performance for 2018/2019 and 2019/2020 Delivery Year) and Incremental Auction associated with the Cleared Buy Bid. Effective 2020/2021 Delivery Year, the product-type specified for a Cleared Buy Bid transaction may only be Capacity Performance product type.

- 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 for~~ the 2014/2015 through 2017/2018 Delivery Years, Base Generation, Base DR/EE, or Capacity Performance for the 2018/2019 and 2019/2020 Delivery Years, start and end dates of the transaction. Effective with the 2020/2021 Delivery Year, the product type specified must be Capacity Performance.

- The Seller of the Locational UCAP must also specify the resource (generation resource, ~~or~~ demand resource, energy efficiency resource, or aggregate resource) and the MW amount of locational UCAP to be transacted. Prior to the 2018/2019 Delivery Year, the resource specified in the transaction must be of the same product type specified in the Locational UCAP transaction. Effective with the 2018/2019 Delivery Year, the resource specified in the transaction must be capable of meeting the requirements of the 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 a product-specific 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, 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.

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

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.

$$\text{CurrentAvailableICAPPosition}_{\text{unit}} = \text{Min}(\text{DailyAvailableICAP})$$

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.

$$\text{MinimumAvailableICAPPosition}_{\text{unit}} = \text{Min}(\text{DailyMinAvailableICAP})$$

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.

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

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.

$$\text{MaximumAvailableICAPPosition} = \text{Min}(\text{DailyMaxAvailableICAP})$$

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.

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



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.

$$\text{DailyUnOfferedICAP}_{\text{unit}} = \text{DailyUnOfferedICAP}_{\text{RPM Auctions}} + \text{DailyUnOfferedICAP}_{\text{Bilateral Sales/Purchases}}$$

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.

$$\text{DailyUnOfferedICAP}_{\text{GenResource}} = \text{MinimumAvailableICAPPosition}_{\text{unit}} - \text{OfferedICAP}$$

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).

$$\text{DailyRPMPosition}_{\text{GenResources}} = (\text{Daily ICAP Owned} - \text{Daily FRR Capacity Plan Commitments} - \text{Daily Unoffered ICAP}) \times (1 - \text{Effective EFORD})$$

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. Effective with the 2018/2019 Delivery Year, the DR Factor is eliminated and no longer considered in the calculation of the Daily Demand Resource Position.

$$\text{DailyResourcePosition}_{\text{Demand Resource}} = \text{DailyNominatedDRValue} \times \text{DRFactor} \times \text{FPR}$$



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. Effective with the 2018/2019 Delivery Year, the DR Factor is eliminated and no longer considered in the calculation of party's Daily Available ICAP.

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

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.

$$DailyUnOfferedICAP_{demand\ resource} = \sum DailyUnofferedICAP_{RPM\ Auctions}$$

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.

$$DailyUnofferedICAP_{DemandResource} = AvailableICAP\ Position - OfferedICAP$$

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.

$AvailableICAP_{Position\ Demand\ Resource} = Min(DailyAvailableICAP)$ 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. Effective with the 2018/2019 Delivery Year, the DR Factor is no longer considered in the calculation of a party's Daily RPM Demand Resource Position.

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

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 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. Effective with the 2018/2019 Delivery Year, the DR Factor is no longer considered in the calculation of a party's Daily EE Resource Position.

$$DailyResourcePosition_{EE\ Resource} = DailyNominatedEEValue \times DRFactor \times FPR$$

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). Effective with the 2018/2019 Delivery Year, the DR Factor is no longer considered in the calculation of a party's Daily Available ICAP.

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

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.

$$DailyUnofferedICAP_{EE\ Resource} = \sum DailyUnofferedICAP_{RPM\ Auctions}$$

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.

$$DailyUnofferedICAP_{EE\ Resource} = AvailableICAP\ Position - OfferedICAP$$

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.

$$AvailableICAP\ Position_{EE\ Resource} = Min(DailyAvailableICAP)$$

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. Effective with the 2018/2019 Delivery Year, the DR



Factor is no longer considered in the calculation of a party's Daily RPM EE Resource Position.

$$\text{DailyRPM Position}_{EE} = (\text{DailyNomEEValue} - \text{DailyFRRCapPlanCom} - \text{DailyUnofferedICAP}) \times \text{DRFactor} \times \text{FPR}$$

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.

4.7.4 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 **including External and Financed**, 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

Participants nominating PRD in advance of a BRA or Third Incremental Auction (for use in RPM Auction or FRR) must establish an RPM Credit Limit before submitting the PRD Plan in advance of the BRA or Third Incremental 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.

For Resources Requiring Credit for RPM, credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction. For price responsive demand requiring credit, credit requests should be made to PJM's Treasury Department at least two weeks prior to the deadline for submitting the PRD Plan. 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 and/or Price Responsive Demand 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 and/or Price Responsive Demand Credit Requirement. If a participant's RPM Credit Requirement and/or Price Responsive Demand 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. ~~However, the credit requirement for Planned Financed Generation Capacity Resources and Planned External Financed Generation Capacity Resources shall be one half of the product of the RPM Auction Credit Rate, as provided in Section IV.D, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction (though for Planned External Financed Generation Capacity Resources, this reduction may be limited subject to limits based on firm transmission secured, as further explained herein).~~ 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 service, the Credit Adjustment Factor will $(1-X)$, where "X" is the MWs of firm transmission service that has been secured for the complete transmission path divided by the MWs of existing external generation resource offered/committed and shall be zero if the Participant has demonstrated that firm transmission service for the complete transmission path has been ~~procured~~secured.
- For Planned generation resources internal and external, financed and non-financed, ~~the Credit Adjustment Factor please see with the incremental reduction and associated credit milestones in Section 4.8.6~~ 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 Planned external generation resources, the Credit Adjustment Factor will be reduced to 0.5 (50%) once the equivalent of an Interconnection Service Agreement has been successfully executed and 50% or more MWs of firm transmission service has been secured. The Credit Adjustment Factor will be reduced to zero when the resource commences Interconnection Service and 100% of the MWs of firm transmission service for the complete transmission path has been secured.~~
- 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 the posting of the BRA results, the RPM Credit Rate for all planned capacity resources other than planned Capacity Performance Resources is equal to the greater of (i) \$20/ MW-day or (ii) .3 ^{times} applicable Delivery Year's Net CONE for the RTO (-in \$/MW-day), times the number of days in the Delivery Year.~~
- Prior to the posting of the BRA results, RPM Credit Rate for planned Capacity Performance Resources is equal to the greater of (i) \$20/MW-day or (ii) 0.5 times applicable Delivery Year's Net CONE for modeled LDA where the resource resides (in \$/MW-day), times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Credit Rate.
- Upon posting the BRA clearing results, the RPM Credit Rate used for planned resource commitments in the BRA other than planned Capacity Performance commitments 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 for 2014/2015 through 2017/2018 Delivery Years and base for 2018/2018 and 2019/20120 Delivery Years) that applies to the planned resource¹⁰, times the number of days in the Delivery Year.

¹⁰~~Resource product types are effective with the 2014/2015 Delivery Year.~~

- Upon posting the BRA clearing results, the RPM Credit Rate used for planned Capacity Performance commitments in the BRA is equal to the greater of [(i) \$20/MW-day, (ii) .2 times the Capacity Performance Resource Clearing Price for the LDA that applies to the planned Capacity Performance resource, or (iii) the lesser of (a) 0.5 times Net CONE for modeled LDA where the resource resides for such Delivery Year (in \$/MW-day) or (b) 1.5 times Net CONE (stated in installed capacity terms as \$/MW-day) for the modeled LDA where the resource resides for such Delivery Year minus the Capacity Performance Resource Clearing Price for the LDA that applies to the planned Capacity Performance Resource], times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Credit Rate.
- For any planned resource not previously committed for a Delivery Year that participates in an Incremental Auction, the Auction Credit Rate for all planned capacity resources other than planned Capacity Performance Resources is equal to the greater of (i) 0.3 times the applicable Delivery Year's Net CONE for the RTO (in \$/MW-day) 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 (i.e., limited, extended summer, and annual for 2014/2015 through 2017/2018 Delivery Years and base for 2018/2019 and 2019/2020 Delivery Years) that applies to the planned resource or (iii) \$20 per MW-day, 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 for all planned Capacity Performance Resources is equal to the greater of (i) 0.5 times RTO Net CONE (in \$/MW-day) or (ii) \$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 other than Capacity Performance commitments 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 (i.e., limited, extended summer, and annual for 2014/2015 through 2017/2018 Delivery Years and base for 2018/2019 and 2019/2020 Delivery Years) 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.
- Upon posting the results of an Incremental Auction, the Auction Credit Rate used for planned Capacity Performance commitments is equal to the greater of [(i) \$20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such Incremental Auction for the LDA that applies to the planned resource, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where resource resides for such Delivery Year (in \$/MW-day) or (b) 1.5 times Net CONE (stated in installed capacity terms as \$/MW-day) minus the Capacity Performance Resource Clearing Price in such Incremental Auction for the LDA that applies to the planned capacity Performance Resource], times the number of days in the

Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Credit Rate.

- 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.
- For Qualified Transmission Upgrades, the Auction Credit Rate applied will be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit (CETL).

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 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. If the RPM Credit Adjustment Factor for a planned capacity resource is less than one, the maximum credit requirement specified in the Sell Offer may exceed the RPM Credit Limit of the resource in order to account for a post-auction credit requirement for the resource that will be based on the product of the post-auction Auction Credit Rate times the RPM Credit Adjustment Factor.

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) except for the case where the RPM Credit Adjustment Factor applicable to the resource is less than one in which case the Maximum Post-Auction Credit Exposure may be specified by the seller as the RPM Auction Credit Requirement divided by the RPM Credit Adjustment Factor. 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 times the appropriate RPM Credit Adjustment Factor. 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 supplier must further notify PJM of the maximum credit requirement (i.e., Maximum Post-Auction Credit Exposure) to be specified in the credit-limited offer and whether the maximum credit requirement to be specified will exceed the seller's RPM Credit Limit assigned to the sell offer in order to account for an RPM Credit Adjustment Factor less than one.
- 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, except for



the case where the RPM Credit Adjustment Factor associated with the planned capacity resource is less than one.

- Coupled **Demand** Resource Offers may not utilize the Credit Limited Offer functionality.

4.8.5 Price Responsive Demand Credit Requirement

A PRD Provider seeking to commit PRD in the Base Residual Auction, Third Incremental Auction, or the FRR Alternative, and for which there is a materially increased risk of non-performance for such PRD, must satisfy the Price Responsive Demand Credit Requirement prior to the deadline for submitting the PRD Plan.

The Price Responsive Demand Credit Requirement shall be based on the maximum Nominal PRD Value in the PRD Plan * Forecast Pool Requirement*Price Responsive Demand Credit Rate. For a PRD Provider, the maximum Nominal PRD Value in the PRD Plan may be reduced by the amount of existing PRD that is currently registered and approved in eLRS system by such PRD Provider on January 1 in advance of the PRD Plan submittal deadline.

Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.3 times Net Cone for the PJM Region for such Delivery Year or (ii) \$20/MW-day) times the number of days in such Delivery Year.

After the posting of the Base Residual Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for price responsive demand committed in the Base Residual Auction or to the FRR Alternative, shall be the (greater of (i) \$20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price for an Annual Resource ([prior to 2018/2019 Delivery Year](#)) or for a Capacity Performance Resource ([effective with 2018/2019 Delivery Year](#))) in such auction for the LDA within the PRD load is located-) times the number of days in the Delivery Year times a final price uncertainty factor of 1.05.

For any additional PRD that seeks to commit in a Third Incremental Auction or seeks to commit PRD to reduce the final unforced capacity obligation of an FRR Entity, the Price Responsive Demand Credit Rate shall be the same rate that is used after posting of the Base Residual Auction results.

After the posting of the Third Incremental Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for all Price Responsive Demand, shall be (the greater of (i) \$20/MW-day or (ii) 0.2 times the Final Zonal Capacity Price for the zone in which the price responsive demand is located) times the number of days in such Delivery Year, but no greater than the post BRA Price Responsive Demand Credit Rate.

4.8.6 Credit Milestones for Planned Generation Capacity Resources

[For Planned Generation Capacity Resources, Planned External Generation Capacity Resources and Planned Financed Generation Capacity Resources^{7,11}, the RPM Credit](#)

¹¹ [Planned Financed Generation Capacity Resource” shall mean a Planned Generation Capacity Resource that has executed an Interconnection Service Agreement and has completed the Financial Close milestone prior to the 2015 Base Residual Auction \(“2015 BRA”\). “Planned External Financed Generation Capacity Resource” shall mean a Planned External Generation Capacity Resource that](#)



Requirement shall be reduced by applying the appropriate **Incremental Credit Reduction** from the table below as the resource attains the stated milestones. **The incremental credit reductions are summed cumulatively to get the total credit reduction from the achieved milestones.** To obtain a reduction in RPM Credit Requirement (except for “ISA effective date” and “Commencement of Interconnection Service”), the Capacity Market Seller must submit a sworn, notarized certification of an independent engineer in a form acceptable to PJM, certifying that the engineer has personal knowledge, or has engaged in a diligent inquiry to determine, that the milestone has been achieved **and that, based on its review of the relevant project information, the independent engineer is not aware of any information that could reasonably cause it to believe that the Capacity Resource will not be in-service by the beginning of the applicable Delivery Year.** **The standard certification form can be found on the PJM website. The Capacity Market Seller, must, if requested by PJM, supply to PJM on a confidential basis all records and documents related to the independent engineer’s certification. PJM may accept a certification by a Professional Engineer in lieu of a certification by an independent engineer. For Balance sheet financed resources a notarized officer certification of financial close can be used instead of an independent engineer certification of financial close.**

The cumulative reduction in credit requirements for planned external resources and planned financed external resources, including the initial 50% reduction for financed resources, shall never be greater than the quotient of the division of firm transmission MW by offered (or cleared) MW.

Credit Reductions (%) for Planned Financed Generation Capacity Resources and Planned financed External Generation Capacity Resources	
Credit Milestones Certified by an Independent Engineer (where applicable)	Incremental Credit Reduction from Initial Credit Requirements
Full Notice to Proceed	50%
Commencement of construction (e.g. footers, or foundation poured)	15%
Main power generating equipment delivered	10%
Commencement of Interconnection Service	25%

The initial credit requirement for Planned Financed Generation Capacity Resources and Planned External Financed Generation Capacity Resources incorporates an initial 50% reduction, with reductions shown in the table being applied to that reduced initial amount. At the time of commencement of interconnection service, once all milestones are met the credit requirement will be zero.

has executed the equivalent of an Interconnection Service Agreement and has completed the Financial Close milestone prior to the 2015 BRA.



Credit Reductions (%) for Planned Generation Capacity Resources and Planned External Generation Capacity Resources	
Credit Milestones Certified by an Independent Engineer (where applicable)	Incremental Credit Reduction from Initial Credit Requirements
Effective date of ISA for Planned Generation Capacity Resources or agreement equivalent to ISA for Planned External Generation Capacity Resources	50%
Financial Close	15%
Full Notice to Proceed and Commencement of construction (e.g., footers or foundation poured)	5%
Main power generating equipment delivered	5%
Commencement of Interconnection Service	25%

- “Effective Date of ISA” shall be as defined in the relevant ISA.
- “Full Notice to Proceed” means that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.
- “Commencement of construction” means the beginning of major construction of the customer facility or customer interconnection facility.
- “Main power generating equipment delivered” means the main power generating equipment has been delivered to the site.
- “Financial Close” shall mean the resource demonstrated, as supported by a sworn, notarized certification of an independent engineer, certifying that the engineer has personal knowledge, or has engaged in a diligent inquiry to determine, that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third party entity. For resources that do not have external financing, PJM may accept instead a sworn, notarized certification by an officer of the company that the project has full funding available, specifying that the project has been duly authorized to proceed with full construction by the appropriate governing body of the company.
- All milestones refer to activities materially related to the delivery of electricity or electric services related to the resource’s commitment in the RPM auction.
- Example 1: A Planned Generation Capacity Resource that has committed 10 MW in a Base Residual Auction with an Auction Credit Rate of 36,500/MW-year would have an initial RPM credit requirement of \$365,000. After the effective date of an executed ISA, the RPM credit requirement would be \$182,500 (50% reduction). After Financial Close the credit requirement would be reduced to \$127,750 (65% reduced). Once the Full notice to proceed and Commencement of construction

milestone is met then the credit requirement would be \$109,500 (70% reduced). Once the Main Power Generating Equipment Delivered milestone is met, the RPM credit requirement would be \$91,250 (75% reduced). Upon Commencement of Interconnection Service, the credit requirement would be zero.

- Example 2: A Planned External Financed Generation Capacity Resource with no firm transmission secured that has committed 20 MW in a Base Residual Auction with an Auction Credit Rate of \$36,500/MW-year would have an initial RPM credit requirement of \$730,000 (the full Auction Credit Rate since no firm transmission has been secured). Upon securing 10 MW (50%) of firm transmission, the RPM credit requirement would drop to \$365,000. After Full Notice to Proceed, the RPM credit requirement would drop to \$182,500, provided 15MW of firm transmission had been secured. After Commencement of Construction and Main Power Generating Equipment Delivered, the RPM credit requirement would be \$91,250 (12.5% of \$730,000), provided 17.5 MW of firm transmission had been secured.

4.9 Aggregate Resources (Effective with 2018/2019 Delivery Year)

Effective with the 2018/2019 Delivery Year, capacity resources which may not, alone, meet the operational requirements of a Capacity Performance product, may combine their capabilities and offer as a single, pseudo aggregate resource. Capacity Market Sellers that own one or more Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources, or environmentally limited resources that are located in the same modeled LDA may create and offer an Aggregate Resource for a PJM approved unforced capacity value that satisfies the requirements of a Capacity Performance product.

The following business rules apply to Aggregate Resources:

- Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources, and environmentally limited resources that are combined to form an Aggregate Resource must be located in the same LDA and must reside in a single Capacity Market Seller account in eRPM.
- Market Sellers that intend to create an Aggregate Resource must submit a written email request to rpm_hotline@pjm.com at least two weeks prior to the opening of the RPM Auction in order to allow adequate time for PJM to review such request and model an Aggregate Resource in the eRPM system.
- Aggregate Resource requests must specify the capacity resources that are being combined to form the Aggregate Resource, the installed capacity owned on each generation capacity resource, the Nominated DR Value for a Demand Resource, or Nominated EE Value for an EE Resource, and the requested unforced capacity value of the Aggregate Resource.
- Aggregate Resource requests must also include a written explanation, including supporting data, to justify that the Aggregate Resource allows one or more of the resources that are being combined to realize a higher level of capacity performance



quantity (in unforced MWs) than the individual resources could provide if offered separately into the RPM Auction.

- The unforced capacity value of the Aggregate Resource may not exceed the sum of the unforced capacity values of the individual resources that are being combined to form the Aggregate Resources.
- PJM will review the Aggregate Resource request and approve the requested unforced capacity value of the Aggregate Resource provided the unforced capacity value is based on satisfying the requirements of a Capacity Performance product.
- The Market Seller may not offer any of the capacity resources that make up the Aggregate Resource separately into the RPM Auction or use the capacity resources that make up the approved Aggregate Resource request in any bilateral capacity transaction while the Aggregate Resource is in effect.
- An Aggregate Resource may be specified as a resource in a Locational UCAP transaction or Auction Specific MW transaction.
- An Aggregate Resource may not be specified as a resource in a unit-specific capacity transaction.
- An Aggregate Resource that includes Existing Generation Capacity Resource(s) is subject to the Must Offer requirement.
- An Aggregate Resource that includes an Intermittent Existing Generation Capacity Resource and/or a Capacity Storage Resource is subject to mitigation and applicable market seller offer cap.
- An Aggregate Resource that includes a planned capacity resource must establish an RPM Credit Requirement prior to the RPM Auction.
- For the 2018/2019 and 2019/2020 Delivery Years, an Aggregate Resource may submit only Capacity Performance sell offer segments ~~only~~ in their resource sell offer, only Base offer segments ~~only~~ in their resource sell offer, or submit separate, but coupled Base and Capacity Performance offer segments in their resource sell offer.
- The total committed quantity of an Aggregate Resource must be allocated by product type (Base, Base DR/EE, and Capacity Performance) to its underlying capacity resources prior to the start of the Delivery Year. Allocations for a delivery day may be adjusted up to 12 noon EPT of the day preceding the delivery day. ~~The daily commitment allocation to an underlying capacity resource will be used in the calculation of Expected Performance for such underlying capacity resource in a Performance Assessment Hour for such day. The sum of the Performance Shortfall/Bonus Performance calculated for the underlying capacity resources that were required to perform during the Performance Assessment Hour establishes the Performance Shortfall/Bonus Performance of the Aggregate Resource for such~~



Performance Assessment Hour. Non-Performance Assessment Charges/Credits will be assessed to the Aggregate Resource.



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 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.
- [A Transitional Incremental Auction will be conducted for the 2016/2017 and 2017/2018 Delivery Years to procure Capacity Performance Generation Resources.](#)



- 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.

5.2 RPM Auction Timeline

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

RPM Activity	Deadline
Post Planning Parameters for BRA	February 1st prior to the Base Residual Auction
Post preliminary estimate of the MOPR Floor Offer Price for the relevant Delivery year	150 days prior to commencement of offer period
Data Submittal (Avoidable Cost Data, Opportunity Cost, & Projected Market Revenues) to IMM if submitting non-zero sell offer price	120 days prior to commencement of offer period
IMM to notify Capacity Market Sellers of Market Seller Offer Caps	90 days prior to commencement of offer period
Participant notification to PJM and IMM whether it has reached agreement with the IMM on the level of Market Seller Offer Cap	80 days prior to commencement of offer period
PJM to notify Capacity Market Seller of its determination on Market Seller Offer Cap	65 days prior to commencement of offer period
Submittal of Minimum Offer Price Rule (MOPR) exemption request (Competitive Entry, Self-Supply or Unit-Specific)	135 days prior to commencement of offer period
IMM to notify Capacity Market Seller of determination on MOPR exemption request	45 days after receipt of exemption request
PJM to notify Capacity Market Seller of determination on MOPR exemption request	65 days after receipt of exemption request
Submittal of minimum level of Sell Offer commitment consistent with Unit-Specific MOPR request	5 days after receipt of PJM determination on Unit-Specific MOPR request
Submittal of preliminary must-offer exemption request for BRA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	Sept 1 st immediately preceding BRA for applicable Delivery Year (Nov 1, 2013 for 2017/18 Delivery Year)
Submittal of final must-offer exemption request for BRA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	Dec 1st immediately preceding BRA for applicable Delivery Year
Submittal of preliminary must-offer exemption	240 days prior to commencement of



RPM Activity	Deadline
request for IA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	offer period
Submittal of final must-offer exemption request for IA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	120 days prior to commencement of offer period
Submittal of must-offer exemption request for any reason other than the reason specified under OATT Attachment M-Appendix § II.C.4.A	120 days prior to commencement of offer period
<u>PJM posts summary of MW of Generation for which it has received requests for exceptions to the must-offer requirement for the reason specified under OATT Attachment M-Appendix § II.C.4.A, on an aggregate basis by Zone and LDA that comprises a subset of a Zone. Posting shall specify the following aggregate ranges: less than 100 MW; 100 to 500 MW; 500 to 1000 MW; and specific MW total if over 1000 MW</u>	Within 5 business days of receipt of request or notification
IMM to notify Capacity Market Seller of determination on must-offer exemption request	90 days prior to commencement of offer period
Participant notification to PJM and the MM if it disagrees with the IMM determination of its request to remove a resource from Capacity Resource status	80 days prior to commencement of offer period
PJM notification to participant of its determination on must offer exemption request	65 days prior to commencement of offer period
Participant notification to PJM and the IMM whether it intends to exclude from its Sell Offer some or all capacity from its generation resource on the basis of an identified exception to the RPM Must Offer Obligation	65 days prior to commencement of offer period
Submittal of request for alternative maximum EFORD	120 days prior to commencement of offer period
IMM provides determination on request for alternative maximum EFORD	90 days prior to commencement of offer period
Participant notification to PJM and the IMM whether agreement has been reached on alternative maximum EFORD.	80 days prior to commencement of offer period
PJM notification to participant of its determination on alternative maximum EFORD (if no agreement reached with IMM)	65 days prior to commencement of offer period



RPM Activity	Deadline
Participant submits to PJM its Initial/Updated Energy Efficiency Resource Measurement & Verification Plan	30 days prior to commencement of the offer period
Participant submits to PJM its Energy Efficiency Resource Measurement & Verification Report	15 days prior to start of Delivery Year for which the resource is committed
Participant submits to PJM its Demand Response Resource Plan	15 business days prior to commencement of offer period
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
Final EFORD fixed for Delivery Year	By November 30 th 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
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
- Short Term Resource Procurement Target [\(prior to 2018/2019 Delivery Year\)](#)
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORD
- Forecast Pool Requirement (FPR)
- Demand Resource (DR) Factor [\(prior to 2018/2019 Delivery Year\)](#)

- 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, 2015/2016 and 2016/2017 Delivery Years)
- Limited Resource Constraints and Sub-Annual Resource Constraints for the PJM Region and each modeled LDA (for the 2017/2018 Delivery Year ~~only~~ and beyond)
- Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint for the PJM Region and each modeled LDA (for the 2018/2019 and 2019/2020 Delivery Years)
 - All applicable Capacity Import Limits
 - 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
 - Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
 - Auction Credit Rate
 - 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. 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, Energy Efficiency Resource, or Aggregate Resource

- Effective with the For the 2014/2015 through the 2017/2018 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 Resource must be at least \$.01/MW-day greater than the offer price of the coupled Limited Demand Resource offer.
- For the 2018/2019 and 2019/2020 Delivery Year, a generation, demand resource, or energy efficiency resource with the potential to qualify as Base or Capacity Performance product type may submit separate, but coupled Base and Capacity Performance sell offer segments and the auction clearing algorithm will select the sell offer segment that yields the least-cost solution. The submission of a coupled sell offer segments shall be mandatory for any Capacity Performance Resource submitting a cost-justified sell offer price greater than the product of the historical balancing ratio times the Net Cost of New Entry in the actual zonal LDA where the resource resides. For such coupled sell offer segments, the sell offer price of a Capacity Performance sell offer segment must be at least \$.01 per MW-day greater than the sell offer price of a coupled Base sell offer segment.
- With the exception of Intermittent Resources and Capacity Storage Resources, each Generation Capacity Resource with available capacity that is capable or can reasonably become capable of qualifying as a Capacity Performance Resource must submit a Capacity Performance sell offer segment.
- Intermittent Resources are generation capacity resources with output that can vary as a function of its energy source, such as wind, solar, landfill gas, run of river hydroelectric power and other renewable resources. An acceptable method for determining the quantity of unforced capacity MWs that may offer as Capacity Performance for an intermittent resource is based on calculating the average of the hourly output (MWh) of the intermittent resource during the expected performance hours in the summer and winter. The expected performance hours in the summer are hours ending 15:00 through 20:00 EPT in the months of June, July, and August. The expected performance hours in the winter are hours ending 6:00 through 9:00 EPT and 18:00 through 21:00 EPT in the months of January and February. Notwithstanding the above, PJM may review and accept alternative proposed methods for determining the quantity of unforced capacity MWs that may be offered as Capacity Performance for an Intermittent resource.
- Capacity Storage Resources shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time. An acceptable method for determining the quantity of unforced capacity MWs that may offer as Capacity Performance for a Capacity Storage Resource is based on calculating the average of the hourly

output (MWh) of the intermittent resource during the expected performance hours in the summer and winter. The expected performance hours in the summer are hours ending 15:00 through 20:00 EPT in the months of June, July, and August. The expected performance hours in the winter are hours ending 6:00 through 9:00 EPT and 18:00 through 21:00 EPT in the months of January and February.

- Exceptions to the capacity performance must-offer requirement will be permitted for a generation capacity resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements for a Capacity Performance Generation Resource. The Seller must submit a request for an exception (with all supporting information) no later than 120 days before the offer window opens for the relevant RPM Auction.
- A generation resource that can qualify as Capacity Performance product type, but requires substantial investment to do so, is not excused from the capacity performance must-offer requirement, but may submit coupled Base and Capacity Performance offer segments.
- Intermittent Resources, Capacity Storage Resources, Demand Resources, Energy Efficiency Resources are not required to submit a Capacity Performance sell offer segment.
- Base Offer Segment mMinimum and maximum amount of installed capacity offered in MWs for the resource by Offer Segment (Base or Capacity Performance offer segment effective with 2018/2019 Delivery Year)
- 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
- New Unit Pricing participation flag for generation resources
- The ICAP MW quantity specified in the Base-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 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 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.
- 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.
- A generation resource's default sell offer cap for any capacity performance offer segment shall be the product of the historical balancing ratio times the Net CONE of the zonal LDA in which the resource resides. Market Sellers may qualify to submit a sell offer price above the default offer cap for a capacity performance offer segment by submitting Avoidable Cost Rate data to IMM and PJM 120 days prior to the RPM Auction.
- 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:

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.

- 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 (Delivery Year 1 BRA) is submitted.
- (2) The capacity cleared from the new entry (including any make-whole MW) in the Delivery Year 1 BRA would move the total LDA resources committed in the BRA from below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a MW quantity at or above the MW quantity at the price-quantity point on the VRR Curve where the price is 40% of the Net CONE divided by the quantity one minus pool-wide average EFORD.
- (3) The seller submits offers into the two immediately following BRAs (Delivery Year 2 BRA and Delivery Year 3 BRA) to sell the entire capacity of the unit committed in the Delivery Year 1 BRA at a price equal to the lesser of (a) the price offered in the Delivery Year 1 BRA where the resource was classified as planned generation; or (b) 90% of the Net CONE applicable in the Delivery Year 1 BRA in UCAP basis.
- (4) Failure to submit a sell offer consistent with condition (3) above in the Delivery Year 3 BRA shall not retroactively revoke the New Entry Price Adjustment for

Delivery Year 2. However, the failure to submit a sell offer consistent with condition (3) in the Delivery Year 2 BRA shall make the resource ineligible for New Entry Price Adjustment for Delivery Years 2 and 3.

New entry revenues:

- (1) If the new entry meets conditions (1) and (2) above and is the marginal offer in Delivery Year 1 BRA, it sets the resource clearing price for the LDA in Delivery Year 1 BRA and receives revenues based on this price in the Delivery Year 1 BRA.
- (2) If the new entry clears its capacity in either of the two subsequent BRAs (Delivery Year 2 BRA or Delivery Year 3 BRA), it will receive revenues based on the LDA clearing price in such subsequent year BRA.
- (3) If the new entry does not clear in either of the two subsequent year BRAs (Delivery Year 2 BRA or Delivery Year 3 BRA), it will be resubmitted at the highest offer price at which the unforced MW amount cleared in the Delivery Year 1 BRA will clear in the subsequent year BRA (Delivery Year 2 BRA or Delivery Year 3 BRA). The resource clearing price and the resources cleared for such subsequent year BRA will be determined from the clearing with the resubmitted sell offer. The new entry shall clear in such subsequent year BRA and be committed in the amount cleared plus any additional make-whole MW from its Sell Offer for such subsequent year BRA, but such make-whole MWs shall not be greater than the make-whole MWs committed in the Delivery Year 1 BRA. The new entry will receive revenues for the entire committed quantity in such subsequent year BRA based on the sell offer price initially submitted for such subsequent year BRA. The difference between the initially submitted sell offer price and the clearing price in such subsequent year BRA and any difference between cleared quantity and committed quantity in such subsequent year BRA will be paid as Resource Make-Whole payments to the new entry. The other capacity resources that clear such subsequent year BRA will receive the clearing price for such subsequent year BRA.

A Capacity Market Seller may make its Sell Offer in the initial BRA (Delivery Year 1 BRA) contingent upon qualifying for New Entry Price Adjustment. Prior to the close of the BRA offer window, a Capacity Market Seller must notify PJM of a NEPA contingent Sell Offer election via an email to rpm_hotline@pjm.com. PJM shall not clear a NEPA contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

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

Submission of the Avoidable Cost Rate (ACR) Data



- 120 days prior to the commencement of the offer period for the auction, participants 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.

Calculation of Sell Offer Caps

- 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 the applicable default rate.
- 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.
- 90 days prior to the commencement of the offer period, the IMM 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 an 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) is intended to prevent the exercise of buyer-side market power. MOPR ensures all new resources are offered into RPM Auctions on a competitive basis. MOPR imposes a minimum offer screening process to determine whether an offer from a new resource is competitive and prevents market participants from submitting uncompetitive, low new entry offers in RPM Auctions to artificially depress auction clearing prices.

Applicability

The Minimum Offer Price Rule (MOPR) of Section 5.14(h) of Attachment DD of the PJM OATT applies to a MOPR Screened Generation Resource.

A MOPR Generation Screened Resources is any of the following:

- Generation Capacity Resource 20 MW or greater, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant
- Uprates to a Generation Capacity Resource of 20 MW or greater, based on a combustion turbine, combined cycle or integrated gasification combined cycle generating plant
- Repowering of an existing plant 20 MW or greater whenever the repowered plant utilizes combustion turbine, combined cycle or integrated gasification combined cycle technology
- External resource that entered commercial service on or after January 1, 2013, that meet the aforementioned criteria and that require sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region

The MW value of 20 MW or greater takes into account the installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System.

MOPR does not apply to the following:

- Any Generation Capacity Resource that is not a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant, such as nuclear, coal, wind, hydro, solar or landfill gas facilities



- ICAP equivalent (measured at time of clearing), of any of a resource's UCAP cleared in any auction prior to February 1, 2013
- Uprates receiving an exception under the unit-specific process for an auction prior to the commencement of the 2016/17 Delivery Year, and clearing in that BRA
- Cogeneration certified or self-certified as a Qualifying Facility, where the Capacity Market Seller is the owner or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load.

MOPR Offer Floor Price

Unless a MOPR exception or exemption is requested and approved according to the process and timelines described below and provided in Section 5.14(h) of Attachment DD of the PJM OATT, the MOPR Floor Offer Price for any auction shall be set equal to 100% of the applicable Net Asset Class CONE. To the extent either a Competitive Entry Exemption or a Self-Supply Exemption is obtained prior to an auction, a sell offer price below the MOPR Floor Offer Price, including an offer price of zero, may be specified. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit Specific Exception, such offer may include an offer price below the MOPR Floor Offer Price but no lower than the Unit Specific minimum offer price determined through the exception process.

Duration

Unless a full or partial exception or exemption is obtained, a MOPR Screened Generation Resource shall be subject to the MOPR Floor Offer Price for all auctions until (and including) the first Delivery Year for which a Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

Exceptions and Exemptions

To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). The qualification criteria for a Self-Supply Exemption are listed in Section 5.14(h)(6) of Attachment DD of the PJM OATT. The qualification criteria for a Competitive Entry Exemption are listed in Section 5.14(h)(7) of Attachment DD of the PJM OATT.

To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than



the minimum offer price determined in such exception process. The qualification criteria for a Unit Specific Exemption are listed in Section 5.14(h)(8) of Attachment DD of the PJM OATT.

Once an exception or exemption is obtained by a MOPR Screened Generation Resource, and that resource has cleared the RPM Auction for which the exception or exemption was obtained, such resource shall not be subject to the MORP Floor Offer Price in any subsequent RPM Auctions for that Delivery Year or any subsequent Delivery Year, except as provided in Section 5.14(h)(10) of Attachment DD (relating to suspected fraud/material misrepresentations or omissions)

Exemption and Exception Process

MOPR Exemption/Exception Action	Deadline
PJM posts preliminary estimate of MOPR Floor Offer Price	No later than 150 days prior to commencement of offer period for an RPM Auction
Capacity Market Seller submit its request for an exemption or exception simultaneously to both the IMM and PJM	No later than 135 days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer.
IMM reviews the request and provide determination	No later than 45 days after receipt of exemption or exception request
PJM reviews the request and provide determination	No later than 65 days after receipt of the exemption or exception request If PJM does not provide its determination within 65 days after receipt of the request, it shall be deemed granted.
If PJM grants a Unit-Specific Exception, the Capacity Market Seller shall notify the IMM and PJM of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit	No later than 5 days after receipt of the PJM's determination

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 through 2017/2018 Delivery Years~~), Base Generation Resource, Base DR/EE Resource, or Capacity Performance Resource (2018/2019 and 2019/2020 Delivery Years) and beyond; All Buy Bids will be for Capacity Performance Resources effective with the 2020/2021 Delivery Year.
- 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 (of the Annual Resource or Capacity Performance Resource type) 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.

$$AvailICAP_{Position} \text{ for a unit} = MinimumDailyValue_{forDY} (DailyICAP_{Owned} - DailyFRR_{CapPlanCommitments})$$

- 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.

$$AvailICAP_{Position} \text{ DR} = MinDailyValue_{forDY} (DailyNomDR_{Value} - DailyFRR_{CapPlanCommitments})$$

- 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.
$$DailyUnofferedICAP_{GenorDR} = AvailICAP_{Position} - OfferedICAP$$
- 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, the Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements (2014/2105 – 2016/2017 Delivery Years), ~~and~~ Limited Resource Constraints and Sub-Annual Resource Constraints (~~effective with the~~ 2017/2018 Delivery Year ~~only~~), and Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint (2017/2018 & 2018/2019 Delivery Year).

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
- for the 2014/2015, 2015/2016 and 2016/2017 Delivery Years, Annual Resource Price Adder, if any, and Extended Summer Price Adder, if any, and
- ~~starting with for~~ the 2017/2018 Delivery Year, Limited Resource Price Decrement, if any, and Sub-Annual Resource Price Decrement, if any, and
- for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Demand Resource Price Decrement, if any, and Base Capacity Resource Price Decrement, if any, and
- Locational Price Adder(s), if any, relevant to such LDA.

Prior to the 2017/2018 Delivery Year, the marginal value of system capacity is the clearing price for Limited DR in the unconstrained area of the PJM region. ~~Effective with For~~ the 2017/2018 Delivery Year, the marginal value of system capacity is the clearing price for Annual Resources in the unconstrained area of the PJM region. Effective with the 2018/2019 Delivery Year, the marginal value of system capacity is the clearing price for Capacity Performance Resources in the unconstrained area of the PJM region.

For the 2014/2015 through 2016/2017 Delivery Years, ~~the~~ Annual Resource Price Adder is applicable for Annual Resources only and applies when the Minimum Annual Resource Requirement is binding. The Extended Summer Price Adder is applicable for Annual Resources and Extended Summer DR and applies when the Minimum Extended Summer Resource Requirement is binding.

For the 2017/2018 Delivery Year, ~~the~~ Sub-Annual Resource Price Decrement is applicable for Limited and Extended Summer DR and applies when the Sub-Annual Resource Constraint is binding, ~~and~~ ~~the~~ Limited Resource Price Decrement is applicable for Limited DR only and applies when the Limited Resource Constraint is binding.

For the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Price Decrement is applicable for Base Demand Resources and Base Energy Efficiency Resources and applies when the Base Capacity Demand Resource Constraint is binding. The Base Capacity Resource Price Decrement is applicable for Base Demand Resources, Base Energy Efficiency Resources, and Base Generation Resources and applies when the Base Capacity Resource Constraint is binding.

Effective with the 2017/2018 Delivery Year, the Resource Clearing Price within an external source zone is the sum of the marginal value of system capacity and any locational price decrement(s), if any, relevant to the external source zone. A locational price decrement is applicable when a region-wide Capacity Import Limit or Capacity Import Limit for an external source zone is binding.

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.

$$\text{ResourceMakewholePayment} = \text{ResourceClearingPrice} \times (\text{SellOfferMinMW} - \text{ClearedMW}_{\text{BRA}})$$

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 **monthlyweekly** during the Delivery Year as the unforced capacity is actually utilized.

5.7 Incremental Auctions

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. **Deferred short-term resource procurement only applies prior to the 2018/2019 Delivery Year.**

- 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.
- For the 2016/2017 and 2017/2018 Delivery Year, a Capacity Performance Transitional Incremental Auction will be conducted to procure Capacity Performance Generation Resources.

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.

$$\text{CurrentAvailableICAPPosition}_{\text{unit}} = \text{Min}(\text{DailyAvailableICAP})$$

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.

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

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.

$$\text{MinimumAvailableICAPPosition}_{\text{unit}} = \text{Min}(\text{DailyMinAvailableICAP})$$

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.

$$\text{DailyMinAvailableICAP} = \text{DailyICAPOwned} - \text{DailyUnofferedICAP} -$$

$$\left[\frac{\text{DailyClearedUCAP}}{(1 - \text{Max}(\text{BRA EFORD}_{1 \text{ yr}}, \text{BRA EFORD}_{5 \text{ yr}}, \text{BRA SellOfferEFORD}))} \right] - \text{DailyFRRCapacityPlanCommitments}$$

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.

$$\text{MaximumAvailableICAPPosition}_{\text{unit}} = \text{Min}(\text{DailyMaxAvailableICAP})$$

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.

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

$$- \text{DailyFRRCapacityPlanCommitments}$$



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.

$$DailyUnofferedICAP_{GenResource} = \sum (DailyUnofferedICAP_{from\ Prior\ RPM\ Auctions} + UnofferedICAP_{Bilateral\ Sales/Purchases})$$

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.

$$AvailableICAPPosition_{Demand\ Resource} = Min(DailyAvailableICAP)$$

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. Effective with the 2018/2019 Delivery Year, the DR Factor is no longer considered in the calculation of Daily Available ICAP.

$$DailyAvailableICAP_{DR} = DailyNominated\ DRValue - DailyUnoffered\ ICAP - \left(\frac{Daily\ RPM\ Resource\ Commitments}{DRFactor \times FPR} \right) - DailyFRRCapPlanCommitments$$

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

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

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 until 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
- Limited Resource Price Decrement, if any, and
- Sub-Annual Resource Price Decrement, if any, and
- Base Capacity Demand Resource Price Decrement, if any, and
- Base Capacity Resource Price Decrement, if any, and
- The Locational Price Adder(s), if any relevant for such LDA.



Prior to the 2017/2018 Delivery Year, the marginal value of system capacity is the clearing price for Limited DR in the unconstrained area of the PJM Region. ~~Effective with~~For the 2017/2018 Delivery Year, the marginal value of system capacity is the clearing price for Annual Resources in the unconstrained area of the PJM Region. Effective with the 2018/2019 Delivery Year, the marginal value of system capacity is the clearing price for Capacity Performance Resources in the unconstrained area of the PJM region.

~~Effective with the 2014/2015 through 2016/2017 Delivery Years,~~ the Annual Resource Price Adder is applicable for Annual Resources only and applies when the Minimum Annual Resource Requirement is binding. The Extended Summer Price Adder is applicable for Annual Resources and Extended Summer DR and applies when the Minimum Extended Summer Resource Requirement is binding.

~~Effective for the 2017/2018 Delivery Year,~~ the Sub-Annual Resource Price Decrement is applicable for Limited and Extended Summer DR and applies with the Sub-Annual Resource Constraint is binding. ~~and~~ The Limited Resource Price Decrement is applicable for Limited DR only and applies when the Limited Resource Constraint is binding.

Effective for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Price Decrement is applicable for Base Demand Resources and Base Energy Efficiency Resources and applies when the Base Capacity Demand Resource Constraint is binding. The Base Capacity Resource Price Decrement is applicable for Base Demand Resources, Base Energy Efficiency Resources, and Base Generation Resources and applies when the Base Capacity Resource Constraint is binding.

Effective with the 2017/2018 Delivery Year, the Resource Clearing Price within an external source zone is the sum of the marginal value of system capacity and any locational price decrement(s), if any, relevant to the external source zone. A locational price decrement is applicable when a region-wide Capacity Import Limit or Capacity Import Limit for an external source zone is binding.

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 and Minimum Extended Summer Resource Requirements (2014/2015-2016/2017 Delivery Years), Limited Resource Constraints and Sub-Annual Resource Constraints (~~effective~~ 2017/2018 Delivery Year), Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint (2018/2019 and 2019/2020 Delivery Years), 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.

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 (for the 2014/2015, 2015/2016 and 2016/2017 Delivery Years);
- ~~(4)~~ An adjustment, if any, to account for price decrements for Limited DR and Extended Summer DR in the LDA for which the zone is located (~~effective~~ for the 2017/2018 Delivery Year);
- ~~(4)~~~~(5)~~ An adjustment, if any, to account for price decrements for Base DR/EE and Base Generation in the LDA for which the zone is located (for 2018/2019 and 2019/2020 Delivery Years);
- ~~(5)~~~~(6)~~ An adjustment, if any, to account for price decrements for external capacity resources (effective for the 2017/2018 Delivery Year);
- ~~(6)~~~~(7)~~ 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 for an LDA 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.
- 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 conducted to date 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 conducted to date 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 in the LDA for which the zone is located for all auctions conducted to date for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity) (for 2014/2015 – 2016/2017 Delivery Year); and
 - ~~(4)~~ An adjustment, if any, to account for price decrements for Limited DR and Extended Summer DR in the LDA for which the zone is located for all auctions conducted to date for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity) (effective for 2017/2018 Delivery Year);
 - ~~(5)~~ An adjustment, if any, to account for price decrements for Base DR/EE and Base Generation in the LDA for which the zone is located for all auctions conducted to date for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity) (2018/2019 and 2020/2021 Delivery Year);
 - ~~(3)~~~~(6)~~ An adjustment, if any, to account for price decrements for external capacity resources (effective with the 2017/2018 Delivery Year); and
 - ~~(4)~~ An adjustment, if required, to account for any resource make-whole payments for all auctions conducted to date 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 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 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 credit for CTR holders, Incremental CTR Holders, resources cleared for LSEs in all RPM Auctions for a

given Delivery Year, Qualifying Transmission Upgrades cleared in the Base Residual Auction, and by LSEs serving load that is committed as price responsive demand for the Delivery Year 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 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.

$$\text{BaseZonalCTRCreditRate}(\$/\text{MW} - \text{Day}) = \frac{\text{EconomicValueofCTR}S_{\text{AllocatedtoLSEsinBRA}}}{\text{ZonalUCAPObligation}}$$

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.

$$\text{FinalZonalCTRCreditRate}(\$/\text{MW} - \text{day}) = \frac{\text{EconomicValueofCTR}S_{\text{AllocatedtoLSEsin all RPM Auctions}}}{\text{FinalZonalUCAPObligation}}$$

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

5.8.4 CTR Settlement Rates

The CTR Settlement Rate (\$/MW-day) is equal to the total Economic Value of CTRs (\$/day) allocated to LSEs in a zone for all LDAs in which the zone resides as a result of all RPM Auctions for a Delivery Year divided by the maximum of the LDA CTR MWs allocated to LSEs in a zone.

$$\text{CTRSettlementRate}(\$/\text{MW} - \text{day}) = \frac{\text{EconomicValueofCTR}S_{\text{AllocatedtoLSEs as a result of all RPM Auctions}}}{\text{MaximumLDACTRMW}S_{\text{AllocatedtoLSEs}}}$$

The **CTR Settlement Rates** are posted by PJM with the Third 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**.



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 Short-Term Resource Procurement Target. 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.

Incremental Capacity Transfer Rights (ICTRs) associated with Regional Facilities and Necessary Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements will be allocated to Responsible Customers to whom the costs of the Regional Facilities and Necessary Lower Voltage Facilities are assigned. Effective with the 2013/2014 Delivery Year, ICTRs associated with Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements will also be allocated to Responsible Customers to whom the costs of the Lower Voltage Facilities are assigned. Incremental Rights-Eligible Required Transmission Enhancements are Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Scheduled 12 of the Tariff) and meet one of the following criteria: (1) cost responsibility assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

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.
- The total amount of Capacity Transfer Rights that are allocated to LSEs in an LDA are equal to the amount of unforced capacity imported into such LDA based on the results of the Base Residual Auction and all Incremental Auctions for such Delivery Year less [the Participant-Funded ICTRs and Incremental Rights-Eligible Required Transmission Enhancements 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 for each modeled LDA in which the RPM Auctions for the Delivery Year resulted in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA.
- The economic value (in \$/day) of Capacity Transfer Rights in an LDA as a result of all RPM Auctions for the Delivery Year is equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the MW quantity of CTRs allocated to LSEs in the LDA. The total economic value (in \$/day) of Capacity Transfer Rights to LSEs in a zone is the sum of the economic values of Capacity Rights in an LDA for all LDAs in which such zone resides.



6.1.2 Participant-Funded Project Incremental Capacity Transfer Rights

Incremental Capacity Transfer Rights (ICTRs) 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.

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.

For LDAs in which the RPM Auctions for such Delivery Year result in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of a Participant-Funded ICTR into such LDA shall receive a payment equal to (i) average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased import capability, multiplied by (ii) MW amount of ICTRs allocated to holder. No payment will be issued to the holder when a zero or negative average weighted Locational Price Adder with respect to the immediate higher level LDA is calculated as a result of the RPM Auctions for such Delivery Year.

Participant-Funded ICTRs may be traded similar to CTRs.

6.1.3 Incremental Capacity Transfer Rights Associated with Incremental Rights-Eligible Required Transmission Enhancements

Incremental Rights-Eligible Required Transmission Enhancements may include Regional Facilities and Necessary Lower Voltage Facilities, and Lower Voltage Facilities. Regional Facilities are Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement (Rate Schedule FERC No. 42) that are included in Regional Transmission Expansion Plan (RTEP) and operate at or above 500 kV. Necessary Lower Voltage Facilities are Transmission Facilities that operate below 500 kV and must be constructed or strengthened to support new Regional Facilities. Lower Voltage Facilities are Transmission Facilities that operate below 500 kV which are included in RTEP to address one or more reliability violations or to address operational adequacy and performance issues and are not Necessary Lower Voltage Facilities. Responsible Customers, as defined in Schedule 12 of the Tariff, that are Network Customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners, and



that are assigned cost responsibility for a Incremental Rights-Eligible Required Transmission Enhancement shall be allocated a share of the ICTRs associated with such facility in accordance with the percentage cost responsibility assigned to Responsible Customers for such facility as set forth in Schedule 12-Appendix to the Tariff.

ICTRs associated with Regional Facilities and Necessary Lower Voltage Facilities are determined and allocated to Responsible Customers. Effective with the 2013/2014 Delivery Year, ICTRs associated with Lower Voltage Facilities are also determined and allocated to Responsible Customers. The ICTRs (in MWs) associated with a given Incremental Rights-Eligible Required Transmission Enhancement are established by PJM prior to the conduct of the Base Residual Auction for the first Delivery Year for which such facility is to be in service. Once established, the ICTRs for such facility are available for allocation for 30 years or the life of the project, whichever is less.

PJM determines the increase in CETL into an applicable LDA as a result of a Incremental Rights-Eligible Transmission Enhancement planned for the Delivery Year. The increase in the CETL represents the ICTRs (in MWs) into the LDA provided by such planned facility. If such facility increases CETL into multiple LDAs, PJM will calculate 'simultaneous' increases in CETL into the LDAs and determine a separate ICTR MW amount for each LDA, equal to the respective increase in CETL into such LDA. .

The allocation (in MWs) of a Delivery Year's ICTRs for the Incremental Rights-Eligible Required Transmission Enhancement to a Responsible Customer may change during the Delivery Year if the percentage cost responsibility assigned to the Responsible Customers for such facility as set forth in Schedule 12-Appendix to the Tariff changes during the Delivery Year.

During the Delivery Year, each Network Customer (LSE) within a zone will be allocated a share of the zone's ICTRs associated with Incremental Rights-Eligible Required Transmission Enhancements for such Delivery Year 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 associated with Incremental Rights-Eligible Required Transmission Enhancements may be traded similar to CTRs.

The economic value of Incremental Rights-Eligible Required Transmission Enhancement ICTRs may change from year to year and will become zero when a zero or negative average weighted Locational Price Adder with respect to the immediate higher level LDA is calculated as a result of RPM Auctions for such Delivery Year.

The economic value (in \$/day) of Incremental Rights-Eligible Required Transmission Enhancement ICTRs in an LDA as a result of all RPM Auctions for the Delivery Year is equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the MW quantity of Regional Project ICTRs in an LDA allocated to Responsible Customers.

6.2 Determination of Capacity Transfer Rights

For LDAs in which a positive average weighted Location Price Adder with respect to the immediate higher level LDA is calculated as a result of all RPM Auctions for the Delivery Year, the total amount of Capacity Transfer Rights in such LDA are equal to the Final Unforced Capacity Imported into such LDA as a result of all RPM Auctions for the Delivery Year. The Total CTRs into a constrained LDA are reduced by (1) an equivalent QTU import capability cleared, (2) Participant-Funded Project ICTRs, and (3) Incremental Rights-Eligible Required Transmission Enhancement 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.

$$LSECapacityTransferRights_{SLDA} = FinalUnforcedCapacityImported_{LDA} - equivalentQTUCleared - ICTRs$$

Where:

The Final Unforced Capacity Imported into an LDA is equal to the Final Unforced Capacity Obligation for such LDA as a result of all RPM Auctions for such Delivery Year less the net participant buy bid/sell offers cleared in the LDA for all RPM Auctions for such Delivery Year.

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

An equivalent QTU import capability cleared into an LDA is determined as the QTU BRA Auction Credits (\$/day) received by the cleared QTU into an LDA divided by the weighted locational price adder of such LDA with respect to the immediate higher level LDA.

If the LDA into which the Incremental Capacity Transfer Rights are allocated or the import capability is increased by a Qualifying Transmission Upgrade is a part of a zone (e.g., DPL South or PS North), the calculations will be made based on the zone instead of the LDA using a Weighted Locational Price Adder for the zone with respect to the immediate higher level LDA 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 in an LDA 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 in an LDA 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.

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 in a zone will receive a daily zonal CTR Credit as described in the Settlements section of this Manual.

Participants that were allocated Incremental CTRs into an LDA will receive a daily Incremental CTR Credit equal to the total Incremental CTRs allocated times the Final Incremental CTR Credit Rate for such LDA.

The Final Incremental CTR Credit Rate for an LDA is equal to the LDA's weighted Locational Price Adder with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year.

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 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) , 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.

Load Obligations are based on the Unforced Capacity Obligation procured in Base Residual Auction and all the Incremental Auctions.

7.2 Unforced Capacity Obligations

7.2.1 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 all Incremental Auctions.

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

- Peak Load Forecasts
- Forecast Pool Requirement (FPR)



7.2.2 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 RTO Short-Term Resource Procurement Target.

$$\text{BaseRTOUnforcedCapacityObligation} = \text{UnforcedCapacityObligation}_{\text{inBRA}} + \text{Short-Term Resource Procurement Target}$$

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 Short Term Resource Procurement Targets. 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) + Zonal Short Term Resource Procurement Target. Effective with the 2018/2019 Delivery Year, the Zonal Short Term Resource Procurement Target is no longer considered in the determination of a Base Zonal Unforced Capacity Obligation.

$$\text{BaseZonalCapObligation} = (\text{ZonalNormalizedSummerPeak} - 4\text{yr} \times \text{BaseZonalRPMScalingFactor} \times \text{FPR}) + \text{ZonalShort-Term Resource Procurement Target}$$

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

7.2.3 Final Zonal Unforced Capacity Obligations

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.

$$\text{FinalRTOUnforcedCapObligation} = \text{SumofPJMBuyBidMWsCleared} - \text{SumofPJMSellOffersCleared}$$

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.

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

The **Final Zonal Unforced Capacity Obligations** are posted after the clearing of the final Incremental Auction for the Delivery Year.

7.3 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 two weeks after the final Incremental Auction.

These scaling factors account for (1) load growth from a prior-year summer to the Delivery Year; (2) any excess resources procured above those required to exactly meet the FPR requirements.

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.

7.3.1 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.



7.3.2 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 Year¹³) * ((RTO 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.

$$BaseZonalRPMScalingFactor = \left(\frac{PrelimZonalPeakLoadForecast}{NormalizedSummerPeak - 4yr} \right)^5 \times \left(\frac{RTOUnforcedCapacityObligation_{inBRA}}{RTO Preliminary Peak Load Forecasts \times FPR} \right)$$

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

7.3.3 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).

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

7.4 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/[area](#) 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.

7.5 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

¹³ 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.

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). Corrections to Obligation Peak Load data may be made up to 12:00 PM Eastern Prevailing Time of the next business day following 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.

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

- 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.

$$\text{DailyUnforcedCapObligation} = \text{ObligationPeakLoad} \times \text{FinalZonalRPMScalingFactor} \times \text{FPR}$$

7.6 Process for Determining Load Obligations

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

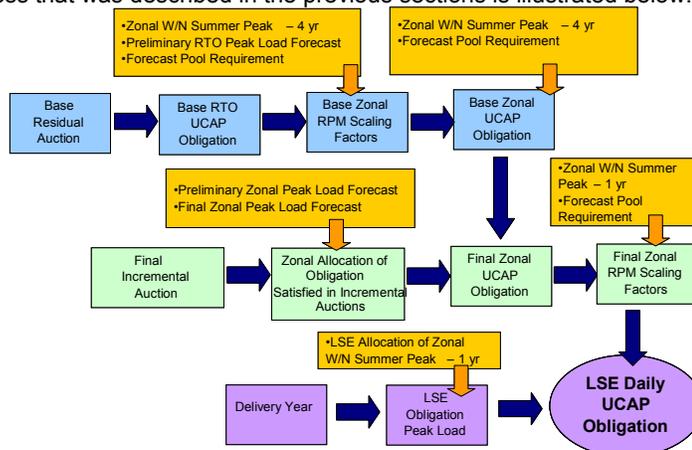


Exhibit 3: Process for determining Load Obligations



7.7 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 January prior to the Final 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 (Prior to 2018/2019 Delivery Year)
- Non-Performance Assessment (effective 2018/2019 Delivery Year for all resources and effective 2016/2017 and 2017/2018 Delivery Year for generation resources with Capacity Performance commitments from a Transitional Incremental Auction)
 - Summer/Winter Capability Testing
 - Peak Season Maintenance (PSM) Compliance (prior to 2018/2019 Delivery Year)
 - Load Management Event Compliance (Prior to 2018/2019 Delivery Year)
 - Load Management Test Compliance
 - EE 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	EE	QTU
RPM Commitment Compliance	X	X	X	X	X	X
X	X					
Summer/Winter Capability Testing	X	X (Annual)				
PSM Compliance (prior to 2018/2019 Delivery Year for RPM, prior to 2019/2020 for FRR)	X					
Load Management Event Compliance (prior to 2018/2019 Delivery Year for RPM, prior to 2019/2020 Delivery Year for FRR)				X		
Load Management Test Compliance				X		
M&V Audit					X	
Non-Performance Assessment (effective 2016/2017 Delivery Year for resources with CP commitments and 2018/2019-2019/2020)	X	X	X	X	X	X



Delivery Years for resources with Base commitments						
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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 to RPM Commitment Compliance. Instead of 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).

$$DailyRPMResourcePosition_{GenResource} = (DailyICAPOwned - Daily FRRCapPlanCommitments - Daily Unoffered ICAP) \times (1 - EffectiveEFORD)$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole 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.

$$\text{DailyRPMCommitmentShortage}_{\text{GenResource}} = \text{DailyRPMResourceCommitments} - \text{DailyRPMGenerationResourcePosition}$$

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 for the 2014/2015 DY through 2017/2018 Delivery Years, 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. Effective with the 2018/2019 and 2019/2020 Delivery Year, the sites registered and approved in the eLRS must be sufficient to support the Base Capacity Resource Commitments and the Capacity Performance Commitments on the committed demand resource. Effective with the 2020/2021 Delivery Year, the sites registered and approved in the eLRS system must be of the Capacity Performance product-type.
- 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. The DR Factor is eliminated effective with the 2018/2019 Delivery Year.

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. Effective with the 2018/2019 Delivery Year, the DR Factor is no longer considered in the calculation of a party's Daily RPM Demand Resource Position.

$$\text{DailyRPMPosition}_{\text{DR}} = (\text{DailyNominatedDRValue} - \text{DailyFRRCapacityPlanCommitments} - \text{DailyUnofferedICAP}) \times \text{DRFactor} \times \text{FPR}$$

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.

$$\text{DailyRPMCommitmentShortage}_{DR} = \text{DailyRPMResourceCommitments} - \text{DailyRPMDemandResourcePosition}$$

Existing demand resources that offered and cleared in Base Residual Auction, First Incremental Auction, or Second Incremental Auction 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.

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. 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 Third Incremental Auction.

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). Effective with the 2018/019 Delivery Year, the DR Factor is no longer considered in the calculation of a party's Daily RPM EE Resource Position.

$$\text{DailyRPMPosition}_{EE} = (\text{DailyNominatedEEValue} - \text{DailyFRRCapacityPlanCommitments} - \text{DailyUnofferedICAP}) \times \text{DRFactor} \times \text{FPR}$$

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.

$$\text{DailyRPMCommitmentShortage}_{EE} = \text{DailyRPMResourceCommitments} - \text{DailyRPMEEResourcePosition}$$

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.

$$\text{DailyRPMCommitmentShortage}_{QTU} = \text{DailyRPMResourceCommitments} - \text{DailyRPMQTUPosition}$$

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).

$$UnitAvgDailyICAPCommitment_{unit} = \frac{(\sum DailyRPMResourceCommitments_{unit} / (1 - EffectiveEFORD_{unit})) + \sum DailyFRRcapPlanCommitments_{unit}}{365\text{ days (or 366 days)}}$$

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).

$$UnitAverageDailyFRRICAPCommitmentAmount = \frac{DailyFRRCapacityPlanCommitments_{forDY}}{365\text{ days (or 366 days)}}$$

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).

$$Provider'sAverageDailyFRRICAPCommitmentAmount_{for\ Gen\ Resource} = \frac{Provider'sDailyFRRCapacityPlanCommitments_{forGenResourceforDY}}{365\text{ days (or 366 days)}}$$

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.

$$\text{Provider's Avg Daily RPM ICAP Commitment} = \left(\frac{\sum \text{Provider's Daily RPM Commitments}}{\sum \text{Total Daily RPM Resource Commitments}} \right) * \text{Unit Avg Daily ICAP Commitment}$$

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.

$$\text{Provider's Share of Total Unit ICAP Commitment Gen Resource} = \text{Provider's Average Daily FRR ICAP Commitment} + \text{Provider's Avg Daily RPM ICAP Commitment}$$

8.4 Generating Unit Peak-Hour Period Availability (Prior to 2018/2019 Delivery Year)

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.

$$EFORp = \frac{(ForcedOutageWhenNeeded + EquivalentForcedPartialOutageHoursWhenNeeded)}{(ServiceHours + ForcedOutageHoursWhenNeeded)}$$

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

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.

Calculation of Eligible Available Capacity (EAC) for Individual Units

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 hydro 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 over performance.

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) in accordance with 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

In accordance with M-21, 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 and pumped storage units must perform rating tests during the Summer test period. 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.

$$\text{Provider's Daily ICAP Shortfall}_{\text{GenResource}} = \frac{\text{Daily Unit ICAP Shortfall} \times \text{Provider's Share of Total Unit ICAP Commitment}}{\text{Total Unit ICAP Commitment}}$$

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.

$$\text{Provider's Daily ICAP Shortfall}_{\text{RPM Resource Commitments}} = \frac{\text{Provider's Daily Unit ICAP Shortfall} \times \text{Provider's Average Daily RPM ICAP Commitment}}{\text{Provider's Share of Total Unit ICAP Commitment}}$$

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.

$$\text{Provider's Daily ICAP Shortfall}_{\text{for FRR Cap Plan Commitments}} = \frac{\text{Provider's Daily Unit ICAP Shortfall} \times \text{Provider's Average Daily FRR ICAP Commitment}}{\text{Provider's Share of Total Unit ICAP Commitment}}$$

A Resource Provider with a positive Daily ICAP Shortfall will be assessed The Generation Resource Rating Test Failure Charge.

8.4A Non-Performance Assessment

Effective with the 2018/2019 Delivery Year¹⁴, a new Non-Performance Performance Assessment will assess performance of resources during emergency conditions. Non-Performance Assessment applies to both Base Capacity and Capacity Performance commitments. Base Capacity commitments are exposed to Non-Performance Charges only for performance during emergency actions in summer months of June through September. Resources that fail to perform are subject to Non-Performance Charge and resources that over-perform may be eligible for Bonus Performance Credit.

¹⁴ Generation Resources with Capacity Performance Commitments in 2016/2017 Transitional Incremental Auction or 2017/2018 Transitional Incremental Auction will be the only resources subject to the Non-Performance Assessment in such transition Delivery Years.



Implementation of the Non-Performance Assessment will eliminate Peak Season Maintenance Compliance and Peak-Hour Period Availability Assessment for generation resources and Load Management Event Compliance for Demand Resources.

The Non-Performance Assessment will compare each Capacity Resource's Expected Performance against its Actual Performance for each Performance Assessment Hour. Performance Assessment Hours are delineated by PJM's declaration of Emergency Actions. Emergency Actions shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action, including but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Actions. Performance is assessed for each hour (or partial hour) that PJM declares the following actions:

- Pre-Emergency Load Management Reduction Action
- Emergency Load Management Reduction Action
- Primary Reserve Warning
- Maximum Emergency Generation
- Maximum Emergency Generation Action Trans
- Emergency Voluntary Energy Only Demand Response
- Voltage Reduction Warning
- Voltage Reduction Action
- Manual Load Dump Warning
- Manual Load Dump Action

The Non-Performance Assessment will encompass all resources located in the area defined by the Emergency Action. If the Emergency Action area is PJM-wide then External Generation Capacity Resources and Net Energy Imports are included in this assessment. QTUs will be deemed to be located in the LDA into which such upgrade increased the CETL and the QTU will be included in the Non-Performance Assessment only if, and to the extent that, the declared Emergency Action encompasses only the LDA into which the upgrade increased the CETL.

For each Performance Assessment Hour, the Actual Performance is equal to:

- for each generation resource (including External Generation Capacity Resources for PJM-wide events), the metered output of delivered energy plus the resource's real-time reserve or regulation assignment¹⁵, if any;
- for each Demand Resource, the demand response provided plus the resource's real-time reserve or regulation assignment, if any;

¹⁵ The metered output of jointly owned generation resources is allocated to each owner pro-rata with each owner's share of the total Installed Capacity of the resource.



- for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation M&V Report¹⁶;
- for each entity providing Net Energy Imports during a PJM-wide event, the Net Energy Import quantity excluding any energy delivered from External Generation Capacity Resources ; and,
- for each Qualified Transmission Upgrade, the cleared MW quantity of the QTU if it is in-service prior to the start of the day of the Performance Assessment Hour, and zero if it is not in-service prior to the start of such day.

For each Performance Assessment Hour, the Expected Performance for purposes of determining both Non-Performance Charges and Bonus Performance Credits is equal to:

- for each generation resource (including External Generation Capacity Resources for PJM-wide events), the resource's committed Unforced Capacity times the ratio¹⁷ of [(total amount of Actual Performance for all generation resources, plus net energy imports¹⁸, plus total Demand Response Bonus Performance for that hour) / (total amount of committed Unforced Capacity of all Generation Capacity Resources)]; and,
- for each Demand Resource and Energy Efficiency Resource, the resources' committed capacity without making any adjustment for the Forecast Pool Requirement (i.e., the actual load reduction quantity the resource committed to provide); and,
- for each Qualified Transmission Upgrade, the committed MW quantity.

The Performance Shortfall for a resource is calculated as Expected Performance minus the Actual Performance. If the Performance Shortfall for such resource is a positive number, the under-performing resource is subject to a Non-Performance Assessment Charge. If the Performance Shortfall is a negative number, the over-performing resource is eligible for Bonus Performance Credit.

For generation resources with a positive Performance Shortfall amount, the Performance Shortfall may be adjusted downward due to exempt MWs. Exempt MWs consist of the following:

- unavailable MWs associated with a generator's approved planned or maintenance outage during the Performance Assessment Hour;
- MWs for which the generator was not scheduled to operate by PJM or MWs for which the generator was scheduled down by PJM, for reasons other than (1) any

¹⁶ Base Capacity Energy Efficiency Resources are not included in the assessment of Performance Assessment Hours that occur outside of the summer months of June through September, inclusive.

¹⁷ This ratio will be capped at 1.

¹⁸ Net Energy Imports are only included in this formula for PJM-wide emergency events.



operating parameter limitations submitted in the resource's offer or (2) submission of a market-based offer higher than its cost-based offer but would have been scheduled if its market-based offer had been equal to its cost-based offer.

For purposes of the Non-Performance Assessment for demand resources, compliance will be measured in a similar manner as load management event compliance in Section 8.5 with the following adjustments:

- compliance will be measured for each Performance Assessment Hour, as opposed to being averaged across all hours of the Load Management event;
- compliance will be measured and summed for all registrations dispatched by PJM within the area defined by the Emergency Action, as opposed to the Compliance Aggregation Area;
- for each registration, the amount of actual non-summer load reduction provided is to be measured using the same Customer Baseline Load (CBL) methodology currently employed for measuring load reductions in the energy market as described in Manual 11. The amount of actual load reduction during a summer (June-September) Performance Assessment Hour is to be measured using the current methodology as described in Manual 19.

For Performance Assessment purposes, the Actual Performance of any resource that has both Base Capacity Commitments and Capacity Performance Commitments will first be assigned to meet the resource's Expected Performance as a Capacity Performance Resource with any remaining Actual Performance next assigned to meet the resource's Expected Performance as a Base Capacity Resource.

For Performance Assessment purposes during the 2016/2017 and 2017/2018 transition years, the Actual Performance of any generation resource that has both an Annual Resource commitment and a Capacity Performance commitment will first be assigned to meet the resource's Expected Performance as a Capacity Performance Resource. Actual Performance above the resource's Expected Performance will then be assigned to meet the resource's Annual commitment with any remaining Actual Performance used for purposes of determining Bonus Performance.

For Performance Assessment Hours occurring outside of the summer period (June-September), Generation Capacity Resources that have a Base Capacity commitment, and Base Capacity Demand Resources, are not evaluated for non-performance, but are eligible for Bonus Performance. For Base Capacity Generation Resources, the Bonus Performance quantity is equal to the resource's Actual Performance minus the resource's Expected Performance. For Base Capacity Demand Resources, the Bonus Performance quantity is equal to the resource's Actual Performance.



For purposes of calculating Bonus Performance, the Actual Performance for a dispatchable resource shall not exceed the MW level at which such resource was scheduled and dispatched by PJM during the Performance Assessment Hour. For self-scheduled generation resources not dispatchable by PJM, the Actual Performance will not exceed the LMP Desired MW value as calculated by PJM based upon the higher of the cost or price schedules submitted for the resource, and will be zero if the LMP Desired MW is less than the lowest point on the higher of the cost or price schedules submitted for the resource.

The hourly Non-Performance Charge is based on either annual Net CONE (in installed capacity terms) for the modeled LDA for which the resource resides and for Delivery Year (for Capacity Performance Resources) or the annual RPM revenues (for Base Capacity Resources), divided by 30, which is intended to represent the number of hours during a year that Emergency Actions could reasonably be expected to be in effect.

Stop-loss provisions limit the total Non-Performance Charge that can be assessed on each Capacity Resource. For Capacity Performance Resources, the maximum yearly Non-Performance Charge is 1.5 times Net CONE times the maximum daily unforced capacity committed by the resource during June 1 of the Delivery Year through the end of the month for which the Non-Performance Charge was assessed. For Base Capacity Resources, there is an annual limit on total Non-Performance Charges, equal to the total capacity revenues due to the resource for the Delivery Year.

Revenue collected from payment of Non-Performance Charges will be distributed to resources (of any type, even if they are not Capacity Resources) that perform above expectations. A resource with Actual Performance above its Expected Performance is considered to have provided Bonus Performance, and will be assigned a share of the collected Non-Performance Charge revenues based on the ratio of its Bonus Performance to the total Bonus Performance (from all resources) for the same Performance Assessment Hour.

The Non-Performance Assessment will apply to generation resources with Capacity Performance commitments for the 2016/2017 or 2017/2018 Delivery Year; however the Non-Performance Charge for the 2016/2017 Delivery Year is based on 50 percent of the Non-Performance Charge Rate and the Non-Performance Charge for the 2017/2018 Delivery Year is based on 60 percent of the Non-Performance Charge Rate. The maximum Non-Performance Charge exposure in the stop-loss calculation is correspondingly reduced such that for 2016/2017, the maximum yearly Non-Performance Charge is 0.75 times Net CONE times the maximum daily unforced capacity committed by the resource during June 1 of the Delivery Year through the end of the month for which the Non-Performance Charge was assessed. For the 2017/2018 Delivery Year, the maximum yearly Non-Performance Assessment Charge is 0.9 times Net CONE times the maximum daily unforced capacity committed by the resource during June 1 of the Delivery Year through the end of the month for which the Non-Performance Charge was assessed. Total revenues collected from Non-Performance Charges for a Performance Assessment Hour during the 2016/2017 or



2017/2018 Delivery Year will be allocated only to over-performing generation capacity resources with a Capacity Performance commitment.

The billing of any Non-Performance Charges incurred in any given month will be done within three calendar months after the calendar month that included such Performance Assessment Hours and such billing of charges will be spread over the remaining months in the Delivery Year.

8.4.7 Peak Season Maintenance (PSM) Compliance (Prior to 2018/2019 Delivery Year)

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 24th through 36th Wednesdays of the calendar year. All weeks start on a Monday and end on Sunday, except the week with the 36th 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).

$$\text{DailyUnitPSMComplianceShortfall} = \text{TotalUnitICAPCommitment} - (\text{SummerNetDependableRating} - \text{AmountofCapacityOutofService})$$

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.

$$\text{Provider's Daily PSM Compliance Shortfall} = \frac{\text{Daily Unit PSM Compliance Shortfall} \times \text{Provider's Share of Total Unit ICAP Commitment}}{\text{Total Unit ICAP Commitment}}$$

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.

$$\text{Provider's Daily PSM Shortfall for RPM Commitments} = \text{Provider's Daily PSM Shortfall} \times \text{Provider's Avg Daily RPM ICAP Commitment} / \text{Provider's Share of Total Unit ICAP Commitment}$$

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.

$$\text{Provider's Daily PSM Shortfall for FRR Commitments} = \text{Provider's Daily PSM Shortfall} \times \text{Provider's Avg Daily FRR ICAP Commitment} / \text{Provider's Share of Total Unit ICAP Commitment}$$

8.5 Load Management Event Compliance (Prior to 2018/2019 Delivery Year)

Compliance is the process utilized to review resource performance during PJM-initiated Load Management events, as defined in the tariff. The process establishes potential under/over compliance values for each dispatched Demand Resource registration.

Compliance is evaluated separately by event in each Compliance Aggregation Area ("CAA") as defined in the tariff for Demand Resources dispatched by PJM. Response to transmission sub-zonal dispatch is voluntary (meaning there are no penalty charges assessed for non-performance) for 2012/2013 and 2013/2014 Delivery Years. Beginning with the 2014/2015 Delivery Year, response to transmission sub-zonal dispatch becomes mandatory (meaning there are penalty charges assessed for non-performance) if the sub-zone is defined and publicly posted the day before the Load Management event. Response to zonal dispatch is mandatory for the DR product type dispatched within the compliance period of such DR product type for all Delivery Years.

Effective with the 2014/2105 Delivery Year, resource providers may use substitute registrations of a different resource product type to cover the commitment of non-performing registrations that cannot respond to a PJM initiated Load Management event. The non-performing registration(s) and corresponding substitute registration(s) must be in the same geographic location defined by the PJM dispatch instruction with the same designated lead time. In addition, the total nominated value of the substitute registration(s) must be comparable (within either +/- 25% or +/- 0.5 MW) to the total nominated value of the corresponding non-performing registration(s). Resource providers that use substitute registrations must submit their list of nonperforming registrations and corresponding



substitute registrations to PJM by 11:59 pm of the event day in the appropriate PJM system. PJM may also request that resource providers submit evidence that notification to respond were sent to substitute registrations in advance or during the event to verify that meter data was not used after the fact in finding the substitutes. Any registration used as a substitute must be included in the submittal of compliance information to the appropriate PJM system. The reduction value(s) of the substitute registration(s) will be used by PJM when measuring event compliance for the corresponding non-performing registration(s). Non-performing registration(s) will be considered to have not performed. Registrations used as substitutes 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. For the 2012/2013 and 2013/2014 Delivery Years, registrations that voluntarily responded to a transmission sub-zonal dispatch must submit compliance information in the eLRS system.

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 hours the registration was dispatched for at least 30 minutes of the clock hour during the event for FSL and GLD customers. Compliance is averaged over all hours the registration was dispatched for non-interval metered DLC programs. For FSL and GLD customers dispatched by PJM for at least 30 minutes of the clock hour (i.e. “partial dispatch compliance hour”), the registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour.

- Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. CSP may provide 1 minute meter data to use for capacity compliance measurement for partial dispatch hour instead of using prorated.

The averaged compliance data will be used to determine a Resource Compliance Position for the Load Management event for each dispatched registration. Compliance data is netted for a DR Provider by CAA for all registrations in the Load Response System that were dispatched.

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 under complied during the event. Resource Compliance Positions that are negative indicate that the registration over complied during the event.

8.5.2 Load Management Event Compliance Allocation

For each Demand Resource (DR) provider, compliance data will be totaled over all Demand Resource registrations dispatched by CAA, to determine the DR Provider’s actual zonal load reduction for the event.

For any Load Management event where the actual net load reduction value achieved by a resource provider in a CAA is less than the provider’s RPM/FRR Resource Commitments in that CAA on the day of the event, the net CAA under-compliance MWs will be allocated back to the registration level on an under-compliance ratio share; however, such net CAA under-compliance MWs will be reduced by the total amount of a Provider’s Daily RPM/FRR Commitment Shortages in a CAA for all their committed Demand Resources that are of the same product type dispatched on the day of the event, before such an allocation occurs. Registrations that were compliant (or over-compliant) in the CAA will not be allocated a portion of the net CAA under-compliance.

For any Load Management event where the actual net CAA load reduction value achieved by a resource provider in a CAA is greater than the provider’s RPM/FRR Resource Commitments in that CAA on the day of the event, the net CAA 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 CAA will not be allocated a portion of the net CAA 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

DR Resource providers are subject to Load Management Test Compliance.

If a registration for 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 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 a Limited Demand Resource is dispatched by a PJM for 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 Limited Demand Resource committed to PJM is dispatched by PJM for a PJM Load Management event in a transmission sub-zone between June 1 and September 30 of the 2012/2013 and 2013/2014 Delivery Years and such registration performs at or above the nominated amount of capacity on the registration, no test will be required and no Load Management Test Failure Charges will be assessed for such registrations. If a registration for a committed Limited Demand Resource is dispatched by a PJM-initiated Load Management Event in a zone between June 1 and 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 an 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 an 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 an 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 an 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:

- 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:

- 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 for such product type by less than 25% of their Summer Average RPM Commitment in the zone for such product type, the resource provider may conduct a retest of the subset of registrations (i.e., end-use customer sites) in the zone for such product type that failed the initial test or a subset of registrations 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 registrations that failed the test, such registrations 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 registration affiliated with a failed registration must also participate in the retest even if the registration passed the initial test, unless the CSP elects to maintain the compliance result achieved in the test for such failed registration through advanced notification to PJM as mentioned above. If a registration and its affiliate both failed the test then such registrations must either be included in the retest or excluded from the retest with the necessary advanced notification to PJM. Affiliated registrations are registrations 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 for such product type by more than 25% of their Summer Average RPM Commitment in the zone for such product type, retesting only a subset of the registrations that failed the initial test is not permitted.

A Provider's Summer Average RPM Commitment in a zone for such product type is equal to the daily average of the provider's total RPM/FRR resource commitments from June 1st through September 30th of the Delivery Year for such product type.

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 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 for a product type will be assessed a Zonal Load Management Test Failure Charge.

Load Management test compliance will be measured in a similar 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 and performance will be aggregated to the zone and not the CAA.

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.

For any Load Management test, a provider's net testing shortfall in a zone for a product type is calculated as the provider's Summer Average RPM/FRR Resource Commitments in such zone for a product type minus the actual zonal load reduction value achieved by the provider in such zone for such product type. A resource provider with a positive net testing shortfall in a zone for a product type (i.e., under compliance MWs in zone for a product type) 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 resource performance assessment shortfalls and the associated deficiency/penalty charges. Participants may not specify replacement resources in order to avoid or reduce performance assessment shortfalls and associated deficiency/penalty charges related to price responsive demand.

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. Upon request to PJM made no later than three business days after a Delivery Day containing a Performance Assessment Hour, Replacement Capacity Transactions may be permitted retroactively effective with the Delivery Day provided such transaction meets the following criteria: (1) the replacement resource must have already been in the same account as the resource being replaced on the Delivery Day, (2) the replacement resource must have been included in the same Performance Assessment Hours as the resource being replaced, (3) the replacement resource must have the same or better temporal availability characteristics as the resource being replaced, and (4) the replacement resource must be located in the same LDA (or a more constrained child LDA) as the resource being replaced. Such requests must be submitted to rpm_hotline@pjm.com and include the start date and end date, resource being replaced, replacement resource, and the desired change in Daily RPM Commitments (in UCAP terms) for the resource being replaced and product type (i.e., Base Generation, Base DR/EE, or Capacity Performance) of the commitment being replaced.

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.

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. Effective for the 2018/2019 and 2019/2020 Delivery Year, the desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced must also indicate the product type (i.e., Base Generation, Base DR/EE, or Capacity Performance) of the commitment 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.
 - Annual Resource commitments can only be replaced by available capacity from an Annual Resource, or by cleared Buy Bids for Annual Capacity, or by Locational UCAP originating from an Annual Resource;
 - Extended Summer DR commitments can only be replaced by available capacity from an Annual Resource or Extended Summer DR, or by cleared Buy Bids for Annual or Extended Summer Capacity, or by Locational UCAP originating from an Annual Resource or Extended Summer DR
 - Limited DR commitments can only be replaced by available capacity from an Annual Resource, Extended Summer DR or Limited DR, or by cleared Buy Bids for Annual, Extended Summer or Limited Capacity, or by Locational UCAP originating from an Annual Resource, Extended Summer DR or Limited DR.

- Capacity Performance Resource commitments can only be replaced by available capacity from a capacity resource that is eligible to be committed as CP, or by cleared Buy Bids or Locational UCAP of the Capacity Performance product type. During the 2016/2017 and 2017/2018 transition Delivery Years, only eligible generation resources can take on a Capacity Performance commitment.
 - Base Capacity commitments on a Generation Resource can only be replaced by available capacity from a generation resource that is eligible to be committed as Base, available capacity from a capacity resource that is eligible to be committed as CP, or by cleared Buy Bids or Locational UCAP for Base Generation product type or Capacity Performance product type
 - Base Capacity commitments on Demand Resource or Energy Efficiency Resources can be replaced by available capacity from a capacity resource that is eligible to be committed as Base or CP, or by cleared Buy Bids or Locational UCAP for Base Generation product type, Base DR/EE product type or Capacity Performance product type.
- 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 Commitment Credits

LSEs may receive credits when Reliability Requirements decrease resulting in an excess capacity.

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.

8.8 Demand Response (DR) Transition Provision for 2012/2013-2014/2015 Delivery Years

Effective with the 2012/2013 Delivery Year, only load reductions below an end-use customer's peak load contribution (PLC) are considered in calculating event/test compliance for guaranteed load drop (GLD) registration. A DR Transition Provision was implemented to provide an interim alleviation provision for Curtailment Service Providers (CSPs) that made commitments in prior RPM Auctions under the prior measurement and verification methodology for GLD programs.

The Transition Provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (i.e., Transition Delivery Years).

A CSP that concludes its Demand Resource cleared in the Base Residual Auction for a Transition Delivery Year is not viable under the revised PLC measurement metric, may seek compensation related to its previously cleared Demand Resource in a Base Residual Auction for such Transition Delivery Year through a DR Capacity Transition Credit or an Alternate DR Transition Credit

A DR Capacity Transition Credit protects a CSP from purchasing more expensive replacement capacity in an Incremental Auction in relation to the Base Residual Auction price. To qualify for a DR Capacity Transition Credit, the CSP must inform PJM in writing no later than 30 days prior to the next scheduled Incremental Auction for the Transition Delivery Year for which the identified Demand Resource cleared. Notifications for the 2013/2014 Delivery Year must be submitted by June 15, 2012 and notifications for the 2014/2015 Delivery Year must be submitted by August 10, 2012.

Such written notification must be submitted to dsr_ops@pjm.com and include Zone, RPM Resource Name, and specify the MW amount of such resource's BRA commitment for which they seek protection. All notifications are subject to PJM review to ensure the CSP is qualified to participate in the DR Transition Provision and approve the maximum MW quantity in an LDA (by product type for the 2014/2015 DY) for which the CSP may seek protection.

The qualified CSP must submit buy bid(s) in any of the remaining Incremental Auctions for the relevant Transition Delivery Year. If the CSP's locational, (product-specific for 2014/2015 Delivery Year) buy bid clears in the Incremental Auction and the Incremental Auction Resource Clearing Price (IA RCP) is greater than the Base Residual Auction LDA Resource Clearing Price (BRA RCP), the CSP shall receive a DR Capacity Transition Credit for such buy bid equal to the price difference between the IA RCP and BRA RCP, multiplied by the



lesser of the (approved LDA, product-specific MW quantity, or the cleared buy bid MW quantity).

The cost of DR Capacity Transition Credits for an LDA is included in the relevant Transition Delivery Year's Final Zonal Capacity Prices for such zones in the LDA and is collected from LSEs in the zones of the LDA via the Locational Reliability Charge.

In lieu of receiving a DR Capacity Transition Credit, a CSP may seek compensation related to its previously cleared Demand Resource in a BRA for such Transition Delivery Year through an Alternate DR Transition Credit.

The Alternate DR Transition Credit protects a CSP that is unavoidably obligated to pay an end-use customer and insulates the CSP from losses when unavoidable contractual obligations exceed any gains from buying replacement capacity in Incremental Auctions for the same Delivery Year. To qualify for the Alternate DR Transition Credit, the CSP must inform PJM in writing no later than 30 days prior to the next scheduled Incremental Auction, for the Transition Year for which the identified Demand Resource cleared, regardless of whether or not the CSP plans to participate in the Auction. Notifications for the 2013/2014 Delivery Year must be submitted by June 15, 2012 and notifications for the 2014/2015 Delivery Year must be submitted by August 10, 2012.

Such written notification must be submitted to dsr_ops@pjm.com and include Zone, RPM Resource Name, and specify the MW amount of such resource's BRA commitment for which they seek protection. All notifications are subject to PJM review to ensure the CSP is qualified to participate in the DR Transition Provision and approve the maximum MW quantity in an LDA (by product type for the 2014/2015 DY) for which the CSP may seek protection.

The CSP must demonstrate to PJM no later than 60 days prior to the start of the relevant Transition Delivery Year that it has a contract executed on or before April 7, 2011 for which the CSP is unavoidably obligated to pay the end-use customer and that the amounts unavoidably owed under the contract exceeds the CSP's gains on any purchases of replacement capacity in Incremental Auctions for the same Delivery Year.

If the CSP is approved by PJM to qualify for the Alternate DR Transition Credit for a Transition Delivery Year, the CSP must submit monthly reports to PJM that describe the actual amounts paid and received by the CSP. Such reports must be submitted within 15 days following the end of each month of the relevant Transition Delivery Year.

The qualified CSP will receive an Alternate DR Transition Credit in an LDA equal to the aggregate amount the CSP is unavoidably obligation to pay as verified by PJM minus any monetary gains from purchases of replacement capacity. Monetary gains are equal to the aggregate LDA Auction Credits from BRA – aggregate LDA Auction Charges for all replacement capacity purchased in Incremental Auctions.

The cost of the Alternate DR Transition Credits in an LDA will be allocated to LSEs in the zones of the LDA on a pro-rata basis based on the LSE's daily unforced capacity obligations.



Section 9: Settlements

Welcome to the *Settlements* 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/FRR for committed supply resources (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”)
- The business rules for DR Transition Provision Credit and Charges (see “DR Transition Provision Credits and Charges (2012/2103-2014/2015 Delivery Years)”)
- The business rules for the penalty charges in RPM/FRR for non-performance of price responsive demand (see “Penalties for Non-Performance of Price Responsive Demand”)
- The business rules for the PRD Credits (see “PRD Credits”)

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.

$$\text{PeakHourPeriodAvailabilityCharge} = \text{DailyPeakHourPeriodAvailability Charge Rate} \times \text{NetPeakPeriodCapShortfall}$$

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).

$$\text{DailyPeakHourPeriodAvailabilityChargeRate}_{RPM} = \text{WeightedAvgResourceClearingPrice}_{inLDA}$$

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 because the committed resources did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), 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.

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 over performed (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 August monthly bill issued in September 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.

$$\text{DailyCapResourceDeficiencyCharge} = \text{DailyDeficiencyRate} \times \text{DailyRPMCommitmentShortage}$$

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 because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), 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.

A resource that is also subject to a Non-Performance Assessment Charge during one or more Performance Assessment Hours occurring during the day of Daily RPM Commitment Shortage shall be assessed a charge equal to the greater of (a) the Daily Capacity



Resource Deficiency Charge or (b) the Non-Performance Assessment Charges for the Performance Assessment Hours occurring during the day of the Daily RPM Commitment Shortage, and shall not be assessed both a Daily Capacity Resource Deficiency Charge and Non-Performance Assessment Charges for Performance Assessment Hours occurring during the day of the Daily RPM Commitment Shortage for such simultaneous occurrence of a commitment shortage and performance shortfall.

Daily Capacity Resource Deficiency Charges are assessed daily and billed weekly.

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.

$$\text{DailyTransUpgradeDelayPenaltyCharge} = \text{QTUDelayPenaltyRate} \times \text{DailyRPMCommitmentShortage}$$

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.

A QTU that is also subject to a Non-Performance Assessment Charge during one or more Performance Assessment Hours occurring during the day of Daily RPM Commitment Shortage shall be assessed a charge equal to the greater of (a) the Daily Transmission Upgrade Delay Penalty Charge or (b) the Non-Performance Assessment Charges for the Performance Assessment Hours occurring during the day of the Daily RPM Commitment Shortage, and shall not be assessed both a Daily Transmission Upgrade Delay Penalty Charge and Non-Performance Assessment Charges for Performance Assessment Hours occurring during the day of the Daily RPM Commitment Shortage for such simultaneous occurrence of a commitment shortage and performance shortfall.

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.

$$\text{GenerationResourceRatingTestFailureCharge} = \text{DailyDeficiencyRate} \times \text{DailyICAPShortfall} \times (1 - \text{EffectiveEFORD})$$

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 because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Average Resource Clearing Price in an LDA will be used.



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.

A resource that is also subject to a Non-Performance Assessment Charge during one or more Performance Assessment Hours occurring during the day of Daily ICAP Shortfall due to rating test failure shall be assessed a charge equal to the greater of (a) the Daily Generation Resource Rating Test Failure Charge or (b) the Non-Performance Assessment Charges for the Performance Assessment Hours occurring during the day of the Daily ICAP Shortfall due to rating test failure, and shall not be assessed both a Daily Generation Resource Rating Test Failure Charge and Non-Performance Assessment Charges for Performance Assessment Hours occurring during the day of the Daily ICAP Shortfall for such simultaneous occurrence of a rating test shortfall and performance shortfall.

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 monthly bill issued in July 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.

$$PSMCompliancePenaltyCharge = DailyDeficiencyRate \times DailyPSMComplianceShortfall \times (1 - EffectiveEFORD)$$

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 because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Average Resource Clearing Price in an LDA will be used.

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 monthly bill issued in July 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 for the product type tested times the LM Test Failure Charge Rate.

$$LoadManagementTestFailureCharge = UnderComplianceMW \times DailyLMTTestFailureChargeRate$$



A Provider's Under-Compliance MWs in a zone for the product type tested will be reduced by the summer average of the provider's Daily RPM/FRR Commitment Shortages in a zone for all their Demand Resources in the zone that are of the same product type tested.

The Daily Load Management Test Failure Charge Rate is equal to the Provider's Weighted Daily Revenue Rate in such zone for the product type tested plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate in such zone for the product type tested, or \$20/MW-day.) In the case where a Provider's Weighted Daily Revenue Rate in such zone for the product type tested is \$0/MW-day because the underlying committed resource(s) did not clear in any RPM Auction (i.e., commitments were due to the resource(s) being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Daily Revenue Rate in such zone for the product type tested 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 Compliance Penalty Charge

Penalties and rewards are assessed for PJM-initiated events on an event basis, following a compliance review.

A Demand Resource Compliance Penalty Charge is assessed to those Providers with committed registrations that under complied during an event. The Load Management Compliance Charge for an under compliant registration is equal to the under compliance MWs for the dispatched registration in a zone times the Load Management Zonal Compliance Penalty Rate applicable to such dispatched registration in a zone.

$$\text{LoadManagementCompliancePenaltyCharge} = \text{UnderComplianceMW} \times \text{LMCompliancePenaltyRate}$$

The LM Compliance Penalty Charges will not be assessed to registrations that are dispatched on a transmission sub zonal basis for the 2012/2013 and 2013/2014 Delivery



Years. Effective with the 2014/2015 Delivery Year, LM Compliance Penalty Charges will not be assessed to registrations that are dispatched on a transmission sub zonal basis unless such subzone is defined and publicly posted the day before the Load Management Event.

The LM Compliance Charges for an event for dispatched registrations in a zone of the Limited DR product type are 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 LM Compliance Charges for an event for dispatched registrations in a zone of the Annual DR or Extended Summer DR product type are assessed daily and billed by the later of the month of June following such Delivery Year or the third billing month following the Load Management event that gave rise to such charge. The billing for the Load Management event for Annual DR or Extended Summer DR will be in a lump sum and reflect the accrued charges for the entire Delivery Year.

Effective with the 2012/2013 through 2013/2014 Delivery Years, the Daily Load Management Zonal Compliance Penalty Rate per MW-event applicable to a registration is equal to the lesser of (one divided by the actual number of events during the summer period for the dispatched registration in such zone, or 0.50) * Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration. In the case where a Provider's Daily Revenue Rate in such zone for the dispatched registration is equal to \$0/MW-day because the committed resource associated with the registration did not clear in any RPM Auction (i.e., commitments were due to the resource being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Daily Revenue Rate applicable to such dispatched registration in such zone will be used.

Effective with the 2014/2015 Delivery Year, the LM Compliance Charge for an event for a dispatched registration 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 on-peak events during the Delivery Year for the dispatched registration in such zone, or 0.50) * Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration, multiplied by the net under-compliance in such on-peak period for the dispatched registration. In the case where a Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration is equal to \$0/MW-day, a PJM Weighted Daily Revenue Rate applicable to such dispatched registration in such zone will be used.

The LM Compliance Charge for an event for a dispatched registration 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 registration, multiplied by the net under-compliance in such off-peak period for dispatched registration. In the case where a Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration is equal to \$0/MW-day because the committed resource associated with the registration did not clear in any RPM Auction (i.e., commitments were due to the resource being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Daily Revenue Rate applicable to such dispatched registration 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 for a dispatched registration will be the higher of the LM Compliance Charge calculated based on the rate applied for the on-peak period and the registration's under-compliance MWs for the event or LM Compliance Charge calculated based on the rate applied for off-peak period and the registration's under-compliance MWs for 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 would receive.

The Demand Resource Compliance Penalty Charges collected from LM Providers with under-compliant registrations for an event are allocated on a pro-rata basis to those LM Providers with committed registrations that provided load reductions in excess of the amount obligated to provide for such event. The total event allocation to each over-performing registration shall not exceed for each committed registration the volume of excess MWs provided by the committed registration during a single event times 1/5 of the provider's weighted daily revenue rate received by the registration dispatched. Any Load Management Compliance Charges for an event collected from under-compliant registrations of the Limited DR product type will be allocated to over-compliant registrations for such event and have the same bill timing as LM Compliance Charges for Limited DR for such event. Any Load Management Compliance Charges for an event collected from under-compliant registrations of the Annual DR or Extended Summer DR product type will be allocated to over-compliant registrations for such event and have the same bill timing as LM Compliance Charges for Annual DR or Extended Summer DR for such event.

Any Demand Resource Compliance Penalty Charges not allocated to over-performing Providers are instead allocated to all LSEs in the RTO 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.

9.1.11 Non-Performance Assessment Charge/Bonus Performance Credit

Non-Performance Assessment Charge will be assessed to a resource provider that had a Performance Shortfall for a Performance Assessment Hour.

Non-Performance Assessment Charge is equal to the Performance Assessment Hour Performance Shortfall (MW) times Non-Performance Charge Rate (\$/MWh)



The Non-Performance Charge Rate to be applied to shortfalls associated with Capacity Performance commitments is equal to [the modeled LDA Net Cone for which the resource resides (\$/MW-day in installed capacity terms) times number of days in Delivery Year] divided by 30.

The Non-Performance Charge Rate to be applied to shortfalls associated with Base Capacity commitments is equal to (Weighted Average Resource Clearing Price (\$/MW-day) for such resource times number of days in Delivery Year) divided by 30

Stop-loss provisions limit the total Non-Performance Charge that can be assessed on each Capacity Resource. For Capacity Performance Resources, the maximum yearly Non-Performance Charge is 1.5 times Net CONE times the maximum daily unforced capacity committed by the resource during June 1 of the Delivery Year through the end of the month for which the Non-Performance Charge was assessed. For Base Capacity Resources, there is an annual limit on total Non-Performance Charges, equal to the total capacity revenues due to the resource for the Delivery Year.

Revenue collected from payment of Non-Performance Charges will be distributed to resources (of any type, even if they are not Capacity Resources) that perform above expectations. A resource with Actual Performance above its Expected Performance is considered to have provided Bonus Performance, and will be assigned a share of the collected Non-Performance Charge revenues based on the ratio of its Bonus Performance to the total Bonus Performance (from all resources) for the same Performance Assessment Hour.

The Non-Performance Assessment will apply to generation resources with Capacity Performance commitments for the 2016/2017 or 2017/2018 Delivery Year; however the Non-Performance Charge for the 2016/2017 Delivery Year is based on 50 percent of the Non-Performance Charge Rate and the Non-Performance Charge for the 2017/2018 Delivery Year is based on 60 percent of the Non-Performance Charge Rate. The maximum Non-Performance Charge exposure in the stop-loss calculation is correspondingly reduced such that for 2016/2017, the maximum yearly Non-Performance Charge is 0.75 times Net CONE times the maximum daily unforced capacity committed by the resource during June 1 of the Delivery Year through the end of the month for which the Non-Performance Charge was assessed. For the 2017/2018 Delivery Year, the maximum yearly Non-Performance Assessment Charge is 0.9 times Net CONE times the maximum daily unforced capacity committed by the resource during June 1 of the Delivery Year through the end of the month for which the Non-Performance Charge was assessed. Total revenues collected from Non-Performance Charges for a Performance Assessment Hour during the 2016/2017 or 2017/2018 Delivery Year will be allocated only to over-performing generation capacity resources with a Capacity Performance commitment.

The billing of any Non-Performance Charges incurred in any given month will be done within three calendar months after the calendar month that included such Performance Assessment Hours and such billing of charges will be spread over the remaining months in the Delivery Year.

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.

$$\text{Locational Reliability Charge} = \text{DailyUnforced Capacity Obligation} \times \text{Final Zonal Capacity Price}$$

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 weekly 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.

$$\text{RPM Auction Credits} = \text{MWCleared}_{\text{inLDA}} \times \text{ResourceClearingPrice}_{\text{inLDA}}$$

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 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. 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 calculated daily and billed weekly 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.

$$RPM\ Auction\ Charges = MW_{Cleared\ in\ LDA} \times Resource\ Clearing\ Price_{in\ LDA}$$

Auction Charges are calculated daily and billed weekly 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.

$$Resource\ make - Whole\ Credit = (Min\ MW\ Offered - Cleared\ MW) \times Resource\ Clearing\ Price_{in\ LDA}$$

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) for all LDAs in which the zone resides as a result of all RPM Auctions for such Delivery Year divided by the maximum LDA CTRs (MWs) allocated to LSEs in a zone.

$$Zonal\ CTR\ Credit = Zonal\ CTRs\ Owned \times Zonal\ CTR\ Settlement\ Rate$$

Each Incremental CTR owner will receive a daily Incremental CTR Credit equal to the Incremental CTRs owned for the LDA multiplied by the LDA Incremental CTR Credit Rate. Credits will be calculated daily and billed weekly during the Delivery Year.

$$Incremental\ CTR\ Credit = Incremental\ CTRs\ Owned \times LDA\ Incremental\ CTR\ Credit\ Rate$$

CTR Credits will be calculated daily and billed weekly 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.

$$Seller\ Charge = Transaction\ Amount \times Weighted\ Average\ Resource\ Clearing\ Price$$

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.

$$Buyer\ Credit = Transaction\ Amount \times Weighted\ Average\ Resource\ Clearing\ Price$$

Charges and Credits for Auction Specific MW Transactions are calculated daily and billed weekly for the duration of the transaction during the Delivery Year.

9.3.6 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)] *

(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.

9.4 DR Transition Provision Credits and Charges (2012/2013 – 2014/2015 Delivery Years)

9.4.1 DR Transition Credit

A CSP qualified for a DR Transition Credit in accordance with Section 5.14A of Attachment DD of the OATT and Section 8.8 of this manual will receive a DR Transition Credit for a cleared buy bid in Transition Delivery Year's Incremental Auction that is charged an Incremental Auction Resource Clearing Price that is higher than the Base Residual Auction Resource Clearing Price.

The DR Transition Credit associated with a cleared buy bid in an LDA is equal to (IA LDA RCP minus BRA LDA RCP) multiplied by the lesser of (the approved LDA, product-specific MW, or the cleared buy bid MW quantity).



The DR Transition Credits to qualified CSPs are assessed daily and billed weekly in the relevant Transition Delivery Year.

The cost of the DR Transition Credits for an LDA will be allocated to LSEs serving load in the LDA via the LSE's Locational Reliability Charges.

9.4.2 Alternate DR Transition Credit

A CSP qualified for an Alternate DR Transition Credit in accordance with Section 5.14A of Attachment DD of the OATT and Section 8.8 of this manual will receive an Alternate DR Transition Credit.

The Alternate DR Transition Credit received by a CSP in an LDA is equal to the aggregate amount the CSP is unavoidably obligated to pay as verified by PJM minus any monetary gains from purchases of replacement capacity. Monetary gains are equal to the aggregate LDA Auction Credits from BRA – aggregate LDA Auction Charges for all replacement capacity purchased in Incremental Auctions.

The cost of the Alternate DR Transition Credits in an LDA will be allocated to LSEs in the zones of the LDA on a pro-rata basis based on the LSE's daily unforced capacity obligations.

The Alternate DR Transition Credits to CSPs and Alternate DR Transition Charges to LSEs will be assessed daily and retroactively billed monthly during the relevant Transition Delivery Year after PJM verifies the amount that CSP is unavoidably obligated to pay (e.g., June credits/charges will appear in the July monthly bill issued in August).

9.5 Penalties for Non-Performance of Price Responsive Demand

9.5.1 PRD Commitment Compliance Penalty & Credits

A PRD Provider with a positive daily commitment compliance shortfall in a sub-zone/zone for RPM or FRR will be assessed a Daily PRD Commitment Compliance Penalty.

The Daily PRD Commitment Compliance Penalty is equal to the MW shortfall in the Sub-zone/Zone * Delivery Year Forecast Pool Requirement * PRD Commitment Compliance Penalty Rate.

The MW Shortfall in Sub-zone/Zone for RPM is the Daily Nominal PRD Value committed in BRA and/or Third IA by the PRD Provider minus the Daily Nominal PRD Value for RPM determined from approved and effective PRD registrations for such PRD Provider.

The MW Shortfall in Sub-zone/Zone for FRR is the Daily Nominal PRD Value committed for FRR by the PRD Provider minus the Daily Nominal PRD Value for FRR determined from approved and effective PRD registrations for such PRD Provider.

The PRD Commitment Compliance Penalty Rate for a PRD Provider that committed PRD for RPM is equal to PRD Provider's Weighted Final Zonal Capacity Price in \$/MW-Day + higher of $[0.2 * \text{PRD Provider's Weighted Final Zonal Capacity Price or } \$20/\text{MW-day}]$.

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in Base Residual Auction and Third Incremental Auction.



The PRD Commitment Compliance Penalty Rate for a PRD Provider that committed PRD for FRR is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

The revenue collected from assessment of the PRD Commitment Compliance Penalty shall be distributed on a pro-rata basis as Daily PRD Commitment Compliance Credit to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

9.5.2 PRD Maximum Emergency Event Compliance Penalty & Credits

A PRD Provider with a positive net event compliance shortfall in a sub-zone/zone for a Maximum Emergency Event is subject to a PRD Maximum Emergency Event Compliance Penalty.

The PRD Maximum Emergency Event Compliance Penalty for the first Maximum Emergency Event is the net event compliance shortfall in zone times * Delivery Year Forecast Pool Requirement * PRD Event Compliance Penalty Rate.

The penalty charge for a subsequent Maximum Emergency Event in the sub-zone/zone shall be assessed only on the portion of the net event compliance shortfall in the sub-zone/zone that exceeds the maximum net event compliance shortfall in any prior Maximum Emergency Events.

The PRD Event Compliance Penalty Rate for RPM PRD is equal to the PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the PRD Provider's Weighted Final Zonal Capacity Price in such Zone or \$20/MW-day) times the number of days in the Delivery Year.

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in BRA and Third IA.

The PRD Event Compliance Penalty Rate for FRR PRD is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

PRD Maximum Emergency Event Compliance Penalty shall be assessed daily and billed the later of (i) third billing month following the Maximum Emergency Event or (ii) the month of December of the Delivery Year.

The revenue collected from assessment of the PRD Maximum Emergency Event Compliance Penalty shall be distributed on a pro-rata basis as Daily PRD Maximum Emergency Event Compliance Credit to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.



9.5.3 PRD Test Failure Charges & Credits

Each PRD Provider with a positive net testing shortfall in a zone will be assessed PRD Test Failure Charge.

The PRD Test Failure Charge is equal to the net testing shortfall in zone times * Delivery Year Forecast Pool Requirement * PRD Test Failure Charge Rate

The PRD Test Failure Charge Rate for RPM PRD is equal to the PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the PRD Provider's Weighted Final Zonal Capacity Price in such Zone or \$20/MW-day) times the number of days in the Delivery Year.

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in BRA and Third IA.

The PRD Test Failure Charge Rate for FRR PRD is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

The PRD Test Failure Charge shall be assessed daily and charged 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 a test failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

The PRD Test Failure Charge shall be assessed daily and billed retroactively in the August bill issued in September after the conclusion of the Delivery Year.

The revenue collected from assessment of the PRD Test Failure Charges shall be distributed on a pro-rata basis as Daily PRD Test Failure Credits to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

9.5.4 LSE PRD Credit

The Load Serving Entity (LSE) identified in the PRD registration that is associated with load served under RPM will receive a Daily LSE PRD Credit each day that the PRD registration is effective. The LSE (FRR Entity) identified in the PRD registration that is associated with load served under the FRR Alternative will not receive a Daily LSE PRD Credit.

LSE PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) + (Share of Zonal Nominal PRD Value committed in Third Incremental Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)] .

Where:



Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration * Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration.

Share of Zonal Nominal PRD Value Committed in Third Incremental Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration * Zonal Nominal PRD Value committed in the Third Incremental Auction by the PRD Provider of such registration.

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year

When the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction or Third Incremental Auction will be based on the Nominal PRD Values committed and registered in a sub-Zone.

A Load Serving Entity will receive a LSE PRD Credit for each approved Price Responsive Demand registration that is effective and applicable to load served by such Load Serving Entity on a given day. The total daily credit to an LSE in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone for load served by such LSE on a given day. Although the PRD Credit is assessed to the LSE of record in the registration, all PRD performance penalties are assessed to the PRD Provider associated with such registration.

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.

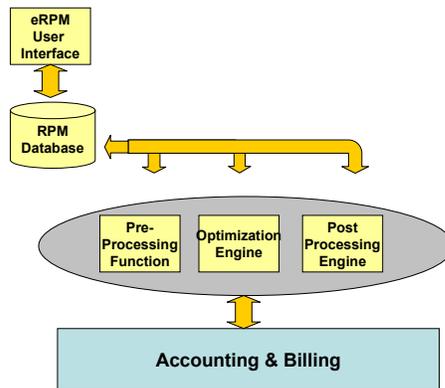


Exhibit 4: RPM Auction Subsystems

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 MUJ 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

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 2012/2013 Delivery Year corresponds to the June 1, 2012-May 31, 2013 Planning Period.

Effective for 2014/2015-2018/2019 Delivery Years, FRR Entities are able to commit Limited DR, Extended Summer DR, and Annual Resources to their FRR Capacity Plan. Effective with the 2019/2020 Delivery Year, FRR Entities are able to commit Base Capacity and Capacity Performance resources to their FRR Capacity Plan. Effective with the 2020/2021 Delivery Year, FRR Entities may only commit Capacity Performance resources to their FRR Capacity Plan.

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.

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 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
- Short-Term Resource Procurement Target
- 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 – 2016/2017 Delivery Years)
- Limited Resource Constraints and Sub-Annual Resource Constraint for PJM Region and each modeled LDA (effective ~~with~~ for 2017/2018 and 2018/2019 Delivery Years for FRR Entities)
- Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint for PJM and each modeled LDA (effective for 2019/2020 Delivery Years)
 - 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 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.

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 Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area shall be reduced by the Nominal PRD Value associated with such load that was approved by PJM in advance of the BRA for such Delivery Year, multiplied by the BRA 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. 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.

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.

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.

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 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 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) $0.03 * \text{Preliminary Daily Unforced Capacity Obligation}$ 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:

- 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 (2014/2015-2016/2017 Delivery Years);
- Limited Resource Constraint and Sub-Annual Resource Constraint (effective for 2017/2018 Delivery Year and 2018/2019 Delivery Year for FRR Entities);
- Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint (effective for 2019/2020 Delivery Year)
- 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, any applicable product type requirements or constraints, 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 (2014/2015-2016/2017 Delivery Years);
- Limited Resource Constraint and Sub-Annual Resource Constraint (Effective for 2017/2018 Delivery Year and 2018/2019 Delivery Year for FRR Entities);
- Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint (effective for 2019/2020 Delivery Years) 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, any applicable product type requirements or constraints, 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, any applicable product type requirements or constraints, 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 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~~resources 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.

Effective with the 2020/2021 Delivery Year, only Capacity Performance Resources may be included in the FRR Capacity Plan.

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 (2014/2015-2016/2017 Delivery Years), Limited Resource Constraints and Sub-Annual Resource Constraints (effective 2017/2018 and 2018/2019 Delivery Years), Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints 2019/2020 Delivery Year) 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

Prior to the start of each Delivery Year, the FRR entity must elect whether it seeks to be subject to the Non-Performance Charge or to physical non-performance assessments for that Delivery Year. If such FRR Entity opted to be subject to physical non-performance assessments, the FRR Entity will be required to update their FRR Capacity Plan for the following Delivery Year with additional MW of Capacity Performance Resources for each MW of FRR net Performance Shortfall for each Performance Assessment Hour in accordance with Section 11.9. Such FRR Entity shall not be eligible for, or subject to, Bonus Performance Credits.

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.¹⁹ If the party's Daily Available 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.

¹⁹ The term of the resource's commitment to the FRR Capacity Plan may be less than a Delivery Year.



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. Effective with the 2018/2020 Delivery Year, the DR Factor is no longer considered in the calculation of a party's Daily Demand Resource Position.

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. Effective with the 2019/2020 Delivery Year, the DR Factor is no longer considered in the calculation of a party's Daily FRR Demand Resource Position.

~~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. Effective with the 2017/2018 Delivery Year, an FRR Entity shall receive no credit for the unforced capacity of Limited Demand Resources to the extent committed in excess of the applicable Limited Resource Constraint and shall receive no credit for the sum of Limited Demand Resources and Extended Summer Demand Resources to the extent the sum of the unforced capacity from such resources exceeds the applicable Sub-Annual Resource Constraint.~~

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. Effective ~~with the for~~ the 2017/2018 and 2018/2019 Delivery Years, an FRR Entity shall receive no credit for the unforced capacity of Limited Demand Resources to the extent committed in excess of the applicable Limited Resource Constraint and shall receive no credit for the sum of Limited Demand Resources and Extended Summer Demand Resources to the extent the sum of the unforced capacity from such resources exceeds the applicable Sub-Annual Resource Constraint.

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. Effective with the



2018/2019 Delivery Year, the DR Factor is no longer considered in the calculation of party's Daily FRR EE Resource Position.

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. Effective for the 2019/2020 Delivery Year, an FRR Entity shall receive no credit for the sum of Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources to the extent committed in excess of the applicable Base Capacity Demand Resource Constraint, and shall receive no credit for the sum of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources, and Base Capacity Generation Resources to the extent committed in excess of the applicable Base Capacity Resource Constraint. Effective for the 2020/2021 Delivery year, an FRR Entity shall only receive credit for Capacity Performance Resources.

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~~ FRR Capacity Plan.

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 of this manual.

In order to commit a Demand Resource to the initial FRR Capacity Plan for a Delivery Year, an FRR Entity must submit no later than 15 business days prior to the initial FRR Capacity Plan submittal deadline a completed DR Plan template (i.e., the DR Sell Offer Plan template described in Attachment C of this Manual). The completed DR Plan template must clearly identify in the Summary section the Existing Nominated DR Value or Planned Nominated DR Value in ICAP MWs that the FRR Entity intends to commit to their initial FRR Capacity Plan. Actual deadline date for the DR Plan template is provided in the RPM Auction Schedule posted on the pjw website.

If an FRR Entity intends to commit demand resources located in a pre-identified zone/sub-zone, PJM will grant conditional approval of the total Nominated DR Value in such zone/sub-zone pending the PJM review of DR Sell Offer Plans for the Base Residual Auction for such Delivery Year.

An FRR Entity with PJM approved or conditionally approved Nominated DR Value(s) in zone/sub-zone(s) will be permitted to commit the associated Demand Resource(s) to the FRR Capacity Plan, provided credit has been posted with the PJM Treasury Department for any Planned Demand Resource(s).

If a review of the DR Sell Offer Plans for the Base Residual Auction for such Delivery Year reveals that any of the conditionally approved MWs in a pre-identified zone/sub-zone are ascribed to another CSP by a letter of support from an end-use customer, such MWs shall be uncommitted from the FRR Capacity Plan and additional capacity resources shall be committed by the FRR Entity to the FRR Capacity Plan to satisfy the FRR Entity's Preliminary Unforced Capacity Obligation.

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). Effective with the 2018/2019 Delivery Year, the DR Factor is no longer considered in the calculation of the UCAP value of a Demand Resource.

The Nominated DR Value for a load management program cannot exceed the maximum value determined in accordance with the **Load Data Systems Manual (M-19)**.

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) $[(0.25 * \text{Preliminary Unforced Capacity Obligation}]$ 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) $0.25 * (\text{FRR Preliminary Daily Unforced Capacity Obligation} + \text{RPM Expected UCAP Obligation})$ 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. The Forecast Pool Requirement updated for the RPM Third Incremental Auction will be used in determining the Final Daily Unforced Capacity Obligation.



The Final Daily Unforced Obligation shall be reduced by the committed Nominal PRD Value associated with such load that was approved by PJM in advance of the BRA and Third IA for such Delivery Year, multiplied by final Forecast Pool Requirement for the Delivery Year.

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.

For the 2014/2015–2016/2017 Delivery Years, 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 (2014/2015-2016/2017 Delivery Years).

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 (2014/2015-2016/2017 Delivery Years).



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 (Prior to 2019/2020 Delivery Year)

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 (Prior to 2019/2020 Delivery Year)

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 (Prior to 2019/2020 Delivery Year)

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



DR Resource providers are required to simultaneously test all of their committed DR 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.

11.9.8 Non-Performance Assessment Charge/Bonus Performance Credit (Effective with 2019/2020 Delivery Year)

An FRR Entity that elected to be subject to financial non-performance assessment as opposed to physical non-performance assessments will be subject to Non-Performance Assessment Charge for each resource committed to the FRR Capacity Plan that had a Performance Shortfall for a Performance Assessment Hour. If a resource committed to the FRR Capacity Plan had Bonus Performance for a Performance Assessment Hour, such resource will be eligible for Bonus Performance Credits.

Please see Section 9.1.11 of this manual for details on Non-Performance Assessment Charge/Bonus Performance Credit.

11.9.9 Physical Non-Performance Assessment

An FRR Entity that elected to be subject to physical non-performance assessment for resources committed to the Delivery Year FRR Capacity Plan as opposed to financial non-performance assessment for such resources will be required to update the subsequent Delivery Year's FRR Capacity Plan and commit additional Capacity Performance Resources beyond the amount of Capacity Performance Resources required for the subsequent Delivery Year as a penalty for those resources committed to the FRR Capacity Plan that experienced Performance Shortfalls for Performance Assessment Hour during the relevant Delivery Year.

For each Performance Assessment Hour, the Actual Performance and Expected Performance of each resource contained in an FRR Entity' Capacity Plan will be determined according to the rules and formulas described in the Non-Performance Assessment section 8.4A, and for such hour, a net Performance Shortfall shall be determined separately for Capacity Performance Resources and for Base Capacity Resources. If the combined Actual Performance of all Capacity Performance Resources committed to the FRR Entity's Capacity Plan exceeds the Expected Performance of such resources, then such over-performance may be applied to any positive Performance shortfall experienced by such FRR Entity's Base Capacity Resources during the Performance Assessment Hour. If the combined Actual Performance of all Base Capacity Resources committed to the FRR Entity's Capacity Plan exceeds the Expected Performance of such resources, then such over-performance may be applied to any positive Performance Shortfall experienced by such FRR Entity's Capacity Performance Resources during the Performance Assessment Hour.



~~The FRR Entity's net Performance Shortfall among Capacity Performance Resources, if any, for each Performance Assessment Hour shall be multiplied by a rate of 0.01667 MWs/Performance Assessment Hour (i.e., 0.5 MWs/30 PAHs) to establish the additional MW of Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the following Delivery Year. The maximum additional MW required by the FRR Entity as a result of non-performance from the FRR Entity's Capacity Performance Resources during a Delivery Year shall not exceed 50% of the MW quantity of the Capacity Performance Resources committed in the FRR Capacity Plan for such Delivery Year.~~

~~The FRR Entity's net Performance Shortfall among Base Capacity Resources, if any, for each Performance Assessment Hour shall be multiplied by a rate of [(0.01667 MWs/Performance Assessment Hour) times (the Base Capacity Resource clearing prices across all RPM Auctions for the Delivery Year for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions divided by the Net CONE established for such LDA for the Delivery Year)] to establish the additional MW of Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the following Delivery Year. The maximum additional MW required by the FRR Entity as a result of non-performance from the FRR Entity's Base Capacity Resources during a Delivery Year shall not exceed a MW quantity equal to [(0.5 times the MW quantity of the Base Capacity Resources committed in the FRR Capacity Plan for such Delivery Year) times (the Base Capacity Resource clearing prices across all RPM Auctions for the Delivery Year for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions divided by the Net CONE established for such LDA for the Delivery Year)].~~

~~The Performance Shortfall MW quantities will be summed across all resources committed to the FRR Capacity Plan for each Performance Assessment Hour and each hour's net result will be summed across all performance hours within the Delivery Year. This net sum, if positive, will be divided by the number of Performance Assessment Hours in the Delivery Year to determine the FRR performance shortfall. For each MW performance shortfall, the FRR Entity will be required to commit an additional MW of Capacity Performance resources to their FRR Capacity Plan for the following Delivery Year.~~

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 MW Transactions 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.



Attachment 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:

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 BRA Short Term Resource Procurement Target. .

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 Short-Term Resource Procurement Target Allocation. 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 $\left[\frac{\text{Preliminary Zonal Peak Load Forecast for the Delivery Year}}{\text{Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Years}} \right] * \left(\frac{\text{RTO Unforced Capacity Obligation Satisfied in Base Residual Auction}}{\text{RTO Unforced Capacity Obligation Satisfied in Base Residual Auction}} \right)$



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) + Short Term Resource Procurement Target. 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 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 2012/2013 Delivery Year corresponds to the June 1, 2012 – May 31, 2013 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 scarce 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).

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 –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. 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 two weeks following the final Incremental Auction.

Final Zonal Unforced Capacity Obligation – 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.

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.

Forecast Pool Requirement (FPR) – the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region.

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.

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.

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.

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. Incremental capacity transfer rights associated with Incremental Rights-Eligible Required Transmission Enhancements are allocated. Incremental Rights-Eligible Required Transmission Enhancements may include Regional Facilities and Necessary Lower Voltage Facilities, and Lower Voltage Facilities.

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.

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.

Interconnection Service Agreement (ISA) – an agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection.

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. The 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 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).

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.

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 RTEPP Process employs a range of planning study tools and methodologies to analyze and assess each component to ensure that reliability remains firm. The RTEPP 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; and (3) the Annual Resource Price Adder, if any, for the LDA; and (4) the Extended Summer Resource 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.

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 $(1 - EFORd-5)$.

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 all 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.

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.

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.

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 is also used to calculate the Auction Credit to DR on the zonal basis if EDC cannot provide DR data by sub-zones.

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 as a result of the clearing of all RPM Auctions for the Delivery Year. A zonal capacity price consists of the following price components: (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 in the Zone, if required, to account for any resource make-whole payments; and (4) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer DR. *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 Base Residual Auction and any Incremental



Auction(s). *Final Zonal Capacity Prices* are determined after the Final Incremental Auction for 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 and as the Final CTR Credit Rate adjusted for the results of all RPM Auctions. Zonal CTR Credit Rate is subtracted from Zonal Capacity Price to estimate Net Load Price.

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: 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 as _____ ("Product type"), the 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: _____



Attachment C: Demand Resource Sell Offer Plan

The Demand Resource Sell Offer Plan (DR Sell Offer Plan) is a PJM template document, requiring the information set forth below, together with an accompanying signed PJM Demand Resource Officer Certification Form (DR Officer Certification Form). A completed DR Sell Offer Plan (including a signed DR Officer Certification Form) must be submitted to PJM no later than 15 business days prior to the relevant RPM Auction by Curtailment Service Providers (CSPs) that intend to offer Demand Resources (DR) in RPM Auctions. The DR Sell Offer Plan must provide information that supports the CSP's intended DR Sell Offers and demonstrates that the DR is being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through DR registrations for the relevant Delivery Year.

The DR Sell Offer Plan encompasses both existing DR and Planned DR. Existing DR is identified as end-use customer sites that the CSP has under contract for the current Delivery Year (i.e. end-use customer sites registered in the PJM eLRS system for the current Delivery Year)²⁰ and that the CSP intends to have under contract for the auction Delivery Year. Planned DR is that quantity of the CSP's intended total DR Sell Offer in excess of the CSP's existing DR and is subject to an RPM Credit Requirement.

Both the signed DR Officer Certification Form and the completed DR Sell Offer template must be submitted to PJM via email to rpm_hotline@pjm.com no later than 15 business days prior to the relevant RPM auction. PJM will review the DR Sell Offer Plan and notify the CSP via email no later than 10 business days prior to the RPM Auction if another CSP has identified the same end-use customer site(s) in their DR Sell Offer Plan and request supporting documentation, such as a letter of support from the end-use customer indicating that the end-use customer and CSP are likely to execute a contract for the auction Delivery Year. Supporting documentation must be submitted via email to the rpm_hotline@pjm.com no later than 7 business days prior to the RPM Auction. PJM will notify all CSPs via the eRPM system of the approved DR MW quantity by zone/sub-zone that the CSP is permitted to offer into the RPM Auction no later than 5 business days prior to the RPM Auction.

I. PJM Demand Resource Officer Certification Form

A DR Officer Certification Form is located in Attachment D of Manual 18 and is posted on the PJM web site. A signed DR Officer Certification Form must accompany the DR Sell Offer Plan. The DR Officer Certification Form specifies that the signing officer has reviewed the DR Sell Offer Plan, that the information provided therein is true and correct, and that the MW quantity that clears the auction is reasonably expected to be physically delivered through DR registrations for the relevant Delivery Year.

²⁰ For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM eLRS system for the subsequent Delivery Year may also be considered as existing DR provided the registrations are in "Confirmed" status by specified deadlines established by PJM and communicated to CSPs in advance of the DR Sell Offer Plan submittal deadline.



II. DR Sell Offer Plan Template

A DR Sell Offer Plan template (in Excel format) is provided on the PJM web site, and consists of the following three sections:

- A. DR Sell Offer Plan Summary
- B. Planned DR Details
- C. Schedule

A. DR Sell Offer Plan Summary

The DR Sell Offer Plan requires the following information to be provided:

- Company name
- Contact information (name, phone number and email address of submitter)
- Existing Nominated DR Value in ICAP MWs by zone/subzone that CSP intends to offer
- Planned Nominated DR Value in ICAP MWs by zone/subzone that CSP intends to offer

Existing DR is identified by the CSP as end-use customer sites that the CSP has under contract and registered in the PJM eLRS System for the current Delivery Year and that the CSP also intends to have under contract for the auction Delivery Year. Planned DR is identified by the CSP as described in the Planned DR Details section of the DR Sell Offer Plan template. Based on the information provided above, a total Nominated DR Value in MWs will be calculated for each zone/sub-zone as the addition of the Nominated DR Value of existing DR plus the Nominated DR Value of Planned DR. The total Nominated DR Value represents the maximum MW amount that the CSP intends to offer for the zone/sub-zone. The actual MW value(s) submitted by a CSP in their Sell Offer(s) for a zone/sub-zone during the auction bidding window may be less than the total Nominated DR Value in their DR Sell Offer Plan Summary.

Certain zones/sub-zones will be pre-identified by PJM as zones for which DR Sell Offers may require additional information to support the plan. Additional information may be required to support DR Sell Offer Plans for zones/sub-zones for which the quantity of cleared zonal/sub-zonal DR from the last BRA exceeds a threshold determined for the applicable LDA group (EMAAC, SWMAAC, Rest of MAAC, or Rest of RTO) as the higher of the maximum DR/ILR quantity registered in eLRS over the past three Delivery Years for the zones in the LDA group or the zonal DR potential quantity for the zones in the LDA group estimated based on a June 2009 FERC Staff Report on "A National Assessment of Demand Response Potential", where DR quantities are expressed in all cases as a percent of the forecasted zonal peak load. This determination of the identified zones is made each year prior to each BRA and is applicable to all auctions conducted for that Delivery Year. Zones or sub-zones remain on the identified list unless the threshold is not exceeded for three consecutive years. Identified zones for a Delivery Year will be posted by PJM to the pjw website no later than December 1 prior to the Base Residual Auction for such Delivery Year. Updates, if any, made to the 2009 FERC Staff Report will be subject to stakeholder review and considered for use in the establishment of thresholds in the future.



For these pre-identified zones/sub-zones, a CSP sell offer threshold is determined for each CSP; and DR sell offer quantities in excess of the CSP sell offer threshold will require site-specific information, as this quantity in excess of the CSP sell offer threshold should reflect Planned DR associated with end-use customer sites that the CSP has a high degree of certainty that it will physically deliver for the Delivery Year. The CSP sell offer threshold is determined as the higher of [(the CSP's maximum DR quantity registered in eLRS for that zone/sub-zone over the past three Delivery Years) or (the CSP's maximum cleared DR quantity for the past three BRAs for that zone/sub-zone) or (10 MW)].

B. Planned DR Details

The Planned DR Details section describes the program or strategy for procuring end-use customers and provides the details and key assumptions behind the development of the Planned DR quantities contained in the CSP's DR Sell Offer Plan. The Planned DR Details section is comprised of three sub-sections.

1. Description and Key Assumptions of Planned DR

The CSP must describe the program(s) that the CSP plans to employ to achieve the Planned Nominated DR Value indicated on the DR Sell Offer Plan Summary. This section must describe key program attributes and assumptions used to develop the Planned Nominated DR Value. This section must include, but is not limited to, discussion of:

- Method(s) of achieving load reduction at customer site(s)
- Equipment to be controlled or installed at customer site(s), if any
- Plan and ability to acquire customers
- Types of customer targeted
- Support of market potential and market share for the target customer base, with adjustments for existing DR customers within this market and the potential for other CSPs targeting the same customers
- Assumptions regarding regulatory approval of program(s), if applicable
- If offering a Direct Load Control (DLC) program, the following additional DLC program details must be provided:
 - Description of the cycling control strategy
 - A list of all load research studies²¹ (with study dates) used to develop the estimated nominated ICAP value (kW) per customer (i.e., the per-participant impact). A copy of all studies must be provided with the DR Sell Offer Plan. If the DLC program employs a radio signal, the CSP may elect to either submit a load research study to support the estimated nominated ICAP value per customer or utilize the per-participant impacts contained in the "Deemed Savings

²¹ Direct Load Control Research Study Guidelines are provided in PJM Load Forecasting and Analysis Manual, Manual 19, Attachment B.



- Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in the PJM Region” Report²².
- o Assumptions regarding switch operability rate (%)

2. Planned Nominated DR Value by Customer Segment

For those Planned Nominated DR Values for which an end-use customer site is not identified in section 3 of the Planned DR Details, the CSP must identify the Planned Nominated DR values by zone/sub-zone and by end-use customer segment. End-use customer segments include residential, commercial, small industrial (less than 3 MW), medium industrial (between 3 MW and 10 MW) and large industrial (greater than 10 MW). If known, the CSP may identify more specific customer segments within the commercial and industrial category.

By zone/sub-zone and by end-use customer segment, the CSP must provide estimates of the following information regarding the Planned DR component of the DR Sell Offer Plan:

- Number of end-use customers to be registered for auction Delivery Year
- Average Peak Load Contribution (PLC) per end-use customer in kW
- Average Nominated DR Value per customer in kW

Based on the above provided information, a total Planned Nominated DR Value in MW will be calculated for each end-use customer segment and for each zone/sub-zone. The total Planned Nominated DR values identified by customer segment and aggregated for each zone/sub-zone in Section 2 of the Planned DR Details plus the total Planned Nominated DR Values identified by end-use customer site(s) and aggregated for each zone/sub-zone in Section 3 of the Planned DR Details must equal the total Planned Nominated DR Value for each zone-sub-zone as identified in the DR Sell Offer Plan Summary.

3. Planned Nominated DR Value by End-Use Customer Site

This section must be completed by the CSP when the end-use customer is known at the time of the submittal of the DR Sell Offer Plan. This section must also be completed for DR Sell Offer quantities identified in the DR Sell Offer Plan Summary as requiring site-specific information, since this identified quantity should reflect Planned DR associated with specific end-use customer sites for which the CSP has a high degree of certainty that it will physically deliver for the relevant Delivery Year.

²² “Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in the PJM Region”, Final Report, RLW Analytics, March 2007, is available at <http://www.pjm.com/~media/documents/reports/20070406-deemed-savings-report-ac-heat.ashx>



The CSP must provide the following information:

- Customer EDC account number (if known)
- Customer name
- Customer premise address
- Zone/Sub-zone
- Customer segment
- Actual value (if known) or estimate of current PLC and estimate of expected auction Delivery Year PLC in kW
- Estimated Nominated DR Value in kW

In the event that multiple CSPs identify the same end-use customer site, the MWs associated with such site will not be approved for offering into the RPM auction by any of the CSPs, unless it can be supported by evidence, such as a letter of support from the end-use customer indicating that they have been in contact with the CSP and are likely to execute a contract with that CSP for the relevant Delivery Year. In the event that multiple letters of support indicating different CSPs are provided from the end use customer, the MWs associated with the end-use customer site will not be approved for offering into the RPM auction by any of the CSPs.

C. Schedule

The CSP must provide an approximate timeline for procuring end-use customer sites in order to physically deliver the total Nominated DR Value (existing and Planned DR) by zone/sub-zone in the DR Sell Offer Summary. For each zone/sub-zone and for each customer segment, the CSP must specify the cumulative number of customers and the cumulative Nominated DR Value associated with that group of customers that the CSP expects to have under contract by the beginning of each of the full Delivery Years occurring between the time of the auction and the auction Delivery Year.



Attachment D: Demand Resource Officer Certification Form

**PJM DEMAND RESOURCE SELL OFFER PLAN
OFFICER CERTIFICATION FORM**

Market Participant Name: _____
(“Participant”)

I, _____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. (“PJM”) and PJM Settlement, Inc. (“PJM Settlement”) are relying on this certification as evidence that Participant meets all requirements for participating in PJM’s Reliability Pricing Model (“RPM”) auctions, as set forth in the PJM Open Access Transmission Tariff (“PJM Tariff”), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (“RAA”), and in the PJM Manuals, hereby certify that, as of the date of this certification, to my knowledge and belief:

1. I have reviewed Participant’s Demand Resource Sell Offer Plan (the “Plan”) and the information supplied to PJM in support of the Plan is true and correct as of the date of this certification.
2. The Participant is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of this certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.
3. This certification does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Participant’s rights and obligations thereunder, including Participant’s ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

Date: _____

By: _____
(Signature)

Print Name: _____

Title: _____

Revision History

[Revision 27 \(01/22/2015\)](#)

- [Conforming revisions for FERC Order ER14-2940, accepted on 11/28/2014 and effective 12/01/2014, to revise the shape of Variable Resource Requirement Curve, the gross Cost of New Entry values, and the methodology to determine Net Energy and Ancillary Services Revenue Offset and Net Cost of New Entry. \(Sections 3.3.1, 3.3.2, 3.3.3, 3.4, & 3.4.1\)](#)

Revision 26 (01/01/2015)

- Conforming revisions for FERC Order ER15-134-000, accepted on 12/01/2014 and effective 01/01/2015, to allow Electric Distribution Companies to correct the Obligation Peak Load data up to 12 noon on the next business day after the Operating Day.

Revision 25 (10/30/2014)

- Conforming revisions for FERC Order ER11-2288-000, accepted on 01/31/2011 and effective 02/1/2011, to clarify the Annual DR Maintenance Outage process.

Revision 24 (07/31/2014)

- Revision to allow Auction Specific MW Transactions for a Delivery Year to be submitted following the completion of the RPM auction to which the transaction applies (Section 4.6.6).

Revision 23 (06/01/2014):

- Conforming revisions for FERC Order ER14-822, accepted on 05/09/2014, and effective on 06/01/2014 for various DR operational changes including: (i) requiring all Demand Resources participating in PJM's capacity market to serve as Pre-Emergency Load Response, unless the resource utilizes behind-the-meter generation that is subject to an environmental restriction; (ii) requiring, on a phased-in basis, that all Demand Resources reduce load reductions within 30 minutes of notification from PJM to the CSP, unless PJM has granted an exemption for a Demand Resource; (iii) limiting the duration of the required minimum load response reduction period from two hours to one hour; (iv) modifying measurement and verification for capacity compliance for all hours where PJM has dispatched the resource for at least 30 minutes of the wall clock hour; (v) modifying measurement and verification to allow aggregation of compliance results by compliance aggregation areas and provide further clarification on definition of "Load Management Event"; and (vi) CSP expected load reductions must be reported at more granular basis to include these changes. (Sections 4.3.1, 4.3.2, 4.3.4, 4.3.5, 4.3.6, 4.3.7, 4.3.9, 8.5, 8.5.1, and 8.5.2)
- Revision to include the ability to request an adjustment to the Nominated DR Value (in MWs) associated with an end-use customer site and used in the determination of a CSP's Existing MWs if certain criteria are satisfied. (Section 4.3.3)

Revision 22 (04/24/2014):

- Conforming revisions for FERC Order ER14-504, accepted on 01/30/2014, and effective on 01/21/2014 to retire the Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements and implement Limited Resource Constraints and Sub-Annual Resource Constraints effective with the 2017/2018 Delivery Year. (Sections 2.4.3, 2.4.3A, 2.4.4, 3.5, 5.3, 5.6.2, 5.7.5, 5.8.1, 11.1.3, 11.3, 11.4.1, & 11.9.1)
- Confirming revisions for FERC Order ER14-503 to employ Capacity Import Limits for RPM Auctions effective with the 2017/2018 Delivery Year. (Sections 2.1.2, 2.2, 2.3, 2.3.4, & 5.8.1)
- Conforming revisions for hydro and pumped storage units to perform rating tests during summer verification window in accordance with PJM Manual 21, Rules and Procedures for Determination of Generating Capability, Revision 11, effective 03/05/2014. (Section 8.4.6)
- Clarifications to deficiency/penalty charge rates when committed capacity resources did not clear in any RPM Auctions (Sections 9.1.1, 9.1.3, 9.1.5, 9.1.6, 9.1.7, & 9.1.9)
- Revisions to permit the maximum credit requirement specified in a credit-limited sell offer to exceed the RPM Credit Limit of a resource when the RPM Credit Adjustment Factor of the resource is less than one (Section 4.8.4).

Revision 21 (01/30/2014):

- Revisions to include demand resource product substitution rules for a load management event (Section 8.5).

Revision 20 (11/21/2013):

- Conforming revisions for FERC Order ER12-513, accepted on 01/31/2013 and effective 01/31/2013, to update Gross CONE values for CONE areas, region-wide Gross CONE value, and Benchmark CONE values. (Section 3.3.1)
- Conforming revisions for FERC Order ER12-513, accepted on 01/30/2012 and effective 01/31/2012, to revise definition of peak-hour dispatch to provide for day-ahead energy market revenues to be considered in the determination of Energy & Ancillary Services revenues. (Section 3.3.2)
- Conforming revisions for FERC Order ER13-535, accepted on 05/02/2013 and effective 02/05/2013, to revise the Minimum Offer Price Rule. (Section 5.2 and 5.3.5)
- Conforming revisions for FERC Order ER13-2140, accepted on 10/10/2013 and effective 10/15/2013, to change the deadline for submission of must-offer exemption requests for resources that are expected to be deactivated prior to or during the relevant Delivery Year. (Section 5.2)
- Conforming revisions for FERC Order ER13-1023, accepted on 04/30/2013 and effective 05/01/2013, to correct the NEPA qualification calculation and allow NEPA contingent sell offers in Base Residual Auction. (Section 5.3.3)

- Revision to correct LSE's options to hedge Locational Reliability charges by offering and clearing resources in Base Residual Auction and Incremental Auctions. (Section 1.2.1)
- Removal of obsolete reference to information on Transition Period. (Section 1.4)
- Revisions to correct number of LDAs and RECO's relationship to parent LDA. (Section 2.3.1)
- Revisions to correct terminology from "Capacity Injection Rights" to "Capacity Interconnection Rights, the defined term in OATT. (Section 4.2.6)
- Revisions to correct indemnification provision for Unit-specific transactions for Cleared MWs to conform with current tariff language. (Section 4.6.2)
- Revisions to correct business rules regarding start and end dates of Auction Specific MW transactions to conform with current tariff language. (Section 4.6.6)
- Removal of obsolete ILR references (Sections 4.6, 7.1, 8.5, & Attachment A).
- Revisions to clarify bill timing for Peak Hour Period Availability Charges/Credits, Generation Resource Rating Test Failure Charges/Credits, and PSM Compliance Charges/Credits (Sections 9.1.2, 9.1.5, and 9.1.6)
- Revisions to clarify that factor for On-Peak Load Management Compliance Penalty Rate is based on number of on-peak events.(Section 9.1.9)

Revision 19 (06/01/2013):

- Revisions for EKPC integration (Section 2.3.1)
- Revisions for Load Reduction Reporting for Emergency Demand Response capacity resources (Section 4.3.9)

Revision 18 (3/18/2013):

- Proposed revisions for Demand Resource Sell Offer Plan Enhancements (Sections 4.3.1, 4.3.3, 4.3.6, and 11.4.7, Attachments C and D)

Revision 17 (12/20/2012):

- Conforming revisions in Docket ER13-305-000 to add a Cleveland LDA (Section 2.3.1)
- Conforming revisions in Docket ER13-149-000 to incorporate task oriented deadlines to ensure timely submission of offer data, exception requests and unit-specific requests by market participants as well as timely responses thereto by PJM and the IMM
- Removal of language restricting replacement transactions on EE Resources with non-EE Resources (Section 8.7)
- Removal of ILR related content
- Removal of Transition Period (2007/08 – 2010/11 Delivery Year) related content
- Removal of pre-2012/13 Delivery Year-specific content
- Glossary updates

Revision 16 (09/27/2012):



- Conforming revisions for FERC Order ER11-4628 accepted on 12/14/2011 and effective 05/15/2012 to integrate Price Responsive Demand (PRD) in PJM Capacity Market.

Revision 15 (06/28/2012):

- Conforming revisions for FERC Order ER12-1372 accepted on 05/31/2012 and effective 06/01/2012, to clarify load management event and test compliance requirements related to sub-zonal and product-specific dispatch (Sections 4.3.1, 8.5, 8.5.2, 8.6, 9.1.7, and 9.1.9).
- Conforming revisions for FERC Order ER11-3322 conditionally accepted on 02/24/2012 and effective June 1, 2012, to implement a Demand Response Transition Provision (DR Capacity Transition Credit and Alternate DR Transition Credit) for the 2012/2013 through 2014/2015 Delivery Years (Sections 8.8 and 9.4).
- Conforming revisions for FERC Order ER12-513, accepted on 01/30/2012 and effective 01/31/2012, to revise point (a) on the VRR Curve (Section 3.4) and clarify New Entry Pricing provision (Section 5.3.3).
- Conforming revisions for FERC Order ER12-636, accepted on 02/16/2012, and effective 02/18/2012, to make corrections, clarifications identified as a result of the Quality Project Initiative including revisions for CTRs and ICTRs (Sections 5.8.3, 5.8.4, 6.1.1, 6.1.2, 6.1.3, 6.2, 6.3, 6.4, and 9.3.4) and removal of obsolete provisions for Single Customer LSE electing the FRR Alternative and the Unauthorized Load Transfer Charge (Section 11.2.3).
- Revisions to correct bill timing from monthly to weekly for Capacity Resource Deficiency Charges (Section 9.1.3), Locational Reliability Charges (Section 9.2.1), Auction Charges/Credits (Sections 9.3.1 and 9.3.2), CTR and ICTR Credits (Section 9.3.4), Auction Specific MW Transaction Credits (Section 9.3.5), and ILR Credits (Section 9.3.6).

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 4/13/2011 and 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)

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
- 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):

- 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.