PJM Manual 18:

PJM Capacity Market

Revision: 63

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Prepared By
Capacity Market & Demand Response Operations

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Approval

Approval Date: 09/10/2026~~01/12/2026~~ Effective Date: ~~12/17/2025~~09/24/2026

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Current Revision

Revision 63 (09/24/2026):

- Periodic Review updated to address:
  - **Conforming changes**
    - Periodic Review for reference resource and VRR curve (ER26-455-000)
      - 3.3 Parameters of the Variable Resource Requirement
      - 3.4 Plotting the Variable Resource Requirement Curves
      - 5.4 Sell Offers in RPM
    - Credit requirement file bilateral transactions (ER25-783-000)
      - 4.6 Bilateral Transactions
    - New penalty for derate caused by decrease in final Accredited AUCAP factor for the Delivery Year (ER25-2002)
      - 9.1.3 Capacity Resource Deficiency Charge
    - Changes to accommodate forecast load adjustments through the RPM and FRR processes (ER24-2447-003)
      - 7.2 Unforced Capacity Obligations and 7.3 RPM Zonal Scaling Factors
      - 7.3 RPM Zonal Scaling Factors
      - 11.2.1 Preliminary Unforced Capacity Obligation
    - GDECs changes (ER26-980)
      - 4.7.1 Resource Position for Generation Capacity Resources (GDECs #1)
      - 4.9 Aggregate Resources (GDECs #1)
      - 4.10 Seasonal Capacity Performance Resources (GDECs #1)
      - 9.1.7 DER Capacity Aggregation Resource Test Failure Charge (GDECs #5 and 10)
    - Load Management and PRD Non-PAI Event penalty (ER26-2319-000)
      - 4.10 Seasonal Capacity Performance Resources
      - 8.4A Non-Performance Assessment
      - 8.4B Non-PAI Event Compliance
      - 8.7 Load Management Test Compliance
      - 9.4 Penalties for Non-Performance of Price Responsive Demand

- 11.3, 11.4.7, 11.8.6, 11.8.7 - FRR Alternative

- **Clarifications**
  - 4.2 Generation Resources – clarified Existing vs Planned (study and decision point) and Internal vs External. Additional clarification to NOI and updated auction schedule. Capmod timing clarification
  - 4.6 and 4.9 - removed reference to EE resource based on prior order. Note – we only removed EE resource references that impact the auction or FRR plans. PJM will remove all references and retire M18B (EE M&V manual) once the rule change is finalized in the courts
  - 4.6.3 Exporting a Generation Resource - must be approved for must offer exception and included additional details on how to administer
  - 4.6.9 Ownership Change Transactions - additional details timing and how to administer
  - 5.4.1 Resource-Specific Sell Offers Requirements - additional details on must offer exception process
  - 8.7 Load Management Test Compliance – Reference impact of capacity resource deficiency shortfall on net testing shortfall
  - 8.6, Measuring Compliance during PAI for DR – Reference timing of PJM event performance review
  - 8.8 Replacement Resources – added information required to PAI retroactive replacement transactions, removed early replacement for export to comply with must offer process and clarified replacement must be from available capacity for the day
  - 9.1.7 DER Capacity Aggregation Resource Test Failure Charge – fixed reference from Load Management to DER
  - 9.1.10 Non-Performance Charge/Bonus Performance Credits- fixed rate to reflect RTO instead of LDA net CONE from previous tariff change

- **Removed references to outdated rules and old Delivery Years and retired Manuals**
  - 1.1 Overview of the PJM Capacity Market
  - 1.5 Transition to Capacity Performance – Removed outdated language/ footnote
  - 2.1 Overview of Resource Adequacy
  - 2.2 Role of Load Deliverability in the Reliability Pricing Model
  - 3A: Integration of Price Responsive Demand
  - 4.2.5 Equivalent Demand Forced Outage Rate (EFORd) (Through 2024/ 2025 Delivery Year)

- 4.7.2 Resource Position for Demand Resources
- 4.8.2 RPM Credit Requirement
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- 11.8.1 FRR Capacity Resource Deficiency Charges

- **Glossary – Updated and/or added definitions**
- **Punctuation, spelling and use of upper-case and lower-case letters – Updated as necessary**

~~**Revision 62 (12/17/2025):**~~

- ~~Add DER conforming changes based on Order 2222~~
- ~~Add expanded Load Management availability window (section 4)~~

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 PJM and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- Energy Market
- Regional Transmission Planning Process
- Reserve
- Accounting and Billing
- Administration
- Miscellaneous

For a complete list of all PJM manuals, go to the Library section on PJM.com.

About This Manual

The ***PJM Manual for PJM Capacity Market*** is one of the PJM reserve 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 4 attachments (labeled A through D). Both the sections and the attachments are listed in the table of contents beginning on page 2.

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:

- Control Center and Data Exchange Requirements (M-01)
- Pre-Scheduling Operations (M-10)
- Energy & Ancillary Services Market Operations (M-11)
- Balancing Operations (M-12)
- Regional Transmission Planning Process (14B)
- Generator Operational Requirements (M-14D)
- Energy Efficiency Measurement & Verification (M-18B)
- Load Forecasting & Analysis (M-19)
- ~~Reserve Adequacy Analysis (M-20)~~
- Reserve Adequacy Analysis (M-20A)
- ~~Rules and Procedures for Determination of Generating Capability (M-21)~~
- ~~Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis (M-21A)~~
- Rules and Procedures for Determination of Generating Capability (M-21B)
- Generator Resource Performance Indices (M-22)
- Open Access Transmission Tariff Accounting (M-27)
- 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.

Note:

Prior to the Transition Date, the Interconnection Service Agreement (ISA) was the form agreement included in the Tariff used to facilitate interconnection to PJM’s transmission system, which used the term “Interconnection Customer” to refer to generation interconnection customers, similar to the Project Developer”. While the ISA is no longer used for interconnection to the transmission system, pre-existing ISAs remain active. On and after the Transition Date, the Generation Interconnection Agreement (GIA) is used as the form agreement included in the Tariff to facilitate interconnection to PJM’s transmission system.

The Tariff defines the Transition Date as the later of: (i) the effective date of PJM’s Docket No. ER22-2110 transition cycle filing seeking FERC acceptance of Tariff, Part VII (Which is January 3, 2023) or (ii) the date by which all AD2 and prior queue window Interconnection Service Agreements or wholesale market participation agreements have been executed or filed unexecuted. Because this section condition happened last, this date establishes the Transition Date.

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”)
- A summary of the transition to Capacity Performance (see “Transition to Capacity Performance”)

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, through either the Reliability Pricing Model (RPM) consisting of a Base Residual Auction and three Incremental Auctions for a Delivery Year or the Fixed Resource Requirement (FRR) Alternative, 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, energy efficiency 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 was enhanced to recognize two product types for Capacity Resources, Capacity Performance Resources and Base Capacity Resources, 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 Resource product-type was phased out such that all capacity resources used to meet the PJM Region's reliability and resource adequacy needs are the Capacity Performance Resource product-type effective with the 2020/2021 Delivery Year.~~

The capacity market design is based on the Capacity Performance Resource product type. Capacity Market Sellers submit sell offers of Capacity Performance Resources on an annual basis. ~~Effective with the 2020/2021 Delivery Year, t~~The Capacity Market design includes the ability to offer Seasonal Capacity Performance Resources directly into the RPM Auction as an alternative to entering into a commercial arrangement to establish and offer an Aggregate Resource. Capacity Market Sellers may also submit sell offers of either Summer-Period Capacity Performance Resources or Winter-Period Capacity Performance Resources and the auction clearing optimization algorithm will be designed to clear equal quantities of off-setting seasonal capacity sell offers thereby creating an annual capacity commitment by matching a Summer-Period Capacity Performance Resource with a Winter-Period Capacity Performance Resource.

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 Capacity Resources, Planned Generation Capacity Resources, bilateral contracts for unit-specific Capacity Resources, existing Demand Resources, Planned Demand Resources, Energy Efficiency Resources, DER Capacity Aggregation Resources ("DER capacity 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 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 Capacity Resources located within the PJM market footprint; or
- Bilateral contracts for available unit-specific Capacity Resources that are Existing Generation Capacity Resources 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.
- External Generation Capacity Resource with an effective External Resource Must Offer Agreement
- Beginning with the 2025/2026 Delivery Year and subsequent Delivery Years, a Planned Generation Capacity Resource associated with a notice of intent to offer submitted

pursuant to Tariff, Attachment DD, section 5.5 shall be required to be offered by the Capacity Market Seller of such resource in the relevant 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 Capacity Resource without an effective External Resource Must Offer Agreement
- Planned Generation Capacity Resource (which includes new Generation Capacity Resources and planned upgrades to Existing Generation Capacity Resources); however, effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order to submit a Sell Offer in an RPM Auction
- Planned External Generation Capacity Resources (which includes new Generation Capacity Resources and planned upgrades to Existing Generation Capacity Resources)
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources
- DER capacity 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

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 has entered contractual arrangements with end-use customers 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 Capacity Resources, Energy Efficiency Resources, planned and existing DER capacity 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.
    - 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 Capacity Exchange 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 time frames presented throughout this Manual are for the steady-state condition of RPM.

1.5 Transition to Capacity Performance

Effective with the 2018/2019 Delivery Year[1], PJM introduced Capacity Performance requirement that requires Capacity Resources to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies~~ and procured two capacity product types through RPM Auctions: Capacity Performance Resources and Base Capacity Resources~~. ~~The Base Capacity Resource product-type was phased out such that only resources that meet the requirements of the Capacity Performance Resource product-type are 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 Resource 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. Internal and external Generation Capacity Resources, Capacity Storage Resources, DER capacity resources and Aggregate Resources that can qualify as Capacity Performance Resource 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, and Qualifying Transmission Upgrades are eligible to offer as the Capacity Performance product-type. Resources that clear and have a Capacity Performance Resource Commitment are subject to Non-Performance Assessment during the relevant Delivery Year in accordance with ***Section 8.4A of this Manual***.

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.~~

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 and satisfy the PJM reliability criterion. PJM performs an assessment of resource adequacy each year for an eleven-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~~three variables: the installed capacity of the resource, the Effective Load Carrying Capability ("ELCC") and the associated Performance Adjustment Factor ~~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 ***Resource Adequacy Analysis Manual*** ~~***(M-20) and***~~ ***(M-20A).***

Note:
The Installed Reserve Margin (IRM) is approved by the PJM Board of Managers no later than 75 days in advance of Base Residual Auction for the Delivery Year and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. 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 RTO Peak Load Forecast and the Zonal Peak Load Forecasts for the Delivery Year are determined by PJM in accordance with the ***Load Forecasting and Analysis Manual (M-19).***

Note:
The Preliminary RTO and Zonal Peak Load Forecasts are determined and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website .

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 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.

2.1.3.1 Deleted ~~Pool-wide Average EFORd (Through 2024/2025 Delivery Year)~~

~~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 EFORd values based on five years history, weighted for unit capability and expected time in service, attributable to all units that are expected to be in service during the Delivery Year. The Pool-Wide Average EFORd includes 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 **_Resource Adequacy Analysis Manual (M-20)_**.~~

Note:
~~The **_Pool-wide average EFORd_** is posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. 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.~~

2.1.3.2 Pool-wide average Accredited UCAP Factor (Starting 2025/2026 Delivery Year)

The Pool-wide average Accredited UCAP Factor for the Delivery Year is the ratio of the total Accredited UCAP to total installed capacity of all resources, as determined pursuant to RAA, Schedule 9.2, that are included in the determination of the Forecast Pool Requirement, stated in percent. The Pool-wide average Accredited UCAP Factor is determined by PJM in accordance with the Resource Adequacy Analysis Manual (M-20A).

Note: The **Pool-wide average Accredited UCAP Factor** is posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. An updated Pool-wide average Accredited UCAP Factor is posted one month prior to its use in an Incremental Auction for the Delivery Year. The Pool-wide average Accredited UCAP Factor that is posted for the Third Incremental Auction for the Delivery Year is the final Pool-wide average Accredited UCAP Factor 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.

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.

~~For Delivery Years through the 2024/2025 Delivery Year, the Forecast Pool Requirement (FPR) for the Delivery Year is equal to (1 + Installed Reserve Margin) times (1-Pool-wide Average EFORd).~~[2]

Starting with the 2025/2026 Delivery Year and for all subsequent Delivery Years, the Forecast Pool Requirement (FPR) for the Delivery Year is equal to (1 + Installed Reserve Margin) times (Pool-wide average Accredited UCAP Factor).

$$ForecastPoolRequirement(FPR) = (1 + InstalledReserveMargin) * (Pool - wide \quad average \quad Accredited \quad UCAP \quad Factor)$$

> **Note:**
> The ***Forecast Pool Requirement (FPR)*** is approved by the PJM Board of Managers by no later than 75 days in advance of Base Residual Auction for the Delivery Year and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website . 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.

2.1.5 Effective Load Carrying Capability and ELCC Resources in Capacity Exchange

Effective Load Carrying Capability (ELCC) establishes the Accredited UCAP value for ELCC Resources. ~~Through the 2024/2025 Delivery Year, an ELCC Resource is a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource. Beginning with the 2025/2026 Delivery Year, a~~An ELCC Resource includes all Generation Capacity Resources, DER capacity resources (beginning with the 2028/2029 Delivery Year) and Demand Resources. ELCC analyzes historical hourly weather and load shapes relative to hourly output of ELCC Resources in order to quantify the ability of such resources to satisfy the reliability criterion. The ELCC method is described in ~~**Manual 20 and**~~ **Manual 20A** (**PJM Resource Adequacy Analysis**), and the calculation of Accredited UCAP for an ELCC Resource is described in ~~**Manual 21A (Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis) and**~~ **Manual 21B (Rules and Procedures for Determination of Generating Capability)**.

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

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 Capacity Emergency Transfer Objective (CETO) of each LDA which is used to determine the amount of generation required to meet the locational reliability standard. For more details regarding the CETO analysis, please see ***Resource Adequacy Analysis Manual ~~(M-20) and~~ M20A.***

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: Regional 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.

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, energy efficiency 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.

Note:
CETOs and CETLs for the LDAs to be modeled in all RPM Auctions for the Delivery Year are posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. Updated CETOs and CETLs for the modeled LDAs are posted one month prior to its use in an Incremental Auction for the Delivery Year.

2.3.1 Locational Deliverability Areas

In the development of the Reliability Pricing Model, the RTEP Process identified 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** (may be listed as DAY)
- RTO => Western PJM => **Duquesne** (may be listed as DLCO or DUQ)
- RTO => Western PJM => **APS**
- RTO => Western PJM => **ATSI**
- RTO => Western PJM => ATSI => **Cleveland** (may be listed as ATSI-Cleveland)
- RTO => Western PJM => **DEOK**
- RTO => Western PJM => **EKPC**
- RTO => Western PJM => OVEC
- RTO => **Dominion (**may be listed as DOM)
- RTO => **MAAC**[3]
- RTO => MAAC => **WMAAC**[4]
- RTO => MAAC => WMAAC => **MetEd**

3 MAAC LDA represents the Mid-Atlantic Region (MAR).

- RTO => MAAC => WMAAC => **PPL** (may be listed as PL)
- RTO => MAAC => WMAAC => **Penelec** (may be listed as PENLC)
- RTO =>MAAC => **EMAAC**[5]
- RTO => MAAC => EMAAC => **AE (**may be listed as AECO)
- RTO => MAAC => EMAAC => **PSEG** (may be listed as PS)
- RTO => MAAC => EMAAC => PSEG => **PSEG northern region** (may be listed as PSEG N or PSNORTH)
- RTO => MAAC => EMAAC => **PECO**
- RTO => MAAC => EMAAC => **JCPL**
- RTO => MAAC => EMAAC => **DPL**
- RTO => MAAC => EMAAC => DPL => **DPL southern region (**may be listed as DPL S or DPLSOUTH)
- RTO => MAAC => EMAAC =>RECO
- RTO => MAAC => **SWMAAC**[6]
- 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. 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 2.4, 3, and 5 of this Manual for the details on Reliability Requirement, Variable Resource Requirement Curve, and RPM Auctions, respectively. 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 with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website.

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4 WMAAC LDA represents the Western Mid-Atlantic Region (WMAR)

5 EMAAC LDA represents the Eastern Mid-Atlantic Region (EMAR)

6 SWMAAC LDA represents the Southwest Mid-Atlantic Region (SWMAR).

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 (1) be allocated across zones based on each zone’s pro-rata share of load in such LDA and (2) within each zone to all LSEs serving load in the LDA, pro rata based on such loads.

2.3.3 Creation of New Locational Deliverability Areas (LDAs)

A prudent planning practice is to continuously monitor system performance and study transmission constraints as they develop. Triggers and criteria to consider a new LDA are specified in ***Manual 14B:PJM Regional Transmission Planning Process, Attachment C, PJM Deliverability Testing Methods***, based on RTEP Market Efficiency Analysis and RTEP Long Term Planning. PJM will make a filing with FERC to amend RAA Schedule 10.1 to add a new LDA (including a new LDA that is an aggregate of Zones), if such new area is projected to have a CETL less than 1.15 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.

2.4 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 the total **unforced capacity** required.

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 and for EE Resources as described in Section 2.4.5 of this manual. 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, plus any necessary adjustment for EE Resources per Section 2.4.5 of this manual, and less any necessary adjustment for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

$$RTORelReq =$$

$$(RTOPeakLoadForecast * FPR) - \Sigma\ PrelimUCapOblig_{FRR\ Entity} + Adj_{EE} - Adj_{PRD}$$

2.4.2 Reliability Requirement in Locational Deliverability Areas

The Locational Deliverability Area Reliability Requirement is the projected internal capacity[7] (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, plus any necessary adjustment for EE Resources per Section 2.4.5 of this manual, 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.

$$\mathrm{LDARelReq} =$$

$$(LDAInternalCapacity + LDACETO - MinInternalResources_{FRR\ Entity}) + Adj_{EE} - Adj_{PRD}$$

2.4.3 Deleted

2.4.3A Deleted

[7] See ~~Manual 20~~: PJM Resource Adequacy Analysis ~~and~~ Manual 20A.

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 as explained in Section 3.4 of this manual.

2.4.5 Adjustments to RPM Auction Parameters for EE Resources (through the 2025/2026 Delivery Year only)

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, designed to achieve a permanent, continuous reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the EE Resource is proposed. Because energy efficiency measures are reflected in the peak load forecast for a Delivery Year for which an auction is being conducted, the auction parameters must be adjusted as described below for the EE Resource(s) that are proposed for that auction in order to avoid double-counting of the energy efficiency measures.[8]

For each auction, the Reliability Requirement of the RTO and each affected LDA will be increased by the total UCAP Value of all EE Resource(s) for which PJM accepted an EE M&V Plan for that auction, and upon which PJM created an EE Resource to be offered into that upcoming auction.[9] If a first-pass auction solution clears fewer EE Resource MW than the amount by which the Reliability Requirement of the RTO and each affected LDA was increased, the Reliability Requirement increase of the RTO and each affected LDA will be reduced such that it is set equal to the cleared EE MW quantity of the first-pass auction solution and the auction will be solved again. This step is repeated until the cleared EE Resource MW across the RTO equals the total EE Addback MW quantity of the RTO or until the sum of squares of the differences across all LDAs increases relative to the previous iteration. The RTO/LDA reliability

[8] Effective for RPM Auctions conducted after January 2016.

[9] The increase in Reliability Requirement is accomplished in each BRA by shifting the VRR Curve of the RTO and each affected LDA to the right by the MW quantity of the increase. The increase in Reliability Requirement is accomplished in each IA by the submittal of a PJM Buy Bid in each affected LDA with the B~~b~~uy B~~b~~id MW quantity set equal to the increase.

requirement increases will be considered in the development of the RTO/LDA VRR Curves as explained in Section 3.4 of this manual.

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 (see "Definition and Purpose of the Variable Resource Requirement")
- The parameters of the Variable Resource Requirement (see "Parameters 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 (LDAs) within the PJM region that are to be modeled in the auction. 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 no adjustments related to FRR Entities' Preliminary Unforced Capacity Obligations. 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 for RPM Auction.

Note:
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 with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website.

The Variable Resource Requirement Curve for the PJM Region is based on a target level (i.e., the PJM Region Reliability Requirement), Cost of New Entry, and Net Energy & Ancillary Services (E&AS) Revenue Offset.

For each LDA, the LDA Variable Resource Requirement Curve is based on a target level (i.e., the LDA Reliability Requirement), Cost of New Entry, and Net E&AS Revenue Offset.

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 or the LDA Reliability Requirement , 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 a single General Electric Frame 7HA turbine as defined in the OATT.

~~The gross Cost of New Entry values for the following four CONE Areas for the 2022/2023 Delivery Year are specified in the OATT, Attachment DD, 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, OVEC (“CONE Area 3”); and~~
4. ~~METED, PENELEC, PPL (“CONE Area 4”).~~

~~For the 2023/2024 Delivery Year, the gross CONE values specified in the OATT for the 2022/2023 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, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus appreciation scheduled under federal tax law, 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 2023/2024 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 55%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 25%). 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, up to and including the 2025/2026 Delivery year, the Benchmark CONE values for all CONE areas except CONE area 5 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, and then multiplying the result by 1.022, to establish the CONE values for such Delivery Year for CONE areas 1 through 4 listed above.~~

~~For the 2025/2026 Delivery Year, a new CONE Area 5 encompassing only the ComEd Zone shall be established and the ComEd Zone will be removed from CONE Area 3. For the 2025/2026 Delivery Year, the Cost of New Entry for CONE Area 5 will be equal to the product of the Cost of New Entry determined for CONE Area 3 for the 2025/2026 Delivery Year multiplied by an asset life factor of 1.0069.~~

~~Through the 2024/2025 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 listed above. For the 2025/2026 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for all five CONE Areas.~~

The gross Cost of New Entry values for the following five CONE Areas for the 2026/2027 Delivery Year are specified in the OATT, Attachment DD, Section 5.10 (a) (iv)(C):

1. AE, DPL, JCPL, PECO, PSEG, RECO ("CONE Area 1");

2. BGE, PEPCO ("CONE Area 2");

3. AEP, APS, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3"); and

4. METED, PENELEC, PPL ("CONE Area 4").

5. COMED ("CONE Area 5")

For the 2026/2027 Delivery Year and 2027/2028~~subsequent~~ Delivery Year~~s~~, the gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the five CONE Areas. For the 2027/2028 Delivery Year, the gross CONE values specified in the OATT for the 2026/2027 Delivery Year for each CONE Area (except for CONE Area 5) 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 for the 2027/2028 Delivery Year for CONE Areas 1 through 4.

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 40%), the BLS Producer Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 15%). 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 the 2027/2028~~subsequent~~ Delivery Year~~s~~, the Benchmark CONE values for all CONE areas except for CONE Area 5 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 for such Delivery Year for CONE Areas 1 through 4.

For the 2027/2028 Delivery Year~~ through and including the 2029/2030 Delivery Year~~, the CONE for CONE Area 5 ~~for a given delivery year~~ shall be set equal to the product of the CONE of CONE Area 3~~ as determined for the relevant Delivery Year~~, multiplied by the asset life factor of ~~applicable to that Delivery Year where such asset life factors are~~ 1.0376 ~~for the 2027/2028 Delivery Year, 1.0581 for the 2028/2029 Delivery Year, and 1.0818 for the 2029/2030 Delivery Year~~.

The gross Cost of New Entry values for the following five CONE Areas for the 2028/2029 Delivery Year are specified in the OATT, Attachment DD, Section 5.10 (a) (iv)(D):

1. AE, DPL, JCPL, PECO, PSEG, RECO ("CONE Area 1");

2. BGE, PEPCO ("CONE Area 2");

3. AEP, APS, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3");

4. METED, PENELEC, PPL ("CONE Area 4");

5. COMED ("CONE Area 5")

For the 2028/2029 Delivery Year and subsequent Delivery Years, the gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the five CONE Areas. For the 2029/2030 Delivery Year, the gross CONE values specified in the OATT for the 2028/2029 Delivery Year for each CONE Area 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 and BEA Price Deflators to establish the CONE values used for the 2029/2030 Delivery Year for CONE Areas 1 through 5.

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 (NAICS 2371) (weighted 15%), the BLS Producer Index for Construction Materials and Components (weighted 10%), the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 46%), and the Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2017=100 (weighted 29%). 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, Pennsylvania for CONE Area 4, and Illinois for CONE Area 5.

For subsequent Delivery Years, the Benchmark CONE values for all CONE areas except for CONE Area 5 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 for such Delivery Year for CONE Areas 1 through 5.

For the 2029/2030 Delivery Year through and including the 2031/2032 Delivery Year, the CONE for CONE Area 5 shall be multiplied by the asset life factor applicable to that Delivery Year where such asset life factors are 1.025 for the 2029/2030 Delivery Year, 1.054 for the 2030/2031 Delivery Year, and 1.088 for the 2031/2032 Delivery Year.

3.3.2 Net Energy and Ancillary Services Offset

Pursuant to Attachment DD, Section 5.10(a)(v and v-1) of the PJM Tariff, PJM determines a Net Energy and Ancillary Services (E&AS) Revenue Offset for the PJM Region and for each Zone.

~~**For Delivery Years 2023/2024 through and including 2025/2026**~~

~~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 Attachment DD, Section 5.10(a)(v) of the PJM Tariff.~~

~~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 with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference Resource as set forth in Attachment DD, Section 5.10(a)(v) of the PJM Tariff; (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.~~

~~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 in this section 3.3.2 with a fuel transmission adder appropriate to the zone.~~

~~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~~.

For the 2026/2027 Delivery Year and 2027/2028~~subsequent~~ Delivery Year~~s~~

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is the annual average of the revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets from three separate simulations, with each simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such shapes. The projected Net E&AS Revenue Offset will be determined for the PJM Region and each Zone as specified in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff

The annual average of energy revenues for the PJM Region is based on (1) heat rate and other characteristics of such Reference Resource; (2) F~~f~~orward D~~d~~aily N~~n~~atural G~~g~~as P~~p~~rices averaged across the fuel pricing points specified in the table above with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference Resource; (4) Forward Hourly LMPs for the PJM Region; (4) Forward Hourly Ancillary Services Prices; and (5) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.

Projected EAS Dispatch means, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource's offer and operating parameters.

The Net E&AS Revenue Offset for each Zone 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) Forward Hourly LMPs of each such Zone are used in place of the Forward Hourly LMPs of the PJM Region; and (2) F~~f~~orward D~~d~~aily N~~n~~atural G~~g~~as P~~p~~rices are used for each such Zone based on the fuel price point to Zone mapping shown in the table below.

The Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and Forward Daily Natural Gas Prices used in the calculation of the Net E&AS Revenue Offset are determined as defined in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff.

In the determination of Forward Hourly LMPs, the ComEd Zone is mapped to N. Illinois Hub, the AEP, ATSI, DAY, DEOK, DUQ, EKPC and OVEC Zones are mapped to the AEP-Dayton Hub, and all other Zones are mapped to the Western Hub. In addition, several of the fuel pricing points of the table below lack sufficient liquidity and are therefore mapped to more liquid hubs for the purposes of calculating Forward Daily Natural Gas Prices. For the purpose of calculating Forward Daily Natural Gas Prices, Transco-Z6 (non-NY) is used in place of Transco-Z5 Dlv and Transco-Z6 (NY)

For the 2028/2029 and subsequent Delivery Years

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is the 67th percentile of all of the calculated zonal Net E&AS Revenue Offsets that the Reference Resource is projected to receive from the PJM energy and ancillary service markets from the three separate simulations, with each simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. The projected Net E&AS Revenue Offset will be determined for the PJM Region and each Zone as specified in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff.

Each Net E&AS Revenue Offset simulation is based on (1) heat rate and other characteristics of such Reference Resource; (2) Forward Daily Natural Gas Prices averaged across the fuel pricing points specified in the table below with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference Resource; (4) Forward Hourly LMPs for the PJM Region; (4) Forward Hourly Ancillary Services Prices; and (5) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.

Projected EAS Dispatch means, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource's offer and operating parameters.

The Net E&AS Revenue Offset for each Zone 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) Forward Hourly LMPs of each such Zone are used in place of the Forward Hourly LMPs of the PJM Region; and (2) Forward Daily Natural Gas Prices are used for each such Zone based on the fuel price point to Zone mapping shown in the table below.

The Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and Forward Daily Natural Gas Prices used in the calculation of the Net E&AS Revenue Offset are determined as defined in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff.

Zone to Fuel Pricing Point Mapping

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, & JCPL	Transco-Z6 (non-NY)
COMED	Chicago Citygates
DUQ, METED, PECO, & PPL	TETCO M3
PEPCO & DOM	Transco Z5 DIv
AEP, OVEC	Columbia-Appalachia TCO
DAY, DEOK, ATSI, EKPC	Mich Con
APS & PENELEC	Dominion South
PSEG & RECO	Transco Z6 (NY)

3.3.3 Net Cost of New Entry

For the 2026/2027 Delivery Year and 2027/2028 Delivery Year

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.

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 New~~t~~ Entry value for such Zone minus the Net E&AS Revenue Offset for such Zone. The Net Cost of New Entry for the Zone is used for a sub-zonal LDA. 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.

For the 2028/2029 and subsequent Delivery Years

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 67^{th} percentile of all the calculated zonal Net E&AS Revenue Offsets for the PJM Region.

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 New Entry value for such Zone minus the Net E&AS Revenue Offset for such Zone. The Net Cost of New Entry for a multi-zonal LDA is the applicable gross Cost of New Entry value for such multi-zonal LDA minus the 67^{th} percentile of all of the calculated zonal Net E&AS Revenue offsets for all Zones within that LDA. The Net Cost of New Entry for the Zone is used for a sub-zonal LDA.

3.4 Plotting the Variable Resource Requirement Curve

~~For the 2022/2023 Delivery Year through and including the 2024/2025 Delivery Year, 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[10] multiplied by (100% plus the approved IRM% minus 1.2%) divided by (100% plus approved IRM %)].~~

~~Basis for Price at Point a:~~

~~Basis for Quantity at Point a:~~

10 ~~The Reliability Requirement used in the unforced capacity quantity equation for points (a), (b), and (c) excludes any adjustment for PRD or EE (through the 2025/2026 Delivery Year for EE only). The VRR Curve that results is adjusted leftward to reflect the impact of PRD and rightward to reflect the impact of EE through the 2025/2026 Delivery Year as explained in section 3.4.1 of this manual.~~

See applicable Delivery Year for calculation of points along the Variable Resource Curve.

~~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 1.9%) divided by (100% plus approved IRM%)]..~~

~~Basis for Price at Point b:~~

~~Basis for Quantity at Point b:~~

~~c. The price is equal to zero and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 7.8%) divided by (100% plus approved IRM %)].~~

~~Basis for Price at Point c:~~

~~Basis for Quantity at Point c:~~

For the 2025/2026 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve is plotted on a graph on which the Unforced Capacity is on the x-axis and price is on the y-axis.

For the 2025/2026 Delivery Year only, 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 (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity is equal to (PJM Region Reliability Requirement multiplied by 98.9%).

b. The price is equal to 0.75 times Net CONE divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 101.6%).

c. The price is equal to zero and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 106.8%).

For the 2026/2027 and 2027/2028 Delivery Years, the Variable Resource Requirement Curve is plotted using the following three points 1, 2, and 3:

1) The price is equal to: the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];

2) The price is equal to: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and

3) The price is equal to zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].

For the 2028/2029 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve is plotted using the following three points 1, 2, and 3:

1) The price is equal to the greater of [{1.15 times the Cost of New Entry minus 0.75 times the Net E&AS Revenue Offset} or 0.2 times the Cost of New Entry] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity is equal to (PJM Region Reliability Requirement multiplied by 99%).

2) The price is equal to 50% of point 1 divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 101.5%).

3) The price is equal to zero and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 106.0%).

For the BRAs for the 2026/2027 through 2029/2030~~and 2027/2028~~ Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted using the points indicated above the appropriate Delivery Year. The plotted Variable Resource Requirement Curve will then be intersected by a horizontal line from the y-axis equal to $256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource until such line intersects the applicable curve for that Delivery Year.~~is based on the following: (i) a straight line connecting points (1) and 2), and (ii) a straight line connecting points (2) and (3), where:~~

- ~~For point (1), price equals: {the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the~~

~~applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];~~

- ~~For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and~~
- ~~For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].~~

Once the horizontal line intersects above the curve, the Variable Resource Requirement Curve shall follow the curve that is based on the applicable~~above~~ points for the Delivery Year until the price reaches $138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at $138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource to infinity.

3.4.1 Plotting the Variable Resource Requirement Curves

The graph below illustrates[1] the process for plotting the Variable Resource Requirement curve. 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).

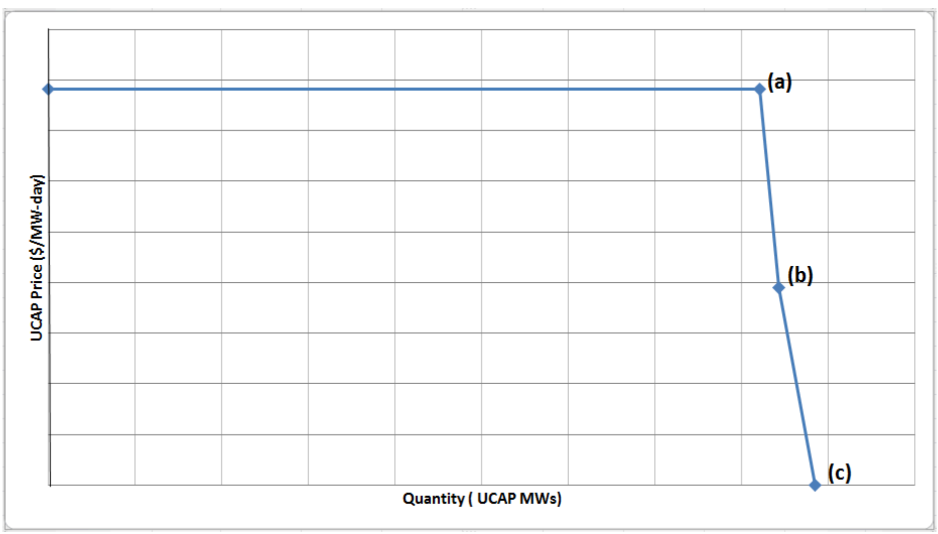

Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve

The same process shall be used to establish the Variable Resource Requirement Curve for each LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement, and the 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.

The Variable Resource Requirement Curve will be further adjusted to reflect the impact of any EE addback through the 2025/2026 Delivery Year. The Variable Resource Requirement Curve will be shifted rightward along the horizontal axis by a quantity equal to the EE addback MW quantity as explained in Section 2.4.5. The Variable Resource Requirement Curve for each LDA in which EE 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. The demand curve in these auctions will be built based on a combination of B~~b~~uy B~~b~~ids submitted by market participants and B~~b~~uy B~~b~~ids, if any, submitted by PJM.

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

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

- The 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 the prior Incremental Auction for the same Delivery Year.
- Plus the amount of non-viable commitments associated with transition provision of OATT, Attachment DD, Section 5.5A(c)(i)(B) (i.e., Prior CIL Exception External Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year) and RAA, Schedule 6, section L.9 (i.e., EE Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year due to prohibition of EE participation by a Relevant Electric Retail Regulatory Authority).
- 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 B~~b~~uy B~~b~~id represented by the portion of the Updated VRR Curve Increment extending right from the left-most portion on that curve in a MW amount equal to the positive quantity. PJM will employ a PJM B~~b~~uy B~~b~~id 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 (adjusted, if applicable, by change in Unforced Capacity commitments associated with transition provision of OATT, Attachment DD, Section 5.5A(c)(i)(B) and RAA Schedule 6, section L.9).

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 (adjusted, if applicable, by change in Unforced Capacity commitments associated with transition provision of OATT, Attachment DD Section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9).

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”)
- The registration requirements of price responsive demand (see “ Registration of Price Responsive Demand”)
- The performance requirements of price responsive demand in the delivery year (see “Performance Requirements of Price Responsive Demand”)
- The bilateral transfer of a price responsive demand obligation (see “PRD Bilaterals”)

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 lead 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 must meet 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 Capacity Exchange 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 is subject to Non-Performance Assessment during the Delivery Year. Failure to comply during a Performance Assessment Interval will result in a Non-Performance Charge for such interval. If PJM does not have an Emergency Action that triggers a Non-Performance Assessment during the Delivery Year that requires a PRD registration to reduce to the Firm Service Level (FSL) in the registration, then PRD registrations in the zone that did not have compliance measured for a Performance Assessment Interval or Non-PAI Event during the Delivery Year must demonstrate that such registrations were tested for a one-hour period during any hour from 10:00 AM EPT to 10:00 PM EPT during June through October or the following May of the relevant Delivery Year. Failure of such PRD registrations in the zone to reduce to the aggregate FSL levels of such registrations in a test will result in a PRD Test Failure Charge.

The PRD Provider will receive a Daily PRD Credit ($/MW-day) during the Delivery Year. A PRD Provider under the FRR Alternative will not be eligible to receive a Daily PRD Credit ($/MW-day) during the Delivery Year.

3A.2 Deleted

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;
- subject to Supervisory Control as defined in the Reliability Assurance Agreement to curtail the demand should PJM declare an emergency condition; and
- Shall exclude Critical Natural Gas Infrastructure

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. ~~Prior to the 2022/2023 Delivery Year, 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 Real-time LMP at the applicable location has exceeded the level at which the load has committed to reduce. Effective with the 2022/2023 Delivery Year, t~~To the extent load was not already reduced, the PRD Provider is required to have remote capability to decrease the load at each location contained in the PRD Registration to the required service level when an Emergency Action triggers a Performance Assessment Interval and the Real-time LMP at the applicable location has exceeded the level at which the load was 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. ~~Effective with 2022/2023 Delivery Year,~~ PRD registrations with an approved exception to the automation requirement will not have compliance measured during the Performance Assessment Intervals that fall within the 15 minute response allowance.

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 Action. 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.

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.

Estimates of the substation/sub-zonal/zonal peak load contribution (PLC) values of such PRD Provider's price responsive load for the Delivery Year if such load were not to be reduced in response to price are to be provided in the PRD Plan. The substation/ sub-zonal/zonal PLC values will be aggregated to determine the Zonal/LDA PLC value for the PRD Provider in such Zone/LDA. In addition, an estimate of the representative loss factor for the Zone/LDA is to be provided. The Firm Service Level (FSL) is the level to which the price-responsive load will be reduced during the Delivery Year when an Emergency Action triggers a Performance Assessment Interval during the Delivery Year. The quantity of load that will be consumed at a price equal to the applicable energy market offer cap for the relevant Delivery Year represents the FSL. The locational FSL quantities (at substation/sub-zonal/zone) will be aggregated to determine the Zonal/LDA FSL 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 Zonal/LDA PLC value minus (the Zonal/LDA FSL quantity times the loss factor).

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.
- Peak Load Contribution Value of PRD by applicable electrical location, if available, or by Sub-zone/Zone Firm Service Level (FSL) 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 aggregate Zonal/LDA Peak Load Contribution value, aggregate Zonal/LDA FSL 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.
- 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:
  - 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.
  - 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.
  - 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 Deleted

3A.4.2.2 Verification of Contractual Arrangement with PRD Provider

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 Capacity Exchange 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 ($/MW-day) pair(s) that meet the following requirements.
    - Up to ten quantity(MW)-price($/MW-day) pair segments for a zone/sub-zone may be submitted
    - A minimum and maximum Nominal PRD Value quantity must be submitted for each segment
    - The smallest increment that may be submitted for a Nominal PRD Value MW quantity is 0.1 MW.
    - 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.
    - 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.

- 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.
- 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 Capacity Exchange 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 DR Hub 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 Deliver 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 EDC, PLC, FSL, EDC-assigned loss factor, PNODE, and whether the load is being served under the RPM or the FRR Alternative. The FSL in the registration represents the load level that the site is committing to be at during a Performance Assessment Interval in the Delivery Year.

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 located at the same PNODE.

The Nominal PRD Value calculated for a registration is equal to the PLC in the registration minus (the FSL in the registration times the 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 DR Hub 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 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 DR Hub 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 Non-Performance Assessment during the Delivery Year in accordance with Section 8.4A. In the absence of a Performance Assessment Interval during the relevant Delivery Year that required the 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 Performance Assessment Interval, 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 Non-Performance Assessment 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 DR Hub 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 Deleted

3A.6.2A Compliance during a Performance Assessment Interval

A PRD Provider is subject to a Non-Performance Assessment in accordance with Section 8.4A. Compliance is measured for a PRD registration upon declaration of a Performance Assessment Interval in same sub-zone/zone of such PRD registration and when the PRD Curve associated with such registration in the PJM Real-time Energy Market has a price point where demand reduction is expected at Real Time LMP recorded during the Performance Assessment Interval. A PRD registration shall not be considered in the calculation of a Performance Shortfall or Bonus Performance when the PRD Curve associated with such registration in the Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

A PRD registration with an approved exception to the automation requirement will not have compliance measured during Performance Assessment Intervals that fall within the 15 minute response allowance. A PRD Provider will only be subject to Non-Performance Assessment and associated Non-Performance Charges/Bonus Performance Credits for those PRD registrations that were measured for compliance.

PRD Providers are responsible for the submittal to PJM of all meter information required to complete this measurement and verification for each Performance Assessment Interval during the Delivery Year that the PRD was required to respond. PJM requires that actual metered data at the end-use customer site for all hours during the day of a Performance Assessment Interval be submitted to PJM via DR Hub system within 45 days after the end of the month in which a Performance Assessment Interval occurs, with accountability for failure to do so. PJM verifies compliance on a registration basis by reviewing the data submitted by the PRD Provider through the DR Hub system.

The actual load reduction provided by the registration for the Performance Assessment Interval is calculated as the registration's Peak Load Contribution minus (the metered load multiplied by the loss factor). A load reduction will only be recognized if metered load multiplied by the loss factor is less than the Peak Load Contribution. When five minute revenue meter data is not available to determine compliance of a PRD registration for a Performance Assessment Interval, the actual load reduction for a Performance Assessment Interval is calculated as the actual hourly load reduction for the hour ending that includes the Performance Assessment Interval(s) multiplied by (twelve divided by the number of five minute intervals the PRD registration was to be measured for compliance). The actual load reduction for a registration for a Performance Assessment Interval is capped at the Peak Load Contribution of the registration. If the PRD Provider failed to submit actual metered data for the registration for all hours during the day of a Performance Assessment Interval, the actual load reduction for such registration will be equal to zero MWs.

For each registration in an Emergency Action Area, the Actual Performance is equal to the actual load reduction for such registration for the Performance Assessment Interval. The Actual Performance for a PRD Provider in the Emergency Action Area for the Performance Assessment Interval is equal to the sum of the Actual Performance of the PRD registrations that were measured for compliance for such Emergency Action Area and Performance Assessment Interval. If a PRD Provider registered PRD to satisfy RPM PRD commitments and PRD to satisfy FRR PRD commitments, an Actual Performance quantity will be calculated for registrations tied to RPM and a separate Actual Performance quantity will be calculated for registrations tied to FRR.

The Expected Performance for a PRD Provider for the Emergency Action Area and Performance Assessment Interval is equal to the Nominal PRD Value committed by PRD Provider in the Emergency Action Area, adjusted to account for any PRD registrations in the Emergency Action Area that were not subject to compliance measurement. If a PRD Provider committed PRD to RPM and committed PRD to FRR, an Expected Performance quantity will be calculated for RPM commitments and a separate Expected Performance quantity will be calculated for FRR commitments.

The Performance Shortfall for a PRD Provider is calculated as Expected Performance minus the Actual Performance. If the Performance Shortfall related to RPM commitments is negative number, the PRD Provider is subject to a Non-Performance Charge, in accordance with Section 8.4A. If the Performance Shortfall related to RPM commitments is a negative number, the PRD Provider may be eligible for a Bonus Performance Credit, in accordance with Section 8.4A. Performance Shortfalls related to FRR commitments are subject to Non-Performance Charge or Bonus Performance Credit if the FRR Entity elected the financial non-performance assessment as opposed to the physical non-performance option described in Section 11.8.7

3A.6.3 Deleted~~PRD Test Compliance (Effective for 2022/2023 Delivery Year)~~

~~If a PRD registration is not measured for compliance for a Performance Assessment Interval in a Delivery Year, then such registered PRD must demonstrate that it was tested for a one hour period between 10:00 AM EPT to 10:00 PM EPT during June through October or May of the relevant Delivery Year. If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.~~

~~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 DR Hub for test compliance evaluation. Test data must be submitted in DR Hub on or after June 1 and no later than July 14th after the Delivery Year. Actual load reduction for a PRD registration in a test is calculated in a manner similar to calculating actual hourly load reduction during an emergency action.~~

~~The MW testing shortfall for a PRD registration is equal to the nominal load reduction value of the registration, capped at daily Nominal PRD Value committed by such registration on the day of the test, minus the actual hourly load reduction for such registration.~~

~~The PRD Provider's daily committed Zonal (or Sub-Zonal LDA) Nominal PRD Value 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.~~

~~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 a PRD Provider committed PRD to RPM and committed PRD to FRR, a net zonal testing shortfall will be calculated for their PRD registrations linked to RPM and a separate net zonal testing shortfall will be calculated for their PRD registrations linked to FRR.~~

3A.6.3A PRD Test Compliance ~~(Effective with 2023/2024 Delivery Year)~~

~~For the 2023/2024 Delivery Year and subsequent Delivery Years, I~~If the registered PRD is not required to reduce the load for a Performance Assessment Interval during the relevant Delivery Year, then such registered PRD shall test for a two hour period between 11:00 EPT to 18:00 EPT on a weekday that is a non-NERC holiday during the relevant Delivery Year and in accordance with the following provisions. The date and time of such test shall be selected by the Office of the Interconnection and notice of such test shall be provided to the PRD Provider in accordance with the procedure described in sections (2) and (3) listed below. If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

1. ~~For the 2023/2024 Delivery Year and subsequent Delivery Years, a~~All PRD registered in a zone will be tested simultaneously for two hours. Performance will be calculated as the two hour average reduction. The Office of the Interconnection may, at its discretion, cancel a test and retest to ensure system reliability.
    a. If 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 re-tests 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. The PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.
    b. If 25 percent or more (by megawatts) of a PRD Provider's total PRD registered in a Zone fails the test the PRD Provider may request PJM to schedule a one-time retest limited to all registrations that failed the prior test, provided that all affiliated registrations 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. The request must be made before the 46th day after the test. The Office of the Interconnection will select the date and time of the retest during the same season period (except if test was conducted in March in which case retest can be conducted in May) and notice is provided consistent with the following procedure.

2. Notification of the initial Office of the Interconnection scheduled test will be provided as follows:
    a. On the first business day of a week, PJM will provide notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, the Office of the Interconnection will post on its website the test date and zones. The Office of the Interconnection will also notify the PRD Providers the test date. On the test date, PRD Providers will receive the start time through web service communications with a 15 minute lead time and as defined in the PJM Manuals.
3. Notification of any scheduled retest by the Office of the Interconnection will be provided as follows:
    a. By 10:00 EPT the day before the retest, the Office of the Interconnection will post the retest date on its website. PJM will also notify the PRD Providers the retest date. On retest date PRD Providers will receive start time through web service communications with a 15 minute lead time and as defined in the PJM Manuals.

The MW testing shortfall for a PRD registration is equal to the nominal load reduction value of the registration, capped at daily Nominal PRD Value committed by such registration on the day of the test, minus the actual load reduction for such registration.

The PRD Provider's daily committed Zonal (or Sub-Zonal LDA) Nominal PRD Value 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.

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 a PRD Provider committed PRD to RPM and committed PRD to FRR, a net zonal testing shortfall will be calculated for their PRD registrations linked to RPM and a separate net zonal testing shortfall will be calculated for their PRD registrations linked to FRR.

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 Capacity Exchange 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 Capacity Exchange 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 Capacity Exchange 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 DER capacity resources
- 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”)
- The business rules for Aggregate Resources (see ”Aggregate Resources”)
- The business rules for Seasonal Capacity Resources (see “Seasonal Capacity Resources”)

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, which 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 Capacity Exchange may consist of:

- Generation Capacity Resources;
- Load Management Resources;
- Energy Efficiency Resources;
- DER capacity resources
- Aggregate Resources
- Qualifying Transmission Upgrades.

Key qualifications and requirements for generation resources are presented in Existing Generation, Planned Generation, and Bilateral u~~U~~nit-s~~S~~pecific t~~T~~ransaction 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 DER capacity resources are presented in the DER capacity resources section of this Manual. Key qualifications and requirements for Aggregate Resources are presented in the Aggregate Resources section of this Manual. Key qualifications and requirements for Qualified Transmission Upgrades are presented in the Qualified Transmission Upgrade section of this Manual.

Note:
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, 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)

Fuel type (generation resources only)

Seasonal eligibility

4.2 Generation Resources

A party's Generation Capacity Resource portfolio may consist of Existing Generation Capacity Resources, Planned Generation Capacity Resources, and bilateral contracts for unit-specific Capacity Resources. Qualifications and requirements for Generation Capacity Resources are presented in the sections below. A Generation Capacity Resources that is being committed to the initial FRR Capacity Plan must satisfy the same qualification requirements as a Generation Capacity Resource offering into a Base Residual Auction; however, the qualification requirements must be satisfied in advance of the FRR Capacity Plan submittal deadline.

4.2.1 Existing Generation Capacity Resources - Internal

An Existing Generation Capacity Resource, as defined by unique queue, located in the PJM region must satisfy either of the following criteria:

- Cleared any RPM Auction for a prior Delivery Year.
- Commenced interconnection service

Existing Generation Capacity Resource 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 ***Open Access Transmission 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) and***~~ ***M-21B*** to verify the net capability of each unit.
- The unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having an "Approved" Capacity Modification in the Capacity Exchange system.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.
- Unoffered MWs for a unit as a result of not satisfying the RPM must offer requirement in the Base Residual Auction or an Incremental Auction for the Delivery Year, are ineligible to be offered in any subsequent Incremental Auctions for that Delivery Year and are ineligible to take on any RPM or FRR commitment for such Delivery Year.

4.2.2 Existing Generation Capacity Resources - External

An Existing Generation Capacity Resource not located in the PJM region must satisfy either of the following criteria:

- Cleared any RPM Auction for a prior Delivery Year.
- Physically and electrically interconnected to an external Control Area, and is in full commercial operation.

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

- For an external Generation Capacity Resource offering as Capacity Performance, the external resource satisfies the requirements to offer as Capacity Performance or qualifies for an exception to such requirements as a Prior CIL Exception External Resource. A Prior

CIL Exception External Resource is defined as an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof), is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

- For a Capacity Market Seller to offer an external Generation Capacity Resource as Capacity Performance, the Capacity Market Seller must demonstrate to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets the following requirements:
  - The Capacity Market Seller has obtained a determination that the Pseudo-Tie required for its External Generation Capacity Resource is feasible, including (without limitation) that such Pseudo-Tie meets the requirements in ***PJM Balancing Operations Manual (M-12)*** and the Capacity Market Seller has committed in writing, via the submittal of an Officer Certification Form, that it will take all steps necessary to implement such Pseudo-Tie prior to the start of the relevant Delivery Year. A template for the Officer Certification Form is posted on the PJM website.
  - The Capacity Market Seller has demonstrated that it has, for transmission outside PJM, obtained long-term firm point-to-point transmission service (evaluated for deliverability from the unit-specific physical location of the resource to PJM load pursuant to a study that is reviewed and approved by PJM in accordance with PJM deliverability criteria to ensure uniformity for internal and external resource deliverability requirements), with rollover rights for the term of the transmission service that is confirmed by the Balancing Authority where such external resource is geographically located.
  - The Capacity Market Seller has demonstrated that it has, for transmission service within PJM, obtained Network External Designated Transmission Service.
  - The Capacity Market Seller has demonstrated by written commitment via the Officer Certification Form that such external resource is subject to the same obligations to offer into RPM Auctions imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of OATT. A Capacity Market Seller that satisfies the requirements to offer as Capacity Performance with respect to an external Generation Capacity Resource Sell Offer submitted in an RPM Auction for a Delivery Year is required to demonstrate satisfaction of such requirements for any Sell Offer with respect to such external resource submitted in an RPM Auction for any subsequent Delivery Year, including without limitation, demonstration that the

required external transmission service continues to satisfy PJM's deliverability standards.

- To qualify for an exception to satisfy the above requirements to offer as Capacity Performance for a Delivery Year RPM Auction , the Prior CIL Exception External Resource must demonstrate that the external resource is (1) owned by a Load Serving Entity and used to self-supply (under arrangements initiated before June 1, 2016, with a duration of at least ten years) such LSE's PJM Region load, for any Delivery Year during the life of such resource or (2) the subject of a contract for energy or capacity or equivalent written agreement entered into on or before June 1, 2016 for a term of ten years or longer with a purchaser that is an internal PJM load customer, for any Delivery Year that covers the term of the agreement.
- The Prior CIL Exception External Resource must continue to comply with all the conditions in place on the grant of its exception to the Capacity Import Limit, subject to the following additional conditions:
  - The Prior CIL Exception External Resource must be Operationally Deliverable, as defined in the Open Access Transmission Tariff. If PJM determines that a Prior CIL Exception Resource is not Operationally Deliverable for a Delivery Year and notifies the Capacity Market Seller of such a determination by no later October 1 immediately preceding such Delivery Year, the Capacity Market Seller may elect to:
    - Take the necessary actions to make the Prior CIL Exception External Resource Operationally Deliverable, in PJM's sole judgement, prior to the beginning of such Delivery Year. If transmission upgrades are required to make the external resource Operationally Deliverable, PJM will facilitate the performance of transmission studies and otherwise cooperate with the external Transmission Provider of the system on which such upgrades are required to identify the upgrades required to meet PJM's deliverability standards;
    - Be relieved of the external resource's capacity obligation for such Delivery Year by providing written notice of such election to the RPM Hotline at rpm_hotline@pjm.com no later than seven (7) days prior to the posting of planning parameters for the Third Incremental Auction for such Delivery Year. As a result of such election, the Capacity Market Seller will not receive any RPM Auction Credits for the external resource's cleared MWs for such Delivery Year, will be relieved of all commitments and any resource performance obligations for such Delivery Year, and will have no further must-offer obligation in RPM Auctions. PJM will consider all such elections from Capacity Market Sellers in the determination of the PJM Buy Bid/Sell Offer for the Third Incremental Auction.
    - Procure and specify replacement capacity in a sufficient quantity to replace the entire commitment on the Prior CIL Exception External Resource for the Delivery Year.
  - A Capacity Market Seller's continued ability to offer as a Prior CIL Exception External Resource in RPM Auctions is conditioned on external Transmission Providers

continuing to honor the firm status of the Capacity Market Seller's transmission service for all Delivery Years that such Capacity Market Seller offered as a Prior CIL Exception Resource.

- ◦ A Capacity Market Seller offering and clearing a Prior CIL Exception Resource shall be relieved of its must offer obligation in future Delivery Year RPM Auctions after the last Delivery Year for which it qualifies for an exception to requirements to offer as a Capacity Performance Resource.

- The unit resides in the Capacity Exchange 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 Capacity Exchange system.
- At least twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's Accredited UCAP Factor.
- 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 and~~ M-21B)*** to verify the net capability of each unit.
- The external capacity without firm transmission service confirmed on the complete transmission path 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.

An Existing Generation Capacity Resource located outside the PJM region is eligible to be traded bilaterally if the unit resides in the Capacity Exchange 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 Capacity Exchange system. For an external resource offering or committing as Capacity Performance, an "Approved" unit-specific transaction status will not be granted until the pseudo-tie for such resource is actually implemented and the external resource has satisfied PJM's deliverability standards, which for CIL Exception External Resource may include completing the necessary actions to make such CIL Exception External Resource Operationally Deliverable for the relevant Delivery Year. Demonstrating deliverability may require transmission upgrades on an external Transmission Provider's system or PJM's system to be completed prior to June 1st of the delivery year. The study process for participant-funded upgrades is defined in Part VI of the

PJM Open Access Transmission Tariff. The following requirements for existing external generation are still applicable for external resources traded bilaterally:

- At least twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's Accredited UCAP Factor.
- 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 and~~ M-21B)*** 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.

If an existing Generation Capacity Resource located outside the PJM region cleared as Capacity Performance Resource in the Base Residual Auction, First Incremental, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction and does not have the pseudo-tie implemented and generation deliverability demonstrated by the start date of associated unit-specific transaction, the status of the associated unit-specific transaction in the Capacity Exchange system will be changed from "Provisionally Approved" to "PJM Withdrawn".

4.2.3 Planned Generation Capacity Resources - Internal

A Planned Generation Capacity Resource 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 the Delivery Year. Interconnection Service requires completion of transmission network upgrades deemed necessary by interim deliverability studies.
- At a minimum, planned generation resources greater than 20 MW must have completed Decision Point II and be in the Phase III study process~~System Impact Study~~ and planned generation resources less than or equal to 20 MW must have completed Decision Point I and be in the Phase II study process~~System Impact Study~~, for the unit to participate in the Base Residual Auction.
- A Generation Interconnection Agreement (GIA) or Wholesale Market Participant Agreement (WMPA) 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 Capacity Exchange.

- Planned Generation Capacity 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 Capacity Resource was committed through the Base Residual Auction and the GIA 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 Capacity Exchange Generation Resource portfolio.
- If a GIA 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 Capacity Exchange Generation Resource portfolio.
- If the Planned Generation Capacity Resource 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.
- Planned Generation Capacity Resources are required to submit an acceptance test to PJM Planning prior to the start date of the submitted CAPMOD in accordance with Manual 21 Section 1.3
- If PJM Planning determines a portion of a Planned Generation Capacity Resource has commenced Interconnection Service, or considered Partially In-Service, the status of the Capacity Modification may be changed from "Provisionally Approved" to "Approved" up to the amount of MWs deemed in-service by PJM Planning. A Capacity Modification for the remaining Planned MWs should be submitted and remain "Provisionally Approved" until PJM Planning confirms the MWs are in-service.
- Effective with the 2025/2026 Delivery Year, an internal Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the internal Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

4.2.3.1 Binding Notice of Intent to Offer (Effective with the 2025/2026 Delivery Year)

Any Planned Generation Capacity Resource, including planned Intermittent Resources, Capacity Storage Resources, and Hybrid Resources, will be required to provide a binding notice of intent to offer ("NOI"), in the format requested by PJM, in order to participate in the RPM Auction. A Capacity Market Seller must provide a binding notice of intent no later than (a) the immediately preceding December 1 for a Base Residual Auction (except that for the 2025/2026 auction the deadline was 12/12/23, and 2027/2028 and 2029/2030 Delivery Years, such notice shall be submitted by 180 days prior to the commencement of the offer period)~~2026/2027 and 2028/2029 Delivery Years, such notice shall be submitted by 180 days prior to the~~

~~commencement of the offer period)~~, or (b) ninety (90) days prior to the commencement of the offer period for an Incremental Auction. A notice of intent to offer should be made by the Capacity Market Seller that intends to offer the Planned Generation Capacity Resource/uprate into the auction. The resource associated with a binding notice of intent is required to be offered into the auction even if a different Capacity Market Seller will offer the resource into the RPM Auction. Any bilateral unit-specific transaction involving the Planned Generation Capacity Resource prior to the auction will transfer the binding notice of intent to the new Capacity Market Seller. If a resource associated with a binding notice of intent is not offered in the auction, then the resource will not be permitted to offer into any subsequent auctions for the relevant Delivery Year or take on a RPM commitment through Locational UCAP or r~~R~~eplacement c~~C~~apacity transaction during the relevant Delivery Year, or take on a FRR Commitment during the relevant Delivery Year.

4.2.4 Planned Generation Capacity Resources – External

A Planned External Generation Capacity Resource 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 being in the Phase II or Phase III System Impact Study as outlined below fora Base Residual Auction and a Generation Interconnection 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. A Planned External Generation Capacity Resource is eligible to be offered into RPM Auction if it meets the following requirements:

- A Planned External Generation Capacity Resource offering as Capacity Performance Resource must satisfy the same requirements for existing external generation capacity resources offering as a Capacity Performance Resource in Section 4.2.2 of this manual.
- The planned unit's start date of Interconnection Service is on or before the start of the Delivery Year. Interconnection Service requires completion of transmission network upgrades deemed necessary by interim deliverability studies.
- At a minimum, planned generation resources greater than 20 MW must have completed Decision Point II and be in the Phase III ~~System Impact S~~study process and planned generation resources less than or equal to 20 MW must have completed Decision Point I and be in the Phase II ~~System Impact S~~study process, for the unit to participate in the Base Residual Auction. A functionally equivalent Generation Interconnection Agreement has been executed for the unit to participate in an Incremental Auction.
- The unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement. A Capacity Modification for the planned unit has been submitted by PJM and "Provisionally Approved" in Capacity Exchange in an External Party (i.e., EXT) account. A unit-specific transaction with External Party as the "Seller" has been submitted

by the provider and "Provisionally Approved" in the Capacity Exchange system to represent the import of capacity into PJM.

- External Planned Generation Capacity 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 Capacity Resource was committed through the Base Residual Auction and the GIA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification and any unit-specific transaction(s) representing the capacity import will be changed from "Provisionally Approved" to "Denied" so that the planned generation will no longer be included in a resource provider's Capacity Exchange Generation Resource portfolio.
- If a GIA 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 and any unit-specific transaction(s) representing the import will need to be submitted and "Provisionally Approved" in order to be re-included in a resource provider's Capacity Exchange Generation Resource portfolio.
- If the Planned Generation Capacity Resource is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification and any unit-specific transaction representing the import will be changed from "Provisionally Approved" to "Denied". A new Capacity Modification and unit-specific transaction representing the import 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 and~~ M-21B)*** 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.
- ~~Effective with the 2025/2026 Delivery Year, a~~An external Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the external Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

4.2.5 Deleted ~~Equivalent Demand Forced Outage Rate (EFORd) (Through 2024/2025 Delivery Year)~~

~~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 the equations and derivations used in calculating a unit's EFORd.~~

~~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_**.~~

~~The EFORd based on forced outage data from an October through September period prior to the Delivery Year is based on all forced outage data and does not exclude forced outage data for Outside Management Control events.~~

~~Since no forced outage data is collected for Variable Resources, an EFORd is not calculated for Variable Resources. The EFORd of Variable Resources is set to zero in the Capacity Exchange 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 Capacity Exchange system. Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the Capacity Exchange 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 Capacity Exchange system by November 30 prior to the execution of the Third Incremental Auction.~~

Note: ~~Through and including the 2024/2025 Delivery Year, the UCAP value of a Generation Capacity Resource (except for a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource or a Combination Resource) is based on the resource's EFORd. Effective with the 2025/2026 Delivery Year, the UCAP value of all Generation Capacity Resources is based on the Accredited UCAP Factor of each resource as determined by ELCC analysis (see Section 4.2.7 Accredited UCAP for ELCC Resources).~~

4.2.6 Capacity Modifications (CAP Mods)

Capacity Modifications (CAP MODs) are a type of Capacity Exchange 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 Capacity Exchange, 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 Capacity Exchange 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 ELCC Resource to be offered into the PJM Capacity Market and by PJM to establish the Delivery Year capacity value of an ELCC Resource.

A CAP MOD may also be submitted by PJM to establish the capacity value of a Winter-Period Capacity Performance Resource for November through April of the Delivery Year.

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 Capacity Exchange 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 Capacity Exchange 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[11].
- CAP MODs cannot be created by a market participant during an RPM Auction’s bidding window and clearing week. CAP MODs may be created, removed, or adjusted by PJM during the auction period.
- 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”.

11 RPM Resource Commitments are placed on a resource when the resource clears or receives make-whole MWs through an RPM Auction, when the resource is specified as a replacement resource, or when the resource is used as the source of a Locational UCAP transaction.

- CAP MODs that would cause the summer rating of a generation resource or the capacity value of an ELCC Resource to exceed such unit's Capacity Interconnection Rights plus transitional resource MWs will be "Denied" by PJM.

4.2.7 Accredited UCAP for ELCC Resources

Effective Load Carrying Capability (ELCC) establishes the Accredited UCAP value for ELCC Resources. Through the 2024/2025 Delivery Year, an ELCC Resource is a Variable Resource, a Limited Duration Resource, or a Combination Resource. Beginning with the 2025/2026 Delivery Year, an ELCC Resource is a Generation Capacity Resource or Demand Resources. Beginning with the 2028/2029 Delivery Year, an ELCC Resource is a Generation Capacity Resource, Demand Resource or DER capacity resource.Through the 2024/2025 Delivery Year, for the sole purpose of Manual 18 and the Capacity Exchange tool, the "ICAP" and "UCAP" for an ELCC Resource are set equal to the lesser of its Accredited UCAP or its Capacity Interconnection Rights plus transitional resource MW, and the EFORd of an ELCC Resource is shown as zero because the actual EFORd of an ELCC Resource, if applicable, has already been used in the determination of its Accredited UCAP.

Through the 2024/2025 Delivery Year, the Accredited UCAP Factor shall mean one minus the EFORd. For the 2025/2026 Delivery Year and subsequent Delivery Years, Accredited UCAP Factor is the ratio of the Capacity Resource's Accredited UCAP to the Capacity Resource's installed capacity.

The ELCC method is described in Manual 20 and Manual 20A (**PJM Resource Adequacy Analysis**), and the calculation of Accredited UCAP for an ELCC Resource is described in Manual 21A and Manual 21B (**Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis**).

4.2.8 Interim Provisions for RMR Generation Resources

For Delivery Years up to and including the 2027/2028 Delivery Year (unless an extension of these provisions are proposed by PJM and approved by FERC), Reliability Must Run (RMR) Generation Capacity Resources that meet the criteria specified in Tariff, Attachment DD, section 5.3(b) will be included in the Base Residual Auction and to the extent there is an increase in Accredited UCAP, the additional MWs shall be included in the Third Incremental Auction with a Sell Offer of $0/MW-day and settled in accordance with the provisions specified in Tariff, Attachment DD, sections 5.3, 5.4 and 5.14. To the extent there is a reduction in Accredited UCAP for such resources between the Base Residual Auction and Third Incremental Auction, PJM will adjust the quantity that it seeks to procure or release in the Third Incremental Auction in accordance with Tariff, Attachment DD, section 5.3 (b) (ii) and 5.4(c). Furthermore, such resources shall not be subject to the rights and obligations of a committed Capacity Resource, and shall not be eligible for Non-Performance Charges or bonus payments. The performance and cleared Unforced Capacity of such Generation Capacity Resources shall also be excluded from the Balancing Ratio, as specified in Tariff, Attachment DD, section 10A.

4.3 Load Management Products

Load management is the ability to reduce metered load, either manually or automatically by the customer, after a request from the resource provider which holds the load management rights or its agent.

A load management program (e.g., Firm Service Level (FSL) or Guaranteed Load Drop (GLD) program) is eligible to (1) be offered by a resource provider as a Demand Resource (DR) into the Base Residual Auction or an Incremental Auction and is paid the applicable LDA product-specific Resource Clearing Price if such resource clears in the auction; or (2) be committed by an FRR Entity to an FRR Capacity Plan.

4.3.1 Requirements of Load Management Products in RPM

In order to offer a Demand Resource in an RPM Auction or commit a Demand Resource in an FRR Capacity Plan, a demand resource provider must submit no later than 30 days prior to the RPM Auction or prior to the deadline for submitting the FRR Capacity Plan 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 or FRR Capacity Plan 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 or commit such Demand Resource in an FRR Capacity Plan, 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. Demand resources that are committed to an FRR Capacity Plan will have an FRR Capacity Plan Commitments for the relevant Delivery Year. 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) customer-specific compliance and verification information within 45 days after the end of the month in which a Performance Assessment Interval occurred, in accordance with the Measuring Compliance during Performance Assessment Interval section, Section 8.6 of this manual. Provide (or contract with another party to provide) customer-specific compliance and verification information in accordance with the timelines established in the Load Management Test Compliance section, Section 8.7 of this manual. Statistical sampling may be used instead of customer-specific compliance and verification information for residential customers without interval

metering when approved by PJM in accordance with **PJM Manual 19: Load Forecasting & Analysis, Attachment D**.

- Provide load drop estimates for all Load Management events (whether initiated by PJM or the resource provider) and provider initiated test event, 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.
    - Capacity Performance DR – Capacity Performance DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption (i) for all hours of the Delivery Year beginning with the 2027/2028 Delivery Year unless there is an Office of the Interconnection approved maintenance outage during October through April, or (ii) for Delivery Years up through the 2026/2027 Delivery Year, 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.
    - Summer-Period DR – Summer-Period 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 such interruption (i) for all hours of the day during such months beginning with the 2027/2028 Delivery Year, or (ii) for Delivery Years up through the 2026/2027 Delivery Year, between the hours of 10:00AM to 10:00PM Eastern Prevailing Time.
- Load management must be able to be implemented within two hours of notification to the resource provider of a PJM-initiated load management event. Load management is 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 Registration 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 Registration 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 Demand Resource Registrations 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.

4.3.2 Types of Load Management Programs

PJM recognizes three types of Load Management programs:

- 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 by fully implemented.

4.3.3 Demand Resources

Both Existing and Planned Demand Resources may participate in RPM Auctions or commit to FRR Capacity Plan if a demand resource provider has a PJM approved Demand Resource Sell Offer Plan.

Existing Demand Resources are those MWs on a demand resource identified in a pre-registration process in the Capacity Exchange system prior to the RPM Auction.[12]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 DR Hub system for the current Delivery Year)[13] and that the CSP intends to have under contract for the auction Delivery Year are considered Existing MWs. The summer Nominated DR Value of a Demand Resource Registration is used in the calculation of Existing MWs. A CSP may request an adjustment to the summer 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 DR Hub.
- The peak load contribution (PLC) reported in the DR Hub 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 summer 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 Capacity Exchange system for an RPM Auction. PJM will notify the CSP of the approval or rejection of their request

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[12] For an FRR Entity, a pre-registration process is performed manually through spreadsheets provided by PJM.

[13] For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM DR Hub 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.

prior to the opening of the pre-registration window in the Capacity Exchange 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 or commit to an FRR Capacity Plan in excess of the CSP's Existing MWs on such demand resource.

> **Note:**
> 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 operating Behind the Meter Generation cannot be netted from load for the purposes of calculating he Peak Load Contributions for the subsequent Delivery Year in accordance with ***Generator Operational Requirements Manual (M-14D), Appendix A: Behind the Meter Generation Business Rules.***

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.

4.3.4 Demand Resource Modifications (DR Mods)

A Demand Resource Modification (DR MOD), a type of Capacity Exchange transaction, can be used to track an increase or decrease of the nominated value of a provider's DR Resource in the Capacity Exchange system. DR MODs are no longer submitted by DR Providers. PJM may submit a DR MOD for an FRR Entity to establish the Daily Nominated DR Value for an FRR Entity's Demand Resource based on PJM's approval of the FRR Entity's DR Sell Offer Plan. After the Delivery Year demand resource registration process begins in DR Hub system, the Daily Nominated DR Value for a Demand Resource is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system. The Daily Nominated DR Value for a Capacity Performance Demand Resource during the summer period of June through October and May of the Delivery Year is based on the sum of the summer nominated DR values of the registrations linked to such Demand Resource. The Daily Nominated DR Value for a Demand Resource during the non-summer period of November through April is based on the lesser of (a) the sum of the summer nominated DR values of the registrations linked to such Demand Resource or (b) the sum of the winter nominated DR values of the registrations linked to such Demand Resource.

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 DR Hub system. 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, Winter Peak Load, EDC Loss Factor, notification period, Firm Service Level data (summer and winter), Guaranteed Load Drop data (summer and winter). Winter Peak Load and winter Firm Service Levels are required for Capacity Performance DR registrations. However, Winter Peak Load and winter Firm Service Levels are not required if such registration indicates that it is a Summer-Period DR Only registration. Economic, Pre-Emergency, or Emergency Load Response registrations that would like to be eligible for Bonus Performance for a Performance Assessment Interval must have both customer-specific summer and winter based data provided in the registration.
- Demand Resource name to link the Demand Resource Registration to the appropriate Demand Resource modeled in the Capacity Exchange system.
- Load Management product type for customer site (Capacity Performance DR, Summer-Period DR[14]).
- 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

[14] Summer-Period DR is included in Capacity Performance DR registration when a Nominated DR Value based on summer data is greater than Nominated DR Value based on winter data. If Summer- Period DR Only is checked on the registration, such registration is only required to provide Nominated DR Value based on summer capability when dispatched in the summer period. If Summer-Period DR Only is not checked on the registration, the registration is required to provide Nominated DR Value based on summer capability and Nominated DR Value based on non-summer capability.

may claim an energy settlement for a PJM-initiated Load Management Event. Capacity Only Option resource providers may not claim an energy settlement for a PJM-initiated Load Management Event for Capacity Only Option registrations.

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

A provider with RPM or FRR Resource Commitments for their Demand Resource must register customer sites that are the Capacity Performance product-type.[15]

A completed Load Response registration in DR Hub 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 ***Energy & Ancillary Services Market Operations Manual (M-11), Section 10.***

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. A summer and winter nominated load reduction value may be calculated for a registration depending on the product-type registration and Delivery Year. 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.

[15] A Capacity Performance product-type registration includes Summer-Period DR when a Nominated DR Value based on summer data is greater than Nominated DR Value based on winter data.

For an end-use customer registration, the summer nominated DR value for the registration is based on the Peak Load Contribution in place at the time of the registration in the DR Hub system. The winter nominated DR value for a Capacity Performance registration is based on the Winter Peak Load at the time of the registration in the DR Hub system.

Nominated Value of Firm Service Level Resources

A registration for a Firm Service Level (FSL) customer includes a summer nominated DR value. Registrations of the Capacity Performance product-type also include a winter nominated DR value.

The summer nominated DR value for a Firm Service Level customer on Capacity Performance DR and Summer-Period DR Only product-type registrations is equal to the difference between its Peak Load Contribution (PLC) and its pre-determined summer firm service level load adjusted for system losses.

$$Summer\ NominatedValueofFSLCustomer = PLC - (SFSL * LossF)$$

Where:

PLC	the customer's EDC-assigned Peak Load Contribution;
SFSL	Summer Firm Service Load level;
LossF	the customer's EDC-assigned loss factor.

The winter nominated DR value for a Firm Service Level customer on a Capacity Performance product-type registration is calculated as (Winter Peak Load for customer multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service Level) times the loss factor.

If a Capacity Performance product-type registration indicates that such registration is for Summer-Period DR Only, the winter nominated DR value for a Firm Service Level registration will be zero.

The Winter Peak Load for Delivery Years through the 2026/2027 Delivery Year is based on the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior to the Delivery Year for which the registration is submitted. For the 2027/2028 Delivery Year and subsequent Delivery Years the Winter Peak Load is based on the average of the Demand Resource customer's specific hourly load during hour ending 9:00 EPT on the PJM defined 5 coincident peak days from December through

February two Delivery Years prior to the Delivery Year for which the registration is submitted. For Delivery Years through the 2026/2027 Delivery Year, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand values may be excluded from the calculation. For the 2027/2028 Delivery Year and subsequent Delivery Years, if the usage in hour ending 9:00 EPT on a winter 5 coincident peak day is below 35% of the average hour ending 9:00 EPT over all five such peak days, then up to two such days may be excluded from the calculation. If no hourly load data exists for December through February two Delivery Years prior to the Delivery Year, or if more than two days meet the exclusion criteria, then the CSP may use the most recent December through February hourly load data to calculate the Winter Peak Load, upon PJM verification. If no hourly load data for the customer exists for the last two December through February periods prior to the Deliver Year, or if more than two days meet the exclusion criteria for the last two December through February periods prior to the Delivery Year, the CSP may provide alternative data to support a Winter Peak Load subject to PJM's review and approval of the use of alternative data.

The Zonal Winter Weather Adjustment Factor is equal to the zonal winter weather normalized peak divided by the zonal average of five coincident peak loads in December through February. PJM posts the RTO winter 5 CP days on the PJM website. PJM calculates and posts the Zonal Winter Weather Adjustment Factors on the PJM website.

Nominated Value of Guaranteed Load Drop Resources

A registration for a Guaranteed Load Drop (GLD) customer includes a summer nominated DR value. Registrations of the Capacity Performance product-type also include a winter nominated DR value and an annual nominated DR value.

The summer nominated DR value for a Guaranteed Load Drop customer on a Capacity Performance DR and Summer-Period DR Only product-type registrations will be the summer guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the resource provider. The summer nominated value shall not exceed the customer's Peak Load Contribution.

$$\mathit{Summer\ NominatedValueofGLD} = \mathit{SGLD}\,(\mathit{LossF})$$

Where:

GLD	Customer's Summer Guaranteed Load Reduction;
LossF	the customer's EDC-assigned loss factor.

The winter nominated DR value for a GLD customer on a Capacity Performance product-type registration shall equal the winter guaranteed load drop amount multiplied by the loss factor, as established by the customer's contract with the resource provider. The winter nominated DR value shall not exceed the Winter Peak Load for customer multiplied by Zonal Winter Weather Adjustment Factor times the loss factor. If a Capacity Performance product-type registration indicates that such registration is for Summer-Period DR Only, the winter nominated DR value for the GLD customer on the registration will be zero.

4.3.8 Determination of the UCAP Value of Load Management

Prior to the 2025/2026 Delivery Year, unforced capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the Forecast Pool Requirement.

$$UCAPValue_{LM} = NominatedValue*FPR$$

Beginning with the 2025/2026 Delivery Year, the unforced capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the applicable ELCC Class Rating.

$$UCAPValue_{LM} = Nominated\ \ Value*\ \ applicable\ \ ELCC\ \ Class\ \ Rating$$

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, and by product-type 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 Data Viewer 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

A Capacity Performance product 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 Capacity Performance 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 or Non-Performance Assessment if the event or Performance Assessment Interval 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 Performance Assessment Interval will not be considered as dispatched for such Performance Assessment Interval.

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 L) of the Reliability Assurance Agreement***. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the e~~E~~nd u~~U~~se c~~C~~ustomer's retail site (during the defined EE Performance Hours and during winter performance period if such EE Resource is a Capacity Performance Resource) that is not reflected in the peak load forecast used for the Auction 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.

Because energy efficiency measures are reflected in the peak load forecast for a Delivery Year for which an auction is being conducted, the auction parameters must be adjusted through the 2025/2026 Delivery Year, as described is Section 2.4.5, for the EE Resource(s) that are proposed for that auction in order to avoid double-counting of the energy efficiency measures.

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 through the 2025/2026 Delivery Year into an RPM auction or commit to an FRR Capacity Plan if it meets the following criteria:

- EE installation must be scheduled for completion prior to DY;

- EE installation is not reflected in peak load forecast used for the auction for which the EE is offered (is not reflected in peak load forecast used as basis for FRR Capacity Plan requirements if committing to an FRR Capacity Plan);
- EE installation exceeds relevant standards at time of installation as known at time of commitment;
- EE installation achieves load reduction during defined EE Performance Hours; and
- EE installation is not dispatchable[16].

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.

If cleared in an RPM Auction, a Capacity Performance EE Resource will receive a Capacity Performance Resource Clearing Price for the LDA in which the EE Resource resides and a Summer-Period EE Resource will receive a Resource Clearing Price applicable to the EE Provider's cleared Seasonal Capacity Performance sell offer as described in Section 4.10 of this manual.

An EE Resource may participate in RPM Auctions or commit to 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 RPM Auction in which the EE Resource is initially offered or 30 days prior to the FRR Capacity Plan 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 or no later than 30 days prior to next FRR Capacity Plan update in which the EE is subsequently committed;
- Submit a completed Nominated EE Value Template with the M&V Plan using the current Nominated EE Value Template posted on the PJM website;
- Establish credit with PJM Credit Department prior to RPM Auction or prior to committing EE Resource to FRR Capacity Plan (for Planned EE Resources);
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed;

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

- Submit Updated Post-Installation M&V Reports no later than 15 business 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.

The following rules apply for Energy Efficiency Resources to facilitate the implementation of any restrictions that may be imposed on Energy Efficiency Resources by a Relevant Electric Retail Regulatory Authority (RERRA) authorized by FERC to opt-out and restrict the sale of Energy Efficiency Resources into PJM Capacity Market (i.e., the Authorized RERRA).

- If a RERRA receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of PJM the following process applies:
  - PJM will publicly post a reference to the FERC authorization of a RERRA order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable EDC(s), and applicable auction(s), and/or Delivery Years.
  - A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources located in the jurisdiction of the Authorized RERRA within the Zone or LDA, as required, and those outside the area but within the Zone or LDA, as required, in the such Seller's Energy Efficiency M&V Plan for the Delivery Year RPM Auction or Seller's Delivery Year Post-Installation M&V Report.
  - PJM shall provide a list of Capacity Market Sellers to the relevant EDC for the specific area(s) to review compliance with the Authorized RERRA. PJM shall provide the list of Capacity Market Sellers within two business days after the deadline for submitting an EE M&V Plan for a DY Auction and within two business days of receipt of Delivery Year Post Installation M&V Report.
  - The relevant EDC shall review compliance with the rules from an Authorized RERRA and provide a response to PJM within five business days after receiving the list of Capacity Market Sellers offering or certifying EE Resources.
  - PJM shall not allow a Capacity Market Seller to offer or certify EE Resources if an EDC denies such Capacity Market Seller to deliver EE Resources in compliance with rules of Authorized RERRA.

A Capacity Market Seller that cannot satisfy its obligations for the relevant Delivery Year due to the prohibition of participation by Authorized RERRA may be relieved of its Capacity Resource Deficiency Charge by notifying PJM no later than seven calendar days prior to the posting of the Planning Parameters for the Third Incremental Auction of such Delivery Year. After providing such notice, the affected Capacity Market Seller shall not be required to obtain replacement capacity for the affected EE Resource and no Capacity Resource Deficiency Charges shall be assessed for the Seller's deficiency in satisfying its RPM obligation for such EE Resource for the relevant Delivery Year. The Capacity Market Seller shall not be entitled to, nor be paid, any

RPM Auction Credits for such EE Resource for the relevant Delivery Year. PJM shall apply corresponding adjustment to the quantity of PJM Buy Bids or Sell Offers in the Third Incremental Auction for such Delivery Year.

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. EE Resources that qualify as a Capacity Performance product type shall also have an expected average load reduction during winter performance period (i.e., 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 determine 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 Capacity Performance value of the Capacity Performance EE Resource. The Nominated EE Value of a Summer-Period Energy Efficiency Resource is the expected average demand reduction during the defined EE Performance Hours in the Delivery Year. The minimum Nominated EE Value accepted in the PJM Capacity Market is 0.1 MW.

The Measurement & Verification (M&V) Plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource (value based on load reduction provided during EE Performance Hours) and the Capacity Performance value (value based on the consideration of load reduction provided during EE Performance Hours and winter performance period) and confirming that the Nominated EE Value and Capacity Performance 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 or committed to an FRR Capacity Plan (on a summer period basis). The Capacity Performance value approved by PJM in the EE Resource Provider's Initial/Updated M&V Plan provides guidance to the EE Resource Provider on the maximum amount of MWs that should be offered in Capacity Performance Offer Segments or committed as Capacity Performance in an FRR Capacity Plan on an annual basis.

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 and final Capacity Performance value that is used to measure RPM Commitment Compliance and FRR Capacity Plan 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 and final Capacity Performance 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 or Capacity Performance value confirmed by the Audit becomes the final Nominated EE Value or final Capacity Performance 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 or Capacity Performance value confirmed by the M&V Audit becomes the basis to determine if any incremental RPM Commitment Compliance Shortfall needs to be assessed retroactively from June 1 of the Delivery Year to May 31 of the Delivery Year.

4.4.2 Determination of the UCAP Value of EE Resource

The UCAP value of a Capacity Performance Resource is the Capacity Performance value of the EE Resource multiplied by the Forecast Pool Requirement. The UCAP value of a Summer Period Energy Efficiency Resource is Nominated EE Value multiplied by the Forecast Pool Requirement.

$$UCAPValue_{CP\ EE} =$$

$$Capacity\ Performance\ Value * FPR$$

$$UCAPValue_{SummerPeriod\ EE} = NominatedEEValue * FPR$$

4.4.3 Energy Efficiency Resource Modifications (EE MODs)

An Energy Efficiency Modification (EE MOD), a type of Capacity Exchange transaction, is used to track an increase or decrease of the EE Nominated Value of a provider’s EE Resource in the Capacity Exchange system. EE MODs are no longer submitted by EE Resource Providers. Prior to the commitment of an EE Resource to an FRR Entity’s FRR Capacity Plan, PJM submits an EE MOD in the Capacity Exchange system to represent the Nominated EE Value of an EE Resource to be effective June through October and May of the Delivery Year and an EE Mod to represent the Capacity Performance Value of an EE Resource to be effective for November through April of the Delivery Year based on an EE Provider’s approved initial/updated EE M&V Plan. Prior to the Delivery Year, PJM submits an EE MOD to represent the final Nominated EE Value of an EE Resource to be effective for June through October and May of the Delivery Year and an EE MOD to represent the Capacity Performance value of the EE Resource to be effective for November through April of the Delivery Year based on PJM’s approval of the provider’s Post Installation M&V Report for such Delivery Year.

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 Department 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, Upgrade Customers must be in the Facilities Study phase 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 Capacity Performance product type 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 no longer eligible to continue to offer the approved incremental import capability value into future RPM Auctions. Once in service, the transmission upgrade is included in the CETL analysis for future Delivery Years and the approved incremental import capability of the upgrade is valued as an Incremental Capacity Transfer Right as described in section 6.1.2 of this manual.

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 a~~A~~uction s~~S~~pecific MW capacity. Parties in all bilateral transactions reported to PJM agree to indemnify PJM against non-performance by their counterparties in such transactions. The transaction may be subject to additional collateral requirements based on PJM's review as outlined in the Tariff, Attachment Q.

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), and 1IA, 2IA, and 3IA pricing points (associated with a First Incremental

Auction (1IA), Second Incremental Auction (2IA), or 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 Capacity Exchange. 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 Capacity Exchange 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 Capacity Exchange 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 (Base Residual Auction, First Incremental Auction, Second Incremental Auction, Third Incremental Auction).
- The Capacity Performance offer segment-type applicable to the MWs cleared: Annual, Seasonal-summer, or Seasonal-winter
- The Resource Clearing Price applicable to the MWs cleared in Seasonal Capacity Performance Resource sell offer
- 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 Accredited UCAP Factor 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 u~~U~~nit-s~~S~~pecific b~~B~~ilateral t~~T~~ransactions:

- An Aggregate Resource may not be specified as a unit transacted in a u~~U~~nit-specific transaction.
- If available capacity type is selected, the Capacity Exchange 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/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.
- Available installed capacity purchased through a bilateral unit-specific transaction that is registered in PJM's Capacity Exchange 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 Capacity Exchange system will validate that the Seller has Daily Unoffered ICAP to offer for the entire term of the transaction and validate that the Buyer is an External Party (EXT).
- 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 Capacity Exchange system will validate that the Seller has cleared capacity of the specified Capacity Performance offer segment-type from the specified auction to offer for the entire term of the transaction.
- An approved unit-specific transaction 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 for the entire term of the transaction. 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 for the entire term of the transaction.
- 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

Participants can export capacity if they received an approved must offer exception request(s) and if they have available capacity after all RPM auctions are complete for a given Delivery Year. Exporting Generation Resources may be subject to the Capacity Export Charge as outline below.

Exporting ~~(formerly known as “Delisting”)~~ a generation resource is accomplished by submitting~~reporting a bilateral transaction~~ a unit-specific transaction with “External Party” (i.e., “EXT”) listed as the “Buyer”. ~~in the unit-specific transaction.~~ Participants should include the corresponding Transmission Service Reservation (TSR) ID(s) and the exporting zone interface in the comments section of the transaction.

Exporting any portion of a generation resource below a party’s Daily RPM Resource Commitments/(Accredited UCAP Factor) 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 all or a portion of a generation resource is to be exported, appropriate documentation must be submitted to the IMM via the MIRA application~~PJM~~ to demonstrate that the party exporting the generation resource has both a financially and physically firm commitment to an external sale of its capacity as well as the required firm transmission~~and therefore,~~. Should the must offer exception request be approved, the relevant capacity 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. A unit-specific transaction that that represents a capacity import from an external resource that is offering as Capacity Performance product will not be granted a "Provisionally Approved" unit-specific transaction status until the requirements to offer as Capacity Performance in sections 4.2.2 or 4.2.4 are satisfied and will not be granted an "Approved" unit-specific transaction status until the pseudo-tie for such external resource is actually implemented and the external resource has satisfied PJM's deliverability standards, which for a Prior CIL Exception External Resource may include completing the necessary actions to make a Prior CIL Exception External Resource Operationally Deliverable for the relevant Delivery Year. Demonstrating deliverability may require transmission upgrades on an external Transmission Provider's system or on PJM's system to be completed prior to June 1st of the delivery year.

See sections 4.2.2 and 4.2.4 for the requirements for offering existing or planned external generation resources into RPM Auctions.

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 "Provisionally 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 Capacity Exchange 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. The Accredited UCAP Factor 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 Non-Performance Charges or Generation Resource Rating Test Failure Charges that may be assessed during the Delivery Year.

4.6.6 Auction Specific MW Transactions

RPM Market Participants have the ability to report a~~A~~uction s~~S~~pecific MW t~~T~~ransactions to PJM through the Capacity Exchange system. Auction s~~S~~pecific MW t~~T~~ransactions 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 a~~A~~uction-s~~S~~pecific MW t~~T~~ransactions:

- Auction s~~S~~pecific MW t~~T~~ransactions are not eligible to be offered in an RPM auction.
- Auction s~~S~~pecific MW t~~T~~ransactions for a Delivery Year may be submitted following the completion of the RPM auction to which the transaction applies.
- Auction s~~S~~pecific MW t~~T~~ransactions may be submitted for MWs cleared for a seasonal period (summer or winter) of the Delivery Year following the completion of the RPM auction to which the transaction applies.
- Both the Buyer and the Seller of a~~A~~uction s~~S~~pecific MW t~~T~~ransaction must confirm the a~~A~~uction s~~S~~pecific MW t~~T~~ransaction via the Capacity Exchange system before the start date of the Delivery Year.

- An a~~A~~uction s~~S~~pecific MW t~~T~~ransaction must specify the buyer, seller, start and end dates of the transaction.
- The Seller of the a~~A~~uction s~~S~~pecific MW must also specify the resource(s) (generation resource, demand resource, DER capacity resource or energy efficiency resource), Auction Type (Base, First, Second, Third, or Conditional), Capacity Performance offer segment type (Annual, Seasonal-Summer, or Seasonal-Winter), and the MW amount of a~~A~~uction s~~S~~pecific MW to be transacted from each resource. PJM will verify that the MW of capacity from each of the resources identified as supplying the a~~A~~uction s~~S~~pecific MW t~~T~~ransaction 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 s~~S~~pecific MW t~~T~~ransactions transfer the capacity rights of the cleared capacity from the Seller to the Buyer. PJM will verify that those capacity rights are not resold by the Seller in a future bilateral transaction by tracking the Seller's remaining capacity rights for each resource identified in the a~~A~~uction s~~S~~pecific MW t~~T~~ransaction.
- Auction s~~S~~pecific MW t~~T~~ransactions for MWs cleared on an annual basis 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 s~~S~~pecific MW t~~T~~ransactions for MWs cleared for a seasonal period must be reported for the seasonal period prior to each Delivery Year. Auction s~~S~~pecific MW t~~T~~ransaction for MWs cleared for summer period must be submitted as an a~~A~~uction s~~S~~pecific MW t~~T~~ransaction with start date of June 1 of Delivery Year and end date of October 30 of Delivery Year and a separate a~~A~~uction s~~S~~pecific MW t~~T~~ransaction with a start date of May 1 of the Delivery Year and end date of May 31 of the Delivery Year. a~~A~~uction s~~S~~pecific MW t~~T~~ransaction for MWs cleared for winter period must be submitted with start date of November 1 of Delivery Year and end date of April 30 of the Delivery Year.
- Auction s~~S~~pecific MW t~~T~~ransactions 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 a~~A~~uction s~~S~~pecific MW t~~T~~ransaction is 0.1 MW.
- The Seller of the a~~A~~uction s~~S~~pecific MW is subject to all applicable resource performance charges, including Capacity Resource Deficiency Charges, Non-Performance Charges Generation Resource Rating Test Failure Charges and DER Capacity Aggregation Resource Test Failure Charge.
- The Buyer of the a~~A~~uction s~~S~~pecific MW will receive any Capacity Performance bonus credits related to the resource(s) identified in the transaction that over-perform during a Performance Assessment Interval. The Buyer's share of bonus credits for each over-performing resource will be based on the ratio of the resource's cleared MWs (in UCAP) transferred in the a~~A~~uction s~~S~~pecific MW t~~T~~ransaction to the greater of the (a) resource's cleared UCAP transferred or (b) Seller's daily Owned UCAP position for such resource.

- The Buyer will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of the a~~A~~uction s~~S~~pecific MW transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the a~~A~~uction s~~S~~pecific MW transaction.
- PJM reserves the right under the PJM Operating Agreement and PJM Open Access Transmission Tariff, to deny reporting of a~~A~~uction s~~S~~pecific MW t~~T~~ransactions in the event one of the parties fails to meet any requirements for such reporting.
- The Seller of an a~~A~~uction s~~S~~pecific MW t~~T~~ransaction will receive a charge equal to the transaction amount (in MW) times the price associated with in the transaction for the term of the transaction.
- The Buyer of an a~~A~~uction s~~S~~pecific MW t~~T~~ransaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction for the term of the transaction.
- The resource(s) transferred to the Buyer in an a~~A~~uction s~~S~~pecific MW t~~T~~ransaction cannot be subsequently resold in another bilateral transaction by the Buyer during the effective time period of the transaction.

4.6.7 Cleared Buy Bid Transactions

RPM Market Participants have the ability to report c~~C~~leared Buy Bid t~~T~~ransactions through the Capacity Exchange system. A c~~C~~leared Buy Bid t~~T~~ransaction allows the holder of a c~~C~~leared Buy Bid from an Incremental Auction to transfer c~~C~~leared Buy Bid MWs to another party for the term of the transaction. A c~~C~~leared Buy Bid t~~T~~ransaction will not change the resource position or load obligation of an entity. However, the Buyer may use the c~~C~~leared Buy Bid MWs as a replacement resource in a r~~R~~eplacement c~~C~~apacity t~~T~~ransaction.

The following are business rules that apply to c~~C~~leared Buy Bid t~~T~~ransactions:

- Cleared Buy Bid MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of c~~C~~leared Buy Bid MWs must confirm the c~~C~~leared Buy Bid transaction via the Capacity Exchange system by 23:59 EPT before the start date of the transaction.
- A c~~C~~leared Buy Bid t~~T~~ransaction must specify the buyer, seller, start and end dates of the transaction, the transaction amount (in MW), the LDA, product-type (and Incremental Auction associated with the c~~C~~leared Buy Bid. The product-type specified for a c~~C~~leared Buy Bid transaction may only be Capacity Performance product type.
- The smallest increment that may be transacted through a c~~C~~leared Buy Bid t~~T~~ransaction is 0.1 MW.
- Cleared Buy Bid transaction results in the “Buyer” receiving the c~~C~~leared 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 t~~T~~ransactions through the Capacity Exchange system. A Locational UCAP t~~T~~ransaction allows a party with available resource-specific capacity to transfer Locational UCAP (MWs) to another party. A Locational UCAP t~~T~~ransaction 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 r~~R~~eplacement c~~C~~apacity t~~T~~ransaction.

The following are business rules that apply to Locational UCAP t~~T~~ransactions:

- 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 t~~T~~ransaction via the Capacity Exchange 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 Accredited UCAP Factor: Locational UCAP transactions will not be accepted.
  - After the locking of the Delivery Year Accredited UCAP Factor, 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 t~~T~~ransaction must specify the buyer, seller, product type, start and end dates of the transaction. The product type specified must be Capacity Performance.
- The Seller of the Locational UCAP must also specify the resource (generation resource, demand resource, energy efficiency resource, DER capacity resource or aggregate resource) and the MW amount of L~~l~~ocational UCAP to be transacted. The resource specified in the transaction must be 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 t~~T~~ransaction 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 t~~T~~ransaction.
- 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.

4.6.9 Ownership Change Transactions

RPM Market Participants should represent a sale of a generation resource from one party to another party using an o~~O~~wnership c~~C~~hange t~~T~~ransaction. This type of RPM transaction is typically used when PJM Members enter into a generation transfer. Upon completion of a generator transfer, Market Participants should contact rpm_hotline@pjm.com to ensure all capacity and transactions are appropriately moved to the account of the Buyer.

- A Capacity Market Seller should not submit an ownership change transaction for a Delivery Year where a RPM Auction has already been conducted, or any transaction is effective.
- An ownership change transaction must be initiated by the Seller.
- Unit-specific transactions should be entered to move all Available and Cleared MWs to the Buyer for Delivery Years in the interim period leading up to the ownership change transaction.

4.7 Resource Portfolio

A party's resource portfolio in Capacity Exchange may consist of Generation Capacity Resources, Demand Resources, Energy Efficiency Resources, DER capacity resources, and Qualifying Transmission Upgrades.

A party's Generation Capacity 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 Capacity Resources, Planned Generation Capacity Resources, and Bilateral u~~U~~nit-s~~S~~pecific t~~T~~ransaction Sections of this Manual.

4.7.1 Resource Position for Generation Capacity Resources

A party's Daily Generation Capacity Resource Position in unforced capacity terms is calculated dynamically by the Capacity Exchange system for each unit and is equal to the party's Daily ICAP Owned on a unit multiplied by the unit's Accredited UCAP Factor.

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 determined in accordance with ***PJM Manual for the Rules and Procedures for the Determination of Generating Capability (~~M-21 and~~ M-21B).*** ~~Through the 2024/2025 Delivery Year, for an ELCC Resource, the term "ICAP" in this manual refers to the lesser of the Accredited UCAP or the resource's CIRs plus any awarded transitional resource MWs in accordance with Manual 21 Section 1.2.~~ The ICAP value of a Winter-Period Capacity Performance Resource is based on an Intermittent ~~or Environmentally Limited~~ Resource's certified Capacity Interconnection Rights for the winter period of the Delivery Year.

A unit that is in a party's Generation Capacity 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/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailICAP_{GEN} =$$

$$DailyICAPOwned - DailyUnofferICAP -$$

$$\left(\frac{DailyRPMResourceCommitments}{Accredited\ \ UCAP\ \ Factor}\right) - DailyFRRCommitments$$

A unit that is in a party's Generation Capacity 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. A Seasonal Capacity Performance Resource may be offered into RPM Auctions if the party has available capacity to offer from the unit for the entire summer/winter season. For each RPM Auction, PJM will calculate a Current 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 entire Delivery Year or summer/winter season.

$$CurrentAvailableICAPPosition_{GEN} = Min\left(DailyAvailableICAP_{GEN}\right)$$

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.

$$DailyUnofferICAP_{GEN} =$$

$$DailyUnofferICAP_{RPMAuction} + DailyUnofferICAP_{BilateralSales\,/\,Purchases}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a generation resource is equal to the party's Current Available ICAP Position minus the Offered ICAP in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$DailyUnofferICAP_{GEN} = CurrentAvailableICAPPosition_{GEN} - OfferedICAP$$

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, the specification of replacement resources, and increases of RPM Resource Commitments due to approved Locational UCAP transactions.

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 Capacity Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(Accredited UCAP Factor).

$$DailyRPMPosition_{GEN} =$$

$$(DailyICAPOwned - DailyFRRCommittments - DailyUnofferICAP)*$$

$$(Accredited \quad UCAP \quad Factor)$$

During the Delivery Year, a party's Daily RPM Generation Capacity 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 ICAP Owned for a specific demand resource is equal to the Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. The Daily Nominated DR Value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to such Demand Resource in the DR Hub system. The Daily Nominated DR Value for a Capacity Performance Demand Resource during the summer period of June through October and May of the Delivery Year is based on the sum of the summer nominated DR values of the registrations linked to such Demand Resource. The Daily Nominated DR Value for a Demand Resource during the non-summer period of November through April is based on the lesser of (a) the sum of the summer nominated DR values of the registrations linked to such Demand Resource or (b) the sum of the winter nominated DR values of the registrations linked to such Demand Resource.

A party's Daily Resource Position for a Demand Resource (in unforced capacity terms) is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned ~~multiplied by the Forecast Pool Requirement prior to the 2025/2026 Delivery Year, or,~~ multiplied by the applicable ELCC Class Rating ~~beginning with the 2025/2026 Delivery Year~~.

A Demand Resource that is in a party's Demand Resource portfolio may be offered into RPM Auctions, if there is Available ICAP to offer from the Demand Resource. A Demand Resource's Available ICAP for an RPM Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such RPM Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such RPM Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of the CSP's DR Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource.

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 approved unit-specific bilateral sales/purchases of cleared capacity and the specification of replacement resources, and to increases of RPM Resource Commitments due to 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.

~~Through the 2024/2025 Delivery Year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Value – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement.~~

~~Starting with the 2025/2026 Delivery Year, a~~A party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Value - Daily FRR Capacity Plan Commitments) * applicable ELCC Class Rating.

$$= (DailyNomDRValue - DailyFRRCommittments)*Applicable \quad ELCC \quad Class \quad Rating$$

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 ICAP Owned for a specific EE Resource is equal to the Daily Nominated EE Value as determined by party's "Approved" EE Modifications (submitted by PJM to represent the final Nominated EE Value or Capacity Performance value of a provider's EE Resource for the Delivery Year based on PJM's approval of the provider's Post- Installation M&V Report for such Delivery Year) adjusted for any ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such EE Resource in effect for such day.

A party's Daily EE Resource Position for an EE Resource (in unforced capacity terms) is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * Forecast Pool Requirement.

$$DailyResourcePosition_{EE} = DailyICAPOwned * FPR$$

An EE Resource that is in a party's EE Resource portfolio may be offered into RPM Auctions, if there is Available ICAP to offer from the EE Resource. An EE Resource's Available ICAP for an RPM Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such RPM Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the RPM Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report, prior commitments for such Delivery Year (if applicable), and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. A Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such RPM Auction and the provider's completion of the EE Planned Setup process in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP for such EE Resource for the relevant RPM Auction Delivery Year. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource.

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 approved unit-specific bilateral sales/purchases of cleared capacity, the specification of replacement resources or the use of EE Resource in a Locational UCAP transaction.

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 ICAP Owned – Daily FRR Capacity Plan Commitments * Forecast Pool Requirement.

$$DailyRPMPosition_{EE} = \left(DailyICAPOwned - DailyFRRCommittments\right)*FPR$$

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 this manual.

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 Capacity Exchange 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.

4.7.5 Resource Position for DER Capacity Resources

A party's DER capacity resource portfolio may consist of existing DER capacity resources or planned DER capacity resources. Qualification requirements for DER capacity resources are presented in DER capacity resources section of this Manual.

A party's Daily ICAP Owned for a specific DER capacity resource is equal to the Daily Nominated DER Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such DER capacity resource in effect for such day. The Daily Nominated DER value for DER capacity resource during the Delivery Year is based on the lesser of (a) the sum of summer nominated DR values for load reductions plus the sum of the annual nominated DG and injections from DR of the registrations linked to such DER capacity resource or (b) the sum of the winter nominated DR values for load reductions plus the sum of the annual nominated DG and injections from DR of the registrations linked to such DER capacity resource.

A party's Daily Resource Position for a DER capacity resource (in unforced capacity terms) is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned multiplied by the applicable Accredited UCAP Factor.

A DER capacity resource that is in a party's DER capacity resource portfolio may be offered into RPM Auctions, if there is Available ICAP to offer from the DER capacity resource. A DER capacity resource's Available ICAP for an RPM Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such RPM Auction and PJM's approval of the DER Aggregator's DER Plan for such RPM Auction. A DER capacity resource's Existing Available ICAP is determined based on the DER Aggregator's completion of the pre-registration process and the DER Existing Setup process in the Capacity Exchange system. A DER capacity resource's Planned Available ICAP is determined based on PJM's approval of the DER Aggregator's DER Plan and the completion of the DER Planned Setup process in the Capacity Exchange system. A DER capacity resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP.

A party's Daily RPM Resource Commitments for a specific DER capacity resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such DER capacity resource 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, and to increases of RPM Resource Commitments due to approved Locational UCAP transactions.

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

A party's Daily RPM DER capacity resource Position for a specific DER capacity resource is equal to the (Daily ICAP Owned Value - Daily FRR Capacity Plan Commitments) * applicable Accredited UCAP Factor.

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

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), Planned DER capacity resources, Qualified Transmission Upgrade, or external capacity without firm transmission (these five together considered herein to be Resources Requiring Credit for RPM) must establish a separate RPM Credit Limit prior to and for each RPM Auction in which the participant offers planned MWs from a Resource Requiring Credit for RPM.

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 Credit Department at least two weeks prior to an RPM Auction. For price responsive demand requiring credit, credit requests should be made to PJM's Credit 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 Credit 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 .VI.B.4 of OATT, Attachment Q, 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 offered/committed by 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 offered/committed by 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 secured.
- For Planned DER capacity resources, the Credit Adjustment Factor will be (1-X), where "X" is the Nominated DER Value that is certified through DER Aggregation registrations linked to the planned DER capacity resource divided by the Nominated DER Value offered/committed by the Planned DER capacity resource.
- For Planned generation resources (internal and external, financed and non-financed), please see the incremental reduction and associated credit milestones in Section 4.8.5 .
- For Qualifying Transmission Upgrades, the Credit Adjustment Factor will be 0.5 (50%) if a full (not provisional) Generation Interconnection 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.

4.8.3 Auction Credit Rate

An Auction Credit Rate is calculated prior to each RPM Auction for such Delivery Year as follows:

- Prior to the posting of the BRA results, the RPM Auction 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. The RPM Auction Credit Rate for planned Seasonal Capacity Resources is the same as the RPM Auction Credit Rate for planned Capacity Performance Resources; however, the rate is reduced to be proportional to the number of days in the relevant season.

- Upon posting the BRA clearing results, the RPM Auction 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. The RPM Auction Credit Rate used for planned Seasonal Capacity Resource commitments in the BRA is the same as the RPM Credit Rate for planned Capacity Performance commitments in the BRA; however, the rate is reduced to be proportional to the number of days in the relevant season.
- For any planned resource not previously committed for a Delivery Year that participates in an Incremental Auction, the RPM Auction Credit Rate for all planned Capacity Performance Resources is equal to the greater of (i) 0.5 times applicable Delivery Year's Net CONE for modeled LDA where the resource resides (in $/MW-day) or (ii) $20 per 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 Auction Credit Rate. The RPM Auction Credit Rate for any planned Seasonal Capacity Resource not previously committed for a Delivery Year that participates in an Incremental Auction is the same as the RPM Auction Credit Rate for planned Capacity Performance Resources; however, the rate is reduced to be proportional to the number of days in the relevant season.
- Upon posting the results of an Incremental Auction, the RPM 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 Auction Credit Rate. The RPM Auction Credit Rate for planned Seasonal Capacity Resource commitments in an Incremental Auction is the same as the RPM Auction Credit Rate for planned Capacity Performance Resource commitments in an Incremental Auction; however, the rate is reduced to be proportional to the number of days in the relevant season.
- 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 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 DR Hub 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) 0.5 times applicable Deliver Year's Net Cone for the modeled LDA where the price responsive demand resides or (ii) $20/MW-day times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

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 prior to the Base Residual Auction, shall be the (greater of (i) $20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such auction for the LDA where the PRD load is located, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where the price responsive demand resides or (b) 1.5 times Net CONE (stated in installed capacity terms as $/MW-day) for the modeled LDA where the price responsive demand resides minus the Capacity Performance Resource Clearing Price for such modeled LDA)times the number of days in the Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

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 greater of (i) 0.5 times applicable Deliver Year's Net Cone for the modeled LDA where the price responsive demand resides or (ii) $20/MW-day) times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

After the posting of the Third Incremental Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for Price Responsive Demand committed in the Third Incremental Auction or committed to the FRR Alternative to reduce the final unforced capacity obligation of an FRR Entity, shall be (the greater of (i) $20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such auction for the LDA where the price responsive demand resides, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where the price responsive demand resides or (b) 1.5 times Net CONE (stated in installed capacity terms as $/MW-day) for the modeled LDA where the price responsive demand resides minus the Capacity Performance Resource Clearing Price in such Incremental Auction for such modeled LDA) times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

4.8.5 Credit Milestones for Planned Generation Capacity Resources

For Planned Generation Capacity Resources, Planned External Generation Capacity Resources and the RPM Credit Requirement shall be reduced by applying the appropriate Incremental Credit Reduction from the tables 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 "GIA 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 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**

Credit Reductions (%) for Planned Generation Capacity Resources and Planned External Generation Capacity Resources	
Effective date of fully executed GIA for Planned Generation Capacity Resources or agreement equivalent to GIA 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%

The following definitions apply to the terms in the tables above:

- “Effective Date of fully executed GIA” shall be as defined in the relevant GIA.
- “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: 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 GIA, 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.

4.9 Aggregate Resources

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[17]. Capacity Market Sellers that own one or more Intermittent Resources that have been granted Capacity Interconnection Rights related to the winter-period and Summer Period Demand Resources~~, Capacity Storage Resources, Demand Resources, Energy Efficiency Resources, or environmentally limited resources~~ may create and offer an Aggregate Resource located in the smallest modeled LDA common to the underlying aggregated resources 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 that have been granted Capacity Interconnection Rights related to the winter-period and Summer Period Demand Resources~~, Capacity Storage Resources, Demand Resources, Energy Efficiency Resources, and environmentally limited resources~~ that are combined to form an Aggregate Resource will be considered to be located in the smallest modeled LDA common to the underlying aggregated resources[18] and must reside in a single Capacity Market Seller account in Capacity Exchange.
- 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 Capacity Exchange system.
- Aggregate Resource requests must specify the capacity resources that are being combined to form the Aggregate Resource, the installed capacity owned on each

17 OATT Attachment DD, Section 5.6.2(h)

18 For example, if one resource is located in EMAAC and the other resource is located in Rest of RTO, the Aggregate Resource will be modeled and compensated in Rest of RTO and compensated at Rest of RTO clearing price. If one resource is located in EMAAC and the other is located in SWMAAC, the Aggregate Resource will be modeled and compensated in MAAC. If one resource is located in COMED and the other resource is located in EMAAC, the Aggregate Resource will be modeled and compensated in Rest of RTO.

generation capacity resource~~,~~or 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. The request must also include an initial seasonal allocation of the Annual Capacity Performance capability of the Aggregate Resource to the underlying resources.

- Aggregate Resource requests must also include a written explanation, including supporting data, to justify how the Aggregate Resource realize a higher level of Annual Capacity Performance capability (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. Once an Aggregate Resource is modeled for a Delivery Year and clears any amount in a Delivery Year RPM Auction, such Aggregate Resource must remain in effect for the entire Delivery Year and may not be terminated for the Delivery Year.
- An Aggregate Resource may be specified as a resource in a Locational UCAP transaction or a~~A~~uction s~~S~~pecific 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 Existing Generation Capacity 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.
- The total committed quantity of an Aggregate Resource must be allocated to its underlying capacity resources prior to the start of the Delivery Year and must be updated within the Delivery Year if the total commitment of the Aggregate Resource is revised due to replacement of all or any part of the Aggregate Resource’s commitment or due to the use of available capacity on the Aggregate Resource as a replacement resource. The total committed quantity must be allocated to the individual underlying resources on a monthly basis and may be updated no later than the last day of each month for months remaining in the Delivery Year. An individual resource may not receive a daily CP commitment allocation that applies for the entire month in excess of their CIRs. 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 Interval for such day.

- If an Aggregate Resource commitment is removed or reduced by a replacement transaction, the Capacity Market Seller responsible for the Aggregate Resource must reduce the allocation of commitment to the underlying resources by a commensurate amount
- If an Aggregate Resource commitment is increased by a replacement transaction, the Capacity Market Seller responsible for the Aggregate Resource must increase the allocation of commitment to the underlying resources by a commensurate amount.
- Individual resources that are part of an Aggregate Resource will be expected to respond to a Performance Assessment Interval (PAI) in the area where they are physically located and its Non-Performance Charge Rate will be based on the location of the physical resources underlying the aggregate. If one or more individual resources that are part of an Aggregate Resource are in the same area where there is a PAI, the under-/over-performance of the Aggregate Resource will be based on the total commitment and performance of all of the individual resources included in the PAI. The Non-Performance Charge Rate applicable to an under-performing Aggregate Resource is based on the rate associated with the LDA in which the under-performing underlying resources are located weighted by the under-performance MW quantity of such resources. The annual non-performance charge limit of an Aggregate Resource is based on the limit applicable to the LDA in which the Aggregate Resource was modeled in the RPM Auction.
- The location of replacement capacity specified for an Aggregate Resource must be in accordance with the r~~R~~eplacement c~~C~~apacity transaction business rules in Section 8.8 of this manual.

4.10 Seasonal Capacity Performance Resources

Capacity Market Sellers may offer Seasonal Capacity Performance Resources into RPM Auctions. A Seasonal Capacity Performance Resource is a Summer-Period Capacity Performance or Winter-Period Capacity Performance Resource, as described below.

A Summer-Period Capacity Performance Resource may include the following types of Capacity Resources that are eligible to submit a sell offer as a Summer-Period Capacity Resource: Summer-Period Demand Resource, ~~Summer-Period Energy Efficiency Resource, Capacity Storage Resource, Intermittent Resources, or Environmentally-Limited Resource~~ that has an average expected energy output during the summer peak-hour periods consistently and measurable greater than its average expected energy output during winter peak hour periods.

Summer-Period Demand Resource is a resource that is placed under the direction of the PJM and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by PJM, and will be capable of maintaining each such interruption (i) for all hours of the day during such months beginning with the 2027/2028 Delivery Year, or (ii) for Delivery Years up through the 2026/2027 Delivery Year, between hours of 10:00 AM to 10:00 PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

~~A Summer-Period Energy Efficiency Resource is a project, including the installation of more efficient devices or equipment or implementation of more efficient process or systems, meeting the requirements of Schedule 6 of the Reliability Agreement and exceeding then-current codes, appliance standards, or other relevant standards, designed to achieve continuous reduction in electric energy consumption at end use customer's retail site during the summer peak periods (i.e., the defined EE Performance Hours in Section 4.4 of this manual) that is not reflected in the peak load forecast used for the Auction Delivery Year for which the Summer-Period EE Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.~~

To the extent that a Summer-Period Capacity Resource clears in an RPM Auction or is otherwise committed as a Summer-Period Capacity Performance Resource, such resource is obligated to deliver energy as scheduled and/or dispatched by PJM during Performance Assessment Intervals occurring during the calendar months of June through October and the following May of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. A committed Summer-Period Capacity Performance Resource will be subject to the relevant resource performance assessments for capacity performance commitments and the associated deficiency/penalty charges for such period of time.

A Summer-Period Capacity Performance Resource that clears in an RPM Auction will only receive a Daily RPM Auction Credit for the MWs cleared in such auction for the summer period of June through October and May of the Delivery Year.

A Winter-Period Capacity Performance Resource may include the following types of Capacity Resources that are eligible to submit a sell offer as a Winter-Period Capacity Performance Resource: Intermittent Resource that has been granted additional Capacity Interconnection Rights related to the winter-period~~Capacity Storage Resource, Intermittent Resource, and Environmentally-Limited Resource that has an average expected energy output during winter peak-hour periods consistently and measurably greater than its average expected energy output during summer peak hour periods~~.

By August 31 of each calendar year, PJM shall solicit requests from generation owners of Intermittent Resources ~~and Environmentally Limited Resources~~ which seek to obtain additional Capacity Injection Rights (CIRs) related to the winter period (November through April of a Delivery Year) for the purposes of creating a Winter-Period Capacity Performance Resource or an Aggregate Resource as described in Section 4.9. Such additional CIRs would be for a one year period as specified by PJM in the solicitation. Responses to such solicitation must be submitted by interested owners by October 31 prior to the upcoming Base Residual Auction. Such requests shall be studied for deliverability similar to any Generation Project Developer seeking to enter the New Service Request study process; however, such requests shall not be required to enter the New Service Request study process. PJM shall study such requests in a manner so as to prevent infringement on available system capabilities on any resource which is already in service, or which has an executed Generation Interconnection Agreement, Transmission Service Agreement, Upgrade Construction Agreement, or has submitted a valid New Service Request. If the Intermittent Resource ~~or Environmentally Limited Resource~~ is accredited as deliverable for additional CIRs for the winter period, such generation owner shall receive the additional CIRs for the winter period of the relevant Delivery Year.

To the extent a Winter-Period Capacity Performance Resource clears an RPM Auction or is otherwise committed as a Winter-Period Capacity Performance Resource, such resource is obligated to delivery energy as scheduled and/or dispatched by PJM during Performance Assessment Intervals occurring in the calendar months of November through April of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. A committed Winter-Period Capacity Performance Resource will be subject to the relevant resource performance assessments for capacity performance commitments and the associated deficiency/penalty charges for such period of time.

A Winter Period-Capacity Performance Resource that clears in an RPM Auction will only receive a Daily RPM Auction Credit for the MWs cleared in such auction for the winter period of November through April of the Delivery Year.

A Capacity Market Seller that clears a Seasonal Capacity Resource in an RPM Auction will receive a Resource Clearing Price that is applicable to the Capacity Market Seller’s Seasonal Capacity Performance sell offer and is reflective of the Locational Price Adder determined as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 and 5.8.5 and any make-whole price, if a make-whole payment is required, for such cleared sell offer.

4.11 DER Capacity Resources

A DER Capacity Aggregation Resource, also known as a DER capacity resource is comprised of one or more DER Aggregation Resource(s) (also known as DER registration(s)). A DER registration is comprised of one of more Component DER(s) (also known as "locations"). A DER location includes resource(s) located within the PJM Region, that are also on the distribution system, any subsystem thereof, or behind a customer meter and can include demand response ("DR"), distributed generation ("DG"), or both.

4.11.1 DER Participation

A DER Aggregator, which is required to be a PJM member, may offer DER capacity resources into an RPM Auction, or an FRR Entity may commit them in an FRR Capacity Plan, starting with the 2028/2029 Delivery Year. A DER Aggregator is a Market Participant that has a fully-executed DER Aggregator Participation Service Agreement as provided in the Tariff, Attachment N-4 prior to participation in an RPM auction or commitment in an FRR plan.

The DER Aggregator must submit a DER Capacity Aggregation Resource Sell Offer Plan ("DER plan") no later than 30 days prior to the RPM Auction or prior to the deadline for submitting the FRR Capacity Plan. DER plans that includes distributed generation or demand response with injections are subject to mitigation and therefore should be submitted in 10 days prior to the MOPR certification deadline (or 160 days prior to the auction). If a DER plan that includes distributed generation or demand response with injections is submitted after the MOPR certification and unit specific market seller offer cap deadline, then such Plan will be subject to the relevant mitigation rules provided in the Tariff (MOPR and MSOC). The specific timelines for participation in an RPM Auction or submission of DER plans and FRR Capacity Plan(s) are provided in the RPM Auction Schedule posted on the PJM website.

DER capacity resources that clear in an RPM Auction will have an RPM Resource Commitment for the relevant Delivery Year. DER capacity resources that are committed to an FRR Capacity Plan will have an FRR Capacity Plan Commitments for the relevant Delivery Year. DER capacity resources are subject to penalties if they do not meet their capacity commitment as defined further in this Manual.

A DER capacity resource is considered homogeneous if comprised of locations with the same type (DG or DR) and technology. For example, a DER capacity resource comprised of DG solar is considered a homogenous resource. DER capacity resources are considered heterogeneous if comprised of locations of different types or technologies. For example, a DER capacity resource with solar and a battery is considered a heterogeneous resource.

A location may only be registered or operate to support one of the following for the same period of time: DER capacity resource, load management resource, Price Responsive Demand resource, Peak Shaving Adjustment resource or Non-Retail Behind the Meter Generation resource.

4.11.2 DER Plan Requirements

A DER Aggregator must submit a DER plan comprised of Existing and/or Planned DER capacity resources to participate in an RPM auction or to commit a DER capacity resource to a FRR plan. DER plans should be provided to PJM in the associated PJM template and/or tool and shall include but is not limited to the following:

- Existing and/or Planned Nominated megawatt quantities by method(s) of achieving generation or load reductions to meet megawatt quantities
- equipment and technology to be installed or controlled

- plan and ability to acquire generating resources or load reductions at customer site(s) and assumptions regarding regulatory approval of program(s), if applicable
- A measurement and verification plan, if applicable
- Zone and LDA information
- An estimated schedule for acquiring the location specific capability

Existing DER MWs are based on approved registration(s) linked to a DER capacity resource for the current Delivery Year by the DER Aggregator that are certified by the DER Aggregator through the pre-registration process to be available and reasonably expected to be under contract to generate or reduce load based on PJM dispatch instructions by the start of the Delivery Year for which the resource is committed. If the DER Aggregator would like to provide additional MWs in their DER plan (i.e., there are no approved registrations for the current Delivery Year), then such MWs will be considered Planned MWs.

Planned DER MWs are based on the DER Aggregator's expected future contracts and the associated location's capacity generation output and curtailment capability or do not otherwise qualify as Existing DER MWs. The Planned DER MWs must establish an RPM Credit Limit prior to an RPM Auction as defined in section 4.8 of this Manual. Credit requests should be made to PJM's Treasury Department at least two weeks prior to the auction or FRR plan deadline.

Distributed generation, or the injection component of a location with both load reduction and injection capability listed in the DER Plan need not go through PJM's interconnection queue in order to participate in the capacity market under the DER Aggregator Participation Model. However, the DER Aggregator must ensure that these technologies are approved for interconnection and/or injection by the Electric Distribution Company prior to the start of the Delivery Year.

An officer of the DER Aggregator must submit a DER certification at the time the DER plan is submitted. A DER Aggregator Officer Certification Form specifies that the signing officer has reviewed the DER Plan, that the information provided therein is true and correct, and that the MW quantity that clears the auction or is committed to an FRR Capacity Plan is reasonably expected to be physically delivered through DER registrations for the relevant Delivery Year.

Homogeneous DER capacity resources solely comprised of DR resources that do not participate in the wholesale capacity market with an injection onto the distribution system are not subject to MOPR or MSOC. All other DER capacity resources are subject to MOPR and MSOC rules. Homogeneous resources are subject to MOPR and MSOC based on their underlying technology. Heterogeneous resources are required to offer at $0 MW-day UCAP or below an approved unit specific MSOC. The auction specific deadlines for MOPR and MSOC are published on pjm.com for each auction. A DER capacity resource with a MOPR price greater than MSOC price is not eligible to participate in the associated auction as described in the Tariff.

DER capacity resource's UCAP will be based on the ELCC class associated with the technology of the underlying location(s) as outlined in Manual 21B. The nominated value of DR will be determined in a manner consistent with the determination of the nominated values for load management in section 4.3.7 of this Manual. If the injection portion of a DR resource is approved to participate in the capacity market and has multiple technologies, then ELCC accreditation will be based on the weighted average of the underlying technology capabilities. The ICAP of DG, or the injection portion of a location with both DR and injection capability, will be based on the minimum of the nameplate value or the amount approved by the Electric Distribution Company to inject onto the distribution system. The Accredited UCAP of the DER capacity resource will be the sum of the Accredited UCAP of the underlying locations or as approved through DER plan.

Resources included in the DER plan or locations included on registrations that are linked to DER capacity resources must comply with the double counting rules specified in the Tariff, Attachment K-Appendix, section 1.4B. For example, a location on an Electric Distribution Company Net Energy Metering ("NEM") agreement may not participate in the capacity market.

4.11.3 Registration Requirements

A DER location is defined by unique Electric Distribution Company account number which typically reflects the point of interconnection to the electric distribution system. The installed capacity of a single location shall be no more than 5 MWs. A DER registration may be single-node or multi-nodal. A single-node DER registration is comprised of location(s) in the same LDA, transmission zone, State, Electric Distribution Company territory and pricing node. A multi-nodal DER registration is comprised of locations in the same LDA, transmission zone, State and Electric Distribution Company territory, but may span multiple pricing nodes. A DER Aggregator shall only use a multi-nodal registration if the location(s) cannot meet the minimum 0.1 MW participation requirement without using such aggregation. A multi-nodal registration must include no more than 1 location (or combination of locations at a single pricing node) that is equal to or greater than 0.1 MW. The total participation of multi-nodal registrations may be no greater than 167 MW across the RTO. DER capacity registrations are linked to DER capacity resource as long as the primary pricing nodes of such registrations are located within the same zone or sub-zonal LDA of the DER capacity resource.

DER registrations used to support DER capacity resource commitments are subject to a must offer requirement in the energy market and must submit both a cost based and price based offer. Cost based offers are based on the rules included in Manual 15. DER registrations are required to follow the associated technology rules to be consistent with Generation Capacity Resources as described in Manual 11, section 2.3.3.1. DER registrations must comply with the review and approval process.

DER registrations with a capacity commitment are required to maintain real time telemetry for each DER registration that meet the requirements specified in M1.

DER registrations are required to submit location specific settlements data, based on the market specific requirements, 1 business day after the day they are dispatched.

4.11.4 Testing Requirements

Each DER capacity resource committed in a Delivery Year shall be obligated to simultaneously test all associated locations on an annual basis. The DER Aggregator may perform an unlimited number of tests and re-tests but shall notify PJM of the test and re-test at least 48 hours in advance. The test and any associated re-test should be conducted for 1 hour between the hours of 11:00 and 18:00 EPT of a non-NERC holiday weekday. The Office of Interconnection may, at its discretion, cancel a test and allow a retest, to ensure system reliability. The DER Aggregator shall notify the applicable Electric Distribution Company at least seven business days prior to each such test, and the Electric Distribution Company may cancel the test consistent with Tariff, Attachment K-Appendix, section 1.4B(f). The re-tests are limited to all locations that failed to meet their nominated ICAP in the prior test or re-test(s).

Energy settlements for registrations tested are compensated based on energy market rules.

Test performance will be based on the aggregate performance for all the locations of the DER capacity resource. Actual delivered MWs for the tests are based on the sum of the load reductions and/or generation output for such tests. A DER capacity resource's total daily ICAP commitment level is determined each day of the delivery year and used to determine if there is a shortfall and associated penalty.

Delivered load reductions will be determined using the methodology specified in M19, Attachment A. Delivered generation MW onto the distribution system will be measured based on the meter data.

If none of the tests during a testing period certify full delivery of the megawatt amount of nominated capacity the DER Aggregator committed, for such Delivery Year, the DER Aggregator shall be assessed a DER Capacity Aggregation Resource Test Failure Charge.

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. Notwithstanding, the Base Residual Auction for the 2025/2026 through 2029/2030 Delivery years shall be conducted in accordance with the RPM Auction Schedule posted on the PJM website. 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.
- 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 determined as a result of the RPM Auction process. The bilateral market is facilitated through the Capacity Exchange system.

5.2 RPM Auction Timeline

The following Auction timeline provides the deadline for key RPM activities[19]:

RPM Activity	Deadline
Submittal of binding notice of intent to offer Planned Generation Capacity Resource into Base Residual Auction (effective with 2025/2026 Delivery Year)	December 1st immediately preceding Base Residual Auction (except for 2025/2026, 2027~~6~~/2028~~7~~ and 2029~~8~~/2030~~29~~ Delivery Year); December 12th 2023 (for 2025/2026 Delivery Year); 180 days prior to commencement of offer period (2027~~6~~/2028~~7~~ and 2029~~8~~/2030~~29~~ Delivery Year)
Post Planning Parameters for BRA	Posting deadline provided in RPM Auction Schedule on PJM website
Requested DER Plan and Officer Certification submission date for DER resources subject to MOPR and/or MSOC	160 days prior to commencement of offer period
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

19 For delivery years where FERC has approved a compressed auction schedule, the actual deadline may be different from the deadline listed in this activity table. Participants should adhere to the activity deadlines on the RPM Auction Schedule posted on the pjm website.

RPM Activity	Deadline
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 (~~U~~unit-s~~S~~pecific)	120 days prior to commencement of offer period
IMM to notify Capacity Market Seller of determination on MOPR exemption request	90 prior to commencement of offer period
PJM to notify Capacity Market Seller of determination on MOPR exemption request	65 days prior to the commencement of offer period
Submittal of minimum level of Sell Offer commitment consistent with u~~U~~nit-s~~S~~pecific MOPR request	5 days after receipt of PJM determination on u~~U~~nit-s~~S~~pecific MOPR request
Submittal of preliminary request to remove a resource from Capacity Resource status and preliminary must-offer exemption request for BRA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	Sept 1st immediately preceding BRA for applicable Delivery Year
Submittal of final request to remove a resource from Capacity Resource status and 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 request to remove resource from Capacity Resource status and preliminary must-offer exemption request for IA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	240 days prior to commencement of offer period
Submittal of final request to remove a resource from Capacity Resource status and 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

RPM Activity	Deadline
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
PJM posts summaries of MW of Generation for which it has received requests to remove a resource from Capacity Resource status, and 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. Postings 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	No later than 5 Business Days after the request/notification deadline
IMM to notify Capacity Market Seller of determination on must-offer exemption request and removal of Capacity Resource status	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 or must-offer exception request	80 days prior to commencement of offer period
PJM notification to participant of its determination on must offer exemption request and removal of Capacity Resource status	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 (prior to 2025/2026 Delivery Year)~~	~~120 days prior to commencement of offer period~~
~~IMM provides determination on request for alternative maximum EFORd (prior to 2025/2026 Delivery Year)~~	~~90 days prior to commencement of offer period~~
~~Participant notification to PJM and the IMM whether agreement has been reached on~~	~~80 days prior to commencement of offer period~~

RPM Activity	Deadline
~~alternative maximum EFORd (prior to 2025/2026 Delivery Year).~~	
~~PJM notification to participant of its determination on alternative maximum EFORd (if no agreement reached with IMM) (prior to 2025/2026 Delivery Year).~~	~~65 days prior to commencement of offer period~~
Preliminary ELCC Class Ratings and Accredited UCAP Factors	Posting deadline provided in RPM Auction Schedule on PJM website
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 business days prior to start of Delivery Year for which the resource is committed
Participant submits to PJM its Demand Response Resource Plan	30 days prior to commencement of offer period
Final DER Plan and Officer Certification submission deadline	30 days prior to commencement of offer period
Base Residual Auction	May, 3 years prior to the Delivery Year
Submittal of binding notice of intent to offer Planned Generation Capacity Resource into Incremental Auction	90 days prior to commencement of offer period
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 (prior to 2025/2026 Delivery Year)~~	~~By November 30th prior to the Delivery Year~~

RPM Activity	Deadline
Final Accredited UCAP Factor for Delivery Year (effective with 2025/2026 Delivery Year)	No later than 5 months prior to the start of 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 with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd (prior to 2025/2026 Delivery Year) and Pool-wide average Accredited UCAP Factor (beginning 2025/2026 Delivery Year)
- Forecast Pool Requirement (FPR)
- 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
- 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
- Net Cost of New Entry (Net CONE) for the PJM Region and each modeled LDA
- Auction Credit Rate
- The amount(s) of unforced capacity to be procured by PJM and the B~~b~~uy B~~b~~id price(s) due to increase in Reliability Requirement or the amount(s) to be released from the

commitment and the sell offer price(s) 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.

5.4 Sell Offers in RPM

5.4.1 Resource-Specific Sell Offer Requirements

Sell Offers for the Base Residual and Incremental Auctions must be submitted in PJM's Capacity Exchange 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, Demand Resource, Energy Efficiency Resource, DER capacity resource or Aggregate Resource
  - Each Existing 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.
    - ELCC Resources that are Generation Capacity Resources may not offer or otherwise provide UCAP MW quantities above the greater of their Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling for the applicable Delivery Year, please see **Manual 14B: Regional Transmission Planning Process**. Notwithstanding, external resources may offer up to their Accredited UCAP.
    - Notwithstanding the above, ELCC Resources may not offer or otherwise provide UCAP MW quantities above their Accredited UCAP.
  - 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 by the start of the Delivery Year, the resource has a financially and physically firm commitment to an external sale of its capacity, or the resource is seeking to remove Capacity Resource status in accordance with Section 5.4.7 of this manual. A must offer exception request is seller and auction specific and should be submitted in the IMM MIRA system. If a must offer exception request is approved for one auction, the seller will still have a must offer requirement for any subsequent auctions(s) for the same Delivery Year or as

described below. 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. Nothing herein provides a defense to a claim of withholding, market manipulation, or the exercise of market power by any entity who is affiliated with or are under common ownership or control of a Capacity Market Seller that does not submit an offer into the capacity market.

    - Capacity Market Sellers seeking an exception for a BRA on the basis that the resource is incapable of meeting the Capacity Performance Resource requirements shall include a documented plan with the submission of their exception request showing the steps the Capacity Market Seller intends to pursue for the resource to become physically capable of satisfying the requirements of a Capacity Performance Resource, and provide periodic updates on the progress of such plan in accordance with Tariff, Attachment DD, section 6.6A(c).

  - Capacity Market Sellers may specify multiple auctions in a written must-offer exception request (with all supporting documentation) to be reviewed by the IMM and PJM with each applicable auction. Capacity Market Sellers must notify PJM and the IMM of any material changes related to the request up through the closing of the relevant auction(s) offer window.

    - When multiple auctions are specified in the written request, Capacity Market Sellers should continue to create a new request in the IMM's online system (MIRA) for each relevant subsequent auction and confirm that the documentation represents the best, current information.

- An Existing Generation Capacity 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; however,
- Demand Resources and DER capacity resources are not required to submit a Capacity Performance sell offer segment.
- Minimum and maximum amount of installed capacity offered in MWs for the resource by Capacity Performance (annual) Offer Segment and Maximum amount of installed capacity offered in a Seasonal (summer or winter) Capacity Performance Offer Segment. The Seasonal Capacity Performance Offer Segment is considered a flexible offer segment with a minimum MW quantity set to zero MW.
- Offer Segment price willing to receive in $/MW-day (in UCAP terms)
- Regular Schedule, Self-Schedule or Flexible Self-Schedule flag
- New Unit Pricing participation flag for Planned Generation Capacity Resources requesting New Unit Pricing Adjustment.
- The ICAP MW quantity specified in the Offer Segment will be converted into an UCAP MW quantity for use in the auction clearing by multiplying the ICAP MW quantity specified by the applicable Accredited UCAP Factor for a Generation Capacity Resource and DER capacity resource, by the applicable ELCC Class rating for a Demand Resource, and by

the Forecast Pool Requirement for an EE Resource. The sell offer price specified in the Offer Segment is in UCAP terms and will not be converted for use in the auction clearing.

- A Capacity Performance (annual), or Seasonal Capacity Performance 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 Offer Segment will consist of block segments at the specified price-quantity pairs.
- The auction specific Accredited UCAP Factor will be determined by PJM. 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 Capacity Performance Offer segment, 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 Current Available ICAP Position for the Delivery Year at the opening of the auction's bidding window. The acceptance of the sell offer is based on the party's Current Available ICAP Position for the entire Delivery Year (annual position) if Capacity Performance Resource, Current Available ICAP Position for summer period (summer position) if Summer-Period Capacity Performance Resource, Current Available ICAP Position for winter period (winter position) if Winter-Period Capacity Performance Resource.
- The total MWs offered across all Capacity Performance offer segments may not exceed the Current Available ICAP Position for the Delivery Year (i.e., the annual position). The total MWs offered across the Capacity Performance offer segments and the Seasonal Capacity Performance-Summer offer segments may not exceed the Current Available ICAP Position for summer period (i.e., the summer position). The total MWs offered across the Capacity Performance offer segments and the Seasonal Capacity Performance-Winter offer segments may not exceed the Current Available ICAP Position for winter period (i.e., the winter position).
- If a participant has a zero or negative Current 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 Capacity Market Seller submitting a sell offer for an existing Generation Capacity Resource or DER capacity resource greater than $0/MW-Day must seek a unit-specific exception request for such sell offer by submitting Avoidable Cost Rate data to IMM and PJM 120 days prior to the RPM Auction, or may, at its election, utilize an offer cap based on the default gross Avoidable Cost Rate of the applicable resource type, if available. For any Third Incremental Auction, a Capacity Market Seller submitting a sell offer for an existing Generation Capacity Resource or DER capacity resource may elect to use a

default offer cap equal to 1.1 times the Resource Clearing Price in the Base Residual Auction of the relevant LDA and Delivery Year.

- All sell offers for a supplier that fails the Three-Pivotal Supplier Test will be capped within the mitigated LDA.
- Cleared MWs and make-whole MWs for Capacity Performance Offer Segments are binding commitments to provide capacity for the entire Delivery Year. Cleared MWs for Seasonal Capacity Performance-Summer Offer Segments are binding commitments to provide capacity for the summer period of June through October and May of the Delivery Year. Cleared MWs for Seasonal Capacity Performance-Winter Offer Segments are binding commitments to provide capacity for the winter period of November through April of the Delivery Year.

5.4.2 Flexible Self Scheduling

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

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

- For each such segment, “flexible self-scheduled” must be selected as the offer type of the segment.
- A flexible self-schedule sell offer must specify an offer price that will be utilized in the market clearing in the event that the resource is not needed to cover the calculated capacity obligation. This is in addition to the data required of a self-schedule resource specific sell offer.
- In conjunction with an offer of a flexible self-schedule segment, the LSE must also submit through Capacity Exchange 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.

5.4.3 New Entry Pricing Adjustment

New Entry Pricing Adjustment[20] 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 Adjustment allows Planned Generation Capacity 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 Adjustment is applicable under the following conditions:

1. The new entry must select the New Entry Pricing Adjustment 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 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 through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.
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.

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[20] OATT, Attachment DD, Section 5.14(c)

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 Adjustment 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 Adjustment 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.

5.4.4 Sell Offer Caps

Submission of the Avoidable Cost Rate (ACR) Data

120 days prior to the commencement of the offer period for an RPM 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 Auction.

Capacity resource owners must supply PJM with their avoidable cost data through the IMM's Member Information Reporting Application ("MIRA").

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.***

A unit must submit unit-specific ACR data, specify an opportunity cost, or use the default rate, in order to submit a sell offer greater than zero.

Projected PJM Market Revenues for any Generation Capacity Resource or DER capacity resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource or DER capacity resource, net of energy and ancillary services market offers for such resource. The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues from the three most recent whole calendar years prior to the year in which the BRA is conducted as described in ***Section 6.8(d) of Attachment DD of the Open Access Transmission Tariff.***

Sell Offer Cap(s) will be calculated for each 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***.

Planned Generation Resources and Planned DER capacity resources may be mitigated in accordance with OATT, Attachment DD, Section 6.5.

No offer caps are applied to sell offers of Demand Resources, DER capacity resources that are exclusively DR or Planned Energy Efficiency Resources.

5.4.5 Deleted

5.4.6 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.

5.4.7 Removal of Generation Capacity Resource Status

A Capacity Market Seller seeking to remove Capacity Resource status from a Generation Capacity Resource shall submit a preliminary and final written request to PJM and the IMM, along with supporting data and documentation, in accordance with Tariff, Attachment DD, section 6.6(g).

- Requests shall be submitted to PJM via email to the rpm_hotline@pjm.com and to the IMM through the MIRA application.
- Preliminary requests must be submitted no later than September 1 prior to a BRA, and 240 days prior to an IA. Final requests must be submitted no later than December 1 prior to a BRA, and 120 days prior to an IA.
- The preliminary request must provide the following information:
  - Identification of the Generation Capacity Resource and MW
  - The beginning Delivery Year in which the Seller is seeking to remove Capacity Resource status from the resource
  - Supporting data and documentation indicating the reasons and conditions upon which the Seller is relying in its analysis to remove Capacity Resource status from the resource

- PJM will post the preliminary and final requested MW of Capacity Resource status changes on an aggregate basis by Zone and LDA that comprises a subset of a Zone.

A request will not be accepted for a resource that holds a capacity commitment during the time period in which it seeks to no longer be a Capacity Resource.

The IMM will analyze the effects of removing Capacity Resource status with respect to potential market power concerns and notify the Seller and PJM of its determination no later than 90 days prior to the applicable RPM auction. Subsequently, PJM shall provide its final determination no later than 65 days prior to the applicable RPM auction.

PJM Planning will be notified of requests and final approvals to incorporate the loss of Capacity Resource status in the appropriate planning models and reliability studies.

Once the Capacity Resource status is removed from a Generation Capacity Resource:

- The generation unit will no longer qualify as an Existing Generation Capacity Resource, and as such, will be removed from the Capacity Resource model and no longer eligible to offer in RPM auctions or take on a capacity commitment.
- The Capacity Interconnection Rights associated with the resource shall be subject to termination in accordance with the rules described in Tariff, Part VI, section 230.3.3.
    - The relevant GIA or WMPA of a Generation Capacity Resource that is removed of its Capacity Resource status will be amended to reflect any such removal of Capacity Interconnection Rights.

5.4.8 Minimum Offer Price Rule

The Minimum Offer Price Rule (MOPR) provisions of Section 5.14(h-2) of Attachment DD of the PJM OATT are applicable to each Generation Capacity Resource that is offered into RPM Auctions for the 2023/2024 Delivery Year and all subsequent Delivery Years and to each DER capacity resource that includes DG or injections from a DR resource for the 2028/2029 Delivery Year and all subsequent Delivery Years.

5.4.8.1 MOPR-Related Business Rules and Process Timeline

The following business rules apply to the sell offer of any Generation Capacity Resource or DER capacity resource that includes DG or injections from a DR resource that in an RPM Auction is subject to the MOPR of Tariff, Attachment DD, section 5.14(h-2):

- The timeline for pre-auction activities related to MOPR is specified in the table below.
- The MOPR Floor Offer Price applicable to a Generation Capacity Resource that based on the certification process described below is subject to the MOPR is dependent upon whether the resource or uprate of the resource previously cleared in an RPM auction for any Delivery Year.
- For a Generation Capacity Resource or DER capacity resource that includes DG or injections from a DR resource that is subject to the MOPR and for which a Sell Offer based

on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year, the applicable New Entry MOPR Floor Offer Price, based on the net cost of new entry for the resource, shall be, at the election of the Capacity Market Seller, either (i) the unit-specific value determined in accordance with the unit-specific exception process for MOPR Floor Offer Prices, or (ii) the default New Entry MOPR Floor Offer Price, if available, of the applicable resource type. A Capacity Market Seller must seek a unit-specific MOPR Floor Offer Price if the resource is of a type for which there is no default New Entry MOPR Floor Offer Price, including hybrid resources. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer for such resource for the relevant RPM Auction.

- For a Generation Capacity Resource or DER capacity resource that includes DG or injections from a DR resource that is subject to the MOPR and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price, based on the net Avoidable Cost Rate, shall be, at the election of the Capacity Market Seller, either (i) the unit-specific value determined in accordance with the unit-specific exception process for MOPR Floor Offer Prices, or (ii) based on the default gross Avoidable Cost Rate, if available, of the applicable resource type net of projected net energy and ancillary service revenues for the resource (Net ACR). A Capacity Market Seller must seek a unit-specific MOPR Floor Offer Price if the resource is of a type for which there is no default gross Avoidable Cost Rate, including hybrid resources. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer for such resource for the relevant RPM Auction.
- The MOPR Floor Offer Price of any Capacity Resource that is subject to the MOPR is expressed in terms of Unforced Capacity MW (“UCAP MW”). A resource’s MOPR Floor Offer Price in $/UCAP MW-Day is applicable to each MW offered by the resource that is subject to MOPR regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.
- If any of the individual underlying resources of a commercially aggregated resource are subject to a MOPR Floor Offer Price, the MOPR Floor Offer Price applicable to the Sell Offer of such an aggregate resource is equal to the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if applicable) of the individual aggregated resources.

MOPR-Related Process Timeline

Activity	Deadline
PJM posts preliminary estimate of MOPR Floor Offer Prices	No later than 150 days prior to commencement of offer period for an RPM Auction

Capacity Market Seller certifies the status of each Generation Capacity Resource and applicable DER capacity resource it intends to offer as it relates to Conditioned State Support and Exercise of Buyer-Side Market Power	No later than 150 days prior to commencement of offer period for an RPM Auction
PJM and/or IMM notify Capacity Market Seller of fact-specific review of ability and incentive to exercise Buyer-Side Market Power	No later than 135 days prior to commencement of offer period for an RPM Auction
Capacity Market Seller submits request for a u~~U~~nit s~~S~~pecific e~~E~~xception with all required documentation simultaneously to both the IMM and PJM	No later than 120 days prior to commencement of the offer period for the RPM Auction
IMM reviews the request and provides its findings to the Capacity Market Seller and PJM of whether the proposed Sell Offer is acceptable	No later than 90 days prior to the commencement of the offer period of the RPM Auction
PJM reviews the request and provides determination to the Capacity Market Seller and the IMM of whether the proposed sell offer is acceptable and if not provides a minimum sell offer based on data and documentation	No later than 65 days prior to the commencement of the offer period of the RPM Auction
Capacity Market Seller notifies PJM and IMM of minimum level of Sell Offer to which it agrees to commit	No later than 60 days prior to the commencement of the offer period of the RPM Auction

5.4.8.2 Certification Requirement

By no later than 150 days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify for each Generation Capacity Resource or DER capacity resource (beginning 2028/2029 Delivery Year) that is not exclusively DR, the Capacity Market Seller intends to offer into the RPM Auction: (i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification, and (ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side

Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

All Capacity Market Sellers are responsible for the timeliness and accuracy of each certification which is undertaken through PJM's Capacity Exchange system. Any Generation Capacity Resource of DER capacity resource (that is not exclusively DR) for which a Capacity Market Seller has not timely submitted the certifications shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception for the relevant Delivery Year, and PJM approves the unit-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) is receiving or expected to receive Conditioned State Support, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller) that owns or controls such Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers have an ongoing obligation to certify to PJM and the IMM a Generation Capacity Resource's or DER capacity resource's (that is not exclusively DR) material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change.

A Capacity Market Seller must certify for each Generation Capacity Resource or DER capacity resource (that is not exclusively DR)the seller intends to offer into each RPM Auction that the seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power. In other words, this status does not carry forward from one auction to the next as does the status regarding Conditioned State Support.

Conditioned State Support

Conditioned State Support is any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where "conditioned on clearing in any RPM Auction" refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource or DER capacity resource (that is not exclusively DR) in the RPM Auction or directives that the Generation Capacity Resource or DER capacity resource (that is not exclusively DR) is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy defined as any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource or DER capacity resource (that is not exclusively DR) and the enactment of such action predates

October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to: policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state administered federal regulatory program (e.g., Cross-State Air Pollution Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

If PJM reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource or DER capacity resource (that is not exclusively DR), PJM shall submit a filing at FERC indicating the intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource or DER capacity resource (that is not exclusively DR) reasonably expected to receive such Conditioned State Support.

Upon FERC acceptance that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) for which a Capacity Market Seller certifies that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by PJM, with the advice and input of the IMM, will be subject to the provisions of the Minimum Offer Price Rule.

Exercise of Buyer-Side Market Power

The Exercise of Buyer-Side Market Power means anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller's (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest. Load Interest means, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity

Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource or DER capacity resource (that is not exclusively DR).

If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource or DER capacity resource (that is not exclusively DR), then the underlying Capacity Resource will be subject to the MOPR. If PJM and/or the IMM reasonably suspects that a certification contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource or DER capacity resource (that is not exclusively DR) may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, then PJM and/or the IMM shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource or DER capacity resource (that is not exclusively DR) and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource or DER capacity resource (that is not exclusively DR). During such fact-specific review, the Capacity Market Seller will have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource or DER capacity resource (that is not exclusively DR)would not be an Exercise of Buyer-Side Market Power.

PJM and/or the IMM shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year. In initiating a review, PJM and/or the IMM shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s)or DER capacity resource(s) (that is not exclusively DR), and the purported beneficiary of any price suppression. PJM and/or the IMM may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, PJM and the IMM shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by PJM and/or the IMM, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the PJM, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource or DER capacity resource (that is not exclusively DR)that could be an Exercise of Buyer-Side Market Power, in accordance with the provisions of Sections 5.14(h-2)(2(B)(i)(a) and (b) of Attachment DD.

The following non-exhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review: (a) the Generation Capacity Resource or DER capacity resource (that is not exclusively DR)is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource or DER capacity resource (that is not exclusively DR)is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource or DER capacity resource (that is not exclusively DR) is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller's long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power. For purposes of evaluating Buy-Side Market Power, Self-Supply Seller is a vertically integrated utility or public power entity where vertically integrated utility means a utility that owns generation or DER, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and public power entity means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Based on the fact-specific review, including the facts and circumstances of the Generation Capacity Resource or DER capacity resource (that is not exclusively DR), with the advice and input of the IMM, PJM shall determine whether a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If PJM determines that a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, PJM shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the PJM's determination of whether a given Generation Capacity Resource or DER capacity resource (that is not exclusively DR) is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that PJM will proceed with administration of the Tariff and market rules based on its determination unless FERC by order directs otherwise.

5.4.8.3 Unit-Specific Exception Process for MOPR Floor Offer Prices

A. Documentation Required in the Unit-Specific Exception Process for New Entry MOPR Floor Offer Price

The Capacity Market Seller of a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) that is subject to the MOPR of OATT Attachment DD, section 5.14(h-2) and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year may request a unit-specific MOPR Floor Offer Price based on the net CONE of the resource by no later than 120 days prior to the commencement of the offer period of the relevant RPM Auction. Such request must be made simultaneously to PJM and the IMM and must include all required documentation. The Capacity Market Seller must include in its request for an exception documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of the offsetting net revenues or sufficient data for PJM and the IMM to produce such net revenue estimates. Estimates of costs and revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the default New Entry MOPR Floor Offer Price established for various resource types. Supporting documentation for project costs may include, as applicable and available, the following:

- Complete project description;
- Environmental permits;
- Vendor quotes for plant or equipment;
- Evidence of actual costs of recent comparable projects;
- Bases for electric and gas interconnection costs and any costs contingencies;
- Bases for support for property taxes, insurances, operations and maintenance (O&M) contractor costs, and other fixed O&M and administrative or general costs;
- Financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments;
- Bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling; and
- Identification and support for any sunk cost that the Capacity Market Seller has reflected as a reduction to its Seller Offer.

The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the resource-specific exception request and that to the best of their knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources or DER capacity resource (that is not exclusively DR) shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits for purposes other than state-mandated or state-sponsored programs), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (e.g., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

The request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in the region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

The Capacity Market Seller shall provide any additional supporting information reasonably requested by PJM or IMM to evaluate the Sell Offer. Requests for additional documentation shall not extend the deadline by which PJM or IMM must provide their determinations of the MOPR exception request.

An evaluated Sell Offer shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's cost, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM in the development of the MOPR Floor Offer Price. The Capacity Market Seller must demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection.

Failure to adequately support costs or revenues so as to enable PJM to make a determination of the MOPR exception request will result in a denial of an exception by PJM.

B. Documentation Required in the Unit-Specific Exception Process for Cleared MOPR Floor Offer Price

The Capacity Market Seller of a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) that is subject to the MOPR of OATT Attachment DD, section 5.14(h-2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year may request a unit-specific MOPR Floor Offer Price based on the net ACR of the resource by no later than 120 days prior to the commencement of the offer period of the relevant RPM Auction. Such request must be made simultaneously to PJM and the IMM and must include all required documentation. The Capacity Market Seller shall submit a Sell Offer based on the net ACR of the resource consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in the region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the unit-specific exception request and that to the best of their knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

The Capacity Market Seller shall provide any additional supporting information reasonably requested by PJM or IMM to evaluate the Sell Offer. Requests for additional documentation shall not extend the deadline by which PJM or IMM must provide their determinations of the MOPR exception request.

An evaluated Sell Offer shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the MOPR Floor Offer Price, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's cost, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM in the development of the MOPR Floor Offer Price. The Capacity Market Seller must demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection.

Failure to adequately support costs or revenues so as to enable PJM to make a determination of the MOPR exception request will result in a denial of an exception by PJM.

5.4.8.4 Default MOPR Floor Offer Prices

A. Default New Entry MOPR Floor Offer Price

The Default New Entry MOPR Floor Offer Price for a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) that is subject to the MOPR and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource or DER capacity resource (that is not exclusively DR), has not previously cleared an RPM Auction for any Delivery Year is based on the net cost of new entry ("CONE") of the applicable resource type. The net CONE values are determined by subtracting the estimated net energy and ancillary service revenues from the gross cost of new entry ("CONE") values shown in the table below. The gross CONE values of the table below are adjusted for Delivery Years subsequent to ~~the 2022/2023 or~~ 2026/2027 Delivery Year, as applicable, as described below. The net energy and ancillary services revenue estimate is determined for each resource type and for each Zone as described in sections 5.14(h-2)(3)(A)(i) through (viii) of Attachment DD of the PJM OATT.[21]

For the capacity resource types listed in the table below, the Default New Entry MOPR Floor Offer Price is set equal to the net CONE of each resource type expressed in terms of Unforced

Capacity (“UCAP”) MW where the net CONE values are initially calculated for each resource type in terms of nameplate MW and then converted to UCAP MW. ~~Through the 2024/2025 Delivery Year the net CONE is converted to UCAP MW terms based on the applicable class average EFORd for thermal generation resource types and battery energy storage resource types and the applicable ELCC Class Rating for battery storage, wind and solar generation resource types. Beginning with the 2025/2026 Delivery Year, t~~The net CONE is converted to UCAP MW terms based on the applicable class average Accredited UCAP Factor (i.e., applicable ELCC Class Rating). The resultant net CONE in nameplate MW terms of the battery energy storage resource type is multiplied by 2.5 prior to converting to UCAP terms.

Gross CONE Values used to Determine Default New Entry MOPR Floor Offer Prices

Resource Type	~~Through the 2025/2026 Delivery Years: Gross CONE (2022/2023 $/MW-Day) (Nameplate)~~	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2026/2027 $/MW-day Nameplate)
Nuclear	~~$2,000~~	$2,568
Coal	~~$1,068~~	$1,480
Combined Cycle	~~$320~~	$540
Combustion Turbine	~~$294~~	394
Fixed Solar PV	~~$271~~	$298
Tracking Solar PV	~~$290~~	$321
Onshore Wind	~~$420~~	$438
Offshore Wind	~~$1,155~~	$1,351
Battery Energy Storage	~~$532~~	$502

[21] For the coal resource type, the net energy and ancillary services revenue estimate uses Northern Appalachian delivered prices from rail and barge.

Beginning with the 2027/2028~~2023/2024~~ Delivery Year, the gross CONE values of the table above will be adjusted annually based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index. The Applicable BLS Composite Index for the combustion turbine and combined cycle resource types shall be the same Applicable BLS Composite Index as that applied to adjust the gross CONE used to determine the VRR Curve for that Delivery Year (see Section 3.3.1 of this manual). For all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment." ~~For the 2023/2024 through 2025/2026 Delivery Years, inclusive, the resultant value shall then be then adjusted further by a factor of 1.022 for nuclear and coal resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. No such further adjustment shall be made to the resultant values for the 2027/2028 Delivery year and subsequent Delivery Years~~.

B. Default Gross Avoidable Cost Rate for Determination of Cleared MOPR Floor Offer Prices

For a Generation Capacity Resource or DER capacity resource (that is not exclusively DR) that is subject to the MOPR and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price is based on the net Avoidable Cost Rate determined by subtracting the estimated net energy and ancillary service revenues of the resource from the gross ACR of the resource. The Cleared MOPR Floor Offer Price of a Generation Capacity Resource shall be, at the election of the Capacity Market Seller, either (i) based on the unit-specific net Avoidable Cost Rate ("ACR"), or (ii) if available, the default gross ACR of the applicable resource type shown in the table below net of energy and ancillary services revenue determined for the resource as described in OATT, Attachment DD, Section 6.8(d)~~section 5.4.8.5 of this manual~~. The gross ACR values of the table below are adjusted for Delivery Years subsequent to the ~~2022/2023 or~~ 2026/2027 Delivery Year, as applicable, using the 10-year average Handy-Whitman Index to account for expected inflation.

For purposes of submitting a Sell Offer, the net ACR values are expressed in terms of Unforced Capacity ("UCAP") MW where the net ACR values are initially calculated for each resource in terms of nameplate MW and then converted to UCAP MW. ~~Through the 2024/2025 Delivery Year the net ACR is converted to UCAP MW terms based on the unit-specific EFORd for thermal generation resource types and battery energy storage resource types and the unit-specific Accredited UCAP value for battery energy storage, solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights). Beginning with the 2025/2026 Delivery Year, the n~~Net ACR is converted to UCAP MW terms for all generation resource types based on the resource-specific Accredited UCAP Factor.

Default Gross ACR Values used to determine MOPR Floor Offer Price of Existing Capacity Resource

Existing Resource Type	~~Through the 2025/2026 Delivery Years:~~ ~~Default Gross ACR (2022/2023 $/MW-Day) (Nameplate)~~	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (20267/ 2027) ($/MW-day) (Nameplate)
Nuclear – Single Unit	~~$697~~	$591
Nuclear – Multi Unit	~~$445~~	$537
Coal	~~$80~~	$94
Combined Cycle	~~$56~~	$113
Combustion Turbine	~~$50~~	$52
Steam Oil & Gas	~~NA~~	$64
Solar PV (Fixed and Tracking)	~~$40~~	$70
Onshore Wind	~~$83~~	147

5.5 Buy Bids in RPM

Buy Bids for the Incremental Auctions must be submitted in PJM's Capacity Exchange 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;
- All Buy Bids will be for Capacity Performance Resources
- 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 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.

5.6 Energy Market Offer Requirements

All generation resources or DER capacity 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 or Capacity Only Option of the Emergency or Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared emergency events. Please refer to the ***Energy & Ancillary Services Market Operations Manual (M-11)*** for details on PJM Energy Market participation.

5.7 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.

5.7.1 Participation in the Base Residual Auction

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

- Existing Generation Capacity Resources
- Planned Generation Capacity Resources
- Existing Demand Resources
- Planned Demand Resources
- Existing or Planned DER capacity resources
- Energy Efficiency Resources
- Aggregate Resources
- Qualifying Transmission Upgrades

Existing Generation Capacity Resources in a party's RPM Resource Portfolio that have no exception to the RPM must offer requirement and 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 or FRR Load Serving Entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year and prohibited from being committed to an FRR Entity's FRR Capacity Plan for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts for generation resources.

Effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

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

- Existing Generation Capacity Resources, existing Demand Resources, existing DER capacity resources, and Energy Efficiency Resources that have an increase in Available ICAP after the Base Residual Auction are eligible to offer the capacity increase into an Incremental Auction for the Delivery Year if the increase is approved prior to the opening of the Incremental Auction bidding window. See Section 5.8.1 for business rules regarding participation in an Incremental Auction.
- For the Base Residual Auction, a party's Current Available ICAP Position for a specific unit for the Delivery Year are equal to the minimum of (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for the Delivery Year.

$$AvailICAPPosition_{GEN} = Min_{DY}\left(DailyICAPOwned - DailyFRRCommitments\right)$$

- For the Base Residual Auction, a party's Current Available ICAP Position for a specific unit for the summer/winter season is calculated. A party's Current Available ICAP Position for the summer season are equal to the minimum (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for June through October and May of the Delivery Year. A party's Current, Available ICAP Position for a specific unit for the winter season are equal to the minimum (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for November through April of the Delivery Year.
- Following a Base Residual Auction, a party's Daily Unoffered ICAP for a generation resource is calculated and is equal to the Available ICAP Position minus the Offered ICAP in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$DailyUnofferICAP_{GEN} = AvailICAPPosition_{GEN} - OfferedICAP$$

- A Demand Resource's Available ICAP to offer into a Base Residual Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such Base Residual Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such Base Residual Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of planned MWs in the CSP's DR

Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by the CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of Aggregate Resource. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/ Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).

- A DER capacity resource' Available ICAP to offer into a Base Residual Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such Base Residual Auction and PJM's approval of the DER Aggregator's DER Plan for such Base Residual Auction. A DER capacity resource's Planned Available ICAP is determined based on PJM's approval of planned MWs in the DER Aggregator's DER Plan and completion of DER setup process in the Capacity Exchange system. A DER capacity resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP.
- An EE Resource's Available ICAP to offer into a Base Residual Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Base Residual Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the Base Residual Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. An Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Base Residual Auction and the provider's completion of the EE Planned Setup process for such Base Residual Auction in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).
- 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.

5.7.2 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), and Locational Constraints, The algorithm will also enforce the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region. The supply curve formed by the Sell Offers submitted within a modeled LDA shall only consider the quantity of MWs from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the modeled LDA's reliability requirement.

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
- Locational Price Adder(s), if any, relevant to such LDA.

The marginal value of system capacity is the clearing price for Capacity Performance Resources in the unconstrained area of the PJM region.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's Reliability Requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDA and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest sell offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher constrained LDA, where they are considered in a similar manner for compensation.

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.

5.7.3 Resource Make-Whole Payments in the Base Residual Auction

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

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

$$ResourceMakewholePayment = RCP^{*}\left(SellOfferMinMW - ClearedMW_{BRA}\right)$$

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 will receive a Resource Make-whole Payment. The Resource Make-whole Payment is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process, multiplied by the cleared MW quantity.

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.

5.7.4 Posting of Base Residual Auction Results

Base Residual Auction results are posted to a participant's Capacity Exchange 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 Capacity Exchange. The results of their sell offer will be categorized as cleared, uncleared, offered, unoffered, or make-whole.

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

5.8 Incremental Auctions

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.

A *Conditional Incremental Auction* may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

5.8.1 Participation in the Incremental Auctions

Existing Generation Capacity Resources in a party's RPM Resource Portfolio that have no exception to the RPM must offer requirement and 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 RPM or FRR Load Serving Entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year and prohibited from being committed to an FRR Entity's Capacity Plan for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts of generation resources.

Effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

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

- Existing Generation Capacity Resources that were offered and not cleared in a prior auction for the same Delivery Year
- Planned Generation Capacity Resources
- Existing Demand Resources, Existing DER capacity resources or Energy Efficiency Resources that were offered and not cleared in a prior auction for the same Delivery Year
- Planned Demand Resources, Planned DER capacity 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 Capacity Resources, Planned Demand Resources, Planned DER capacity 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, Planned DER capacity resource or Energy Efficiency Resource meets the requirements specified in Section 4 of this manual.

- Existing Generation Capacity Resources, existing DER capacity resources and existing Demand Resources or Energy Efficiency Resources that have increases in Available ICAP after an Incremental Auction are eligible to offer the capacity increase into a subsequent Incremental Auction for the Delivery Year if the Available ICAP increase is approved prior to the opening of the subsequent Incremental Auction bidding window.
- For Incremental Auctions, a Current Available ICAP Position is calculated for generation resources. An Available ICAP Position is also determined for demand resources and energy efficiency resources that intend to offer into such Incremental Auction. These Available ICAP positions are determined for annual period and for summer/winter period if Seasonal Capacity Performance Resource.

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 or during summer/winter season.

$$CurrentAvailableICAPPosition_{GEN} = Min\left(DailyAvailableICAP_{GEN}\right)$$

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP – (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailICAP_{GEN} =$$

$$DailyICAPOwned - DailyUnofferICAP - \left(\frac{DailyRPMResourceCommitments}{Accredited \quad UCAP \quad Factor}\right)$$

$$- DailyFRRCommitments$$

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.

$$DailyUnofferICAP_{GEN}$$

$$= \sum\left(DailyUnofferICAP_{Prior\ RPMAuctions} + UnofferICAP_{BilateralSales\,/\,Purchases}\right)$$

For an Incremental Auction, a party's Daily Unoffered ICAP for generation resource is equal to the Current Available ICAP Position minus the Offered ICAP in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$DailyUnofferICAP_{GEN} = MinAvailableICAPPosition - OfferedICAP$$

A Demand Resource's Available ICAP to offer into an Incremental Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such Incremental Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such Incremental Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of planned MWs in the CSP's DR Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by the CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance and MWs intend to offer as Summer-Period Capacity Performance. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).

DER capacity resource's Available ICAP to offer into an Incremental Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such Incremental Auction and PJM's approval of the DER Aggregator's DER Plan for such Incremental Auction. A DER capacity resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP.

An EE Resource's Available ICAP to offer into an Incremental Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Incremental Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the Incremental Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. A Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Incremental Auction and the provider's completion of the EE Planned Setup process for such Incremental Auction in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer for Annual period and MWs intend to offer for Summer period. Such classification is used to establish the maximum Existing/ Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).

5.8.2 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.

5.8.3 Resource Make-Whole Payments in Incremental Auctions

A 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.

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.8.5 will receive a Resource Make-whole Payment. The Resource Make-whole Payment is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process, multiplied by the cleared MW quantity.

Make-whole payments required in the Auction will be charged to all cleared participant and PJM B~~b~~uy B~~b~~ids 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 B~~b~~uy B~~b~~ids cleared by PJM will be assessed to LSEs in the LDA via the Final Zonal Capacity Price.

5.8.4 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.

5.8.5 Auction Clearing Mechanism – Incremental Auctions

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

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

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

The Resource Clearing Price within an LDA is equal to the sum of:

- The marginal value of system capacity and
- The Locational Price Adder(s), if any relevant for such LDA.

The marginal value of system capacity is the clearing price for Capacity Performance Resources in the unconstrained area of the PJM region.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying participant and PJM Buy Bids in an LDA. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDA and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest sell offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher constrained LDA, where they are considered in a similar manner for compensation.

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 and submitted supply offers.

The algorithm will also enforce the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region. The supply curve formed by the Sell Offers submitted within a modeled LDA shall only consider the quantity of MWs from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the participant and PJM Buy Bids in a modeled LDA.

5.8.6 Posting of Incremental Auction Results

The Incremental Auction results are posted to a participant's Capacity Exchange 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 the fifth business day after the close of the RPM Auction offer window.

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

Incremental Auction purchases/sales (i.e., Auction Charges/Auction Credits) are charged/ credited weekly during the Delivery Year.

5.9 Auction Clearing Results

5.9.1 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); and
3. 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.

Note:
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)[22]; and
3. 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).

Note:
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 . In addition, Final Zonal Capacity Prices reflect any price adjustments that are necessary to account for any transition provisions that are in effect for the Delivery Year (e.g., Prior CIL Exception External Resources that elected prior to the Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year, or EE Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year due to prohibition of EE participation by a Relevant Electric Retail Regulatory Authority.

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.

[22] A weighted average Locational Price adder may be a negative number.

Note:
The ***Final Zonal Capacity Prices*** for the Delivery Year are posted by PJM following the Third Incremental Auction for that Delivery Year.

5.9.2 CTR Credit Rates

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

$$BaseZonalCTRCreditRate = \frac{BRAZonalEconomicValueofCTRs_{LSEs}}{BaseZonalUCAPOblig}$$

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

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

$$FinalZonalCTRCreditRate = \frac{FinalZonalEconomicValueofCTRs_{LSEs}}{FinalZonalUCAPOblig}$$

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

5.9.3 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.

$$FinalZonalCTRSettlementRate = \frac{FinalZonalEconomicValueofCTRs_{LSEs}}{ZonalMaxLDACTRMWs_{LSEs}}$$

Note:
The ***CTR Settlement Rates*** are posted by PJM with the Third Incremental Auction clearing results.

5.10 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 Section 3, 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). 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 Project Developer, Eligible Customer, or Upgrade 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. ICTRs associated with Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements are also 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) for LSEs will be allocated in MWs for each modeled LDA in which the RPM Auctions for the Delivery Year resulted in a non-zero 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 an Upgrade 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, which may reduce the Incremental Capacity Transfer Rights available to Participant-Funded Projects.

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 respected 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 an 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. 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 an 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, CTRs will first be allocated to a cleared QTU. Any remaining CTRs will be allocated to ICTRs associated with Participant-Funded Projects and Incremental Rights-Eligible Required Transmission Enhancements pro rata based on their original ICTR certified amount. For LDAs in which the average Locational Price Adder with respect to the immediate higher level LDA is negative, the Total CTRs are allocated only to LSEs.

$$LDACTR_{LSEs} = FinalLDAUCAPImported - LDAQTUEquivalents - LDAICTRs$$

Where:

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.
Final LDA Unforced Capacity Obligation	is equal to the sum of the Final Zonal Unforced Capacity Obligations for the zones in the LDA.
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 a) installed capacity rated at summer conditions that is not, on average, experiencing a forced outage or forced de-rating or b) Effective UCAP provided by ELCC Resources. 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) , DER capacity resources, 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)
    - Load Adjustments

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.

$$BaseRTOUCAPOblig = UCAPOblig_{BRA}$$

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. See Section 7.3.2 for Base Zonal RPM Scaling Factor equation.

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. 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 ((Preliminary Zonal Peak Load Forecast for the Delivery Year / RTO Preliminary Peak Load Forecast for the Delivery Year) * RTO Unforced Capacity Obligation satisfied in the Base Residual Auction~~Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement~~).

$$BaseZonalUCAPOblig =$$

$$(ZPLDY / RPLDY) \quad * \quad RUCO$$

> **Note:**
> ***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.

$$FinalRTOUCapOblig = \sum PJMBuyBidMWsCleared - \sum PJMSellOfersCleared$$

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.

$$FinalZonalUCAPOblig = \left(\frac{ZonalFinalPeakLoadForecast}{RTOFinalPeakLoadForecast}\right) * FinalRTOUCAPOblig$$

Note:
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 with the clearing of 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 (RUCO) (Base & Final)
- ~~Zonal Peak Load Forecasts (ZPLF) (Preliminary & Final)~~
- Forecast Pool Requirement (FPR)
- Zonal Weather Normalized Summer Peaks (ZWNSP)
- Zonal Load Forecast for such Delivery Year (ZPLDY) (Preliminary & Final)
- RTO Preliminary Peak Load Forecast (RPLDY) (Base & Final)
- Zonal Load Adjustment (ZLA) (Preliminary & Final)

- Load Adjustment OPL (LAOPL) = Forecast Load Adjustment scaled to DY = ZLA * (ZWNSP/(ZPLDY-ZLA))
- Adjusted ZWNSP (Preliminary & Final) = ZWNSP adjusted to include Scaled Load Adjustment = ZWNSP + LAOPL

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 Forecasting & Analysis 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 Capacity Exchange defined “area” within their zone by December 31 prior to the start of the Delivery Year. See ***Reliability Assurance Agreement Schedule 8, Section A and Generator Operational Requirements Manual (14-D), Appendix A*** for the limitations in the netting of operating Non-Retail Behind the Meter Generation against wholesale area load.

7.3.2 Base Zonal RPM Scaling Factor

A Base Zonal RPM Scaling Factor is determined for each zone and is equal to the Base Zonal UCAP Obligation / (Adjusted Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year * the Forecast Pool Requirement). ~~[(Preliminary Zonal Peak Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year)* ((RTO Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement))]~~. Adjusted Zonal Weather Normalized Summer ~~p~~Peak is further adjusted to remove the load associated with zone/areas ~~is adjusted for peak loads of zone/areas~~ that elected FRR option.

$$BaseZonalRPMScalingFactor = BaseZonalUCAPOblig / (Adjusted\ ZWNSP * FPR)$$

> **Note:**
> ***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 Adjusted Zonal Weather Normalized Peak for the summer prior to the Delivery Year).

$$FinalZonalRPMScalingFactor = \frac{FinalZonalUCAPOblig}{FPR * Adjusted \quad ZWNSP \quad DY - 1)}$$

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 Adjusted Zonal Weather Normalized Summer Peak~~normalized previous summer's peak~~ to each customer in the zone (both retail and wholesale). LSE Obligation Peak Load represents the summation of Peak Load Contributions for each of an LSE's customers.

The following business rules apply to Delivery Year Obligation Peak Load data for a zone/area:

- The Obligation Peak Load allocation for a zone/area is constant and effective for the entire Delivery Year.
    - For zone/areas with an identified Load Adjustment, the LAOPL will be added to the entered Obligation Peak Load
- 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.
- Non-dispatched charging energy for Energy Storage Model Participants and Open-Loop Hybrid Resources shall not be allocated a Peak Load Contribution value in accordance with Manual 27.

7.5 Daily Unforced Capacity Obligations

The following business rules apply to daily Obligation Peak Load data used in determining LSE Daily Unforced Capacity Obligations:

- The EDC is responsible for uploading Obligation Peak Load data into Capacity Exchange for every LSE serving load in their zone/area during the Delivery Year. The file upload must be performed in accordance with Capacity Exchange'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.

$$DailyObligPeakLoadScalingFactor = \frac{AnnualZoneAreaObligPeakLoadAllocation}{\sum ZoneAreaObligPeakLoadUploads}$$

- 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.

$$DailyUCAPOblig = ObligPeakLoad * FinalZonalPRMScalingFactor * FPR$$

7.6 Process for Determining Load Obligations

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

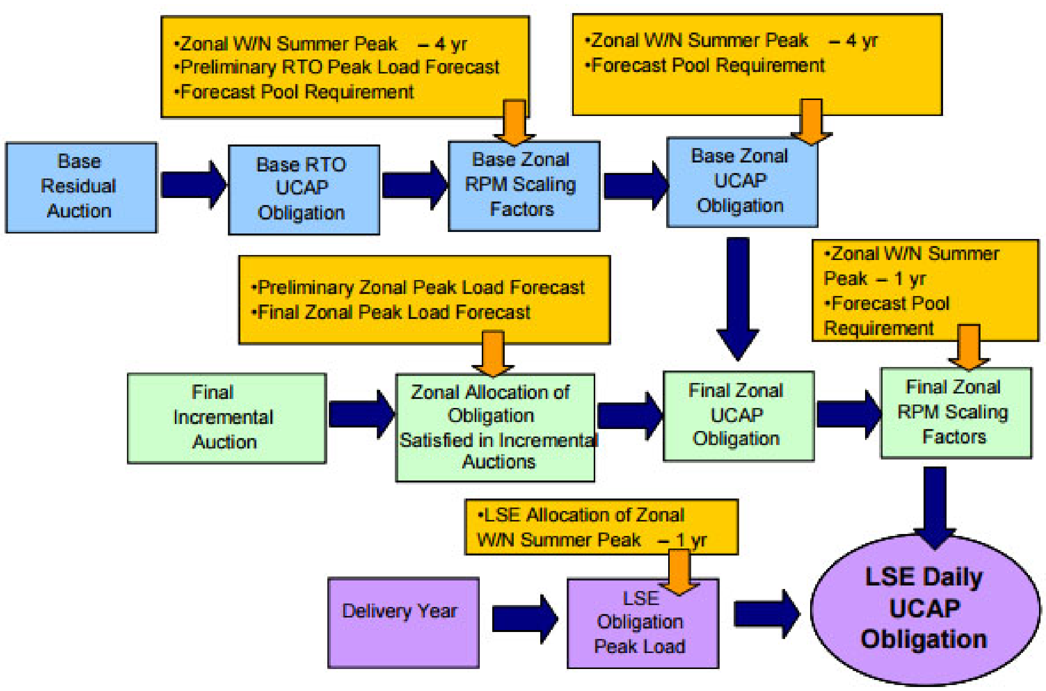

Exhibit 3: Process for determining Load Obligations

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 Capacity Exchange 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 Non-Performance Assessment (see "Non-Performance Assessment")
- The business rules for assessing compliance with Summer/Winter capability testing (see "Summer/Winter Capability Testing")
- 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
- Generation Operational Testing
- Summer/Winter Capacity Testing
- Non-Performance Assessment
- Load Management Test Compliance
- DER capacity resource testing
- 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 or as the source of a Locational UCAP transaction. 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 Variable Resources)	Variable Resources	DR	DER	EE	QTU
RPM Commitment Compliance	X	X	X	X	X	X
Generation Operational Test	X					
Summer/Winter Capability Testing	X					
Load Management Test Compliance			X			
M&V Audit					X	
DER Test				X		
Non-Performance Assessment	X	X	X	X	X	X
Non-PAI Event			X			

8.2 RPM Commitment Compliance

A resource committed to RPM is expected to be able to deliver unforced capacity during the Delivery Year that is equal to or greater than the unforced capacity committed through RPM Auctions or through the specification of replacement capacity. RPM Commitment Compliance is evaluated daily during the Delivery year on a resource-specific basis to determine if a party satisfied their Daily RPM Resource Commitments on their generation resources, demand resources, DER capacity 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 Capacity Exchange system).
- Accredited UCAP Factor decreases – The final Accredited UCAP Factor for a generation resource for the Delivery Year results in fewer UCAP MW on the resource than that cleared 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)*(Accredited UCAP Factor).

$$DailyRPMPostion_{GEN}$$
$$= (DailyICAPOwned - DailyFRRCommitments - DailyUnofferICAP)$$
$$*(Accredited\ \ UCAP\ \ Factor)$$

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.

$$DailyRPMCommitmentShortage_{GEN} = DailyRPMCommitments - DailyRPMPosition_{GEN}$$

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 DR Hub system prior to the start of the Delivery Year to support the nominated value of the demand resource committed for such Delivery Year. The sites registered and approved in the DR Hub system must be of the Capacity Performance product-type and sufficient to support the summer and non-summer commitments on the Demand Resource.
- Decrease in the Forecast Pool Requirement or ELCC Class Rating- The final UCAP value of the demand resource during the Delivery Year is determined based on the final FPR for the Delivery Year (prior to the 2025/2026 Delivery Year) or the final applicable ELCC Class Rating (starting with the 2025/2026 Delivery Year). Decreases in either of these factors can result in a final UCAP value being less than the UCAP MW cleared by the demand resource in RPM Auctions for the 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.

~~Through the 2024/2025 Delivery year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement~~.

~~Starting with the 2025/2026 Delivery Year, a~~A party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Owned - Daily FRR Capacity Plan Commitments) * applicable ELCC Class Rating.

$$DailyRPMPosition_{DR} = (DailyICAPOwned - DailyFRRCommitments) * applicable\ \ ELCC\ \ Class\ \ Rating$$

A party’s Daily ICAP Owned for a specific demand resource is equal to Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party’s approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. The Daily Nominated Value of a Demand Resource for a Delivery Year is based on confirmed registrations in “completed” status linked to such Demand Resource in the DR Hub system. The Daily Nominated Value of a Demand Resource is determined for summer period of June through October and May of Delivery Year and non-summer period of November through April of Delivery Year based on information provided in the linked Capacity Performance registrations in the DR Hub system.

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 or use of such demand resource in a Locational UCAP transaction.

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

$$DailyRPMCommitmentShortage_{DR} = DailyRPMCommitments - DailyRPMPosition_{DR}$$

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 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 EE value or Capacity Performance Value of EE Resource – The final nominated value or final Capacity Performance value of the energy efficiency resource for the Delivery Year is less than the Nominated value or Capacity Performance Value that was used as the basis of the energy efficiency resource 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 ICAP Owned – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement).

$$DailyRPMPosition_{EE} = (DailyICAPOwned - DailyFRRCommitments) * FPR$$

A party's Daily ICAP Owned for a specific EE Resource is equal to the initial ICAP Owned set by PJM through "Approved" EE Modifications, adjusted for any ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such EE Resource in effect for such day.

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 or use of such EE resource in a Location UCAP transaction.

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

$$DailyRPMCommitmentShortage_{EE} = DailyRPMCommitments - DailyRPMPosition_{EE}$$

8.2.4 Qualifying Transmission Upgrade (QTU):

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

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

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

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

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

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

$$DailyRPMCommitmentShortage_{QTU} = DailyRPMCommitments - DailyRPMQTUPosition$$

8.2.5 DER

A DER Aggregator may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Failure to have enough nominated MWs for the locations registered and approved in the DR Hub system prior to the start of the Delivery Year to support the DER commitment for such Delivery Year.
- Accredited UCAP Factor decreases – The final Accredited UCAP Factor for DER for the Delivery Year results in fewer UCAP MW on the resource than that cleared in RPM Auctions for the Delivery Year.
- During the Delivery Year, failure to meet DER commitments will be determined by comparing a party's Daily RPM DER capacity resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM DER capacity 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.

DailyRPMPositionDER capacity resource = (DailyICAPOwned- DailyFRRCommitments) * applicable AUCAP factor

A party's Daily ICAP Owned for a specific DER capacity resource is equal to Daily Nominated Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such DER capacity resource in effect for such day. The Daily Nominated DER Value of a DER capacity resource for a Delivery Year is based on confirmed registrations in "completed" status linked to such DER capacity resource in the DR Hub system. A party's Daily RPM Resource Commitments for a specific DER capacity resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such DER capacity resource in RPM Auctions to decreases/increase of RPM Resource Commitments due to the specification of replacement resources or use of such DER capacity resource in a Locational UCAP transaction.

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

DailyRPMCommitmentShortageDER resource = DailyRPMCommitments - DailyRPMPositionDER capacity resource

8.3 Deleted ~~Commitment Level Used in Summer/Winter Capability Tests (Through the 2024/2025 Delivery Year)~~

~~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 (TUICA) is calculated for each unit and used as the basis for assessing the performance of a unit for summer/winter capability tests through the 2024/2025 Delivery Year.~~

~~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~~[23] ~~or (b) maximum Summer Net Dependable Rating of the Unit during the Delivery Year.~~

23 ~~For days in which unit's Daily ICAP Commitment is greater than Daily ICAP Owned, Daily ICAP Owned is used in determining Unit Average Daily ICAP Commitment for DY.~~

~~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).~~

~~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 are 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).~~

~~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.~~

~~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, summer/winter capability testing.~~

~~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).~~

~~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.~~

~~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.~~

8.4 Deleted

8.4A Non-Performance Assessment

A Non-Performance Assessment[24] will assess performance of resources during emergency conditions. Non-Performance Assessment applies to Capacity Performance Resource commitments and Price Responsive Demand commitments. Capacity Performance Resource commitments and PRD commitments are exposed to Non-Performance Charges for under-performance during Emergency Actions throughout the entire Delivery Year. Resources that fail to perform are subject to Non-Performance Charge and resources that over-perform may be eligible for Bonus Performance Credit.

The Non-Performance Assessment will compare each Capacity Resource's Expected Performance against its Actual Performance for each Performance Assessment Interval. Performance Assessment Interval shall mean each Real-time Settlement Interval for which an Emergency Action as defined in the OATT has been declared by PJM. A Performance Assessment Interval is triggered based on either of the two conditions defined below and such condition must be in effect for the entire Real-time Settlement Interval.

- Condition 1 - A Primary Reserve Shortage is determined for the Reserve Zone or active Reserve Sub-zone and one of the following emergency procedures is issued that encompasses such Reserve Zone or active Reserve Sub-zone:
  - Voltage Reduction Warning and Reduction of Non-Critical Plant Load
  - Manual Load Dump Warning
  - Maximum Emergency Generation Action
  - Voltage Reduction Warning and Curtailment of Non-Essential Building Load

The following table illustrates which resources will be assessed for a PAI based on the location of the resource and the location of the above Emergency Procedure and location of the Primary Reserve Shortage

		Primary Reserve Shortage			
Condition 1 Emergency Procedures		Reserve Zone (RTO)	Reserve Subzone (MAD)	Reserve Zone and Reserve Subzone (RTO & MAD)	None
	Reserve Zone (RTO)	RTO	MAD	RTO	None

24 OATT, Attachment DD, Section 10A

		Primary Reserve Shortage			
	Reserve Subzone (MAD)	None	MAD	MAD	None
	None	None	None	None	None

- Condition 2 - One of the following emergency procedures is issued for the entire Reserve Zone or Sub-Zone:
  - Deploy All Resources Action
  - Voltage Reduction Action
  - Manual Load Dump Action
  - Load Shed Directive

See Manual 13 for details on the issuance of emergency procedures and Manual 11 for detail on Primary Reserve Shortage which is determined when the reserve MW assigned in the dispatch run is less than the Primary Reserve requirement for either the Reserve Zone or active Reserve Sub-zone.

When assessment is for the Reserve Sub-zone, the list of resources subject to assessment is determined based on the active subzone bus and resource list effective at the time of the PAI. The posting is found on the Ancillary Service page of PJM.com. DR/PRD dispatched and located in the Reserve Sub-zone will be included in the Reserve Sub-zone assessment.

If the Emergency Action area is for the Reserve Zone, Net Energy Imports are included in this assessment. External Generation Capacity Resources are included in the assessment if such external resource would have helped resolve the declared Emergency Action that was the subject of the assessment. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned for Non-Performance Assessment purposes. 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 Interval, the Actual Performance and the Expected Performance is used to calculate a Performance Shortfall that determines both the Non-Performance Charge and Bonus Performance Credit applicability.

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

- for each generation resource (including External Generation Capacity Resources when applicable), the metered output of delivered energy plus the resource's real-time reserve or regulation assignment[25], if any; however, the resulting MW quantity is floored at 0 MW;

- for each Demand Resource, the demand response provided plus the resource's real-time reserve or regulation assignment, if any;
- for each DER Aggregation Resource, the sum of location performance calculated in accordance with the generation resource, storage resource, demand resource calculations herein.
- 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 Report;
- 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 ;
- 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 Interval, and zero if it is not in-service prior to the start of such day; and,
- For each PRD Provider, the Actual Performance is calculated in accordance with Section 3A.6.2A.

For each Performance Assessment Interval, the Expected Performance is equal to:

- for each generation resource (including External Generation Capacity Resources when applicable), the resource's committed Unforced Capacity times the ratio[26] of [(total amount of Actual Performance for all generation resources and injections from DER Aggregation resources, plus net energy imports[27], plus total Demand Response and DER Aggregation resource DR load reduction Bonus Performance for that interval, plus total PRD Bonus Performance for that interval / (total amount of committed Unforced Capacity of all Generation Capacity Resources and DER capacity resource including only unforced capacity of DG or injection from DR resource)];
- 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);
- for DER Aggregation Resource, the sum of generation and storage location performance calculated as (Resource Committed Capacity * the Balancing Ratio) and the sum of demand resource calculated as (Resource Committed Capacity)
- for each Qualified Transmission Upgrade, the committed MW quantity; and,
- for each PRD Provider, the Expected Performance is calculated in accordance with Section 3A.6.2A.

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25 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.

26 This ratio will be capped at 1.

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

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

For generation and DER capacity 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 Interval;
- MWs for which the resource was not scheduled to operate by PJM; or
- MWs for which the resource was on-line but was scheduled down by PJM based on the determination by PJM that such scheduling action was appropriate to the security constrained economic dispatch of the PJM Region[28].
- If such resource was needed by PJM and would otherwise have been scheduled by PJM to perform, but was not scheduled to operate, or was scheduled down solely due to (1) any operating parameter limitations submitted in the resource's offer or (2) submission of a market-based offer higher than its cost-based offer, then these MWs will not be considered exempted and will not result in a downward adjustment to the Performance Shortfall.
- For purposes of the Non-Performance Assessment for demand resources and the load reduction portion of a DER capacity resource, compliance will be measured in accordance with Section 8.6 of this manual.
- During the Performance Shortfall calculation and the exempt MW determination, PJM will ensure that each energy offer complies with Manual 11, Section 2.3.7 and has the required associated information. If this information is not included, then no MWs will be exempt.

For purposes of calculating Bonus Performance quantity, 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 Interval[29]. During the Bonus Performance quantity calculation, PJM will ensure that each energy offer complies with Manual 11, Section 2.3.7 and has the required associated information associated. If this information is not included, then the Bonus Performance quantity will be zero. 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

[28] Scheduled MW appropriate to the security constrained economic is determined based on the results of the Dispatch Run described in Manual 11

[29] Scheduling and dispatch shall be determined based on the results of the Dispatch Run described in Manual 11

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 interval Non-Performance Charge is calculated as Performance Shortfall multiplied by the Non-Performance Charge Rate. The Non-Performance Charge Rate for Capacity Performance commitments is equal to {[the modeled LDA through the 25/26 DY, otherwise the RTO Net CONE ($/MW-day in installed capacity terms) for which the resource resides times number of days in the Delivery Year] divided by 30} divided by the number of Real-Time Settlement Intervals in an hour. The modeled LDAs and their respective Net CONE are provided in the Delivery Year BRA Planning Parameters posted on the PJM website.

~~Through the 2024/2025 Delivery Year, for Capacity Performance Resources or PRD Providers, the maximum yearly Non-Performance Charge is 1.5 times the modeled LDA Net CONE ($/MW-day in installed capacity terms) in which the resource resides times number of days in Delivery Year times the maximum daily unforced capacity committed by the resource or PRD Provider during June 1 of the Delivery Year through the end of the billing month for which the Non-Performance Charge was assessed. For Seasonal Capacity Performance Resources, the maximum yearly Non-Performance Charge is based the number of days of the applicable season and the maximum daily unforced capacity committed by the resource for such season. The modeled LDAs and their respective Net CONE are provided in the Delivery Year BRA Planning Parameters posted on the PJM website.~~

~~Effective with the 2025/2026 Delivery Year f~~For Capacity Performance Resources or PRD Providers, the maximum yearly Non-Performance Charge plus Non-Curtailment Charges is 1.5 times the RPM Base Residual Auction clearing price applicable to the modeled LDA in which the resource resides times number of days in Delivery Year times the maximum daily unforced capacity committed by the resource or PRD Provider during June 1 of the Delivery Year through the end of the billing month for which the Non-Performance Charge and/or Non-Curtailment Charges were~~as~~ assessed. For Seasonal Capacity Performance Resources, the maximum yearly Non-Performance Charge plus Non-Curtailment Charge is based on the number of days of the applicable season and the maximum daily unforced capacity committed by the resource for such season. The modeled LDAs and their respective clearing prices are provided in the Delivery Year BRA results posted on the PJM website

Revenue collected from payment of Non-Performance Charges will be distributed to resources (of any type, even if they are not Capacity Resources) and PRD Providers that perform above expectations. A resource or PRD Provider 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 in the form of a Bonus Performance Credit. This credit is based on the ratio of its Bonus Performance quantity to the total Bonus Performance quantity (from all resources or PRD Providers) for the same Performance Assessment Interval.

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 Intervals and such billing of charges will be spread over the remaining months in the Delivery Year. Bonus Performance Credits will follow the same billing methodology as Non- Performance Charges.

For Public Distribution Microgrid Generators that are Generation Capacity Resources:

- If the Public Distribution Microgrid load is reported to PJM as wholesale load when the PDM is islanded, then any islanded generation MWh output that is settled through the PJM energy market counts towards Capacity Performance obligation as Actual Performance.
- If the Public Distribution Microgrid load is not reported to PJM as wholesale load when the PDM is islanded, then any islanded Public Distribution Microgrid Generators should not report their islanded output as PJM supply. In this case, the islanded Public Distribution Microgrid Generator is not available to supply PJM load, and their Actual Performance is zero for the intervals in which the Public Distribution Microgrid is islanded.
- Whether a Public Distribution Microgrid load is or is not reported to PJM as wholesale load when the PDM is islanded, the Expected Performance during a Performance Assessment Interval is what it would have been had the Public Distribution Microgrid Generator still been grid-connected.

Definitions and additional business rules for Public Distribution Microgrids can be found in PJM Manual 14D, Appendix B: Public Distribution Microgrid Business Rules and PJM Manual 14D, Appendix C: Voluntary Guideline on Public Distribution Microgrid Operations.

8.4B Non-PAI Event Compliance

Effective with the 2028/2029 Delivery Year and as outlined in Tariff, Attachment DD, section 10B, the performance of Demand Resources and Price Responsive Demand with capacity commitments shall be measured for purposes of this assessment for all Non-PAI Events and as defined in the Tariff, Attachment DD and the Reliability Assurance Agreement, Schedules 6 and 6.1.

Expected performance of such committed Demand Resource or Price Responsive Demand, and the magnitude of any such shortfall, based on the following formula:

Performance Shortfall = Expected Curtailment - Actual Curtailment

Where Expected Curtailment is defined as:

Demand Resource committed capacity = the total megawatts of capacity committed without making any adjustment for the Forecast Pool Requirement for the registrations dispatched by the Office of the Interconnection.

Price Responsive Demand committed capacity = the nominal PRD value of megawatts committed by the PRD Provider for the registrations required to respond based on the associated PRD Curves.

Actual Curtailment is defined as:

for each Demand Resource, the demand response provided to PJM by such resource during the Non-PAI Event, as established through the PJM demand response settlement procedure consistent with the standards specified in RAA, Schedule 6 and Manual 18, section 8.6 and Manual 19, Attachment A;

for each PRD Provider, the actual load reduction provided by the PRD Provider during a Non-PAI Event, determined in accordance with RAA, Schedule 6.1 and Manual 18, section 3A and Manual 19, Attachment A;

Subject to the Non-Performance Charge Limit specified in the Tariff, Attachment DD, section 10A(f-1), each Curtailment Service Provider and Price Responsive Demand provider shall be assessed a Non-Curtailment Charge for each committed Demand Resource and Price Responsive Demand that has a positive Performance Shortfall during a Non-PAI Event interval based on the following formula:

Non-Curtailment Charge = Performance Shortfall * 50% * Non-Performance Charge rate specified in Tariff, Attachment DD, section 10A(e)

Revenues collected from assessment of Non-Curtailment Charges shall be distributed to Curtailment Service Providers and/or Price Responsive Demand providers and/or Load Serving Entities for each interval that are not associated with an FRR entity that elected the physical penalty option.

Non-Curtailment Charges will be allocated to Curtailment Service Providers and PRD Providers that had a negative shortfall based on the minimum of (sum of negative shortfalls * -1) / (sum of positive shortfalls), or 1 and then multiplied by Non-Curtailment Charges collected and then prorated to each provider based on such negative shortfalls. Any remaining Non-Curtailment Charges collected shall be distributed on a pro-rata basis to LSEs that were charged a Locational Reliability Charge on the Non-PAI Event day.

The Office of the Interconnection shall invoice Non-Curtailment Charges and credits on the monthly bill issued within three calendar months after the calendar month that included such Non-PAI Event.

Performance Shortfalls related to FRR commitments are subject to Non-Curtailment Charge if the FRR Entity elected the financial non-performance assessment.

8.5 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-21B)*** ~~through the 2024/2025 Delivery Year and M-21B effective with the 2025/2026 Delivery Year~~ and submit test results through the eGADS system. Variable Resources, and variable components of Hybrid Resources, are exempted from the summer/winter capability testing requirement and are not assessed Generation Resource Rating Test Failure Charges. The purpose of the summer/winter net capability verification is to demonstrate that the unit can achieve the claimed summer/winter net capabilityrating 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 a Summer/Winter Net Corrected Test Capability value at least equal to the total daily ICAP commitment level on the unit, or non-variable components of a Hybrid Resource. The Summer/Winter Net Corrected Test Capability value of a Hybrid Resource with multiple non-variable resource components will be the sum of the Summer/Winter Net Corrected Test Capability values of the non-variable resource components. The total daily ICAP commitment level of the non-variable component(s) of a Hybrid Resource during the Jun-October and May of the Delivery Year equals the total daily ICAP commitment level of the Hybrid Resource minus the actual 95th percentile hourly summer net output between the hours ending 11AM and 10PM EPT for the variable component(s). The total daily ICAP commitment level of the non-variable component(s) of a Hybrid Resource during November through April of the Delivery Year equals the total daily commitment level of the Hybrid Resource minus the actual 95th percentile hourly winter net output in all hours except for hours beginning 9AM to 5PM EPT for the variable component(s). ~~Through the 2024/2025 Delivery Year, a unit's total daily ICAP commitment level is measured by the unit's Total Unit ICAP Commitment Amount ("TUICA") which is determined as described in section 8.3 of this manual. Effective with the 2025/2026 Delivery Year,~~ A~~a~~ unit's total daily ICAP commitment level is determined each day of the delivery year and is calculated as the resource's total daily UCAP commitment level divided by the Accredited UCAP Factor of such resource.

In accordance with M-~~21 and~~ 21B, 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. 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 daily ICAP commitment level, those parties with RPM Resource Commitments and FRR Capacity Plan Commitments from such unit may be subject to 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 Summer/Winter Net Corrected Test Capability as described in ***PJM's Rules and Procedures for Determination of Generating Capability (~~M-21 and~~ M-21B)***). T~~hrough the 2024/2025 Delivery Year, the Unit ICAP Shortfall is determined as described in Section 8.5.1. Effective with the 2025/2026 Delivery Year, t~~he Unit ICAP Shortfall is determined as described in Section 8.5.2. A Unit ICAP Shortfall forms the basis for a Generation Resource Rating Test Failure Charge.

8.5.1 Deleted ~~Determination of Unit ICAP Shortfall (through the 2024/2025 Delivery Year)~~

~~Through the 2024/2025 Delivery Year, the Unit ICAP Shortfall for the summer/winter testing period is equal to the Total Unit ICAP Commitment Amount minus the highest Summer/Winter Net Corrected Test Capability achieved in a summer/winter 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 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.~~[30]

~~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.~~

[30] This implicitly occurs through the calculation of the unit's Total Unit ICAP Amount. For days in which a unit's Daily ICAP Commitment is greater than Daily ICAP Owned, Daily ICAP Owned is used in determining Unit Average Daily ICAP Commitment for the Delivery Year.

~~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.~~

~~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.~~

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

8.5.2 Determination of Unit ICAP Shortfall (Effective with the 2025/2026 Delivery Year)

Effective with the 2025/2026 Delivery Year, the Unit ICAP Shortfall is determined for each Generation Capacity Resource (with the exception of Variable Resources) on a daily basis. Each day of the Delivery Year, the Daily Unit ICAP Shortfall is calculated as (i) the installed capacity committed for that day (adjusted for any replacement capacity), minus (ii) the highest Summer/Winter Net Corrected Test Capability determined for the resource in any test during the relevant testing period.

The summer period capability test result submitted in eGADS is used in this determination for each day in the months of June through October and the following May of each Delivery Year, and, winter period capability test result submitted in eGADS is used in this determination for each day in the months of November through April of each Delivery Year.

In the event a resource is eligible for an out of period capability test for the relevant season, as described in **PJM Rules and Procedures for Determination of Generating Capability Manual (M21B)** an updated Unit ICAP Shortfall would be determined based on the out of period test and the updated Unit ICAP Shortfall becomes effective on the date of the out of period test, and extends through the relevant seasonal period.

A positive Unit ICAP Shortfall in any day represents a failure to certify the total daily ICAP commitment amount on such resource through capability testing.

If portions of the unit were committed by multiple Resource Providers, the Daily Unit ICAP Shortfall is allocated to the Resource Providers based on each provider's pro-rata share of the total installed capacity commitment for that day (adjusted for any replacement capacity).

The daily installed capacity committed used for determining a resource's shortfall, or allocating a resource's shortfall to multiple providers, shall be capped at the ICAP Owned for such resource or provider to avoid double counting of shortfalls under the capability testing assessment and commitment compliance.

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 (i) a Daily ICAP Shortfall for RPM Resource Commitments based on the ratio of the Provider's installed capacity committed to RPM for the day divided by the Provider's total installed capacity committed for the day and (ii) a Daily ICAP Shortfall for FRR Capacity Plan Commitments based on the ratio of the Provider's installed capacity committed to FRR for the day divided by the Provider's total installed capacity committed for the day.

A Resource Provider with a positive Daily ICAP Shortfall will be assessed The Generation Resource Rating Test Failure Charge as described in Section 9.1.5.

8.5A Generation Operational Testing

Effective with the 2025/2026 Delivery Year, Generation Capacity Resources, with the exception of Variable Resources, that are committed to RPM or FRR shall be subject to operational testing initiated by the Office of the Interconnection up to two times in each of the summer and winter seasons during the relevant Delivery Year. The operational testing requirements, retest requirements, and determination of when a shortfall is assessed are found in **Generator Operational Requirements Manual (M14D)**.

When a unit fails a retest of the Generation Operational Test, a Generation Operational Test Failure Charge may be assessed. The Generation Operational Test Failure Charge shall equal the Daily Deficiency Rate multiplied by the applicable daily committed UCAP MW of such Generation Capacity Resource.

The applicable daily committed UCAP MW value subject to the Generation Operational Test Failure Charge will account for:

- any RPM and FRR commitments on the unit;
- any unit modeling differences that may exist between the energy market and capacity market; and
- any portions of the unit that were committed by multiple Capacity Market Sellers, provided, however, a Capacity Market Seller shall not be assessed a Generation Operational Test Failure Charge to the extent (i.e., for the same megawatts and time period) that such seller is assessed a Capacity Resource Deficiency Charge for such resource.

The Daily Deficiency Rate shall equal the value defined in section 9.1.5A.

8.6 Measuring Compliance during Performance Assessment Interval for Demand Resources

A Capacity Performance Demand Resource is subject to Non-Performance Assessment during a Performance Assessment Interval that occurs during the Delivery Year during the availability window when linked registrations to such Capacity Performance Demand Resource are dispatched by PJM during such Performance Assessment Interval. A Summer-Period Capacity Performance Demand Resource is subject to Non-Performance Assessment during a Performance Assessment Interval that occurs during June through October and May of the Delivery year during the availability window when linked registrations to such Summer-Period Capacity Performance Demand Resource are dispatched by PJM during such Performance Assessment Interval.

Compliance is the process utilized to review Demand Resource performance during a Performance Assessment Interval and establishes a Performance Shortfall or Bonus Performance for such Demand Resource.

Compliance will be measured for each registration dispatched by PJM within the area defined by the Emergency Action for each Performance Assessment Interval. Compliance is measured for partial clock hour dispatch if dispatched for 30 minutes or more of the clock hour. Compliance is not measured if dispatched for less than 30 minutes of the clock hour.

DR Providers are responsible for submittal of compliance information to PJM through the DR Hub System within 45 days after the end of the month in which a Performance Assessment Interval occurred. Compliance reviews of a single event will be completed within 2 months of the end of the month in which the event took place.

PJM verifies compliance on an end-use customer basis by reviewing the data submitted by the DR Provider through the DR Hub system. Load management compliance for non-interval metered residential customers may be verified using a statistical sample of end-use customers in accordance with ***PJM Manual 19: Load Forecasting & Analysis, Attachment D*** and subject to PJM approval.

DR Providers may use substitute registrations of a different resource product type to cover the commitment of non-performing registrations that cannot respond for the Performance Assessment Interval. 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 (summer or non-summer, as applicable) of the substitute registration(s) must be comparable (within either +/- 25% or +/- 0.5 MW) to the total nominated value (summer or non-summer, applicable) of the corresponding non-performing registration(s). DR Providers that use substitute registrations must submit their list of nonperforming registrations and corresponding substitute registrations to PJM by 11:59 pm on the day of the Performance Assessment Interval 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 Performance Assessment Interval 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 compliance during a Performance Assessment Interval 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. A registration may only be used as a substitute for a non-performing registration dispatched for a Performance Assessment Interval in the winter period if the registration provided winter data (Winter Peak Load, winter Firm Service Level, or winter Guaranteed Load Drop data) at the time of registration and meets the criteria outlined above.

For a Firm Service Level (FSL) customer on a registration, the actual load reduction provided for the hour ending that includes a Performance Assessment Interval(s) in the summer period (June through October and May of the Delivery Year) is calculated as the end-use customer’s Peak Load Contribution minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Peak Load Contribution. For the non-summer period (November through April of the Delivery Year), the actual load reduction for a Performance Assessment Interval is calculated as (end-use customer’s Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by loss factor) minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor.

For a Guaranteed Load Drop (GLD) customer on registration, the actual load reduction provided for the hour ending that includes a Performance Assessment Interval(s) in the summer period is calculated as the lesser of (a) the (comparison load minus the hourly metered load) multiplied by the loss factor or (b) end-use customer’s Peak Load Contribution minus (hourly metered load multiplied by loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Peak Load Contribution. For the non-summer period (November through April of the Delivery Year), the actual load reduction for a Performance Assessment Hour is calculated as lesser of (a) (comparison load minus the hourly metered load) multiplied by the loss factor or (b) the end-use customer’s Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by loss factor minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by loss factor is less than the Winter Peak Load multiplied by the Zonal Winter Weather Adjustment Factor multiplied by the loss factor.

DR Provider must submit 24 hours of actual load data for the day in which Performance Assessment Interval occurred and for all days required to determine comparison loads. Comparison loads must be developed in accordance with the guidelines included in ***PJM***

Manual M-19 Load Forecasting & Analysis, Attachment A: Load Drop Estimate Guidelines, and note which method was employed.

A Load Management customer may not reduce their metered load below zero (i.e., export energy into the system). No compliance credit will be given for the incremental load drop below zero. Hourly load reduction for a registration is floored at 0 MW.

For a partial dispatch clock hour, the Expected Performance of a Demand Resource is not adjusted by the percentage of the hour dispatched. When ~~five-minute~~ one-minute revenue meter data is submitted to determine compliance for a Performance Assessment Interval, the actual load reduction for a Performance Assessment Interval is calculated using the ~~five-minute~~ one-minute metered load data for such Performance Assessment Interval as opposed to using hourly metered load data. When ~~five- minute~~ one-minute revenue meter data is not submitted to determine compliance of a Demand Resource for a Performance Assessment Interval, the actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour. The actual load reduction for a Performance Assessment Interval is calculated as the actual hourly load reduction multiplied by (twelve divided by the number of five-minute intervals the Demand Resource was dispatched in the hour). The actual load reduction for a registration for a Performance Assessment Interval is capped at the Peak Load Contribution of the registration in the summer period and at the Winter Peak Load of the registration multiplied by Zonal Winter Weather Adjustment Factor in the winter period.

For each dispatched registration in the Emergency Action Area, the Actual Performance is equal to the actual load reduction plus any real-time reserve or regulation assignment for such registration for the Performance Assessment Interval. The Actual Performance for a Demand Resource for a Performance Assessment Interval is equal to the sum of the Actual Performance of the dispatched registrations linked to such Demand Resource. If a Demand Resource is owned by multiple parties, the Actual Performance of a Demand Resource shall be allocated to the owners of the Demand Resource based on ICAP ownership share to determine each Capacity Market Seller's Actual Performance for such Demand Resource.

The Expected Performance for the Performance Assessment Interval for a Capacity Market Seller's Demand Resource[31] is equal the Capacity Market Seller's committed capacity on the Demand Resource in installed capacity terms (i.e., the actual load reduction quantity the resource committed to provide), adjusted to account for any linked registrations that were not dispatched by PJM.

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[31] The Actual and Expected Performance of dispatched economic registrations are not considered in the performance of a committed Demand Resource. Actual Performance will be calculated for an economic registration in the same way it is calculated for a Pre-Emergency or Emergency registration and such registration may be eligible for Bonus Performance since its Expected Performance will be zero MW.

The Capacity Market Seller’s Expected Performance minus the Actual Performance for a Demand Resource establishes the seller’s initial Performance Shortfall for such Demand Resource. A positive initial Performance Shortfall indicates the seller’s Demand Resource under-complied for the Performance Assessment Interval. A negative initial Performance Shortfall indicates the seller’s Demand Resource over-complied for the Performance Assessment Interval. The Capacity Market Seller’s initial Performance Shortfalls for Demand Resources in the Emergency Action Area (EAA) are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller’s Demand Resources that under-complied within the EAA on a pro-rata basis based on the under-compliance MWs, and such seller’s Demand Resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller’s Demand Resources that over-complied within the EAA on a pro-rata basis based on over-compliance MWs, and such Market Seller’s Demand Resources will be assessed Bonus Performance.

8.7 Load Management Test Compliance

DR Resource providers are subject to Load Management Test Compliance.

For Demand Resources committed for the 2023/2024 Delivery Year and subsequent Delivery Years:

1. For Annual Demand Resources: if an Annual Demand Resource registration for the 2023/2024 Delivery Year is not dispatched by the Office of the Interconnection for a Load Management event in the Delivery Year or if an Annual Demand Resource registration for the 2024/2025 Delivery Year or subsequent Delivery Years is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year and assessed for performance during Performance Assessment Intervals or Non-PAI Event, then the registration committed by a Capacity Market Seller in a zone shall be tested as described in section (3) listed below, for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday during June through October or November through March of the relevant Delivery Year, where date and time are selected by the Office of the Interconnection and notice is provided consistent with the procedure described in sections (4) and (5) listed below . If an Annual Demand Resource registration for the 2023/2024 Delivery Year is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year or if an Annual Demand Resource Registration for 2024/2025 Delivery Year or subsequent Delivery Years is dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year and assessed for performance during Performance Assessment Intervals or Non-PAI Events, then no test will be required.

   ~~Subject to the conditions in this paragraph beginning in Delivery Year 2024/2025 and subsequent Delivery Years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event. Elections are made on or after June 1 and no later than July 14th after the Delivery Year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14th after the Delivery Year. Only one event result (either test event or non-PAI LM event) for each end use customer site will be used in the zonal test evaluation:~~

   a. ~~The duration of non-PAI LM event must be at least 30 minutes of a clock hour~~
   b. ~~The election of non-PAI LM events to be used as zonal test performance will be done at the registration lead time interval.~~
   c. ~~For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.~~
   d. ~~CSP's Load Reduction Capability data submission(s) must account for registrations that will not participate in a PJM scheduled test.~~
      i. ~~In accordance with the load reduction reporting requirements in section 4.3.9, any updates to the Load Reduction Capability data for non-participation in PJM scheduled test must be reported no later than 4 p.m. on the day prior to the PJM scheduled test.~~

~~PJM will take into consideration non-PAI LM events when scheduling tests. This could result in test event postponements when non-PAI LM events occur within a scheduled test window.~~

2. For Summer-Period Demand Resources: if a Summer- Period Demand Resource registration for the 2023/2024 Delivery Year is not dispatched by the Office of the Interconnection for a Load Management event during June through October or the following May of the Delivery Year or if a Summer-Period Demand Resource registration for the 2024/2025 Delivery Year or subsequent Delivery Years is not dispatched by the Office of the Interconnection for a Load Management event during the June through October or the following May of the Delivery Year and assessed for performance during Performance Assessment Intervals or Non-PAI Event, then the registration committed by a Capacity Market Seller must demonstrate that it was tested as described in section (3) listed below, for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday, during June through October of the relevant Delivery Year, where date and time are selected by the Office of the Interconnection and notice is provided consistent with the procedure described below.

   ~~Subject to the conditions in this paragraph beginning in Delivery Year 2024/2025 and subsequent Delivery Years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event. Elections are made on or after June 1 and no later than July 14th after the Delivery Year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14th after the Delivery Year. Only one event result (either test event or non-PAI LM event) for each end-use customer site will be used in the zonal test evaluation:~~

   a. ~~The duration of a non-PAI LM event must be at least 30 minutes of a clock hour~~

   b. ~~The election of non-PAI LM events to be used as zonal test performance will be done at registration lead time level.~~

   c. ~~The non-PAI LM event must have occurred in the summer.~~

   d. ~~For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.~~

   e. ~~CSP's Load Reduction Capability data submission(s) must account for registrations that will not participate in a PJM scheduled test.~~

      i. ~~In accordance with the load reduction reporting requirements in section 4.3.9, any updates to Load Reduction Capability data non-participation in PJM scheduled test must be reported no later than 4 p.m. on the day prior to the PJM scheduled test.~~

   ~~PJM will take into consideration non-PAI LM events when scheduling tests. This could result in test event postponements when non-PAI LM events occur within a scheduled test window.~~

3. All registrations in a zone will be tested simultaneously for two hours for each product. Registration performance will be calculated as the two hour average reduction. The Office of the Interconnection may, at its discretion, cancel a test and retest on an event day to ensure system reliability.
    a. If less than 25 percent (by megawatts) of a Curtailment Service Provider's total Demand Resources in a zone fail the test, the Curtailment Service Provider may conduct re-tests limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that such re-test(s) must be during the same season period (except if test was conducted in March in which case retest can be conducted in May), at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registrations must test simultaneously, where affiliated means registrations that have any ability to shift load and are owned or controlled by the same entity. If less than 25 percent of resources fail the test and the Curtailment Service Provider chooses to conduct a retest, the Curtailment Service Provider may elect to maintain the performance compliance result for the registration(s) that achieved during the test if Curtailment Service Provider: (1) notifies the Office of the Interconnection 48 hours prior to the retest under this election; and (2) the Curtailment Service Provider retests affiliated registrations under this election as set forth in the PJM Manual.
    b. If 25 percent or more (by megawatts) of a Curtailment Service Provider's Demand Resources fail the test, the Curtailment Service Provider may request the Office of Interconnection to schedule a one-time retest limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that all affiliated registrations must test simultaneously. Affiliated means registrations that have any ability to shift load and are owned or controlled by the same entity. The request must be made before the 46th day after the test. The Office of the Interconnection will select the date and time of the retest during the same season period (except if test was conducted in March in which case retest may be conducted in May) and notice is provided consistent with the procedure described below.
4. Notification of the initial Office of the Interconnection scheduled test will be provided based on the following procedure.
    a. The Office of Interconnection shall schedule, on an alternating basis, one test during June through October or November through March for each Delivery Year that a test is required. On the first business day of a week, PJM will provide notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, the Office of the Interconnection will post on its website the test date and zones. The Office of the Interconnection will also notify the Curtailment Service Providers of the test date. On the test date, Curtailment Service Providers will be notified of start time of test through the same notification protocol used for an event and as described in the PJM Manuals.

5. Notification of any scheduled retest by the Office of the Interconnection will be provided based on the following procedure.
    a. By 10:00 EPT the day before the retest, the Office of the Interconnection will post the retest date on its website. PJM will also notify the Curtailment Service Providers the retest date. On the retest date, Curtailment Service Providers will be notified of start time of retest through the same notification protocol used for an event and as described in the PJM Manuals.

Load Management test compliance for a registration will be measured based on Performance Assessment Interval compliance for a registration; 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 or Performance Assessment Interval and performance will be aggregated to the zone and not Performance Assessment Area.

Resource Compliance Position for a registration for a test is determined as the Nominated Load Reduction Value reported in the DR Hub system minus the actual load reduction, where the Nominated Load Reduction Value is capped at the Summer Average RPM/FRR Commitment for such registration. The Nominated Load Reduction Value determined based on summer capability is used to test Capacity Performance DR product-type registrations.

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 Capacity Exchange 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 by netting the Resource Compliance Positions of the product-type registrations tested in a zone. The net testing shortfall in such Zone for such product(s) tested shall be reduced by the Curtailment Service Provider's summer daily average of the Capacity Resource deficiency shortfalls, determined pursuant to Tariff, Attachment DD, section 8, in such Zone for all of the Curtailment Service Provider's committed Demand Resources that are of the same product(s) tested. 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. A net testing shortfall in zone for Capacity Performance DR product-type (which may include Summer-Period DR) may be separated into net testing shortfall in zone due to annual commitments or summer-only commitments, as appropriate.

If a Demand Resource is committed by multiple parties, a portion of the provider's net testing shortfall in a zone for a product-type may be assessed to each party that has a commitment if tested registrations linked to such Demand Resource under-complied, based on the each party's commitment share of the Demand Resource.

8.8 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 P~~p~~rice R~~r~~esponsive D~~d~~emand.

Replacement capacity for generation resources, Demand Resources, Energy Efficiency Resources, DER capacity resources or Qualifying Transmission Upgrades committed to RPM may be specified via the Capacity Exchange system by entering a ~~“R~~replacement c~~C~~apacity~~”~~ transaction prior to a designated effective date~~before the start of the Delivery Day~~. However, upon a request to PJM made no later than three business days after an effective date ~~Delivery Day~~ containing a Performance Assessment Interval, r~~R~~eplacement c~~C~~apacity t~~T~~ransactions 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 sub-account as the resource being replaced on the effective date~~Delivery Day~~, (2) the replacement resource must have been included in the same Performance Assessment Intervals as the resource being replaced, (3) the replacement resource must have the same or better temporal availability characteristics as the resource being replaced, (4) the replacement resource must be located in the same LDA (or a more constrained child LDA) as the resource being replaced, and (5) the resulting total Daily Resource Commitments (RPM and FRR) (in UCAP terms) on a generation resource used as a replacement resource cannot exceed such replacement resource's Actual Performance during the Performance Assessment Intervals. Such requests must be submitted to rpm_hotline@pjm.com and include:

- Product type (Capacity Performance) of the commitment being replaced.
- Desired change in Daily RPM Commitments (in UCAP terms) for the resource being replaced
- Replacement resource
- Resource being replaced
- Start date and end date

~~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 (Capacity Performance) of the commitment being replaced.~~

Through the ~~“R~~replacement c~~C~~apacity~~”~~ transaction functionality in Capacity Exchange, PJM will provide participants with a list of the available capacity for each generation, DER capacity resource or D~~d~~emand R~~r~~esource in their portfolio as well as a list of cleared B~~b~~uy B~~b~~ids from any Incremental Auction via the Capacity Exchange system and a list of resources with RPM Resource Commitments. Participants will have the ability to match a generation resource, Demand Resource, DER capacity resource, Energy Efficiency Resource or Qualifying Transmission Upgrades ~~resource~~ committed to RPM that they would like to replace with available capacity from a generation resource, DER capacity resource, D~~d~~emand R~~r~~esource, cleared B~~b~~uy B~~b~~ids in an Incremental Auction, or from Locational UCAP transactions. Available capacity from an Energy Efficiency Resource may be utilized to replace the commitment of only another Energy Efficiency Resource because such commitments are accompanied by the adjustment that is required to avoid double-counting of energy efficiency measures as described in section 2.4.5 of this manual.

The following are business rules that apply to r~~R~~eplacement r~~R~~esources for r~~R~~esources c~~C~~ommitted to RPM:

- The start date and end date of the replacement must be specified.
- The Delivery Year commitment of a Generation Capacity Resource or DER capacity resource may not be replaced until after the final Accredited UCAP Factor for the Delivery Year has been locked in the Capacity Exchange system. After the final Accredited UCAP Factor for the ~~prior~~ Delivery Year has been locked in and prior to the conduct of the Third Incremental Auction for the Delivery Year, the commitment of such a resource may be replaced but only up to the quantity of any commitment deficiency of the resource.
- Any or all of a Delivery Year commitment of a Generation Capacity Resource, Demand Resource, DER capacity resource or Energy Efficiency Resource may be replaced any time prior to the conduct of the Third Incremental Auction for that Delivery Year when the owner of the replaced resource provides transparent and verifiable evidence to support the expected final physical position of the resource at the time of request. Such requests shall be submitted in writing simultaneously to PJM rpm_hotline@pjm.com and the Independent Market Monitor rpmacr@monitoringanalytics.com documenting the reason for the early replacement. PJM will approve or deny a request for early r~~R~~eplacement c~~C~~apacity, based upon the below criteria, with input from the Market Monitor, within 15 days of receiving a completed early r~~R~~eplacement c~~C~~apacity request.
    - Acceptable reasons for early replacement are:
        - Generator d~~D~~eactivation (properly noticed to PJM and posted to the website)
        - A pending request to PJM for removal of Generation Capacity Resource status (in accordance with Manual 18, section 5.4.7, and subject to PJM approval)
        - Withdrawal of generation New Service Request/ cancellation of generation project (accompanied by written notification to PJM Interconnection Projects manager)
        - Generation delayed in-service date (accompanied by written notification to PJM Interconnection Projects manager)
        - Permanent departure of load used as a basis for an existing DR or EE resource at the time of commitment
        - ~~A financially and physically firm commitment to an external sale of its capacity for the entire Delivery Year that is demonstrated with supporting evidence as~~

~~specified in Tariff, Attachment DD, Section 6.6(g), for the 2023/24, 2024/25, 2025/26 Delivery Years where there is only one Incremental Auction~~

  - Generation replaced prior to the Third Incremental Auction may not be recommitted for the Delivery Year. Therefore, the resource may not resell the replaced MW in a subsequent RPM auction for the applicable Delivery Year, and has no requirement to submit a Must-Offer Exception request for such auctions.
  - DR/EE/DER sites replaced may not be registered or committed for the Delivery Year.

- A r~~R~~eplacement r~~R~~esource 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 r~~R~~eplacement r~~R~~esource when the start date of the r~~R~~eplacement c~~C~~apacity 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 have resulted if the r~~R~~eplacement c~~C~~apacity transaction was approved.
- The desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced and the replacement resource must be specified. The change in Daily RPM Resource Commitments cannot result in a negative value for the Daily RPM Resource Commitments for the resource being replaced. The desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced must also indicate the product type (Capacity Performance) of the commitment being replaced.
- The replacement resource must be located in the same sub-account as the resource that is 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. However, if there is remaining import capability into the LDA after the Third Incremental Auction, a replacement resource may be located in a parent LDA, subject to the following restriction:~~s.~~ The ability to submit a replacement capacity transaction from a parent LDA into a child LDA is limited by the import capability remaining into the LDA. After the Third Incremental Auction, the remaining import capability of each LDA is posted on the PJM website.
- Resources located in a constrained LDA can serve as replacement capacity for a generation resource located in a less constrained parent LDA.
- A resource can only replace a daily commitment in the future with available capacity from another resource for the same day~~The replacement resource must have the same or better temporal availability characteristics as the resource that is being replaced~~.
- 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.
- Available capacity of a Capacity Resource with State Subsidy for which the Capacity Market Seller has not elected to forego receipt of any State Subsidy for the relevant

Delivery Year and does not qualify for one of the categorical exemptions may not be used to replace the commitment of a Capacity Resource that (1) is not a Capacity Resource with State Subsidy or (2) is a Capacity Resource with State Subsidy for which the Capacity Market Seller elected the competitive exemption and reported that it will forego receipt of any State Subsidy for the relevant Delivery Year or (3) a Capacity Resource with State Subsidy that qualifies for one of the categorical exemptions.

- If a generation, demand, DER capacity resource 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, DER capacity resource 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 B~~b~~uy B~~b~~ids 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 Capacity Resources, QTU, Energy Efficiency Resources, DER capacity 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 for future delivery days~~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.

8.8.1 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 r~~R~~eplacement c~~C~~apacity or traded bilaterally.

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 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 Deleted

9.1.2 Deleted

9.1.3 Capacity Resource Deficiency Charge

The Daily Capacity Resource Deficiency Charge is applicable to a capacity resource with a RPM commitment that does not have enough unforced capacity value on such resource to cover its RPM commitments. The Daily Capacity Resource Deficiency Charge is equal to the Daily Deficiency Rate times the Daily RPM Commitment Shortage for generation resource, Demand Resource, DER capacity resource or Energy Efficiency Resource.

$$DailyCapResourceDeficiencyCharge = DDR * DailyRPMCommitmentShortage$$

Starting with the 2026/2027 Delivery Year, PJM will determine the portion of a party's Daily RPM Commitment Shortage caused by a reduction of a resource's Accredited UCAP Factor. The Daily Deficiency Rate ($/MW-day) applied~~applicable~~ to the portion of a party's Daily RPM Commitment Shortage caused by a reduction in a resource's Accredited UCAP Factor ~~a shortage~~ is ~~equal to~~ the Party's Weighted Average Resource Clearing Price for such resource. The Daily Deficiency Rate ($/MW-day) applied to the remainder of a party's Daily RPM Commitment Shortage is a party's Weighted Average Resource Clearing Price plus the higher of 0.2*p~~P~~arty's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a p~~P~~arty'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's commitments is determined by calculating the weighted average of segment-specific (i.e., annual, seasonal-summer, seasonal-winter) resource clearing prices received on the deficient day for such resource across all Delivery Year RPM Auctions, weighted by a party's segment-specific cleared and make-whole MWs for such resource. Segment-specific cleared MWs acquired or transferred through a u~~U~~nit s~~S~~pecific t~~T~~ransaction for cleared capacity are accounted for in the calculation of a party's Weighted Average Resource Clearing Price.

The PJM Weighted Average Resource Clearing Price for commitments in an LDA is determined by calculating the c weighted average of segment-specific resource clearing prices applicable in the LDA across all Delivery Year RPM Auctions, weighted by the total segment-specific cleared and make-whole MWs in the LDA.

A resource that is also subject to a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily RPM Commitment Shortages associated with Capacity Performance commitments shall be assessed a charge equal to the greater of (a) the total Daily Capacity Resource Deficiency Charges calculated for shortages associated with Capacity Performance commitments for such continuous time period or (b) the total Non-Performance Charges calculated for the Performance Assessment Intervals occurring during such continuous time period. The sum of the Daily Capacity Resource Deficiency Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

Note:
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.

$$DailyQTUDelayPenaltyCharge = QTUDelayPenaltyRate * DailyRPMCommitmentShortage$$

The QTU Delay Penalty Rate is equal to the higher of (i)1.2 times the Capacity Resource Clearing Price of the LDA into which the QTU is cleared or (ii) the Net Cost of New Entry.

A QTU that is also subject to a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily RPM Commitment Shortages shall be assessed a charge equal to the greater of (a) the total Daily Transmission Upgrade Delay Penalty Charges calculated for such continuous time period or (b) the total Non-Performance Charges calculated for the Performance Assessment Intervals occurring during such continuous time period. The sum of the Daily Transmission Upgrade Delay Penalty

Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

Note:
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 is applicable to all generation resources (with the exception of Variable Resources) committed to RPM or FRR that have a positive Daily Unit ICAP shortfall due to a rating test failure. The determination of the Daily Unit ICAP Shortfall for a generation resource and a Provider's Daily ICAP Shortfall is described in ~~Section 8.5.1 for Delivery Years through the 2024/2025 Delivery Year and~~ Section 8.5.2 for Delivery Years starting with the 2025/2026 Delivery Year.

~~For Delivery Years through the 2024/2025 Delivery Year, the Daily Generation Resource Rating Test Failure Charge shall be equal to the Daily Deficiency Rate times: a) for Combination Resources and Limited Duration Resources, the appropriate Accredited UCAP value that corresponds to the Provider's Daily ICAP Shortfall, or; b) for Unlimited Resources, the Provider's Daily ICAP Shortfall times (1 – Effective EFORd) for a generation resource~~.

~~Effective with the 2025/2026 Delivery Year, t~~The Daily Generation Resource Rating Test Failure Charge shall be equal to the Daily Deficiency Rate times the Provider's Daily ICAP Shortfall of the resource converted to Unforced Capacity terms using the Generation Capacity Resource's final Accredited UCAP Factor for the Delivery Year.

$$GenerationResourceRatingTestFailureCharge = DDR * DailyICAPShortfall * AUCAPFactor$$

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 Daily ICAP Shortfall for FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all Delivery Year 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 a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily ICAP Shortfalls due to rating test failure shall be assessed a charge equal to the greater of (a) the total Daily

Generation Resource Rating Test Failure Charges calculated for such continuous time period or (b) the total Non-Performance Charges for the Performance Assessment Intervals occurring during such continuous time. The sum of the Daily Generation Resource Rating Test Failure Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge. A resource that is subject to a Generation Operational Test Failure Charge shall not also be subject to a Generation Resource Rating Test Failure Charge for the same megawatts during overlapping time periods.

Note:
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.

9.1.5A Generation Operational Test Failure Charge

The Generation Operational Test Failure Charge is applicable to all generation resources (with the exception of Variable Resources) committed to RPM or FRR that fail the Generation Operational retest in accordance with Manual 14D.

The Daily Generation Operational Test Failure Charge applicable to RPM commitments shall be equal to the Daily Deficiency Rate times the applicable daily RPM committed UCAP MW of that Generation Resource.

RPM Daily Generation Operational Test Failure Charge = DDR × Applicable Daily RPM Committed UCAP MW

The Daily Deficiency Rate applicable to 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 for the corresponding LDA will be used.

The Daily Generation Operational Test Failure Charge applicable to FRR commitments shall be equal to the Daily Deficiency Rate times the applicable daily FRR committed UCAP MW of that Generation Resource).

FRR Daily Generation Operational Test Failure Charge = DDR × Applicable Daily FRR Committed UCAP MW

The Daily Deficiency Rate applicable to FRR Resource Commitments is equal to 1.2 times theweighted average of the resource clearing prices across all RPM Auctions for the relevant Delivery Year, 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 Charge during one or more Performance Assessment Intervals occurring during a continuous time period of a generation operational test failure shall be assessed a charge equal to the greater of (a) the total Daily Generation Operational Test Failure Charges calculated for such continuous time period or (b) the total Non-Performance Charges for the Performance Assessment Intervals occurring during such continuous time. The sum of the Daily Generation Operational Test Failure Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

9.1.6 Load Management Test Failure Charge

The Daily Load Management Test Failure Charge is equal to the net testing shortfall in zone (expressed in UCAP) times the LM Test Failure Charge Rate. A net testing shortfall in zone will be separated into net testing shortfall in zone due to annual commitments and summer-only commitments, as appropriate.

The Daily Load Management Test Failure Charge Rate for zonal net testing shortfall due to annual commitments is equal to the Provider's Weighted Daily Revenue Rate for annual commitments in such zone plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate for annual commitments in such zone, or $20/MW-day). In the case where a Provider's Weighted Daily Revenue Rate for annual commitments in zone 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 or commitments due to FRR Alternative), a PJM Weighted Daily Revenue Rate for annual commitments in such zone will be used. A Daily Load Management Test Failure Charge, equal to the net testing shortfall in zone due to annual commitments times the Daily Load Management Test Failure Charge Rate, will apply for each day in the Delivery Year.

The Daily Load Management Test Failure Charge Rate for zonal net testing shortfall due to summer-only commitments is equal to the Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments, or $20/MW-day). In the case where a Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments 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 source of a Locational UCAP transaction or as replacement capacity or commitments due to FRR Alternative), a PJM Weighted Daily Revenue Rate in such zone for summer-only commitments will be used. A Daily Load Management Test Failure Charge, equal to net testing shortfall in zone due to summer-only commitments times the Daily Load Management Test Failure Charge Rate, will apply for June through October and May of the Delivery Year.

Note:
The Load Management Test Failure Charges will be assessed in August monthly bill issued in September after the conclusion of the Delivery Year.

9.1.7 DER Capacity Aggregation Resource Test Failure Charge

The Daily DER Capacity Aggregation Resource Test Failure Charge is equal to the net testing shortfall (expressed in UCAP) times the DER Capacity Aggregation Resource~~LM~~ Test Failure Charge Rate.

The DER Capacity Aggregation Resource Test Failure Charge rate shall equal such Seller's Weighted Daily Revenue Rate in such Zone for the DER Capacity Aggregation Resource that tested plus the greater of (0.20 times the Weighted Daily Revenue Rate in such Zone for the product(s) tested or $20/MW-day). A Seller that is also subject to a Capacity Resource Deficiency Charge for such resource shall not be assessed a DER Capacity Aggregation Test Failure Charge to the extent (i.e., for the same MWs and time period) that such seller is assessed a Capacity Resource Deficiency Charge. Provided further, a seller that is also subject to a Non-Performance Charge for such resource during one or more Performance Assessment Intervals occurring during a continuous time period of net testing shortfalls due to DER Capacity Aggregation Resource test failure shall be assessed a charge equal to the greater of (a) the total Daily DER Capacity Aggregation Resource Test Failure Charges calculated for such continuous time period or (b) the total Non-Performance Charges for the Performance Assessment Intervals occurring during such continuous time. The sum of the Daily DER Capacity Aggregation Resource Test Failure Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

In the case where a Party's Weighted Daily Revenue Rate for such DER capacity 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 resource being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Daily Revenue Rate in the applicable LDA will be used. A Party's Weighted Daily Revenue Rate for such resource's commitments is determined by calculating the weighted average of resource clearing prices received on the deficient day for such resource across all Delivery Year RPM Auctions, weighted by a party's cleared and make-whole MWs for such resource. Cleared MWs acquired or transferred through a u~~U~~nit s~~S~~pecific t~~T~~ransaction for cleared capacity are accounted for in the calculation of a party's Weighted Daily Revenue Rate. The PJM Weighted Daily Revenue Rate for commitments in an LDA is determined by calculating the weighted average of annual segment-specific resource clearing prices applicable in the LDA across all Delivery Year RPM Auctions, weighted by the total annual segment-specific cleared and make-whole MWs in the LDA.

The Weighted Daily Revenue Rate applied to the daily net testing shortfall for FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all Delivery Year RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

Such 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.

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, Generation Operational Test Failure

Charges, Load Management Test Failure Charges and DER Capacity Aggregation Resource 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, DER Capacity Aggregation Resource Test Failure 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 Emergency Procedures Charges

The Emergency Procedures Charges outlined in ***Schedule 13 of the Reliability Assurance Agreement and section 13 of Attachment DD of OATT*** 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.

9.1.10 Non-Performance Charge/Bonus Performance Credit

Non-Performance Charge will be assessed to a resource provider or PRD Provider that had a Performance Shortfall for a Performance Assessment Interval.

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

The Non-Performance Charge Rate to be applied to shortfalls associated with Capacity Performance commitments or PRD commitments is equal to {[the RTO~~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} divided by the number of Real-Time Settlement Intervals in an hour.

Stop-loss provisions limit the total Non-Performance Charge that can be assessed on each Capacity Resource or to a PRD Provider. The stop-loss provision (i.e., the maximum year Non-Performance Charge) is covered in section 8.4A of this Manual.

Revenue collected from payment of Non-Performance Charges will be distributed to resources (of any type, even if they are not Capacity Resources) and PRD Provider that perform above expectations. A resource or PRD Provider 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 in the form of a Bonus Performance Credit. This credit is based on the ratio of its Bonus Performance quantity to the total Bonus Performance quantity (from all resources and PRD Providers) for the same Performance Assessment Interval.

Note:
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 Intervals and such billing of charges will be spread over the remaining months in the Delivery Year. Bonus Performance Credits will follow the same billing methodology as Non-Performance Charges.

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.

$$LocationalReliabilityCharge = DailyUCAPOblig*FinalZonalCapacityPrice$$

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.

Note:
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

$$RPMAuctionCredits = MWCleared_{LDA}*RCP_{LDA}$$

Each generation, demand, energy efficiency, or QTU resource provider that clears Capacity Performance sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Capacity Performance sell offer segments times the applicable LDA resource clearing price in such RPM Auction for the entire Delivery Year.

Each generation, demand, or energy efficiency resource provider that clears Seasonal Capacity Performance-Summer sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Seasonal Capacity Performance-Summer sell offer segments times the resource clearing price applicable to the resource’s Seasonal Capacity Performance-Summer sell offer segments in such RPM Auction. The Daily Auction Credit shall apply for June through October and May of the Delivery Year.

Each generation resource provider that clears Seasonal Capacity Performance-Winter sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Seasonal Capacity Performance-Winter sell offer segments times the resource clearing price applicable to the resource's Seasonal Capacity Performance-Winter sell offer segments in such RPM Auction. The Daily Auction Credit shall apply for November through April of the Delivery Year.

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.

Note:
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 an 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.

$$RPMAuctionCharges = MWCleared_{LDA} * RCP_{LDA}$$

Note:
Auction Charges are calculated daily and billed weekly during the Delivery Year.

9.3.3 Resource Make-Whole Credit

A 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 Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the RPM Auction. The difference between the minimum MW offered and the cleared MW quantities is equal to the Make-whole MWs.

$$ResourceMakeWholeCredit = (Min\ MWOffered - MWCleared) * RCP_{LDA}$$

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 and 5.8.5 will receive a Resource Make-whole Credit. The Resource Make-whole Credit is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process times the cleared MWs.

The Resource Make-whole Credit to a Seasonal Capacity Performance sell offer is incorporated in the Daily Auction Credit to the Seasonal Capacity Performance Resource since the Resource Clearing Price applicable to the Seasonal Capacity Performance Resource will include a seasonal make-whole price, if applicable.

Resource Make-Whole Credits from the First, Second, or Third Incremental Auctions are charged to all cleared participant and PJM B~~b~~uy B~~b~~ids on a pro-rata basis based on the MWs cleared in such auction. Make-whole charges assessed to B~~b~~uy B~~b~~ids cleared by PJM will be assessed to LSEs in the LDA via the Final Zonal Capacity Price

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.

*ZonalCTRCredit = ZonalCTRsOwned*ZonalCTRSettlementRate*

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. The LDA Incremental CTR Credit Rate is equal to 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.

*IncrementalCTRCredit = IncrementalCTRsOwned*LDAIncrementalCTRCreditRate*

> **Note:**
> ***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 a~~A~~uction s~~S~~pecific Capacity t~~T~~ransaction 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, segment-specific Cleared MWs identified in the transaction.

*SellerCharge = TransactionAmount*WeightedAvgRCP*

The Buyer of an a~~A~~uction s~~S~~pecific MW t~~T~~ransaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction.

*BuyerCredit = TransactionAmount*WeightedAvgRCP*

> **Note:**
> ***Charges and Credits for a~~A~~uction s~~S~~pecific MW t~~T~~ransactions*** 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 Penalties for Non-Performance of Price Responsive Demand

9.4.1 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 * PRD Provider's Weighted Final Zonal Capacity Price or $20/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.

See 8.4B for details about Non-PAI Event charges and credits

9.4.2 Deleted

9.4.3 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 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.

9.4.4 PRD Credit

The PRD Provider identified in the PRD registration will receive a Daily PRD Credit each day that the PRD registration is effective. The PRD Provider (FRR Entity) identified in the PRD registration will not receive a Daily PRD Credit.

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

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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.

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 PRD Provider will receive a 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 a PRD Provider in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone on a given day. The PRD Credit PRD Performance penalties are assessed to the PRD Provider in the registration.

Section 10: Capacity Exchange

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

- A description of the PJM Capacity Exchange tool (see "PJM Capacity Exchange Overview").

10.1 Overview

PJM Capacity Exchange tool is an Internet application that allows Market Participants to participate in PJM's RPM Auctions, the FRR Alternative, and view load and obligation data.

The graphic below presents a conceptual view of the RPM auction subsystems.

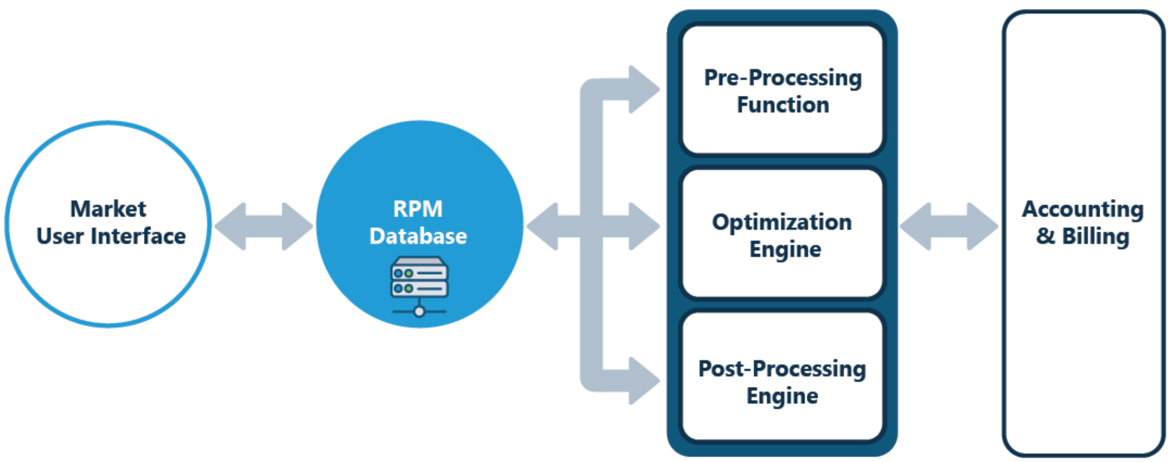

Exhibit 4: RPM Auction Subsystems

The Market User Interface (MUI) allows market participants to:

- Maintain their resource portfolio by increasing or decreasing their installed capacity values for generation via Capacity Modifications.
- View resource position
- Report u~~U~~nit s~~S~~pecific Bilateral t~~T~~ransactions with a counterparty
- Report a~~A~~uction s~~S~~pecific MW t~~T~~ransactions with a counterparty
- Report Locational UCAP t~~T~~ransactions
- Report c~~C~~leared Buy Bid t~~T~~ransactions
- Submit Resource Offers to sell capacity into an RPM auction

- Submit replacements for RPM Auction Commitments
- View Auction Results
- View load and obligation data
- Submit FRR Capacity Plan
- View deficiency data related to RPM/FRR Commitments

All data entered into the MUI is validated and entered into the RPM database by the MUI.

A ***Capacity Exchange User Guide*** is posted on the pjm website to help participants use the Capacity Exchange tool.

The RPM auction subsystem consists of the following three components:

- *Pre-processing Function* – performs all activities necessary to setup Auctions, including specifying the Planning Year Parameters as inputs into the solution and evaluating submitted resource offers.
- *Optimization Engine* – performs auction clearing process to ensure the most economical capacity threshold is met. Assigns unit commitments based on the entered offers, demand curves, and specific planning year parameters.
- *Post-processing Function* – ensures that the appropriate data items are transferred to the RPM auction database for posting on the MUI and ensures the results are transferred to the accounting and billing subsystems.

Section 11: Fixed Resource Requirement Alternative

Welcome to the *Fixed Resource Requirement Alternative* section of the ***PJM Manual for the PJM Capacity Markets***. In this section, you will find the following information:

- An overview of the Fixed Resource Requirement Alternative (see “Overview of the Fixed Resource Requirement Alternative”)
- The business rules for determining Load Obligations in FRR (see “Load Obligations”)
- The business rules for creating the Capacity Plan in FRR (see “Capacity Plan”)
- The business rules for supply resources in the FRR Alternative (see “Supply Resources in the FRR Alternative”
- The business rules for locational constraints in the FRR Alternative (see “Locational Constraints in the FRR Alternative”)
- The conditions on sales by FRR Entities (see “Conditions on Sales by FRR Entities”)
- The business rules for Delivery Year Activity (see “Deliver Year Activity”)
- The business rules for the calculation of deficiency charges and penalties (see “Deficiency Charges and Penalties”)
- The business rules for the allocation of deficiency charges (see “Allocation of Deficiency Charges”)
- The business rules for a~~A~~uction s~~S~~pecific MW t~~T~~ransactions (see “a~~A~~uction s~~S~~pecific MW t~~T~~ransactions”

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.

FRR Entities may commit Capacity Performance Resources and Seasonal 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 for the first time, an LSE must notify PJM of such election in writing at least four 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 Capacity Exchange database have been completed to allow the LSE to submit a FRR Capacity Plan through the Capacity Exchange 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 Capacity Exchange 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. An FRR Entity may terminate its election of the FRR Alternative prior to meeting its minimum five year commitment without penalty for any Delivery Year after the first Delivery Year of the FRR Entity's minimum five year commitment for which PJM will be required to establish a separate Variable Resource Requirement Curve, as described in Section 11.5 below. 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. In addition, an FRR Entity that elected the FRR Alternative for a Delivery Year prior to the 2025/2026 Delivery Year, may terminate its election of the FRR Alternative prior to meeting the minimum term of five years without penalty by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for a Delivery Year through and including the 2028/2029 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, except a new FRR Entity's initial election, the following information shall be posted by PJM with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Installed Reserve Margin (IRM)
- ~~Pool-wide Average EFORd through 2024/2025 Delivery Year~~
- Pool-wide average Accredited UCAP Factor starting with the 2025/2026 Delivery Year
- Forecast Pool Requirement (FPR)
- 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

- 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. However, if an alternative retail LSE is providing capacity resources to the FRR Entity to satisfy the alternative retail LSE's capacity obligation in lieu of providing compensation to the FRR Entity in accordance with RAA Schedule 8.1D, section 9; the alternative retail LSE as opposed to the FRR Entity will be subject to any applicable credit requirements for capacity resources provided.

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 Capacity Exchange 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 + Load Adjustments) * 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 Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area shall be increased by the UCAP Value of any EE Resource that is used in the FRR Capacity Plan because energy efficiency measures are reflected in the peak load forecast that is used as the basis for determining the UCAP Obligation of the FRR Entity.

The Base Zonal FRR Scaling Factor is equal to (Preliminary Zonal Peak Load Forecast minus Zonal Load Adjustment) 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 minus Zonal Load Adjustment) 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 determined by PJM and provided to the FRR Entity 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), ~~Pool-wide Average EFORd through the 2024/2025 Delivery Year,~~ and the Pool-wide average Accredited UCAP Factor starting with the 2025/2026 Delivery Year.

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 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 RTO/LDA Reliability Requirements in all future Incremental Auctions for such Delivery Year, and such shifted load shall pay a Locational Reliability Charge for such Delivery Year. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE and the Base Residual Auction has not been conducted for a Delivery Year, the FRR LSE should no longer commit capacity resources for the shifted load in its FRR Capacity Plan. PJM will include the shifted load in the future Base Residual Auctions.

11.3 Capacity Plan

The most important requirement in electing FRR Alternative is for the FRR Entity to commit Capacity Resources to meet their daily unforced capacity obligations, any applicable Percentage of Internal Resources Required in an LDA, plus any additional threshold if the FRR Entity plans to sell capacity. Failure to commit the required resources would result in FRR Commitment Insufficiency Charge and ineligibility to continue the FRR Alternative. An FRR Capacity Plan is the long-term plan for the commitment of Capacity Resources to satisfy the daily zonal unforced capacity obligations of an LSE that has elected the FRR Alternative in an FRR Service Area and any applicable Percentage of Internal Resources Required in a Locational Deliverability Area (LDA).

If the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such a resource in any RPM Auctions or as a replacement resource in RPM, the LSE must also maintain a Threshold Quantity in its FRR Capacity Plan prior to the Delivery Year.

The Threshold Quantity is equal to the Preliminary Daily Unforced Capacity Obligation plus the lesser of (a) 0.03 * Preliminary Daily Unforced Capacity Obligation or (b) 450 MW.

An LSE must submit an initial FRR Capacity Plan at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year by demonstrating that it has sufficient capacity resources in its FRR resource portfolio in Capacity Exchange 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; and
- Threshold Quantity, if applicable.

If the initial FRR Capacity Plan does not satisfy the LSE's Preliminary Daily Zonal Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted deadline for FRR Capacity Plan submittal, the LSE's election of the FRR Alternative will not be approved by PJM. The LSE will be required to serve its entire load in the FRR Service Area under the RPM for the Delivery Year such election was to be effective.

An LSE must annually demonstrate through the Capacity Exchange 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; and
- Threshold Quantity, if applicable.

If the FRR Capacity Plan for a succeeding Delivery Year does not satisfy the LSE's Preliminary Daily Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted deadline for FRR Capacity Plan submittal, the LSE will be assessed an FRR Commitment Insufficiency Charge for any shortage of unforced capacity in meeting the Percentages of Internal Resources Required in LDA or the Preliminary Daily Unforced Capacity Obligations (including any Threshold Quantity) for any remainder of the minimum term of the FRR election. The 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. ~~Through the 2024/2025 Delivery Year, the FRR Commitment Insufficiency Charge in a zone is equal to two times the Cost of New Entry ($/MW-day) in the zone times the shortage amount.~~ For Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year, no FRR Commitment Insufficiency Charge shall be assessed. Effective with the 2029/2030 Delivery Year and subsequent Delivery Years, an FRR Commitment Insufficiency Charge is equal to the price level corresponding to point (1) of the Variable Resource Requirement curve for the relevant Locational Deliverability Area, in $/MW-day, times the shortage amount.

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, Existing and Planned DER capacity resources (effective with 2028/2029 Delivery Year), bilateral contracts for unit-specific capacity resources, existing demand resources, planned demand resources, energy efficiency resources, Aggregate Resources , and Seasonal Capacity Performance Resources may be used in the FRR Capacity

Plan if these 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.

Capacity Performance Resources or Seasonal Capacity Performance Resources may be included in the FRR Capacity Plan.

~~Through the 2024/2025 Delivery Year, 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. The EFORd applied to the Final FRR Capacity Plan evaluated throughout 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. The final Accredited UCAP value of a resource will be applied to the Final FRR Capacity Plan evaluated throughout the Delivery Year.~~

~~Effective with the 2025/2026 Delivery Year, t~~The UCAP MW quantity of generation resources and DER capacity resources that are committed to the initial FRR Capacity Plan will be based on the Accredited UCAP Factor determined for each generation resource and DER capacity resources prior to the Base Residual Auction, and the UCAP MW quantity of committed demand resources will be based on the applicable ELCC Class Rating determined prior to the Base Residual Auction. The final Accredited UCAP Factor of a generation resource or DER capacity resource and the final applicable ELCC Class Rating for a demand resource for the Delivery Year will be applied to the Final FRR Capacity Plan evaluated throughout 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 MWs committed to RPM for such Delivery Year.

Any capacity resource that was not offered by the FRR Entity or offered but did not clear by the FRR Entity in any RPM Auction for such Delivery Year may be included in an FRR Capacity Plan. Such MWs are classified as Available MWs and would be eligible to commit to 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) 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 and DER capacity resources that have a FRR Capacity Plan Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources that have an FRR Capacity Plan Commitment must be registered to participate in the Full Program Option or Capacity Only Option of the Emergency or Pre-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 such Delivery Year. An FRR Entity may not elect the physical non-performance assessment option if such FRR Entity will not be an FRR Entity for the following Delivery Year and will be serving load their under the RPM. 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 Interval and Non-PAI Event in accordance with Section 11.8. 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 Capacity Exchange system, before the FRR Capacity Plan submittal deadline, the amounts of installed capacity from resources in their Capacity Exchange 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 Capacity Exchange system for each unit and is equal to the Daily ICAP Owned on a unit multiplied by the unit's Accredited UCAP Factor

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.

~~Through the 2024/2025 Delivery Year, the Accredited UCAP Factor shall mean one minus EFORd. 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 Capacity Exchange system.~~

~~Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the Capacity Exchange 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 Capacity Exchange system by November 30 prior to the execution of the Third Incremental Auction.~~

~~Effective with the 2025/2026 Delivery Year, t~~The Accredited UCAP Factor is the ratio of the Capacity Resource's Accredited UCAP as determined by ELCC analysis (see Section 4.2.7 Accredited UCAP for ELCC Resources) to the Capacity Resource's installed capacity.

A unit that is in a party's Generation Resource portfolio in Capacity Exchange 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.[32] If the party's Daily

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

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/(Accredited UCAP Factor)) – 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 L~~l~~ocational 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 (Accredited UCAP Factor).

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 Capacity Exchange.

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 ICAP Owned for a specific demand resource is equal to the Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. Prior to the Delivery Year demand resource registration process in DR Hub system, the Daily Nominated DR Value for an FRR Entity's Demand Resource is established based on PJM's approval of the FRR Entity's DR Sell Offer Plan and PJM's submittal of a corresponding DR Modification into the Capacity Exchange system. After the Delivery Year demand resource registration process begins in DR Hub system, the Daily Nominated DR value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system in accordance with Section 4.3.4 of Manual 18.

~~Through the 2024/2025 Delivery Year, a party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * Forecast Pool Requirement. Starting with the 2025/2026 Delivery Year, a~~A party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * applicable ELC Class Rating. 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.

~~Through the 2024/2025 Delivery Year, a party's, Daily Available ICAP for a specific demand resource is equal to the resource's Daily ICAP Owned- (Daily RPM Resource Commitments/ Forecast Pool Requirement) – Daily FRR Capacity Plan Commitments.~~ ~~Effective with the 2025/2026 Delivery Year, a~~A party's Daily Available ICAP for a specific demand resource is equal to the resource's Daily ICAP Owned - (Daily RPM Resource Commitments/applicable ELCC Class Rating) - 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 L~~l~~ocational 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.

~~Through the 2024/2025 Delivery Year, a party's Daily FRR Demand Resource Position for a specific demand resource is equal to Daily FRR Capacity Plan Commitments* Forecast Pool Requirement.~~ ~~Effective with the 2025/2026 Delivery Year, a~~A party's Daily LDA FRR Demand Resource Position is calculated by summing the Daily FRR Demand Resource Positions of all demand resources in the LDA.

A party's Daily DER capacity resource Position is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * Accredited UCAP Factor. A party's Daily LDA FRR DER capacity resource Position is calculated by summing the Daily FRR DER capacity resource Positions of all DER capacity resources in the LDA.

A party's Daily ICAP Owned for a specific DER capacity resource is equal to the Daily Nominated DER Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such resource in effect for such day. Prior to the Delivery Year DER capacity resource registration process in DR Hub system, the Daily Nominated DER Value for an FRR Entity's resource is established based on PJM's approval of the FRR Entity's DER Plan and PJM's submittal of a corresponding DER Modification into the Capacity Exchange system. Prior to the start of the Delivery Year the DER registration process begins in DR Hub system, the Daily Nominated DER Value for a resource for a Delivery Year is established based on confirmed registrations in "completed" status linked to the DER capacity resource in the DR Hub system in accordance with Section 4 of Manual 18.

A DER capacity resource that is in a party's DER capacity resource portfolio may be committed to the FRR Capacity Plan, if there is Daily Available ICAP to commit from the DER capacity resource for the entire term of the commitment specified in the FRR Capacity Plan.

A party's Daily Available ICAP for a specific DER capacity resource is equal to the resource's Daily ICAP Owned- (Daily RPM Resource Commitments/ Accredited UCAP Factor) – Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific DER capacity resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such DER capacity 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 L~~l~~ocational UCAP transactions.

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

~~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* Forecast Pool Requirement. A LSE's Daily Total FRR EE Resource Position is equal to the sum of the Daily FRR EE Resource Position of all EE resources in their resource portfolio in Capacity Exchange.~~

~~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 DER capacity resource Positions ~~and Daily FRR EE Resource Positions~~ of all resources in their Capacity Exchange resource portfolio. After the FRR Capacity Plan submittal deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Preliminary Unforced Capacity Obligation to determine if the LSE has satisfied their Preliminary Unforced Capacity Obligation for the entire Delivery Year.

After the FRR Capacity Plan submittal deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Threshold Quantity, if applicable, to determine if the LSE has satisfied their Daily Threshold Quantity for the entire Delivery Year.

During the Delivery Year, an LSE's Daily Total FRR Resource Position is compared to their Daily Final Unforced Capacity Obligation to determine if a Capacity Resource Deficiency Charge is to be assessed.

An LSE's Daily LDA FRR Resource Position is calculated by summing the Daily LDA FRR Generation Resource Positions, Daily LDA FRR Demand Resource Positions, and Daily LDA

FRR DER capacity resource ~~positions and Daily LDA FRR EE Resource~~ Positions of all resources in their 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 Capacity Exchange 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 u~~U~~nit-s~~S~~pecific t~~T~~ransactions in Section 4 of this manual apply to the FRR Alternative.

Available installed capacity purchased through a bilateral unit-specific transaction that is reported via PJM's Capacity Exchange 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 Capacity Exchange 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 4.6.3 Exporting a Generation Resource 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, the Upgrade Customer must be in the Facilities Study phase 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., 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 Forecasting & Analysis 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 30 days prior to the initial FRR Capacity Plan submittal deadline a DR Sell Offer Plan as described in Attachment C of this Manual (i.e., a completed DR Plan template and DR Officer Certification Form). 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. The FRR Entity must further classify the Existing/Planned Nominated DR Value as MWs intend to commit as Annual Capacity Performance for annual period and MWs intend to commit as Summer–Period Capacity Performance for summer period, and MWs intend to commit as part of an Aggregate Resource. Actual deadline date for the DR Plan template and DR Officer Certification is provided in the RPM Auction Schedule posted on the PJM 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 committed to an FRR Capacity Plan is equal to ~~the Nominated DR Value committed * Forecast Pool Requirement through the 2024/2025 Delivery Year, and starting with 2025/2026 Delivery Year is equal to~~ the Nominated DR Value committed * the applicable ELCC Class Rating. The Nominated DR Values (summer, winter, or annual) for a load management program registration are determined in accordance with Section 4.3.7 of this manual and the Daily Nominated DR Value of a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to such Demand Resource in DR Hub system in accordance with Sections 4.3.4 and 4.7.2 of this manual.

A resource provider who has FRR Capacity Plan Commitments for their demand resource must meet (or contract with another party to meet the requirements specified in Section 4.3.1 of this manual.

A resource provider who has FRR Capacity Plan Commitments for their demand resource will be subject to Non-Performance Assessment, Non-Curtailment Charge 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 are no longer submitted by participants. A DR Mod submitted by PJM based on FRR Entity's approved DR Sell Offer Plan 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. After the Delivery Year demand resource registration process begins in DR Hub system, the Daily Nominated DR value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system in accordance with Sections 4.3.4 and 4.7.2 of this manual.

11.4.9 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 Capacity Exchange system (An EE MOD is submitted by PJM)
- 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.

11.4.10 Energy Efficiency Modifications (EE MODs)

RPM Business Rules for EE MODs in Section 4 of this manual apply to the FRR Alternative.

EE MODs submitted by PJM based on the FRR Entity's approved initial/updated M&V Plan 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 or final Capacity Value of an EE Resource for the Delivery Year. An EE MOD decrease may result in the reduction of FRR Capacity Plan Commitments.

11.5 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. For each LDA for which PJM is required to establish a separate Variable Resource Requirement Curve for the Delivery Year, a Percentage of Internal Resources Required for such LDA will be defined. PJM shall be deemed required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), or Mid-Atlantic Region ("MAR"), or for other LDAs if separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the OATT.

The constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year and Percentage of Internal Resources Required for such LDA (if applicable) 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. For each LDA that PJM is required to establish a separate Variable Resource Requirement Curve for the Delivery Year, the minimum Percentage of Internal Resources Required for such 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.

11.6 Conditions on Sales by FRR Entities

If an FRR LSE has not satisfied a Threshold Quantity, they may not offer to sell capacity in excess of the amount needed to satisfy Preliminary/Final Daily Unforced Capacity Obligation bilaterally into RPM or in RPM Auctions; however, they may offer to sell such excess capacity to an External Party (i.e., delist) or to an FRR Entity. If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the amount needed to satisfy their Threshold Quantity bilaterally into RPM or in RPM Auctions up to a Sales Cap Amount. The Sales Cap and other rules related to sales by FRR Entities are shown below:

- The Sales Cap Amount is equal to the lesser of (a) 0.25 * Preliminary Unforced Capacity Obligation or (b) 1300 MW.
- If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the Preliminary/Final Daily Unforced Capacity Obligation to an External Party (i.e., delist) or to another FRR Entity. In order for this type of sale to proceed, the Seller's FRR Capacity Commitments on the unit must be reduced.
- Sell offers in RPM Auctions and bilateral unit-specific transactions will be subject to offer and bilateral transaction checks to ensure that the seller does not violate any "Conditions on Sales by FRR Entities".
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" will be rejected.

If an FRR LSE serves load under the FRR Alternative and additional load under the RPM, the LSE may self-supply capacity resources in RPM Auctions and avoid the requirement to satisfy a Threshold Quantity; however, the MW amount of their sell offer(s) may not exceed a Self-Supply Offer Cap Amount, where:

- The Self-Supply Offer Cap Amount is the lesser of (a) 0.25 * (FRR Preliminary Daily Unforced Capacity Obligation + RPM Expected UCAP Obligation) or (b) 200 MW.
- An LSE's RPM Expected UCAP Obligation in a Zone is equal to the LSE's allocation of the Zonal Weather Normalized Summer Peak for summer four years prior to the Delivery Year (i.e., an Obligation Peak Load) * (Preliminary Zonal Peak Load Forecast/Zonal Weather Normalized Summer Peak for summer four years prior to Delivery Year) * Forecast Pool Requirement.

11.7 Delivery Year Activity

11.7.1 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.

11.8 Deficiency Charges & Penalties

11.8.1 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.

~~Through the 2024/2025 Delivery Year, the FRR Capacity Resource Deficiency Charge is equal to 1.2 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such zone, weight-averaged for the Delivery Year based on the prices established and the quantities cleared in such auctions, multiplied by the shortage. The weighted average resource clearing price for the LDA will be calculated considering all cleared MWs in RPM Auctions for the Delivery Year and such weighted average resource clearing price will apply to all shortages for the Delivery Year.~~ Starting with the 2025/2026 Delivery Year, the FRR Capacity Resource Deficiency Charge is equal to the price level corresponding to Point (1) of the Variable Resource Requirement curve for the Locational

Deliverability Area encompassing the Zone of the FRR Entity, multiplied by the shortage. FRR Capacity Resource Deficiency Charges are assessed daily and billed weekly.

11.8.2 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.

11.8.3 DER Capacity Aggregation Resource Test Failure Charge

Please see DER capacity resource testing requirement in section 4.11 and DER capacity resource test failure charge in section 9.1 of this Manual

11.8.4 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.

11.8.5 Load Management Test Compliance

DR Resource providers are required to simultaneously test all of their non-dispatched registrations in a zone in the absence of being dispatched by PJM for an Emergency Action that triggers a Non-Performance Assessment during the Delivery Year.

Please see Section 8.7 of this manual for details on Load Management Test Compliance.

11.8.6 Non-Performance Charge/Bonus Performance Credit

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 or price responsive demand committed to reduce the FRR Entity’s unforced capacity obligation that had a Performance Shortfall for a Performance Assessment Interval. If a resource committed to the FRR Capacity Plan or price responsive demand committed to reduce the FRR Entity’s unforced capacity obligation had Bonus Performance for a Performance Assessment Interval, such resource or price responsive demand will be eligible for Bonus Performance Credits.

Please see Section 9.1.11 of this manual for details on Non-Performance Charge/Bonus Performance Credit and Section 8.4B for Non-Curtailment Charges.

11.8.7 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 or price responsive demand committed to reduce the FRR Entity's unforced capacity obligation 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 or Seasonal 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 Interval and Non-PAI Event during the relevant Delivery Year.

For each Performance Assessment Interval and Non-PAI Event, 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 8.4B,and for such interval, a net Performance Shortfall associated with FRR commitments [33]shall be determinedfor Capacity Performance Resources. . The net Performance Shortfall for Capacity Performance Resources shall also include the performance of Seasonal Capacity Performance Resources included in the FRR Capacity Plan and include the performance of price responsive demand committed to reduce the FRR Entity's unforced capacity obligation.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources and price responsive demand , if any, for each Performance Assessment Interval shall by multiplied by a rate of 0.00139 MWs/Performance Assessment Interval [i.e., 0.5 MWs/30 PAHs/12 intervals per hour]] 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 and price responsive demand committed for such Delivery Year .

The additional MWs of Capacity Performance Resources required for Performance Assessment Intervals (PAIs) that occur during February through May of the Delivery Year shall be committed to the FRR Entity's FRR Capacity Plan for the remainder of the following Delivery Year by established deadlines below.

- February PAIs: by July 1 of the following Delivery Year
- March PAIs: by August 1 of the following Delivery Year

[33] If a market participant has both RPM commitments and FRR commitments on a resource, the final Shortfall MW or Bonus MW on a resource will be allocated to RPM and FRR commitments on a pro-rata basis based on the amount of RPM and FRR CP commitments in unforced capacity terms.

- April PAIs: by September 1 of the following Delivery Year
- May PAIs: by October 1 of the following Delivery Year

11.9 Allocation of Deficiency Charges

The Daily FRR Capacity Resource Deficiency Charges, FRR Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, DER Capacity Aggregation Resource Test Failure Chargesand 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, DER Capacity Aggregation Resource Test Failur Charges and Load Management Test Failure Charges are allocated on a pro-rata basis to RPM LSEs based on their daily unforced capacity obligation.

11.10 Auction Specific MW Transactions

LSEs that elect the FRR Alternative may report a~~A~~uction s~~S~~pecific MW t~~T~~ransactions if they have cleared capacity in RPM Auctions through the Capacity Exchange system.

The MWs associated with approved a~~A~~uction s~~S~~pecific MW t~~T~~ransactions 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:

Adjusted Zonal Capacity Prices – are determined based on the results of RPM Incremental Auctions. Preliminary Zonal Capacity Prices that result from the Base Residual Auction are adjusted to account for the procurement in the RPM Incremental Auctions.

Accredited UCAP is defined in the RAA as the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Auction Specific MW Transactions – are transactions reported to PJM via Capacity Exchange between a buyer and seller that report the transfer of physical MW between the buyer and seller using the Capacity Exchange system and PJM settlement process. Auction s~~S~~pecific MW t~~T~~ransactions are not eligible to be offered in an RPM auction. Auction s~~S~~pecific MW t~~T~~ransactions 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 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.

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. 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 Base Zonal UCAP Obligation / (Adjusted Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year * the Forecast Pool Requirement) ~~[(Preliminary Zonal Peak~~

~~Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Years) * ((RTO Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement))]~~. Base Zonal RPM Scaling Factors are posted with the Base Residual Auction results.

Base Zonal Unforced Capacity Obligation – determined for each zone and is equal to the ((Preliminary Zonal Peak Load Forecast for the Delivery Year / RTO Preliminary Peak Load Forecast for the Delivery Year) * RTO Unforced Capacity Obligation satisfied in the Base Residual Auction)~~(Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement)~~. Base Zonal Unforced Capacity Obligations are posted with the Base Residual Auction clearing results.

Behind the Meter Generation – Behind The Meter Generation" shall refer to a generation 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 has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource or DER Capacity Aggregation Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Bilateral Market – provides LSEs the opportunity to hedge the Locational Reliability Charge determined through the RPM Auctions by purchasing available capacity in the bilateral market to offer into an RPM 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 Capacity Exchange, or to request an MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

Capacity Resources – "Capacity Resources" shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and Reliability Assurance Agreement, Schedule 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity

Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; or (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6; or (iv) generation and load reduction capability provided by a DER Capacity Aggregation Resource, pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.2 and the PJM Manuals.

Capacity Resource with State Subsidy – (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

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 satisfy the locational reliability criteria established in the RAA~~, M20,~~ and M20A.

Capacity Only Option - participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Attachment DD of the Tariff and as applicable, a capacity payment for load reductions during a pre-emergency or emergency event.

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.

Combination Resource – shall mean a Generation Capacity Resource, or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

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:

- 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)
- Maintain scheduled interchange with other Control Areas
- Maintain the frequency of the electric power system(s)
- Maintain power flows on transmission facilities within appropriate limits to preserve reliability
- 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 RPM Incremental Auctions divided by the Total CTR MWs allocated to LSEs in the zone.

Daily Unforced Capacity Obligation - 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, Energy Efficiency Resource, Aggregate Resource or Qualified Transmission Upgrade committed to RPM.

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 – an Annual Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6. A Demand Resource may be an existing or planned resource.

Demand Resource Modification (DR Mods) – transaction submitted by PJM to track an increase or decrease of the nominated value of the Demand Resource in a party's resource portfolio in Capacity Exchange.

Demand Resource Registration - a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with OATT, Attachment K-Appendix, Section 8. A Demand Resource Registration is linked to a Demand Resource.

Effective UCAP is defined in the RAA as a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Resource shall mean a Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, a Generation Capacity Resource, or a Demand Resource.

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) – Electric Distribution Company" shall mean, exclusively for purposes of the Tariff, Attachment K-Appendix, section 1.4B and Operating Agreement, Schedule 1, section 1.4B, a PJM Member, or an entity that mutually agrees with a PJM Member that the PJM Member shall represent the entity and act on their behalf, 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 Region under rates and tariffs approved or authorized by the applicable Relevant Electric Retail Regulatory Authority.

Emergency – an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scare fuel; or a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End Use Customer – a member that is a retail end-user of electricity within the PJM region.

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

Equivalent Demand Forced Outage Rate (EFORd-5) (Prior to the 2025/2026 Delivery Year)– 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 includes 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 (Prior to the 2025/2026 Delivery Year)– the most recently calculated EFORd that has been bridged to the Capacity Exchange 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 includes the events that are outside management control (OMC events..

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 or to account for Non-Viable MWs for any transition provisions that are in effect for the Delivery Year.

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 Adjusted Zonal Weather Normalized Peak for the summer prior to the Delivery Year). The Final Zonal RPM Scaling Factors are posted with the results of 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.

Full Program Option - participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Attachment DD of the Tariff and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for load reductions during a pre-emergency or emergency event.

Generation Capacity Resource – A Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity 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.

Generation Interconnection Agreement – an agreement among the Transmission Provider, a Project Developer, and applicable to a Generation Interconnection Request or Transmission Interconnect Request.

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/release of resource commitments to satisfy an increase/decrease in the RTO/LDA Reliability Requirements through PJM Buy Bids/Sell Offers. Allows a resource provider to submit a Sell Offer to procure replacement capacity to cover commitment shortfalls due to a generation resource cancellation, delay, derating, EFORd increase, Accredited UCAP Factor decrease, or decrease in the unforced capacity value of a Demand Resource or Energy Efficiency 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 determined in accordance with PJM's Rules and Procedures of the Determination of Generating Capacity in ~~M21, M21A, and~~ M21B. ~~For an ELCC Resource through the 2024/2025 Delivery Year, the term “ICAP” in this manual refers to the lesser of the Accredited UCAP or the resource's CIRs plus any awarded transitional MWs.~~

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 Resource Adequacy Analysis Manual ~~(M-20) and~~ (M-20A). The IRM is approved and posted prior to its use in an RPM Auction for the Delivery Year.

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.

Jointly Owned Cross-Subsidized Capacity Resource – a Capacity Resource that is supported by a facility that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, and therefore shall be considered a Capacity Resource with State Subsidy; provided however, in the event that the material rights and obligations of such generating facility are in pari passu, meaning that such rights and obligations are allocated among the owners pro rata based on ownership share, only Capacity Resources of those owners entitled to receive or receiving a State Subsidy shall have their share of such resource considered a Capacity Resource with a State Subsidy and Capacity Resources of owners not entitled to a State Subsidy shall not be considered a Capacity Resource with a State Subsidy. Each of these designations may be overcome by either Capacity Market Seller demonstrating to the Office of Interconnection, with advice and input from the Market Monitoring Unit, that there is no cross-subsidization or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.

Limited Duration Resource shall mean a Generation Capacity Resource or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Adjustment - Any MW quantity of adjustments to summer peak load at the "zone/area" level and summed by Zone.

Load Management – is the ability to reduce metered load, either manually or automatically, by the customer, after a request from the resource provider which holds the Load management rights or its agent.

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 revenue data for a reference combustion turbine and an assumed value for ancillary services revenues as set forth in OATT. The energy revenues are calculated using a historical average of the three most recent calendar years preceding the Base Residual Auction.

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.

New Service Request – Interconnection Request.

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. Tthe maximum load reduction for Capacity Performance registration also takes into consideration the Winter Peak Load for the customer. 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.

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 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. At a minimum, planned generation resources greater than 20 MW must be in the Phase III System Impact Study and planned generation resources less than or equal to 20 MW must be in the Phase II System Impact Study for the unit to participate in the Base Residual Auction. Generation Interconnection Agreement (GIA) or Wholesale Market Participant Agreement (WMPA) 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 (Prior to the 2025/2026 Delivery Year)– 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. OMC events are considered in the EFORd values used to calculate Pool-Wide Average EFORd.

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, at a minimum the Upgrade Customer must be in the Facilities Study phase for their proposed transmission upgrade.

Regional Transmission Expansion Planning Process (RTEPP) – is PJM's comprehensive annual process that examines the three interrelated components of electric power system reliability: load, generation, and transmission. The RTEP Process employs a range of planning study tools and methodologies to analyze and assess each component to ensure that reliability remains firm. The RTEP Process is designed to meet established reliability criteria, keep markets robust and competitive, and ensure stable operations.

Regional Transmission Owner (RTO) – Each entity that owns, leases, or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce or that provides Transmission that is a party to the PJM Transmission Owners Agreement and PJM Operating Agreement

Reliability Pricing Model (RPM) – is PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Resource Clearing Price – is the clearing price in the Base Residual Auction or Incremental Auctions as determined by optimization algorithm for each auction. The Resource Clearing Price within an LDA is equal to the sum of (1) the marginal value of system capacity; and (2) the Locational Price Adder, if any, for the LDA. The Resource Clearing Price for Capacity Performance Resources in 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.

RPM Resource Commitment – MWs committed from a Capacity Resource to RPM as a result of such Capacity Resource clearing or receiving make-whole MWs in a Delivery Year RPM Auction(s), being specified as a replacement resource in a r~~R~~eplacement c~~C~~apacity transaction(s), or being specified as the source of a Locational UCAP transaction(s).

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.

State Subsidy – a direct or indirect payment, concession, rebate, subsidy, nonbypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or (2) will support the construction, development, or operation of a new or existing Capacity Resource; or (3) could have the effect of allowing the unit to clear in any PJM capacity auction. Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

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.

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) – prior to the 2025/2026 delivery year, the installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating, calculated for each generation Capacity Resource based on EFORd data for the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit. For an ELCC Resource, the UCAP is the Accredited UCAP of the unit, not to exceed its Capacity Interconnection Rights plus any awarded transitional resource MWs. Effective with the 2025/2026 Delivery Year, for an ELCC Resource that is a Generation Capacity Resource, the UCAP is the Accredited UCAP of the unit, not to exceed its Capacity Interconnection Rights plus any awarded transitional resource MWs.

Unlimited Resource is defined in the RAA as a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource shall mean a Generation Capacity Resource or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

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 segment-specific Resource Clearing Prices that result in all the auctions for a party's specific Capacity Resource, weighted by the segment-specific Unforced Capacity cleared for that particular resource. This value is used to determine a party's Daily Deficiency Rate for an individual resource.

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); and (3) an adjustment in the Zone, if required, to account for any resource make-whole payments. *Preliminary Zonal Capacity Prices* are the result of the clearing of the Base Residual Auction. *Adjusted Zonal Capacity Prices* are the result of the clearing of the 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.

Zone/Area - An area within a Zone for which the relevant EDC specifies a separate OPL MW value. A service area of an EDC that is a separately identifiable, geographic area bounded by wholesale metering.

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 Capacity Exchange 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 Accredited UCAP Factor 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 and Non-Performance Assessment Charges that may be assessed (including those resulting from a reduced Accredited UCAP), and, for the duration of the delivery year, its proportional share of any Generation Test Resource Rating Test Failure Charges, or that may be assessed under RPM rules.

The undersigned, having been granted Capacity Exchange 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 Demand Resource 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 DR Hub system for the current Delivery Year)[34] 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. The CSP shall not include Critical Natural Gas Infrastructure in their Plan.

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 Capacity Exchange 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

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[34] For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM DR Hub system for the subsequent Delivery Year may also be considered as existing DR provided the Demand Resource 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.

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 Demand Resource Registrations for the relevant Delivery Year.

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/DR Hub 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. Effective with the 2020/2021 Delivery Year, a CSP must apportion the total Nominated DR Value for the zone/sub-zone into the quantity that the CSP intends to offer into the auction as Annual Capacity Performance , the quantity that the CSP intends to offer into the auction as Summer-Period Capacity Performance, and the quantity that the CSP intends to offer into the auction as part of an Aggregate Resource, such that, the sum of such quantities must equal the total Nominated DR Value 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/DR Hub 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 pjm 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/DR Hub 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

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.

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:_______________________________

Attachment E: DER Officer Certification Form

DER 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 DER 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 DER registrations with similar technology characteristics to those submitted in the Plan 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 62 (12/17/2025):

- Add DER conforming changes based on Order 2222
- Add expanded Load Management availability window (section 4)

Administrative Change (Pete Langbein approved 08/01/2025):

- Added missing changes from Revision 60 back into Revision 61

Revision 61 (07/23/2025):

- Conforming changes were made to the following sections to incorporate provisions of FERC orders (ER25-682) and (ER25-785) and (er24-2995-000).
- 2.4.5 Adjustments to RPM Auction Parameters for EE Resources
- 3.3 Parameters of the Variable Resource Requirement
- 3.3.1 Cost of New Entry
- 3.4 Plotting the Variable Resource Requirement Curve
- 4.7.1 Resource Position for Generation Capacity Resources
- 5.1 Overview of RPM Auctions
- 5.4.1 Resource-Specific Sell Offer Requirements
- 5.4.8.4 Default MOPR Floor Offer Prices
- 8.4A Non-Performance Assessment

Revision 60 (06/01/2025):

- Conforming changes were made to the following sections to incorporate provisions of FERC's CIFP-RA order (ER24-99)
- 8.1 - Overview of Resource Performance Assessments
- 8.3 - Commitment Level Used in Summer/Winter Capability Tests (through the 2024/2025 Delivery Year)
- 8.5 - Summer/Winter Capability Testing
- 8.5.1 - Determination of Unit ICAP Shortfall (through the 2024/2025 Delivery Year)
- 8.5.2 - Determination of Unit ICAP Shortfall (effective with the 2025/2026 Delivery Year)
- 8.5A - Generation Operational Testing
- 9.1.5 - Generation Resource Rating Test Failure Charge
- 9.1.5A - Generation Operational Test Failure Charge
- 9.1.7 - Allocation of Deficiency and Penalty Charges

- Update 5.2 to include preliminary ELCC Class Rating and Accredited UCAP Factors on the auction timeline as approved by the 5/21/25 MRC.

Administrative Change (Pete Langbein approved 02/26/2025):

- Added missing content in Section 8.7.1

Revision 59 (06/27/2024):

- Conforming changes were made to the following sections to incorporate provisions of FERC's CIFP-RA order (ER24-99) and CONE Area 5 order (ER24-462):
- 1.2.2 Participation of Resource Providers
- 2.1.1 Installed Reserve Margin
- 2.1.2 Peak Load Forecasts
- 2.1.3.1 Pool-wide Average EFORd (Through 2024/2025 Delivery Year)
- 2.1.3.2 Pool-wide average Accredited UCAP Factor (Starting with 2025/2026 Delivery Year)
- 2.1.4 Forecast Pool Requirement
- 2.1.5 Effective Load Carrying Capability and ELCC Resources in Capacity Exchange
- 2.2 Role of Load Deliverability in the Reliability Pricing Model
- 2.3 Locational Constraints in the Reliability Pricing Model
- 2.3.1 Locational Constraints in the Reliability Pricing Model
- 2.4 Reliability Requirements
- 3.3 Parameters of the Variable Resource Requirement
- 3.3.1 Cost of New Entry
- 3.4 Plotting the Variable Resource Requirement Curve
- 4.2.1 Existing Generation Capacity Resource – Internal
- 4.2.2 Existing Generation Capacity Resources – External
- 4.2.3 Planned Generation Capacity Resources – Internal
- 4.2.3.1 Binding Notice of Intent to Offer (Effective with the 2025/2026 Delivery Year)
- 4.2.4 Planned Generation Capacity Resources – External
- 4.2.5 Equivalent Demand Forced Outage Rate
- 4.2.7 Accredited UCAP for ELCC Resources
- 4.3.1 Requirements of Load Management Products in RPM
- 4.3.8 Determination of the UCAP Value of Load Management
- 4.4 Energy Efficiency Resources
- 4.6.2 Entering Unit-Specific Bilateral Transactions
- 4.6.3 Exporting a Generation Resource

- 4.6.5 Treatment of Unit-Specific Capacity Transactions that Start/End Mid-Delivery Year
- 4.6.8 Locational Unforced Capacity (UCAP) Transactions
- 4.7.1 Resource Position for Generation Capacity Resources
- 4.7.2 Resource Position for Demand Resources
- 5.2 RPM Auction Timeline
- 5.3. RPM Auction Parameters
- 5.4.1 Resource-Specific Sell Offer Requirements
- 5.4.3 New Entry Pricing Adjustment
- 5.4.4 Sell Offer Caps
- 5.4.8.4 Default MOPR Floor Offer Prices
- 5.7.1 Participation in the Base Residual Auction
- 5.8.1 Participation in the Incremental Auctions
- 8.1 Overview of Resource Performance Assessments
- 8.2.1 Generation (RPM Commitment Compliance)
- 8.2.2 Demand Resources (RPM Commitment Compliance)
- 8.4A Non-Performance Assessment
- 8.7 Load Management Test Compliance
- 8.8 Replacement Resources
- 9.1.9 Non-Performance Charge/Bonus Performance Credit
- 11.1.3 Participation in the FRR Alternative
- 11.2.1 Preliminary Unforced Capacity Obligation
- 11.3 Capacity Plan
- 11.4.1 Resource Portfolio
- 11.4.7 Load Management Products
- 11.8.1 FRR Capacity Resource Deficiency Charges

Revision 58 (11/15/2023):

- Conforming changes for interconnection process (ER22-2110)
- Section 4.7.1, 4.2.6, 4.2.7: RAA updated for Transitional MW (Docket No. ER23-1067-000)
- Section 7.4: Conforming language for Order 841 and Hybrid Order (ER22-1420)
- Section 8.2.2: Remove reference to DR Factor
- Section 3.3 and 3.4: Conforming to approved quad review filing (ER22-2984-000)
- Section 8.4A: Change to PAI Trigger (ER23-1996-000)
- Section 5.4.8.4: Updated Default Gross CONE and Gross ACR for MOPR (ER23-1700)

Revision 57 (07/26/2023):

- Interconnection Process Reform Taskforce nomenclature updates
  - Section 4.2.3: Updated terminology for IPRTF updates
  - Section 4.2.4: Updated terminology for IPRTF updates
  - Section 4.5: Updated terminology for IPRTF updates
  - Section 4.8.2: Updated terminology for IPRTF updates
  - Section 4.8.5: Updated terminology for IPRTF updates
  - Section 4.10: Updated terminology for IPRTF updates
  - Section 5.4.7: Updated terminology for IPRTF updates
  - Section 6.1: Updated terminology for IPRTF updates
  - Section 6.1.2: Updated terminology for IPRTF updates
  - Section 8.8: Updated terminology for IPRTF updates
  - Section 11.4.6: Updated terminology for IPRTF updates
  - Glossary A: Updated terminology for IPRTF updates

Administrative Change (Approved by Peter Langbein 04/28/2023):

- Removed reference to Manual 10 Section 6 in Section 8.5. Justification for this change is due to the decision for Section 6's removal stated in M10 "based on RFC Standard MOD-024-RFC-01, which permits verification of winter gross Real Power capability by adjusting the summer verification, eliminating the need for exemption program. Revisions approved by stakeholders at MRC on November 30, 2009"

Revision 56 (02/09/2023):

- Change to Section 8.8 to allow early replacement actions for export under specific conditions as approved at 11/16/22 MRC.

Revision 55 (02/09/2023):

- Updated section 3A.3 and Attachment C to prohibit Critical Natural Gas Infrastructure

Administrative Change (Approved by Peter Langbein 01/05/2023):

- Section 5.4.8.3: Updated binary pronoun usage (e.g., "his/her" to a gender-neutral equivalent (e.g., "their," etc.) in order to support PJM's diversity, equity and inclusion efforts.

Revision 54 (09/21/2022):

- Periodic Review updates include:
  - Deletion of outdated information in the following sections:
    - Section 1.5
    - Sections 2.1.3, 2.2, 2.3, 2.3.4, 2.4.3, 2.4.3A, 2.4.4, & 2.4.5

- Sections 3.3.1, 3.3.2, 3.4, 3.5, 3A.1, 3A.2, 3A.3, 3A.4.1, 3A.4.2, 3A.5, 3A.6, 3A.6.2, & 3A.6.2A
- Sections 4.1, 4.2.2, 4.2.4, 4.2.5, 4.2.6, 4.3.1, 4.3.3, 4.3.4, 4.3.5, 4.3.7, 4.3.8, 4.3.10, 4.4, 4.4.1, 4.4.2, 4.4.3, 4.5, 4.6.2, 4.6.4, 4.6.5, 4.6.6, 4.6.7, 4.6.8, 4.7.1, 4.7.2, 4.7.2, 4.7.3, 4.8.3, 4.8.4, 4.8.5, 4.9, & 4.10
- Sections 5.3, 5.4.1, 5.4.4, 5.4.5, 5.4.8, 5.5, 5.7.1, 5.7.2, 5.7.3, 5.8.1, 5.8.3, 5.8.5, & 5.9.1
- Section 6.1.3
- Section 7.2.2
- Sections 8.1, 8.2.1, 8.2.2, 8.2.3, 8.3, 8.4, 8.4A, 8.5, 8.6, 8.7, 8.8
- Sections 9.1.1, 9.1.2, 9.1.3, 9.1.5, 9.1.6, 9.1.9, 9.3.1, 9.3.3, 9.4.2, 9.4.4
- Sections 11.1.2, 11.3, 11.4.1, 11.4.7, 11.4.8, 11.8.1, 11.8.3, 11.8.5, 11.8.6, & 11.8.7
- Attachment A: Glossary of Terms

- Added reference to Section 3.4 for development of VRR Curves (Sections 2.4.4 & 2.4.5)
- Added missing OVEC zone to CONE Area (Section 3.3.1)
- Added footnote to clarify the Reliability Requirement used in UCAP quantity equation for points (a), (b), and (c) of VRR Curve excludes any adjustment for PRD or EE (Section 3.4)
- Clarified VRR Curve is adjusted rightward for EE addback (Section 3.4)
- Clarified information to be verified in Resource Confirmation process to reflect current practice in Capacity Exchange system (Section 4.1)
- Clarified generation resource committed to FRR Capacity Plan must satisfy same qualification requirements as resource offering into RPM Auction (Section 4.2)
- Moved Prior CIL Exception Resource definition from Section 2.3 to this section (Section 4.2.2)
- Clarified load management programs and EE installations are eligible to be committed to FRR Capacity Plan (Section 4.3 & Section.4.4)
- Updated DR Plan deadline from 15 business prior to 30 days prior (Sections 4.3.1, 5.2, 11.4.7, & Attachment C: DR Sell Offer Plan)
- Replaced "annual" product availability with "Capacity Performance" (Section 4.3.10)
- Added Nominated EE Value Template requirement to reflect current practice (Section 4.4)
- Updated EE Modification process to reflect current practice (Section 4.4.3)
- Clarified UCAP Value of CP EE Resource and Summer Period EE Resource (Section 4.4.2)

  - Added Generation Resource Rating Test Failure Charge to list of charges applicable to Seller of Auction Specific MW Transaction (Section 4.6.6)
  - Added footnote to reference RPM Auction schedule on website for DYs FERC approved a compressed auction schedule (Section 5.2)
  - Added Capacity Performance value when missing (Section 8.2.3)
  - Clarified party/PJM Weighted Average Resource Clearing Price to consider segment-specific RCPs (Section 9.1.3)
  - Clarified LDA Incremental CTR Credit Rate (Section 9.3.4)
  - Changed “product-specific” to “segment-specific” in description of price applicable to Auction Specific MW transaction (Section 9.3.5)
  - Clarified Capacity Exchange tool functionality (Section 10.1)
  - Clarified alternative retail LSE is subject to credit requirement as opposed to FRR Entity for alternative retail LSE’s Planned Resources (Section 11.1.3)
  - Corrected the treatment of switched load between FRR Entity and RPM LSEs to be in compliance with RAA (Section 11.2.3)
  - Clarified EE Modification submittal process (Section 11.4.9)
  - Clarified the requirement to perform Load Management test (Section 11.8.5)
  - Added footnote to clarify final Shortfall or Bonus MW will be allocated to RPM and FRR if have both RPM and FRR commitments on resource (Section 11.8.7)
  - Clarified definition of DR Mod, EFORd, Effective EFORd, Nominated DR Value, Pool-wide average EFORd, Resource Clearing Price, Weighted Average Resource Clearing Price, and Zonal Capacity Price (Attachment A: Glossary of Terms)
  - Administrative updates throughout manual
    - Corrected manual or agreement references
    - Consolidated information
    - Deleted duplicative information
    - Updated tool name to Capacity Exchange
    - Corrected grammar and formatting
- Update the process for Capacity Market Seller to demonstrate written commitment to must-offer requirement for an External Resource via Officer Certification Form as opposed to External Resource Must Offer Agreement (Section 4.2.2)
- Updates to include certain Hybrid Resources in the exemption to the RPM must offer requirement (Sections 4.7.1, 5.4.1, 5.7.1, and 5.8.1)
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Revision 53 (07/27/2022):

- Conforming revisions for FERC Order ER20-1590-000 issued on September 3, 2020 approving changes to Load Management and Price Responsive Demand testing requirements to make testing more closely simulate actual emergency events. This includes details on scheduling tests, notification of tests, duration of tests and retesting provisions.

  - Section 3A.6.3A establishes the testing requirements for PRD effective with 2023/2024 Delivery Year.
  - Section 8.7 modified for Load management testing requirements effective with 2023/2024 Delivery Year.

Revision 52 (02/24/2022):

- Update to section 3.3.2 to reflect that Net EAS of the Reference Resource CT is calculated using the forward-looking methodology with application of the 10% adder for only the 2022/2023 Delivery Year. The Net EAS is determined using the historical approach and without application of the 10% adder for all other delivery years.
- Update to section 5.4.1 to reflect that sell offers of existing generation capacity resources above $0/MW-Day must seek unit-specific exception or elect to use MSOC based on gross ACR of applicable resource type, if available, effective 9/2/2021. Added language specifying that sellers may elect to use a default offer cap of 1.1 times the BRA RCP for any 3rd IA.
- Updated section 5.4.4 to reflect that the Net EAS of units seeking a net ACR-based exception is calculated using the forward-looking methodology for only the 2022/2023 Delivery Year. The Net EAS is determined by historical net revenues for all other delivery years.
- Updated section 5.4.5 to make clear that this section and its sub-sections which describe the MOPR provisions of Sections 5.14(h) and 5.14(h-1) of Attachment DD of the PJM OATT are not applicable after the 2022/2023 Delivery Year. Deleted language in section 5.4.5.2 describing consequences of accepting State Subsidy after electing competitive exemption or certifying that resource is not state subsidized.
- Added new section 5.4.8 to describe the MOPR provisions of Section 5.14(h-2) of Attachment DD of the PJM OATT which are effective with the 2023/2023 Delivery Year.

Revision 51 (10/20/2021):

- Updates to Section 2.4.5 to reflect new EE Addback methodology to be used in all RPM Auctions conducted for the 2023/2024 Delivery Year and all subsequent delivery years.

Revision 50 (09/01/2021):

Revision includes:

• Updates to Section 8.4A to clarify Scheduled MW used for Excusal and Bonus purposes in Performance Assessment Interval settlement is calculated using Dispatch Run LMP due to Fast Start Pricing implementation on 9/1/2021.

Revision 49 (08/01/2021):

Revised the following sections to make confirming changes to implement Effective Load Carrying Capability to calculate the capacity value of renewables and storage. Unless otherwise noted, section changes were made to update and clarify terminology usage related to ICAP, UCAP, and EFORd, and replacing the terms "wind" and "solar" with "Variable Resources":

- New Section 2.1.5 – provides a summary description of ELCC and describes the use of the terms "ICAP" and "UCAP" for ELCC Resources in the context of Manual 18
- 4.2.5 and 4.2.6
- New Section 4.2.7 – provides a summary description of ELCC and describes the use of the terms "ICAP" and "UCAP" for ELCC Resources in the context of Manual 18
- 4.7.1 – clarifies that ELCC Resources may not offer or otherwise provide UCAP MW quantities above their Capacity Interconnection Rights.
- 5.4.1 and 5.4.5.6
- 7.1
- 8.1 – revised the table of generator assessments to reflect rules for Variable Resources
- 8.4
- 8.5
- 8.8 – reflects application of commitment deficiency rules given the Accredited UCAP values of ELCC Resources
- 9.1.1
- 9.1.5 – reflects application of the Daily Generation Resource Rating Test Failure Charge given the Accredited UCAP value of ELCC Resources
- 11.3
- 11.4.1
- Attachment A – added the RAA definitions for several new ELCC-related terms, such as Accredited UCAP, Combination Resource, Variable Resource, ELCC Resource, etc.

Revision 48 (05/26/2021):

- New paragraph in Section 8.4A to clarify treatment of Public Distribution Microgrid Generators that are Generation Capacity Resources for Non-Performance Assessment.
- PRD – Approved as per Docket Nos. ER21-1243--0000 and ER21-1243-001 on 4/28/2021, effective on 06/01/2021:
    - Removed reference to LSE from PRD Provider description (Section 1.2.3)
    - Revised PRD Provider description, changed PRD Credit recipient from LSE to PRD Provider (Section 3A.1)
    - Removed LSE-specific requirements for PRD (Section 3A.4.2)
    - Removed section 3A.4.2.1 - Verification of Retail Rate Structure with LSE

- Removed reference to LSE (Section 3A.4.2.2)
- Removed identification of LSE from registration requirement (Section 3A.5)
- Changed PRD Credit recipient from LSE to PRD Provider (Section 9.4.4)

Revision 47 (01/27/2020):

- Conforming changes were made to the following sections to incorporate provisions of FERC's expanded MOPR order (EL16-49, EL18-178, ER18-1314) and Forward Net EAS order (EL19-58):
    - Section 3.3.2 Demand in RPM
    - Section 5.4.4 Sell Offer Caps
    - Section 5.4.5 Minimum Offer Price Rule (MOPR)
    - Section 8.8 Replacement Resources
    - Attachment A Glossary of Terms

Revision 46 (11/19/2020):

- Section 8.4A – Corrected effective date from 2021/2022 to 2020/2021 Delivery Year for when External Generation Capacity Resources that would have helped resolve the declared Emergency Action are included in a performance assessment in order to conform with the effective date in the OATT.

Administrative Change (06/23/2020):

- Updated manual ownership to Peter Langbein

Revision 45 (05/28/2020):

- Conforming revisions for FERC Order ER20-271-001 issued on February 28, 2020 to clarify that Price Responsive Demand (PRD) registration will not be considered in the calculation of a performance shortfall or bonus performance for a Performance Assessment Interval (PAI) when the PRD Curve associated with registration indicates a price point where no demand reduction is expected at the real-time LMP recorded during the PAI. (Section 3A.6.2A)
- Conforming revisions for FERC Order ER20-217-000 issued on December 30, 2019 to update certain rules and requirements for PRD to conform to rules and requirements for Capacity Performance resources.
    - Added prior to 2022/2023 Delivery Year, PRD Provider is subject to performance compliance during Maximum Emergency Events. Added effective with 2022/2023 Delivery Year, PRD Provider is subject to Non-Performance Assessment during the Delivery Year (Sections 3A.1, 3A.3, 3A.6, 3A.6.2, 8.4A, 9.1.9, and 9.4.2)
    - Deleted outdated provisions related to the Transition Period for PRD (Section 3A.2)

- Added footnote that any PRD Plan submitted and approved for 2022/2023 Delivery Year BRA may be withdrawn or modified no later than 30 days prior to the commencement of the 2022/2023 Delivery Year BRA. (Section 3A.4.1)
- Added that Zonal Scaling Factors for use in preparation of PRD Plans will be posted by PJM prior to the 2022/2023 Delivery Year. (Section 3A.4.1)
- Added effective with 2022/203 Delivery Year, the PRD Value for Zone/LDA provided in a PRD Plan is based on a Zonal/LDA Peak Load Contribution (PLC) value minus (the Zonal/LDA Firm Service Level (FSL) quantity times the loss factor). (Section 3A.4.2)
- Added Expected Peak Load Value of PRD is submitted prior to 2022/2023 Delivery Year and Peak Load Contribution value of PRD is submitted effective with 2022/2023 Delivery Year. (Section 3A.4.2)

Revision 44 (12/05/2019):

- Conforming revisions for FERC Order ER19-2417 issued on September 16, 2019 that (1) enable Capacity Market Sellers to request removal of the Generation Capacity Resource Status and (2) require Capacity Market Sellers seeking an exception to the RPM must offer requirement on the basis that an existing Generation Capacity Resource is physically unable to satisfy the requirements of Capacity Performance (CP) to include a documented plan to become capable of participating in RPM.
    - Updated RPM Auction Timeline to include activities associated with removal of a resource from Capacity Resource status (Section 5.2)
    - Included the requirement to submit a documented plan showing steps that intend to pursue for a resource to become physically capable of satisfying the requirements of a CP Resource, and provide periodic updates on progress of such plan, effective with must-offer exception requests for the 2023/2024 Delivery Year (Section 5.4.1)
    - Added new section “Removal of Generation Capacity Resource Status” to document the process to voluntarily request removal of a Capacity Resource from Generation Capacity Resource status (Section 5.4.7)
- Clarification updates to RPM must-offer exception process:
    - Clarified that timing is an acceptable reason for must-offer exception request (Section 5.4.1)
    - Clarified that sellers may specify multiple auctions in a written must-offer exception request (Section 5.4.1)
    - Added that a pending request to PJM for removal of Generation Capacity Resource status is an acceptable reason for early replacement (Section 8.8)

Revision 43 (12/03/2019):

- Conforming revision for FERC Order 841: Electric Storage participation (ER19-462) in Section 7.4 to address Energy Storage Resources not being allocated a Peak Load Contribution.

Revision 42 (07/25/2019):

- Periodic Review updated to address:
  - Corrections/Clarifications of Existing Provisions
    - Clarify Delivery Year applicability of Limited Resource Constraint, Sub-Annual Resource Constraint, Base Capacity Demand Resource Constraint, and Base Capacity Resource Constraint for FRR Alternative in Sections 2.4.3A, 2.4.3B and 5.3
    - Clarify treatment of Qualifying Transmission Upgrade once in service in Section 4.5
    - Clarify Behind the Meter Generation provisions in Sections 4.3.3 and 7.3.1
    - Correct Non-Performance Charge Rate in Sections 8.4A, 9.1.11 and 11.8.8
    - Clarify replacement capacity rules when remaining import capability into an LDA in Section 8.9
    - Add Aggregate Resource to list of capacity resources in Sections 4.1, 5.7.1 and Glossary
    - Clarify charges applicable to Owner in Authorization to Self-Schedule Capacity in Attachment B
  - Deletion of Outdated Provisions
    - Capacity Performance Transition IAs in Sections 1.5, 4.6.2, 4.6.6, 5.1, 5.8 and 5.9
    - Minimum Annual and Extended Summer Requirements in Sections 2.4.3, 2.4.4, 2.4.5, 3.5, 5.3, 5.7.2, 5.8.5, 5.9, 11.1.3, 11.3 and 11.8
    - EE adjustments for 2016/17 – 2018/2019 Delivery Years in Section 2.4.5
    - Short-term Resource Procurement Target in Sections 3.3, 3.5, 5.1, 5.4.3, 5.8, 6.1, 7.2.2, 11.1.3 and Glossary
    - Demand Response Legacy Direct Load Control Transition Provision in Sections 3.5 and 5.9
    - Limited Resource Constraint and Sub-Annual Resource Constraint (when it relates to RPM Auctions) in Sections 3.5, 5.7.2, 5.8.5, and 5.9
    - Product types (Limited DR, Extended Summer, and Annual) for RPM Auctions in Sections 4.1, 4.5, 4.6.2, 4.6.7, 4.6.8, 4.8.3, 5.5, 8.2.2, and 8.9
    - Out-dated qualification requirements for generation resource prior to 2019/2020 Delivery Year in Section 4.2.3
    - Legacy Direct Load Control Programs in Section 4.3.1
    - Credit-Limited Offers in Section 4.8.4
    - Coupled Sell Offers in Section 5.4

- Peak Season Maintenance Compliance in Sections 8.1, 8.6, 9.1.6, 9.1.8 and 11.8.5
- Load Management Event Compliance in Sections 8.1, 8.7, 9.1.9 and 11.8.6
- Non-Performance Assessment provisions for 2016/2017 – 2017/2018 Delivery Years in Sections 8.4A, 9.1.4 and 9.1.11

- Conforming Revisions for FERC Orders
  - OVEC Integration (ER18-459, ER18-460) in Section 2.3.1
  - Periodic Review of Variable Requirement Curve Shape and Key Parameters (Quadrennial Review) (ER19-105-001,002) in Sections 3.3 and 3.4
  - Energy Efficiency Resources Compliance with Authorized Relevant Electric Retail Regulatory Authority (RERRA) Rules to Opt-Out or Restrict Sales of EE Resources (ER18-870) in Sections 3.5, 4.4 and 5.9
  - Minimum Offer Price Rule Remand (ER13-535-005, 006) in Sections 5.2 and 5.4.5
  - FERC Order 841: Electric Storage Participation (ER19-462) in Section 5.4.1

Revision 41 (01/01/2019):

- Revisions for FERC Order ER19-244, accepted on December 31, 2018 and effective January 1, 2019, to amend Demand Resource registration rules and define a summer period and winter period nominated value for a Capacity Performance registration and to change the methodology used to determine the daily nominated capacity values for Capacity Performance Demand Resources.
- Revisions for FERC Order ER19-142, accepted on December 17, 2018 and effective December 17, 2018, to modify the definition of Winter Peak Load to exclude atypically low usage winter peak days from the calculation of Winter Peak Load.

Revision 40 (02/22/2018):

- Conforming revisions for FERC Order ER17-1138, accepted on November 17, 2017 and effective May 9, 2017 to implement enhancements to the rules for external capacity resources.

Revision 39 (12/22/2017)

- Revisions to Sections 4.3 (4.3.1, 4.3.5, & 4.3.10), 4.6 (4.6.6), 4.9, 4.10, 8.4, 8.4A, 8.7A, 8.8, 8.9, 9.1 (9.1.3, 9.1.4, 9.1.5, & 9.1.11), 11.3, and 11.8 (11.8.8 &11.8.9) to accommodate sub-hourly settlements (FERC Order 825).

Revision 38 (07/27/2017)

- Revisions to Section 8.4A to describe that if energy offer does not comply with Manual 11, Section 2.3.7, then no MWs from generation resource will be exempt or considered for bonus performance during the Performance Assessment Hour.

Revision 37 (4/27/2017)

- Conforming revisions for FERC Order ER17-367 issued on March 21, 2017, to enhance aggregation rules, implement Seasonal Capacity Performance Resources, provide opportunity for Intermittent and Environmentally Limited Resources to request additional Capacity Interconnection Rights in winter, and modify measurement and verification rules for Demand Resources.

Revision 36 (12/22/2016)

- Revisions to include restrictions on early replacement of RPM capacity commitments as endorsed by MRC on 12/22/2016 (Section 8.9)

Revision 35 (11/17/2016)

- Revisions to remove the restrictions on early replacement of RPM capacity commitments as endorsed by MRC on 11/17/2016 (Section 8.9).

Revision 34 (07/28/2016)

- Revisions to clarifying the details of Auction Specific MW bilateral transactions (Section 4.6.6)

Revision 33 (06/30/2016)

- Revisions needed as a result of a Cover to Cover Periodic Review
- Revisions needed to clarify the implementation details of Capacity Performance

Revision 32 (04/01/2016)

- Conforming revisions for FERC Order ER16-873-000, accepted on 4/1/2016 and effective 4/1/2016 to eliminate the RRMSE requirement for Load Management registrations that will use a customer baseline to measure capacity compliance in non-summer periods.

Revision 31 (02/25/2016)

- Conforming revisions for FERC Order ER16-333, accepted on 12/22/2015 and effective 01/16/2016 to change (1) instances in which FRR Entities would not be required to meet the Percentage of Internal Resource Requirement, (2) circumstances in which an FRR Entity can terminate its five-year minimum commitment period, and (3) the FRR Alternative election dates for new FRR Entities (Sections 11.1.3 & 11.6).

Revision 30 (12/17/2015)

- Revisions to accommodate EE Resource participation in the PJM capacity market when the peak load forecast reflects energy efficiency measures (sections 2.4.5, 4.4, 8.7 & 11.2.1).

Revision 29 (10/16/2015)

- Revisions to Section 8.7, endorsed at the July 23, 2015 MRC meeting, to add provisions for replacement capacity transactions earlier than November 30th prior to start of Delivery Year when the owner of the replaced resource provides transparent and verifiable evidence to support the expected final physical position of resource at the time of the request.

Revision 28 (08/03/2015)

- 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 ER15-1849, accepted on 7/23/15 and effective 8/3/15, to improve measurement and verification procedures for CSPs with Residential Demand Response Customers. Direct Load Control is re-defined as Legacy Direct Load Control and is only effective through May 31, 2016. Statistical sampling may be used instead of customer-specific compliance and verification information for residential customers without interval metering.

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)

Revision17 (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 4/13/2011and effective 04/20/2011, to allow Credit-Limited Offers in RPM Auctions for planned resources (whether generation, demand resources, or energy efficiency) (Section 4.8.4).
- Conforming Revisions for FERC Order ER11-4143, accepted on 09/12/2011 and effective 06/01/2007, to correct time periods for critical peak periods for the assessment of Peak Hour Period Availability from eastern prevailing time (EPT) to local prevailing time (LPT) (Section 8.4).
- Conforming Revisions for FERC Order ER09-412, accepted on 03/26/2009, and effective 06/01/2009 to allow excess available capacity that satisfies all capacity resource

obligations of a committed resource to serve as replacement capacity to offset potential peak hour period availability penalties. (Sections 8.4.5 and 8.4.5.1)

- Conforming Revisions for FERC Order ER10-2917, accepted on 10/29/2010, and effective 11/23/2010 to further clarify that PJM considers committed capacity first in determining net peak hour period capacity shortfalls in an LDA and then considers uncommitted, available capacity to adjust the net peak hour period capacity shortfall in an LDA only to extent necessary to mitigate or eliminate any availability shortfalls for committed capacity (Sections 8.4.5 and 8.4.5.1).
- Conforming Revisions for FERC Order ER12-271, accepted on 12/27/2011 and effective 12/30/2011, to modify the bill timing of the Demand Resource and ILR Compliance Penalty Charge such that charges are assessed and billed in two phases. (Section 9.1.9)
- Conforming Revisions needed to clarify Fixed Resource Requirement Alternative business rules in Section 11.3 and conform to Schedule 8.1 of the Reliability Assurance Agreement.
- Conforming Revisions for FERC Order ER11-2875 regarding MOPR (Section 5.3.5)

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.