UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER24-___-000**

Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy

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October 13, 2023

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER24-___-000
Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, hereby submits key reforms to the Reliability Pricing Model ("RPM") and related rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA") designed to enhance PJM's resource adequacy risk modeling and capacity accreditation processes and enhance testing requirements of Capacity Resources.[1] Adoption of this proposal will significantly improve the market signals conveyed by the capacity market by better aligning the market representation of capacity supply and demand with expected resource performance and system resource adequacy risks. These changes will also better balance demonstrated resource performance with financial incentives by increasing testing requirements and improve investability by removing extreme tail risk for Capacity Market Sellers via a reduction in the annual stop-loss limit. Finally, within these reforms are

[1] For the purpose of this filing, capitalized terms not defined herein shall have the meaning as contained in the Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), or the RAA.

beneficial changes to the Fixed Resource Requirement ("FRR") alternative that allow time for transition to accommodate the modeling and accreditation changes, but also align incentives for FRR Entities to procure the required amount of capacity with the incentives to avoid a capacity shortfall in the rest of the PJM Region. These reforms are a critical but certainly not final step in maintaining resource adequacy in the PJM region given a changing resource mix and increased customer demands for reliable energy supplies to meet an increasingly digital economy.

PJM requests that the enclosed revisions become effective on December 12, 2023, which is 60 days after the date of this filing. Such an effective date will provide sufficient notice to Market Participants in advance of all pre-auction deadlines for the Base Residual Auction associated with the 2025/2026 Delivery Year.[2]

The capacity market reforms PJM proposes in this FPA section 205 filing complement the reforms PJM is proposing in a companion FPA section 205 filing, in Docket No. ER24-98-000. Those reforms update the rules for (1) the Market Seller Offer Cap, (2) Capacity Performance; and (3) application of a forward-looking approach for determination of the energy and ancillary services revenue in the determination of Minimum Offer Price Rule offer prices and the Market Seller Offer Cap. PJM's proposed revisions in this proceeding are just and reasonable on a standalone basis, as explained and supported by this transmittal and the attached affidavits, and PJM's proposed revisions in Docket No. ER24-98-000 are also just and reasonable on a standalone basis, for the reasons

[2] *See RPM Auction Schedule*, PJM Interconnection, L.L.C. (Sept. 25, 2023), https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.

stated in PJM's transmittal and affidavits filed in that proceeding. However, acceptance of the combined revisions of the two section 205 filings is preferable and would provide a just and reasonable capacity construct for the PJM Region.

Thus, PJM urges that the Commission accept both sets of filings concurrently within the requested timeframe so that the reforms set forth in this filing align with the changes proposed in PJM's concurrent filing on risk modeling and accreditation. Such acceptance will allow the synergies between the filings to be realized, e.g., compensation for risk and bonus eligibility with the new testing requirements and accreditation rules that will apply to Capacity Resources that are committed in the capacity market. In addition, acceptance of both files concurrently and without delay will allow these enhancements to be implemented with the upcoming Base Residual Auction associated with the 2025/2026 Delivery Year. Delaying acceptance of either one of these proposals beyond the requested 60-day timeframe would shorten the amount of time that Market Participants, PJM, and the Independent Market Monitor for PJM ("Market Monitor") have to prepare for the next Base Residual Auction and likely require PJM to (1) initiate the pre-auction activities on a parallel path (one under the existing rules and another under the proposed rules) or (2) proceed with the upcoming Base Residual Auction without the proposed enhancements that are the subject of a delayed Commission order.

Because neither is an optimal outcome and in light of limitations the Commission may otherwise face under the *NRG* precedent if these were combined into a single filing,[3] PJM is submitting these complementary, but independent, proposals in separate section

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[3] *See NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017).

205 filings. In this way, should the Commission deem that additional information is necessary in one of these proceedings, it does not need to delay acceptance of the other enhancements in the separate filing. Regardless, PJM particularly urges timely Commission action on this filing as the accreditation and risk modeling changes take more time to implement (due, for example, to software and data gathering issues), and given that the Base Residual Auction associated with the 2025/2026 Delivery Year is scheduled to commence in June 1, 2024,[4] with many associated pre-auction deadlines upcoming in mid-January, 2024,[5] time is more of the essence for this filing.

I. INTRODUCTION

PJM's capacity market is designed to meet near-term and long-term objectives simultaneously: (1) procuring sufficient capacity in the near-term through a competitive auction process to maintain resource adequacy—and thus reliability; and (2) in combination with the other wholesale markets, contributing to efficient entry and exit so that the PJM Region has sufficient capacity resources in service to maintain resource adequacy over the long-term at reasonable cost.[6] The need for enhancements to the capacity market are primarily driven by the evolution in the resource mix that has already started and is expected to continue throughout the energy transition, and empirical observations of resource adequacy risk in PJM and other regions occurring during non-

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[4] Tariff, Attachment DD, section 5.4(a).

[5] *See RPM Auction Schedule*, PJM Interconnection, L.L.C. (Sept. 25, 2023), https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.

[6] *See* Attachment C, Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. ¶ 13, Figure 2 ("Keech Aff."); Attachment D, Affidavit of Dr. Walter Graf on Behalf of PJM Interconnection, L.L.C. ¶ 5 ("Graf Aff.").

peak load periods that point to a need to adopt more sophisticated tools to model the various factors influencing resource adequacy risks including extreme weather and correlated outages of generation resources.

A. Changes in Resource Mix Affect When Load Shed Risk Occurs, Both in Time of Day and Time of Year.

PJM aims to facilitate the energy transition while simultaneously fulfilling PJM's obligation to maintain resource adequacy in a cost-effective manner. Historically, the PJM Region has been able to maintain resource adequacy largely by using the traditional practices of setting target procurement levels at the peak load plus a reserve margin and using Equivalent Demand Forced Outage Rate ("EFORd") as a metric to accredit generation resources. Using these practices, the PJM Region has operated with capacity beyond its Installed Reserve Margin ("IRM") and has been able to avoid shedding load due to a capacity emergency for the last several decades. However, as with many other regions pursuing similar reforms, the PJM resource mix has changed considerably over the past ten years and will continue to change in the future.[7] The resources coming online have different operating characteristics and vulnerabilities than those they are replacing. Additionally, recent operating experiences, particularly in the winter periods, such as Winter Storm Elliott, have demonstrated that current modeling approaches focused on peak load conditions and average performance do not fully capture all of the risks that impact resource adequacy needs and resource performance. As such, without enhancements in

[7] *See Energy in Transition in PJM: Resource Retirements, Replacements and Risks*, PJM Interconnection, L.L.C. (Feb. 24, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx ("Resource Retirements, Replacements & Risks Report").

these areas, the capacity market will provide insufficient incentives to retain and attract sufficient Capacity Resources necessary to maintain reliability.

Over the last decade, PJM has experienced a significant increase in the amount of natural gas-fired resources. In fact, in 2022, natural gas-fired resources provided over 40% of the energy consumed in PJM.[8] Many of these resources are extremely flexible and provide much needed ancillary services in PJM as well. Looking into the future, approximately half of the over 230,000 megawatts ("MWs") in PJM's interconnection queue are standalone solar and wind resources; while storage and hybrid (e.g., solar or wind resources in combination with on-site energy storage) resources comprise approximately 47% of the queue.[9] In total, standalone renewable or hybrid resources make-up 97% of the 230,000 MW currently in the PJM interconnection queue.[10]

Additionally, PJM's February 2023 paper, *Energy in Transition in PJM: Resource Retirements, Replacements and Risks*,[11] shows that a significant amount of existing generation is at risk of retiring.[12] Retirements of these resources would further reduce the megawatts available from resources that have long since been relied on for reliability and the types of resource operating characteristics (fuel supply is always available, the resource is able to be committed/de-committed by the system operator, dispatchable, etc.) that have

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[8] Keech Aff. ¶ 11, Figure 2 (providing breakdown of 2022 PJM fuel mix).

[9] *See* Keech Aff. ¶ 10.

[10] *See* Keech Aff. ¶ 10.

[11] *Energy in Transition in PJM: Resource Retirements, Replacements and Risks*, PJM Interconnection, L.L.C. (Feb. 24, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx ("Resource Retirements, Replacements & Risks Report").

[12] *Id.* at 5-10.

driven the assumptions and modeling techniques the industry has used for decades to define resource adequacy. The Independent Market Monitor's *2022 State of the Market Report for PJM* analysis also identifies the risk of retirement of these resources, noting that coal and gas peaker units primarily comprise the megawatts at risk.[13] The inevitable replacement of these traditional resources with ones that have markedly different performance characteristics, output profiles, and vulnerabilities, plus empirical observations of winter reliability risk not captured in the current paradigm, necessitate a review of resource adequacy risk modeling and accreditation approaches.

The changes in resource mix also pose emerging challenges to PJM's ability to maintain reliability. The expected increase in reliance on intermittent renewables resources presents new challenges that must be addressed in order to maintain resource adequacy. As these resources replace retiring ones, maintaining adequate output throughout the day becomes an operating challenge for PJM—a challenge generally not present under the historical resource mix—because renewable resources' availability and ability to provide energy may not align with forecasted quantities or periods of system stress. These resources can only generate at their maximum capability as weather permits and those times may not necessarily coincide with when the system operator needs them most. This phenomenon on its own is a driver of resource adequacy risk that must be accounted for and modeled.

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[13] *2022 State of the Market Report for PJM*, Monitoring Analytics, LLC, 2 (Mar. 9, 2023), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec7.pdf.

Regarding natural gas resources, many of these resources are extremely flexible and provide a significant amount of the energy and grid services PJM needs to maintain reliability; however, those that do not have on-site secondary fuel sources may be exposed to a common-mode failure created by the upstream natural gas production and transportation system.[14] As examples, this common-mode failure negatively affected their performance during the 2014 Polar Vortex[15] and Winter Storm Elliott in 2023.[16] Such correlated outages must be considered in risk modeling and accreditation in order to properly anticipate the performance of these resources, particularly during the winter, and to understand how the common-mode failures can drive resource adequacy risks. Common-mode failures of natural gas resources driven by failures of the natural gas production and transportation system are just one example of correlated outage risks. In recent years, PJM resources have demonstrated outage correlation with weather more generally. More specifically, cold weather has been demonstrated to be a significant driver of resource adequacy risk. PJM's proposed enhancements to risk modeling and resource accreditation, as described by Dr. Rocha-Garrido, would allow PJM to capture the correlation of forced outages with weather in addition to other effects after controlling for

[14] *See* Keech Aff. ¶ 11.

[15] *See Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, PJM Interconnection, L.L.C., at 39 (May 8, 2014), https://www.hydro.org/wp-content/uploads/2017/08/PJM-January-2014-report.pdf.

[16] *Winter Storm Elliott Event Analysis and Recommendation Report*, PJM Interconnection, L.L.C. (July 17, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

weather, and thus allow for more accurate identification of risk and more accurate determination of resources' capacity capability.[17]

The changing resource mix presents new issues to maintaining resource adequacy. For example, it is well understood that the rise of renewable generation will shift the hours of risk on the system. An observed example of this are the rotating customer interruptions experienced in California in the summer of 2020. In the report[18] analyzing the root causes of the event, the California Independent System Operator Corp. ("CAISO") summarizes the second key driver of the rotating customer interruptions:

> In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.
>
> The rotating outages both occurred after the period of gross peak demand, during the "net demand peak," which is the peak of demand net of solar and wind generation resources. With today's new resource mix, behind-the-meter and front-of-meter (utility-scale) solar generation declines in the late afternoon at a faster rate than demand decreases. This is because air conditioning and other load previously being served by solar comes back on the bulk electric system. These changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability, and this challenge is amplified during an extreme heat wave.[19]

For the CAISO, the simultaneous (correlated) reduction in the output of these resources combined with relatively high load levels created resource adequacy risk. CAISO

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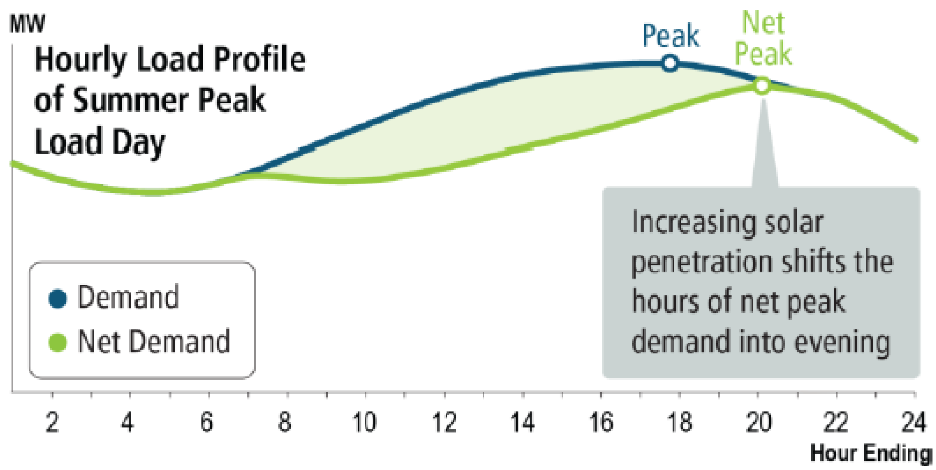
[17] Attachment E, Affidavit of Dr. Patricio Rocha-Garrido on Behalf of PJM Interconnection, L.L.C. ¶ 27(a) ("Rocha-Garrido Aff.").

[18] *Root Cause Analysis Mid-August 2020 Extreme Heat Wave*, California Independent System Operator Corp. (Jan. 13, 2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[19] *Id.* at 4.

identified this shifting of risk from gross-peak demand to net-peak demand as a key contributor of the rotating customer interruptions experienced in in August 2020. Figure 1 below provides an illustration of this shift in load shed risk.

Figure 1: Illustrative Impact of Solar on Net Peak Demand



Adapting risk modeling and capacity accreditation to consider this shift in resource adequacy risk allows transmission providers to plan for such correlated unavailability.

Traditionally, PJM's resource adequacy studies have identified PJM's resource adequacy risk to be concentrated in the summer season. However, an examination of PJM's experiences during the 2014 Polar Vortex and Winter Storm Elliott demonstrate that PJM has significant risk outside the summer season. Recognition that more risk occurs outside the summer peaking season than has historically occurred requires PJM to adopt new risk modeling methods and new approaches to such modeling.

While future changes driven by the energy transition including increases in renewable penetration and electrification of load present compelling reasons to make the changes to resource adequacy risk modeling and accreditation in preparation for the future, Winter Storm Elliott has demonstrated that the current methods for identifying resource adequacy risks and accrediting resources are insufficient today. The need to make a step change in the sophistication of these processes is present, with recognition that there will be further refinements to these approaches in the near future

B. Recent Experience and Analyses Show the Need to Enhance PJM's Risk and Accreditation Modeling.

The thrust of this filing is to refine and improve PJM's risk modeling framework to improve PJM's understanding of when and how risk occurs, and to change how both supply and demand are accounted for in the RPM construct to better align their market representation with the resource adequacy fundamentals. PJM's recent analyses, its experience with Winter Storm Elliott, and similar experiences of other independent system operators ("ISO")/regional transmission organizations ("RTOs") with shifting risk drivers and patterns, have identified needed enhancements to PJM's risk modeling to properly assess correlated outages and risks. The enhancements proposed herein adopt a more temporally granular, hourly framework for assessing risk drivers and probabilities of resource and energy inadequacy throughout the year rather than only during periods associated with peak loads, as under PJM's current approach. This proposed framework also better incorporates the magnitude and duration of such events rather than just the frequency of their occurrence.

Resource adequacy requires more than a simple comparison of available megawatts peak demand plus reserves. The historical resource adequacy paradigm focused on planning for the system peaks given the concentration of risks at that time.[20] Dr. Graf

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[20] *See* Graf Aff. ¶ 18.

explains that "[w]ith the implementation of effective ELCC for certain resources, PJM started down a path of more fully recognizing resources' differential contributions to reliability over time and across scenarios."[21] The new resource adequacy paradigm PJM proposes in this filing will allow PJM to "identify[] the least-cost, efficient portfolio of resources that—in aggregate—is expected to provide resource and energy adequacy in every hour of the year, across all potentially anticipatable scenarios, up to the target reliability metric."[22]

To do so, PJM proposes to model resource adequacy risk in all hours of the year under the system supply and demand conditions consistent with meeting the 1-day-in-10-years Loss of Load Expectation ("LOLE") target. Under the proposed process, PJM will calibrate the risk analysis to establish the target reliability level using the current 1-day-in-10-years LOLE standard for the RTO. PJM will then calculate the expected unserved energy ("EUE") level corresponding to the 1-day-in-10-years LOLE (approximately 1,100 MWh/year RTO-wide based on preliminary estimates).[23] PJM will use the RTO EUE level to accredit Capacity Resources consistent with their marginal impact on system-wide EUE, or more directly, how they reduce expected megawatts of load shed in the reliability analysis on the margin. In sum, PJM proposes to calibrate annually the target reliability metric in EUE terms to maintain the same target level of reliability as under the current LOLE metric, and will accredit Capacity Resources based on their marginal impact on the

[21] Graf Aff. ¶ 18.

[22] Graf Aff. ¶ 18.

[23] *See* Rocha-Garrido Aff. ¶ 44.

system-wide EUE. This process, as further described in the affidavits of Dr. Rocha-Garrido and Dr. Graf, aligns the accredited level of capacity with the expected performance of the resources during periods of resource adequacy risk.

C. PJM's Analyses Concluded that Reforms Will Improve PJM's Ability to Maintain Resource Adequacy.

PJM's paper, "Energy in Transition: Resource Retirements, Replacements and Risks," explores a range of plausible scenarios, "focus[ing] on resource adequacy in the near term through 2030," looking at the composition of the resource mix, particularly the balance between different resource types, as informed by resource retirements, resource new entry, and demand growth.[24] There, PJM identified four trends that, even under a low new entry by renewable resources scenario, "in combination, present increasing reliability risks during the transition, due to a potential timing mismatch between resource retirements, load growth and the pace of new generation entry."[25]

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region.
- Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these

[24] Resource Retirements, Replacements & Risks Report at 1.

[25] Resource Retirements, Replacements & Risks Report at 1.

> resources, we need multiple megawatts of these resources to replace 1 MW of thermal generation.[26]

PJM found that it "could face decreasing reserve margins should these trends continue."[27] To avoid such a circumstance, PJM concluded that it could mitigate the adverse resource adequacy effects from "the potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry" by "enhanc[ing] the accreditation, qualification and performance requirements of capacity resources."[28] PJM seeks to advance this goal through the market rule changes proposed in this filing.

D. Observed Changes in Resource Mix and Risk Patterns, Plus Expected Further Evolution of the Resource Mix, Support Acceptance of the Proposed Capacity Reforms.

The reforms to PJM's capacity rules proposed in this filing, and the companion filing are just and reasonable, as they address known and reasonably foreseeable challenges to maintaining resource adequacy at reasonable cost. While PJM and its stakeholders began examining many of these reforms starting in October 2021 in the Resource Adequacy Senior Task Force, Winter Storm Elliott in December 2022 increased the urgency for their adoption. In particular, Winter Storm Elliott highlighted the need to enhance resource adequacy risk modeling and accreditation approaches, and also demonstrated the value of winterization and a robust operational testing regime.[29] Further, Winter Storm Elliott highlighted that the limitations of the current processes for resource

[26] Resource Retirements, Replacements & Risks Report at 1.

[27] Resource Retirements, Replacements & Risks Report at 3.

[28] Resource Retirements, Replacements & Risks Report at 3.

[29] *Winter Storm Elliott Event Analysis and Recommendation Report*, PJM Interconnection, L.L.C. (July 17, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

adequacy risk modeling and accreditation can have reliability implications today, not just in a future system with higher renewable penetration or different patterns of risk. PJM's multi-year, multi-phase study of the resource adequacy challenges facing PJM now and in the future also show how the energy transition and evolving resource mix requires PJM to change its historical approaches to evaluating resource adequacy risk and accreditation.

The package of reforms in this filing and the companion filing present a substantial step forward in improving the status quo, helping PJM to maintain resource adequacy over the near- and long-terms. PJM and its stakeholders are committed to continuing to assess the design of PJM's capacity construct, including whether and how a seasonal capacity construct could help support reliability and efficiency for the PJM Region. But such ongoing process does not undermine the reasonableness of these near-term achievable reforms, which PJM proposes in this filing and the companion filing under FPA section 205.

E. PJM and Its Stakeholders Have Been Evaluating These and Other Capacity Market Reforms Over the Past Two Years.

Recognizing the need for reform to PJM's capacity rules, in October 2021, PJM and its stakeholders established the Resource Adequacy Senior Task Force ("RASTF"), and began examining a number of issues presented in this filing and the companion filing. The RASTF held 30 meetings between October 2021 and March 2023. Complementing the RASTF, PJM undertook a parallel review of near- and long-term resource adequacy challenges, and published four papers, as discussed above.

In February 2023, the PJM Board of Directors ("Board") initiated a Critical Issue Fast Path ("CIFP") accelerated stakeholder process to focus stakeholder efforts on enhancements in specific areas and also set a deadline for work to be completed. The Board recognized that "[w]hile PJM currently has a healthy reserve margin, Winter Storm Elliott demonstrated that PJM is not immune to reliability challenges as the system was stressed, even with a reserve margin in excess of the target and a lower level of renewable penetration than other regions."[30] The Board also appreciated that "the healthy reserve margins [the PJM Region] enjoy[s] now cannot be taken for granted into the future," and directed PJM and its stakeholders to identify "near-term changes to the Reliability Pricing Model (RPM) [] necessary to ensure that PJM can maintain resource adequacy into the future."[31]

On August 23, 2023, at the final meeting of the CIFP, PJM, Monitoring Analytics (the Independent Market Monitor for PJM), and numerous stakeholders presented and discussed proposals in a meeting with members of the Board. Over the next month, the Board deliberated and determined that the reforms proposed in this filing would provide near-term changes to PJM's capacity construct to maintain resource adequacy at reasonable costs during the energy transition.

On September 27, 2023, the Board directed PJM to file a suite of capacity market reforms to, among other things: enhance resource adequacy risk modeling; improve resource accreditation to apply a marginal effective load carrying capability ("ELCC") approach to all Generation Capacity Resources and Demand Resources; update financial

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[30] Letter from Mark Takahashi, Chair, PJM Board of Managers, to PJM Interconnection, L.L.C. Stakeholders (Feb. 24, 2023) (https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230224-board-letter-re-initiation-of-the-critical-issue-fast-path-process-to-address-resource-adequacy-issues.ashx).

[31] *Id.*

performance incentives consistent with the effects of the proposed market reforms; and better align the capacity market with the FRR alternative.[32] The Board also expressed support for continued evolution of the capacity market, "including a more granular approach to the market" such as a seasonal market construct, as it continues to "focus on evolving our markets to meet the energy transition." PJM and stakeholders discussed sub-annual market design approaches but ultimately the Board, pursuant to stakeholder feedback, elected to allow more time for discussion on the design and implementation of such an approach.

On October 5, 2023, PJM reviewed draft revisions to the Tariff and RAA to implement the reforms proposed in this section 205 filing and the companion section 205 filing. Over the course of five months, PJM and its stakeholder held 16 CIFP stakeholder meetings in which various capacity market reforms were discussed and analyzed to achieve this goal. In total, PJM has held 47 stakeholder meetings since October 2021, about two meetings per month, to pursue necessary reforms to the capacity market.

II. RESOURCE ADEQUACY MODELING AND ACCREDITATION ARE APPROPRIATE IN THE FACE OF SHIFTS IN RISK OCCURRENCE

The expansion of resource adequacy risk beyond the historic assumption of summer peak periods compels PJM to alter its approach for risk modeling and resource accreditation so that PJM can procure resources on which it can rely to perform during all identified periods of risk. As explained below, the changes PJM is proposing to these two

[32] Letter from Mark Takahashi, Chair, PJM Board of Managers, to PJM Interconnection, L.L.C. Stakeholders (Sept. 27, 2023) (https://pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230927-pjm-board-letter-re-its-decision-within-the-cifp-ra.ashx).

components are highly interrelated given that PJM plans to use the same model to perform its resource adequacy risk analysis and determine the accredited capacity levels of each Generation Capacity Resource and Demand Resource using marginal ELCC. Use of the same model is critical to incorporating the changing patterns and drivers of resource adequacy risk into the approach used for capacity accreditation. PJM's proposed "changes will more robustly determine periods of resource adequacy risk and more accurately estimate resource performance during those risk periods."[33]

A. Updating the ELCC Accreditation Approach to Measure Marginal Reliability Value for All Generation Capacity Resources and Demand Resources.

1. In General, ELCC Is a Probabilistic Approach to Accrediting Capacity Capability that Analyzes the Performance Characteristics of Each Resource and Evaluates it Over a Range of Possible Scenarios in Each Hour of the Delivery Year.

To accredit the capacity capability for certain Capacity Resources, PJM currently employs an ELCC methodology, which, as a general matter, is a technology-neutral probabilistic approach to simulate loss-of-load probability across scenarios designed to determine resources' effective contribution to resource adequacy.[34] Using probabilistic modeling, the ELCC analysis evaluates a resource's contribution to system reliability; the analysis distinguishes among generators with differing levels of reliability, size, and hourly output profiles to determine an ELCC rating for a given resource or a class of resources (an "ELCC Class Rating"). Resources that are able to consistently produce energy during

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[33] Keech Aff. ¶ 13.

[34] L.L. Garver, *Effective Load Carrying Capability of Generating Units*, IEEE Transactions on Power Apparatus and Systems, vol.PAS-85, issue no.8, Aug. 1966, at 910-919.

hours with load shed risk have a higher ELCC rating than resources less able to do so. Under the ELCC construct, the applicable capacity value is sensitive to resource deployment levels and to load shapes, and so the analysis and accreditation is updated annually. As such, the ELCC analysis acts as a reliability backstop, preventing the PJM Region from over-relying on resources that do not perform consistently during periods of risk at the expense of system reliability.

The ELCC methodology recognizes and accounts for the unique characteristics of diverse resource types. It compares the expected hourly output of a resource (or resource class) against expected hourly load for all hours of a planned year. It captures variations in hourly variable resource availability, any correlation in hourly output with load patterns, seasonal variations, and the limited duration characteristic associated with the dispatchability of the storage component. PJM's ELCC methodology accounts for this interrelationship between the output of different resources within distinct categories, resources outside of those categories, and load.[35]

Because ELCC recognizes the potential diminishing returns associated with greater levels of deployment for most of the ELCC Resource types (as explained below), it will help prevent the PJM Region from becoming over-dependent on any single resource type with inherent limitations, which could contribute to inadequate system reliability. As future installments of these resource types observe the diminishing returns in reliability contribution (and their ability to earn capacity revenues decreases), market forces could induce technological advancements that offset or actually increase their reliability

[35] *See* Rocha-Garrido Aff. ¶ 27.

contribution. At the same time, ELCC recognizes the synergistic relationship among distinct resource types, thus potentially facilitating greater provision of reliability from the various resource classes pooled together across the PJM Region than what those same classes could provide in isolation. ELCC also evolves with a changing load shape, which may be a feature of a future grid that could see greater electrification of heating and transportation.

The capacity capability determined through the ELCC approach, i.e., a resource's "Accredited UCAP," is not solely a function of the resource's installed capacity and performance during historical time periods without consideration of resource adequacy risk patterns during such time periods (e.g., MW * [1 – EFORd], which has long been used for traditional thermal resources). Rather, in general, Accredited UCAP is the product of (1) the maximum physical output capability of the resource, (2) the output of the ELCC analysis (by way of the class rating), and, as applicable, (3) the resource's performance relative to other members of the ELCC Resource's class. In short, a resource's Accredited UCAP reflects the resource's *expected* performance during hours of resource adequacy risk.

PJM currently uses an "average" ELCC analysis, under which PJM estimates the amount of load that, on average, each resource can serve when the system is stressed (or, stated another way, how many megawatts of capacity the resource can be expected to provide), while also considering load uncertainty and the probabilistic nature of generation shortfalls and random forced outages as driving factors of those stressed system conditions. PJM applies the "average" ELCC approach to accredit the capacity capability of three types of non-traditional resources: (1) Variable Resources (e.g., Intermittent Resources, such as wind and solar power); (2) Limited Duration Resources (e.g., battery storage resources); and (3) Combination Resources (e.g., resources with a wind or solar component and a storage component).

In this filing, PJM proposes to (1) switch to a "marginal" ELCC approach that will better tailor the determination of Accredited UCAP values to each resource's marginal contribution to maintaining reliability when the system is most stressed; and (2) expand application of the new marginal ELCC approach to include all Generation Capacity Resources and Demand Resources. Determining Unforced Capacity values (which are the bases of Sell Offers in RPM and FRR plan commitments) through ELCC will best align the expected performance of Generation Capacity Resources and Demand Resources during periods of resource adequacy risk with accredited capacity levels. Such alignment will result in more reliable clearing results from the capacity market as Dr. Graf demonstrates in his affidavit[36] and more efficient price signals that promote resource adequacy at the lowest reasonable cost.

The only Capacity Resource type for which ELCC will not apply is Energy Efficiency Resources. PJM proposes to exclude Energy Efficiency Resources from the ELCC approach and continue assessing their value under the existing approach that is based on post-installation and measurement and verification reporting (which estimate the impact of energy efficiency measures on peak loads). Dr. Graf explains that, "[b]ecause the impact of energy efficiency is largely already included in the PJM load forecast models, it would be inappropriate to include such resources" again directly in the ELCC analysis,

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[36] *See* Graf Aff. ¶ 50.

which considers the PJM load forecast to in accrediting capacity value.[37] Indeed, including Energy Efficiency Resources in the ELCC model would double-count their energy efficiency impact, improperly affect modeled system risk patterns in a counterfactual manner, mislead PJM's assessment of risk patterns, and distort the assessed capacity value of all other modeled resources.[38] In short, Energy Efficiency Resources are tied directly to the load forecast, rather than serving as a dispatchable resource in real time, and as such their capacity contributions are already appropriately considered on the load side through reductions in the load forecast. This distinguishes them from other Capacity Resource types, including Demand Resources, which participate in the markets and provide load reductions in real-time.[39]

2. Switching to a Marginal ELCC Approach Will Better Identify the Reliability Contribution of Each Resource Is Capable of Providing and Is Consistent with Recent Commission Precedent.

PJM's proposed marginal ELCC construct would provide PJM a more accurate understanding of the reliability contribution of each resource on its system and can appropriately plan resource adequacy to sustain the 1-in-10-year loss of load expectation (i.e., 0.1 LOLE) standard. As with the current model, the marginal ELCC model will provide outcomes that are consistent with PJM's reliability target of 0.1 LOLE. However, marginal ELCC, estimated in terms of EUE benefit to the system, will better tailor the

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[37] Graf Aff. ¶ 22.

[38] *See* Graf Aff. ¶ 22.

[39] PJM likewise is not proposing to use the ELCC approach with respect to Price Responsive Demand. Price Responsive Demand is not a supply-side capacity product offered into the market. Further, Price Responsive Demand does not "clear" the market or receive the market clearing price. Price Responsive Demand is compensated through reductions in the applicable load-serving entity's capacity obligation. *See* RAA, Schedule 6.1.

Unforced Capacity quantities each such resource may offer to commit to provide as capacity in PJM (either RPM or FRR) with each resource's marginal contribution to maintaining the system's resource adequacy and reliability.

In a "marginal" accreditation framework, resources are accredited based on their marginal contribution to system resource adequacy given an anticipated resource mix and a number of scenarios across which resource performance is analyzed. Dr. Rocha-Garrido explains that a "marginal ELCC approach will be reflective exclusively of the output of the resources in hours of system risk identified after adding the last resource [of a studied ELCC Class] to the expected system portfolio."[40] He continues that, thus, "the marginal ELCC approach will better identify which resource types will provide more reliability benefit, relative to additional MW increment from another resource class, and thus which resource type in which sellers should invest, *given the expected resource mix in the system*."[41]

The marginal framework does not generally credit a *portfolio* of resources for its total contribution to resource adequacy—that is PJM's current average approach. Rather, the marginal ELCC accredited values of resources will reflect the incremental resource adequacy benefit of adding an individual resource to the expected system portfolio. If the expected performance of such resource is to a large or small degree correlated with expected hours of resource adequacy risk in the system, the marginal reliability contribution will be less than the average reliability contribution. In particular, holding all

[40] Rocha-Garrido Aff. ¶ 9.

[41] Rocha-Garrido Aff. ¶ 9.

else equal in the resource mix, increasing buildout of one class in which the class members have unavailability patterns that are correlated will decrease the marginal reliability value within that class because the unavailability patterns are likely to add resource adequacy risk to the system.

Generally speaking, a marginal ELCC framework can use the ELCC analysis to develop an economically efficient signal to the market for entry and exit of Capacity Resources. Mr. Keech explains that PJM's marginal ELCC approach will "send[] investment signals that are consistent with the marginal reliability benefit of a resource resulting in strong incentives to invest in resources that directly improve resource adequacy (measured as a reduction in EUE)."[42] Indeed, a marginal approach to capacity accreditation should encourage resource owners to invest in "resources that offer the greatest reliability per dollar" and investors will "steer[] away from resources that are more costly for the incremental reliability they provide."[43] Thus, resources with lower reliability value relative to net costs will be signaled, through lower accreditation, to retire.[44] The Commission likewise has found that a "marginal capacity accreditation approach will send a more accurate investment signal to market participants about the reliability value of various resource types in each Capability Year as compared to the average accreditation approach," like PJM's current ELCC approach.[45] Thus, a marginal ELCC-influenced price "signal

[42] Keech Aff. ¶ 19.

[43] Graf. Aff. ¶ 26.

[44] Graff Aff. ¶ 26 ("Moreover, it signals the retirement less efficient resources whose energy, ancillary services, capacity, and other market and non-market value is less than their operational, maintenance, and amortized costs of necessary investments. As a result, resources that remain on the grid are those that best balance cost and reliability.").

[45] *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102, at P 80 (2022) ("*NYISO*").

will guide more efficient entry decisions as it will help investors understand the reliability impacts of adding incremental capacity to [a regional transmission] system."[46]

Because a resource's marginal reliability contribution changes as the result of factors specific to the resource (e.g., maintenance and upkeep; more generally performance) and external factors (e.g., the resource's synergistic and antagonistic relationship with other resources on the transmission system), PJM will annually re-evaluate each resource's Accredited UCAP to appropriately assign the risk of a resource's capacity value to investor who have the ability to choose between alternative resource types, rather than such risk being borne by consumers. Thus, investors will be more incented to invest in resources that are better able to perform during the hours the model identifies for resource adequacy risk as such resources will be accredited with higher capacity values than other resources.[47]

Mr. Keech testifies that an "important benefit" of PJM adopting the marginal ELLC approach is that it will "naturally align expected resource performance with the risk periods identified in the resource adequacy risk models," which "aligns the accredited level of capacity with the resource's marginal benefit to system reliability."[48] In addition, the marginal ELCC accreditation will improve the efficiency of RPM market outcomes and better ensure reliability by: (1) accrediting at a higher proportion of installed capacity resources that provide higher marginal reliability benefit—thereby signaling investors to

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[46] *NYISO*, 179 FERC ¶ 61,102, at P 80.

[47] *See* Rocha-Garrido Aff. ¶¶ 11-12 (providing an example).

[48] Keech Aff. ¶ 15.

build more of this type of megawatts if cost-effective; (2) not assigning capacity capability to the proportion of installed capacity that risk modeling shows not likely to perform during EUE events—thereby better ensuring the capacity committed, and for which load is paying, will actually show up when needed most; and (3) ensuring that each megawatt of capacity provides the same reliability value and therefore is substitutable one-for-one with other megawatts of PJM-accredited capacity.[49]

PJM's proposed ELCC methodology will provide an appropriate measure of an ELCC Resource's actual reliability contribution, using a detailed framework that considers the simultaneous reliability contribution of all resources, and recognizes the complementary and antagonistic interactions among resources expected to be able to provide capacity in a given Delivery Year.[50]

a. PJM's proposal is comparable to the marginal ELCC approach the Commission found just and reasonable for NYISO

The specifics of PJM's proposed marginal approach are comparable to the specifics of the marginal ELCC approach the Commission found just and reasonable last year for the New York Independent System Operator, Inc. ("NYISO"). There, NYISO proposed to accredit resource types based on their marginal contribution to system reliability, and to

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[49] *See* Keech Aff. ¶ 19.

[50] In the order accepting PJM's current "average" ELCC approach, the Commission note that its acceptance "does not preclude PJM from further considering the tradeoffs between average and marginal ELCC approaches, and potentially proposing some form of marginal ELCC approach in the future." *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056, at P 39 (2021). The Commission recognized that PJM "intends to conduct an initial review of the ELCC construct in the summer of 2022 and perform a comprehensive assessment of whether the ELCC model proposed herein is achieving its purpose of valuing and compensating capacity resources as accurately as practicable," and the Commission "encourage[d] PJM and its stakeholders to further consider the tradeoffs between the two ELCC approaches, and potentially alternative approaches, as part of this planned review." *Id.*

calculate a resource's unforced capacity as the product of its capacity accreditation factor, and the resource's individual performance or availability derating factor.[51] NYISO proposed its marginal ELCC approach to allow "the calculation of the UCAP values for ICAP Suppliers to [reflect] their marginal contribution to maintaining the reliability of the system when it is most needed."[52] NYISO asserted that marginal ELCC approach would improve the efficiency of NYISO's ICAP Market outcomes and would "send the proper price signals for each class of resources based upon the current system configuration and which resource class is best suited to support grid reliability, regardless of whether those resources receive out-of-market payments or rely more heavily on capacity market revenues."[53]

The Commission agreed and found NYISO's marginal ELCC approach to "objectively measure each resource's reliability contribution to the NYISO system."[54] Further, the Commission agreed that "it is appropriate to define a resource's UCAP such that each resource is assigned a UCAP value based on how its *marginal* contribution to resource adequacy compares to the *marginal* contribution of 'perfect capacity.'"[55] Further, the Commission found that it "is just and reasonable and not unduly discriminatory or preferential to accredit a resource's capacity value (i.e., its UCAP) based on its marginal reliability contribution because this value represents the resource's incremental reliability

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[51] *See NYISO*, 179 FERC ¶ 61,102, at P 44.

[52] *NYISO*, 179 FERC ¶ 61,102, at P 48.

[53] *NYISO*, 179 FERC ¶ 61,102, at P 48.

[54] *NYISO*, 179 FERC ¶ 61,102, at P 75.

[55] *NYISO*, 179 FERC ¶ 61,102, at P 76.

contribution to the NYISO system as it exists, including the presence of other resources that affect the subject resource's capacity value."[56]

Like NYISO's marginal ELCC approach, PJM's proposed marginal ELCC approach is a just, reasonable, and not unduly discriminatory improvement over the current approaches for accrediting the capacity capability of Generation Capacity Resources and Demand Resources. PJM's marginal ELCC approach will better tailor the Unforced Capacity quantities each such resource may offer to commit to provide as capacity in PJM with each resource's marginal contribution to maintaining resource adequacy and reliability of the PJM Region.

3. Extending ELCC Accreditation Approach to All Generation Capacity Resources and Demand Resources.

Currently, PJM applies the ELCC approach to only three types of resources: (1) Variable Resources (e.g., Intermittent Resources, such as wind and solar power); (2) Limited Duration Resources (e.g., battery storage resources); and (3) Combination Resources (e.g., resources with a wind or solar component and a storage component). For other types of Generation Capacity Resources, PJM relies on the EFORd metric to establish the UCAP value of such resources which quantifies the average period of time a resource is on a forced outage.[57] As Demand Resources are assumed to provide 100% performance at any time, their Unforced Capacity is determined as the product the resource's expected

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[56] *NYISO*, 179 FERC ¶ 61,102, at P 76.

[57] *See* RAA, Schedules 5 and 9.

load reduction and the PJM Region's Forecast Pool Requirement,[58] which is based on the average EFORd of all generation resources in the region.[59]

However, a reevaluation of how PJM determines the capacity capability of resources is required to ensure PJM procures capacity megawatts that will be able to perform when called upon. In particular, the correlation of forced outages with cold weather, projected continued increase in renewable penetration and the rise of just-in-time fuel resources as the predominant resource types calls for a change capacity accreditation. Each of these represent a type of correlated outage that impacts that capacity capability of each resource but also can be a driver of resource adequacy risk. As a result, PJM's current approach of determining a resource's capacity capability based solely on that resource's historical average forced outage rate or nominated capability, without considering the outages of any other resource or alignment with resource adequacy risk periods, fails to properly account for the actual reliability benefit that the resource provides during hours of expected system risk.

To achieve competitive market outcomes, the megawatts offered by resource owners into the market must be comparable, i.e., 1 megawatt offered by Resource A must be comparable to 1 megawatt offered by Resource B. Achieving comparability between offered megawatts historically was straightforward for traditional generation resources (e.g., coal, nuclear, and natural gas powered resources) due to the fact that unplanned outages experienced by these resources were generally assumed to be random, which

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[58] *See* RAA, Schedule 6, section B; Tariff, Attachment DD-1, section B.

[59] *See* RAA, Schedule 4.1.

means that the chance of having a large amount of these resources on an outage simultaneously was not a major factor in resource adequacy planning. In other words, a resource mix composed of a high percentage of such traditional resources was not typically associated (correctly or incorrectly) with the occurrence of reliability issues due to high resource unavailability. PJM has traditionally employed a metric that simply quantifies the average time a resource is on a forced outage, known as the EFORd, to establish the UCAP value of such resources.

A more robust analysis is called for to ensure the various performance risks faced by each resource are properly considered when determining their capacity capability for a given Delivery Year. Accordingly, PJM proposes to discontinue use of EFORd starting with the 2025/2026 Delivery Year,[60] and employ PJM's proposed marginal ELCC approach to determine each Generation Capacity Resource's capacity accreditation (i.e., "Accredited UCAP"). The marginal ELCC approach will "provide[] a more accurate comparison between the reliability benefit of resources, and the corresponding accreditation that resources should receive, given the expected resource mix in the system."[61]

PJM's proposal includes using the Accredited UCAP of an individual resource to derive a resource's Accredited UCAP Factor. The Accredited UCAP Factor represents the share of the installed capacity of a resource that is accredited as Capacity and is equal to "the ratio of the Capacity Resource's Accredited UCAP to the Capacity Resource's

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[60] *See* proposed RAA, Schedule 5, section B; proposed Tariff, Attachment M – Appendix, sections C.3 and C.5.

[61] Rocha-Garrido Aff. ¶ 9.

installed capacity." The Accredited UCAP Factor will replace the EFORd-based metric ("one minus EFORd") starting with the 2025/2026 Delivery Year.[62]

Further, by extending the ELCC accreditation approach to virtually all Capacity Resources, as discussed next, PJM will have a single cohesive analytic framework for accrediting capacity capability and allowing each megawatt of capacity to provide the same reliability value and be substitutable one-for-one with each other.[63] While each class of ELCC Resources offers unique capabilities in various configurations, a comprehensive, uniform approach is necessary to ensure comparable capacity accreditations across diverse resource types.

4. RAA Revisions to Implement Marginal ELCC Approach Starting with the 2025/2026 Delivery Year.

To implement the shift to a marginal ELCC approach and apply it to all Generation Capacity Resources and Demand Resources, PJM is proposing to amend RAA, Schedule 9 to make explicit that, starting in the 2025/2026 Delivery Year and all subsequent Delivery Years, the ELCC approach in new Schedule 9.2 will be used to "determine the capability of Generation Capacity Resources to meet a Load Serving Entity's obligations,"[64] while the RAA will limit the current approach through the 2024/2025 Delivery Year.[65] PJM is proposing a similar revision to RAA, Schedule 6, section B, to specify that, starting in the 2025/2026 Delivery Year, a Demand Resource's UCAP value will be determined in

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[62] *See, e.g.*, Attachment DD, sections 5.14(h-2)(3)(A) and (B).

[63] *See* Keech Aff. ¶ 16 ("The benefit of a single accreditation approach is even more critical because it creates a single, fungible capacity product which could be argued to not be the case under the current rules given the various accreditation methods used.").

[64] Proposed RAA, Schedule 9, section D.

[65] Proposed RAA, Schedule 9, section C.

accordance with RAA, Schedule 9.2, while the current rules remain in effect through the 2024/2025 Delivery Year.[66]

Because the current average ELCC approach will remain in effect for through the 2024/2025 Delivery Year, PJM is not removing RAA, Schedule 9.1, which sets forth the average ELCC approach.[67] PJM is also revising the definition of ELCC Resource to delineate that, starting in the 2025/2026 Delivery Year, an ELCC Resource is "a Generation Capacity Resource or a Demand Resource."[68]

PJM is proposing an entirely new Schedule 9.2 to set forth the marginal ELCC rules. Because the average and marginal ELCC share foundational elements, much of Schedule 9.2 mirrors what is in Schedule 9.1. However, there are significant differences, discussed below, necessary to implement the marginal ELCC approach and expand the scope of Capacity Resources to which the ELCC analysis will apply.

a. Changes to model inputs for marginal ELCC approach

As compared to section A of Schedule 9.1, PJM proposes to include in Schedule 9.2, section A that the marginal ELCC model will "consider similar data and forecasts as that used in development of the [Forecast Pool Requirement], as described in Schedule 4.C" and include inputs related to "correlated outage risks" and modeling parameters for Demand Resources.[69] Also, the sole output of the ELCC model will be the ELCC Class

[66] Proposed RAA, Schedule 6, section B.

[67] PJM is proposing one minor change to RAA, Schedule 9.1, section J to remove the requirement to post ELCC Class UCAP values. Inclusion of this posting requirement was in error, as such information could inadvertently divulge competitively sensitive market information about Capacity Resources. For that reason, PJM has not posted these values.

[68] Proposed RAA, Article 1 – Definitions (defining ELCC Resource).

[69] Proposed RAA, Schedule 9.2, section A.

Rating, because the marginal ELCC approach does not compute the ELCC Portfolio UCAP or ELCC Class UCAP values like the average ELCC approach does, as the average requires a determination of the ELCC Class UCAP to be allocated among the members of the class, whereas the marginal ELCC approach evaluates the capacity capability of each resource individually, based on class and resource-specific characteristics.[70] For this reason, PJM is not carrying over RAA, Schedule 9.1, Sections C and D, which, respectively, detail the calculation of the ELCC Portfolio UCAP and the allocation of the ELCC Portfolio UCAP to ELCC Class UCAP.

PJM also proposes to generally carry over the determination of installed capacity for Limited Duration and Combination Resources, and add that the installed capacity for Variable and Unlimited Resources shall be determined in accordance with the PJM Manuals.[71] For purposes of performing the marginal ELCC analysis, PJM proposes to use the forecasted level of Demand Resources in the applicable PJM Load Forecast,[72] which is reasonable given the lack of annual continuity of end-users underlying each Demand Resource.

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[70] *See* proposed RAA, Schedule 9.2, section A.

[71] *See* proposed RAA, Schedule 9.2, section G. PJM Manual 21 has detailed provisions for determining a generation resource's installed capacity. *See generally* System Planning Department, *PJM Manual 21: Rules and Procedures for Determination of Generating Capability*, PJM Interconnection, L.L.C., section 1.2.1 (July 26, 2023), https://pjm.com/-/media/documents/manuals/m21.ashx (discussing PJM's methodology for determining the installed capacity for Variable and Unlimited Resources).

[72] *See* proposed RAA, Schedule 9.2, section G.

b. Addition of ELCC Classes for types of Unlimited Resources and Demand Resources

In RAA, Schedule 9.2, section B, PJM continues to list all the existing ELCC Classes,[73] and PJM proposes to add ELCC Classes of Unlimited and Demand Resources listed above. PJM proposes to include all Demand Resources in the same Demand Resource ELCC Class. For Unlimited Resources, PJM proposes to establish ELCC Classes for each Unlimited Resource type, recognizing that all members of a class must share a common set of operational characteristics. Thus, PJM proposes to add the following ELCC Classes for Unlimited Resources: Nuclear Class, Coal Class, Gas Combined Cycle Class, Gas Combustion Turbine Class, Gas Combined Cycle Dual Fuel Class, Gas Combustion Turbine Dual Fuel Class, Diesel Utility Class, Steam Class, and Other Unlimited Resource Class.[74]

For a resource to qualify for a dual fuel ELCC Class, the resource must be capable of "start[ing] and operat[ing] independently on an alternate, onsite fuel source up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level."[75] Such requirements define the dual fuel classes to include only those resources that are truly dual fuel and capable of providing energy from either fuel type during emergency conditions. The

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[73] However, PJM proposes to specify that the existing ELCC Class for Variable Resources reliant on landfill gas should be call "Intermittent Landfill Gas." *See* proposed RAA, Schedule 9.2, section B(1)(a).

[74] *See* proposed RAA, Schedule 9.2, section B.

[75] Proposed RAA, Article 1 – Definitions (defining Gas Combined Cycle Dual Fuel Class and Gas Combustion Turbine Dual Fuel Class).

requirement for resources to be capable of operating two 16-hour periods on two consecutive days to qualify in a dual fuel class is reasonable, given that the purpose of an ELCC Class is to study resources of similar operational characteristics for the purpose of determining their capacity contribution to the system. First, empirical observations of event durations during the 2014 Polar Vortex and Winter Storm Elliott in 2022 show that two-day events can and do happen, and such two-day events align with the duration of resource adequacy risk events identified in PJM's resource adequacy risk analysis. Operating for 16-hour periods on the alternative fuel is also important. Recall that, by definition, Unlimited Resources must be capable of "maintain[ing] output at a stated capability continuously on a daily basis without interruption."[76] Thus, for a resource to be considered "dual fuel," the alternative fuel capability should offer comparable performance assurance.

Moreover, being capable of operating for 16 hours on two consecutive days is consistent with other reliability-related requirements. For example, PJM's emergency dispatch operations, as detailed in PJM Manual 13, provide that when resources that otherwise can run for periods of 24 hours or longer become limited to 16 hours, or 32 hours over a two-day period, of runtime, PJM will hold those resources back from dispatch and reserve them for "Maximum Emergency,"[77] i.e., for use in emergency conditions. The proposed 16-hour runtime standard also is consistent with the fuel assurance standards the

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[76] RAA, Article 1 – Definitions (defining Unlimited Resource).

[77] *See* System Operations Division, *PJM Manual 13: Emergency Operations*, PJM Interconnection, L.L.C., section 6.4 (Aug. 24, 2023), https://www.pjm.com/-/media/documents/manuals/m13.ashx.

Commission recently accepted.[78] Thus, the two-day, 16-hour per day runtime standard is appropriate.

While PJM proposes this as the criteria for a dual fuel class based on current observation and analysis, there is a possibility that benefit arises in the future from having longer duration dual fuel classes. In fact, based on stakeholder feedback, PJM re-considered an earlier proposal for a three-day, 16-hour per day runtime standard and found little additional resource adequacy benefit given the patterns of multi-day resource adequacy risks identified in the modeling results, and thus expects negligible differences in accreditation between the two potential class definitions. However, should a longer duration benefit arise, PJM will propose to update its ELCC Class definitions at that time.

PJM is also proposing to add definitions to the RAA defining these classes. Because the name of each proposed ELCC Class is generally descriptive of the resources of the class, the proposed definitions are generally self-explanatory, e.g., PJM proposes to define the "Coal Class" as "an ELCC Class consisting of Unlimited Resources primarily fueled by coal."[79]

c. Performing PJM's ELCC analysis and simulating the output of ELCC Resources in a way that appropriately accounts for their reliability value and operational realities

In his affidavit, Dr. Rocha-Garrido provides, in great detail, how PJM will perform the marginal ELCC analysis. In particular, he explains that PJM will "model[] the performance of resource portfolios under a range of future system conditions on an hourly

[78] *See* Tariff, Schedule 6A, section 18; *PJM Interconnection, L.L.C.*, 185 FERC ¶ 61,013 (2023).

[79] Proposed RAA, Article 1 – Definitions (defining Coal Class).

basis,"[80] with "the primary inputs to determine the range of future system conditions are Load Uncertainty and Resource Performance Uncertainty."[81] Each modelled scenario "has a probability of occurrence associated with it," making the "methodology [] probabilistic in nature."[82]

PJM will use an hourly interval in performing the ELCC analysis, "compar[ing] expected hourly load levels (based on historical weather)" with the expected output of the "expected future resource mix" for each hour to "identify the relative marginal resource adequacy value of each individual ELCC Class compared to an Unlimited Resource with no outages."[83] The proposed RAA language specifies that the ELCC analysis "shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; (iii) expected output of Limited Duration Resources and of Combination Resources; (iv) expected Unlimited Resource output; and (v) expected Demand Resource output."[84] Stated another way, PJM will model for two broad types of uncertainty—load uncertainty and resource performance uncertainty.[85]

To model for load uncertainty, PJM will develop "multiple 8,760 Hourly Load Scenarios" to cover a range of load conditions,[86] derived from the hourly load scenarios

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[80] Rocha-Garrido Aff. ¶ 24.

[81] Rocha-Garrido Aff. ¶ 24.

[82] Rocha-Garrido Aff. ¶ 24.

[83] Proposed RAA, Schedule 9.2, section H.

[84] Proposed RAA, Schedule 9.2, section H.

[85] Rocha-Garrido Aff. ¶ 24.

[86] Rocha-Garrido Aff. ¶ 25.

produced as part of the PJM Load Forecast using weather data starting on June 1, 1993.[87] The quantity of ELCC/Reserve Requirement Study ("RRS") Scenarios will be a function of the number of Hourly Load Scenarios and Resource Performance Patterns. Dr. Rocha-Garrido states that "the number of Hourly Load Scenarios depends on the number of weather delivery years and weather rotations while the number of Resource Performance Patterns analyzed for each Hourly Load Scenario is one hundred. Therefore, the total quantity of ELCC/RRS Scenarios is determined by the product of weather delivery years *times* weather rotations *times* one hundred."[88]

PJM is proposing to use in the model the hourly load scenarios produced as part of the PJM Load Forecast using weather data starting on June 1, 1993. Dr. Rocha-Garrido testifies that using weather data back to June 1, 1993 (i.e., the first day of the 1993/1994 Delivery Year) is an improvement over the current RRS model, which has historically used 15 years of data or less. The expanded weather data allows the model "to examine a wider range of load scenarios (as weather is the most significant driver of load in the PJM system) and to simulate the expected performance of resources under those scenarios (particularly for those resources whose performance is weather-dependent.)."[89] Expanding the weather history to 30 years' of data provides significant benefit to the analysis, given that two primary grounds for adopting the marginal ELCC approach are (1) forecasted increasing levels of renewable resources (whose performance are largely weather driven), and

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[87] Rocha-Garrido Aff. ¶ 25.

[88] Rocha-Garrido Aff. ¶ 30.

[89] Rocha-Garrido Aff. ¶ 20(a).

(2) correlated outages caused by weather events. While discussed in the stakeholder process and strongly considered by PJM, PJM is not adopting any explicit "climate change adjustment" at this time.

Dr. Rocha-Garrido justifies this decision, explaining that "climate change is affecting weather but, when analyzing PJM-region temperature data starting June 1, 1993, no clear consistent trend is observed in the period 1993-2022."[90] Further, PJM elected to utilize weather data starting June 1, 1993, because PJM's Load Forecast generally relies on this same set of weather data and there is no universally accepted way to adjust the means or extremes in temperatures. PJM examined a few options for adjusting the data and observed that the reliability results were quite sensitive to the adjustment performed. Also disconcerting was that each adjustment method led to a reduction in winter resource adequacy risk, which ran counter to PJM's recent experience with Winter Storm Elliot and gave PJM low confidence in the adjustments.[91] However, he notes that "as PJM adds each Delivery Year's weather data, PJM will continue to analyze the data for any observable trends and adjust for such trends, as applicable."[92]

To model for resource output uncertainty, PJM will "deriv[e] the hourly output of each resource in each Hourly Load Scenario," where "correlation of Unlimited Resources forced outages and Variable Resources unavailability (or to put it differently, the

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[90] Rocha-Garrido Aff. ¶ 20(a).

[91] For example, the winter of 1994 was one of the coldest in the region's history and led to rolling blackouts in PJM. It was followed by warmer winters in subsequent years. The climate adjustments that were under consideration all tended to mask the impact of that event despite the fact that there is conflicting evidence that such cold temperatures would not be realized again in the PJM Region.

[92] Rocha-Garrido Aff. ¶ 20(a). *See* Graf Aff. ¶¶ 162-163.

correlation of their output levels) will be captured. . . as a function of weather,"[93] underscoring the desirability of a larger pool of weather data. PJM will carryover from the current ELCC model resource performance data back to June 1, 2012, with data from each passing Delivery Year added to the model.[94] To best model Unlimited and Variable Resources, PJM will also consider ambient derates as well as planned and maintenance outages.[95]

With regard to Limited Duration Resources, Combination Resources, and Demand Resources, PJM will simulate their performance "based on an hourly-simulated dispatch that depends on other system conditions (load, other resources' performance) for that same hour,"[96] because these resource categories can vary their output based on system conditions, in contrast to Variable Resources, which generally produce the maximum available energy unless curtailed. However, because software limitations prevent PJM from proposing to simulate an economic dispatch in the ELCC model at this time, PJM proposes a simulated dispatch that dispatches resources and that "includes simulating the

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[93] Rocha-Garrido Aff. ¶ 27(a). Dr. Rocha-Garrido explains that PJM will use binning methods to develop 100 different Resource Performance Patterns of Unlimited Resources and Variable Resources to be used in the ELCC/RRS model. The resource performance data will be used as recorded for resources that were in-service at the time the historical observation was recorded; for resources that were not in service at the time the historical observation was recorded, class average availability rates will be used as putative values for each hour. *Id.*

[94] *See* proposed RAA, Schedule 9.2, section H (using as model inputs actual resource output "after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist."); RAA, Schedule 9.1, section H (same).

[95] Rocha-Garrido Aff. ¶ 21.

[96] Rocha-Garrido Aff. ¶ 27(c).

charging or charging-equivalent process whereby Limited Duration Resources and Combination Resources replenish their storage components."[97]

Dr. Rocha-Garrido provides extensive discussion regarding the simulation dispatch. He explains that the simulation's dispatch of Limited Duration Resources, Combination Resources, and Demand Resources will be governed by two general principles: (1) "[l]ess available resources are dispatched after the more available resources to maximize the system reliability benefit;" and (2) there is "variability of resources within some ELCC Classes."[98] Dr. Rocha-Garrido testifies that the first principle provides that, "if during a certain hour early on in the emergency event PJM has to choose between serving load with a more available resource (e.g., Demand Resource available for more than 10 hours) and serving load with a less available resource (e.g., a four-hour Limited Duration resource), PJM will dispatch the more available resource first." A benefit of this assumption is that "during the final hours of the emergency event (but still within the availability window of the Demand Resources), PJM will have at its disposal the megawatts from the more available resource *plus* the megawatts from the less available resources." Additionally, this principle has the benefit of being the order of operations PJM Operations would follow under these circumstances.[99]

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[97] Rocha-Garrido Aff. ¶ 27(d). Dr. Rocha-Garrido also details the five-step procedure to derive the simulated dispatch for Limited Duration Resources and Combination Resources applied to each hour in each ELCC Scenario. *See id.*

[98] Rocha-Garrido Aff. ¶ 27(c)(i)-(ii).

[99] *See* Rocha-Garrido Aff. ¶ 27(c)(i) ("It is my understanding that PJM Operations would adhere to this principle under the circumstances described above.").

The second principle ("variability of resources within some ELCC classes") merely recognizes that certain ELCC Classes cannot be modeled, "for simulated dispatch purposes, in an aggregate fashion," because, for example, the members of a such class (e.g., Hydropower with Non-Pumped Storage) show a wide range of values for a given parameter that is heterogeneous relative to the class (e.g., how quickly a Hydropower with Non-Pumped Storage resource can replenish their storage component, as this parameter is a function of hourly streamflow data and storage size).[100]

With respect to the simulated dispatch of Demand Resources, PJM assumes that Demand Resources will be dispatched (and thus perform) only during the seasonal performance window as defined in the PJM Manuals[101] and that all Demand Resources "are categorized as Firm Service Level," and "when dispatched, must reduce their megawatt consumption to a specified firm level."[102]

d. Determination of ELCC Class Ratings

PJM will configure the ELCC model to "iteratively adjust the load scenarios until the LOLE criterion of 0.1 days per year is achieved,"[103] and that "PJM is also proposing to calculate the EUE associated with an LOLE of 0.1 days per year for purposes of resource

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[100] Rocha-Garrido Aff. ¶ 27(c)(ii).

[101] *See* Capacity Market & Demand Response Operations, *PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C., section 4.3.1 (July 26, 2023), https://www.pjm.com/-/media/documents/manuals/m18.ashx (Requirements of Load Management Products in RPM) ("Capacity Performance DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.").

[102] Rocha-Garrido Aff. ¶ 28.

[103] Rocha-Garrido Aff. ¶ 34.

accreditation and zonal resource adequacy calculations."[104] As discussed in more detail in part II.B.2 below, EUE measures the expected unserved megawatt-hours during the shortage events, allowing an analysis to differentiate each event in duration and especially, magnitude. Dr. Rocha-Garrido details the iterative process,[105] which includes the calculations of both the LOLE and the EUE of each modelled scenario. Once the model identifies a scenario with the 0.1 LOLE, which is designated the "Solved Load,"[106] "the EUE associated with the LOLE criterion is calculated." The EUE value of the Solved Load case is the "Portfolio EUE."[107]

The Portfolio EUE forms the baseline in determining marginal ELCC Class Rating.[108] The ELCC Class Ratings for Variable Resources, Limited Duration Resources, Unlimited Resources (except Other Unlimited Resources), and Demand Resources are calculated as the "ratio of the expected unserved energy improvement resulting from adding an incremental quantity of the subject ELCC Class to the expected unserved energy improvement resulting from adding an incremental quantity of an Unlimited Resource with no outages, where expected unserved energy improvement is calculated relative to the

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[104] Rocha-Garrido Aff. ¶ 31.

[105] Dr. Rocha-Garrido explains that "[t]his iterative process is required due to the fact that PJM uses a forecasted resource portfolio which includes all units that are likely to offer into a given RPM Auction. This forecasted resource portfolio may fall long or short in meeting the LOLE criterion." Rocha-Garrido Aff. ¶ 34.

[106] Rocha-Garrido Aff. ¶ 34.

[107] Rocha-Garrido Aff. ¶ 34.

[108] *See* proposed RAA, Article 1 – Definitions ("'Portfolio Expected Unserved Energy' shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.").

Portfolio EUE for the Delivery Year."[109] Thus, the marginal ELCC model solves for the megawatt value of reliability a resource adds based on the ELCC Class's marginal contribution to system resource adequacy needs, when the system meets the stated reliability metric.

For those ELCC Classes "whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics," including "Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class," PJM proposes to not model such resources as a class and to determine resource-specific ELCC ratings.[110] That is, the individual resources within the class are so unique and include parameters that impact their potential dispatch, and therefore, do not lend themselves to be modeled, for simulated dispatch purposes, in an aggregate fashion. For example, Hydropower with Non-Pumped Storage resources are too distinct from one another for them to be modeled as a class because they generally consist of a dam on a river system that has either pondage or a reservoir in which the owner can store and release water in a controlled fashion across the hours of an Operating Day, making their generation output discretionary and dispatchable, unlike hydro plants without such water storage. PJM proposes to model these and other resources that comprise classes but are physically and operationally distinct from other class members, through a resource-specific ELCC analysis.

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[109] Proposed RAA, Schedule 9.2, section C(1).

[110] Proposed RAA, Schedule 9.2, section C(2).

e. Determination of Accredited UCAP

The determination of a Variable Resource's and Limited Duration Resource's capacity accreditation (i.e., "Accredited UCAP") generally follows the same formula used to determine the Accredited UCAP for as under the current ELCC approach, with the only difference being that the Accredited UCAP value for such resource's being capped at "the lesser of the resource's Capacity Interconnection Right or the product of" the resource's Effective Nameplate Capacity, its ELCC Class Rating, and its resource-specific performance adjustment.[111] While the current approach does not explicitly cap the Accredited UCAP for Variable Resources and Limited Duration Resources at their Capacity Interconnection Rights, this rule is effectively in place as such resources may not be offered to provide capacity in an amount greater than it has Capacity Interconnection Rights.[112] PJM's proposal in this regard makes clear a rule that is already in place.

The determination of an Unlimited Resource's capacity accreditation (i.e., "Accredited UCAP") generally follows the same formula used to determine the Accredited UCAP for Variable Resources and Limited Duration Resources. That is, the Accredited UCAP for most Unlimited Resources generally will be the product of: (1) its installed capacity; (2) its ELCC Class Rating, which is a rating factor uniform for the entire ELCC Class that reflects the ELCC Class's performance characteristics or history of the resource type; and (3) the ELCC Resource Performance Adjustment, which is specific to that

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[111] *See* proposed RAA, Schedule 9.2, section D(1)(a).

[112] *See PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056, at P 53 (2021) ("[A]fter PJM has determined ELCC Resources' Accredited UCAP, PJM will limit an ELCC Resource's capacity market offer to be no greater than its CIRs, ensuring that the capacity market clearing process will not give an ELCC resource a capacity supply obligation that exceeds the capacity the resource can physically deliver.").

resource and determined based on how that resource has actually performed relative to other members of its ELCC Class.[113]

To determine a Capacity Resource's ELCC Resource Performance Adjustment, for Variable, Limited Duration, and Unlimited Resources, PJM proposes to determine the performance adjustment "based on a metric consisting of the weighted average hourly output of the resource in the ELCC model" and PJM proposes that "(i) the weights correspond to the modeled probability of losing load in such hour and (ii) the expected hourly output is based on the resource's modeled output during the same hour on days since June 1st, 2012 identified as having similar weather from an RTO-perspective."[114] In other words, the ELCC Resource Performance Adjustment is the "ratio of such metric to the average (weighted by the Effective Nameplate Capacity in the case of Variable and Limited Duration Resources and installed capacity in the case of Unlimited Resources) of such metrics for all units in the applicable Variable Resource ELCC Class or applicable Unlimited Resource ELCC Class."[115] Such determination will thus, consistent with the marginal ELCC approach, base the adjustment on how well the resource performed in the hours with high resource adequacy risk.

Further, consistent with changes adopted earlier this year for Variable Resources, PJM will continue to cap the modelled output of a Variable Resource at its Capacity Interconnection Rights for the June through October summer period."[116] However, PJM

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[113] *See* proposed RAA, Schedule 9.2, section D(1)(c).

[114] Proposed RAA, Schedule 9.2, section D(2)(a).

[115] Proposed RAA, Schedule 9.2, section D(2)(a).

[116] Proposed RAA, Schedule 9.2, section D(2)(a).

also proposes that such summer period output cap be set at the "greater or" the resource's Capacity Interconnection Rights or the resource's "transitional system capacity."[117] For the November through May winter period, PJM proposes a slight tweak to the current approach of capping a Variable Resource's output at its "winter deliverability MW, as defined in the PJM Manuals" to "assessed deliverability, as defined in the PJM Manuals."[118] The import of this change is to allow for differentiation between wind and solar Variable Resources. The current "winter deliverability MW" approach is too limiting, and does not account for "light load deliverability MW," which PJM also measures in its deliverability analysis of wind and solar resources.[119] Thus, the current winter period approach does not include all measured deliverability, and could understate the capacity capability of a wind or solar resource. Accordingly, PJM proposes to broaden the deliverability megawatts considered in the determination of a Variable Resource's

[117] *See* proposed RAA, Schedule 9.2, section D(2)(a). The Commission accepted the use of the resource's "transitional system capacity" as a limiting factor on its output. *See PJM Interconnection, L.L.C.*, 183 FERC ¶ 61,009, at P 32, *reh'g denied*, 183 FERC ¶ 62,126 (2023). PJM submitted a compliance filing to include this language in RAA, Schedule 9.1 in Docket No. ER23-1067-001, effective with the 2025/2026 Deliver Year, and the compliance filing is pending before the Commission. Given that PJM proposes in this instant filing to sunset RAA, Schedule 9.1 with the 2024/2025 Delivery Year and use proposed RAA, Schedule 9.2 starting with the 2025/2026 Delivery Year, acceptance of this filing, and Schedule 9.2 in particular, will moot the compliance filing in Docket No. ER23-1067-001, but will not upset the Commission's findings in *PJM Interconnection, L.L.C.*, 183 FERC ¶ 61,009. Consistent with the use of transitional system capacity and Capacity Interconnection Rights as a cap on a resource's output in the ELCC model, PJM also proposes to carry forward the Docket No. ER23-1067-001 change to the definition of Effective Nameplate Capacity such that the Effective Nameplate Capacity of a Limited Duration Resource shall not exceed "the greater of" its Capacity Interconnection Rights, or its "transitional system capability." Proposed RAA, Article 1 - Definitions (defining Effective Nameplate Capacity).

[118] *See* proposed RAA, Schedule 9.2, section D(2)(a).

[119] Transmission Planning Department, *PJM Manual 14B: PJM Region Transmission Planning Process*, Attachment C, section C.3.1.3 (July 26, 2023), https://www.pjm.com/-/media/documents/manuals/m14b.ashx.

performance adjustment to be all of the resource's "assessed deliverability, as defined in the PJM Manuals."[120]

For Unlimited Resources, PJM also proposes to cap the output of an Unlimited Resource in any hour of the year at "greater or" the resource's Capacity Interconnection Rights or the resource's "transitional system capacity."[121]

For Demand Resources, the Accredited UCAP will be the product of: the resource's Nominated Value, the determination of which will continue to be governed by RAA, Schedule 6, sections I and K, and its ELCC Class Rating.[122] PJM proposes to not include a resource-specific performance adjustment to Demand Resources, because of the general lack of continuity of the end-users comprising a Demand Resource from year-to-year. If the individual sites underlying a Demand Resource in the capacity market change from year-to-year, as they can, then use of historic performance as a means to estimate future performance could be misleading. As such, without year-to-year continuity of the underlying sites, any resource-specific performance adjustment likely would not properly accredit the resource's capacity capability.

The Accredited UCAP of those resources for which no ELCC Class Rating was determined, PJM will perform "a resource-specific effective load carrying capability

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[120] Proposed RAA, Schedule 9.2, section D(2)(a).

[121] *See* proposed RAA, Schedule 9.2, section D(2)(a). The Commission accepted the use of the resource's "transitional system capacity" as a limiting factor on its output. *See PJM Interconnection, L.L.C.*, 183 FERC ¶ 61,009, at P 32. PJM submitted a compliance filing to include this language in RAA, Schedule 9.1 in Docket No. ER23-1067-001, effective with the 2025/2026 Deliver Year, and the compliance filing is pending before the Commission. Given that PJM proposes in this instant filing to sunset RAA, Schedule 9.1 with the 2024/2025 Delivery Year and use proposed RAA, Schedule 9.2 starting with the 2025/2026 Delivery Year, acceptance of this filing, and Schedule 9.2 in particular, will moot the compliance filing in Docket No. ER23-1067-001, but will not upset the Commission's findings in *PJM Interconnection, L.L.C.*, 183 FERC ¶ 61,009.

[122] *See* proposed RAA, Schedule 9.2, section D(1)(d).

analysis based on the resource's unique parameters."[123] This methodology is carried over from PJM's existing ELCC rules.[124]

f. <u>Changes to the RAA-stated ELCC methodology</u>

RAA, Schedule 9.2, section H details the methodology of marginal ELCC analysis. While PJM is carrying over much of the methodology described in RAA, Schedule 9.1, section H, the switch to a marginal approach necessitates updated certain aspects of the methodology. These are discussed in the next section detailing how PJM will run the marginal ELCC model.

PJM also proposes to carry over that the marginal ELCC analysis will rely on forecast resource deployment levels,[125] Sell Offers submitted in RPM Auctions, or FRR Capacity Plans for the applicable Delivery Year, and add that the analysis will also consider any binding notice of intent to offer in an RPM Auction submitted by a Planned Generation Capacity Resource without a must-offer requirement.[126] PJM will cap the output of Variable Resources and Unlimited Resource in the same manner as used in the determination of their resource-specific performance adjustment, including capping a Variable Resource's output for the November through April winter period at its "assessed deliverability, as defined in the PJM Manuals."[127] This proposed binding notice

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[123] Proposed RAA, Schedule 9.2, section D(1)(b).

[124] *See* RAA, Schedule 9.1, section F(1)(b)(iv).

[125] The forecast resource deployment levels are developed by PJM and include multiple inputs including: forecasted resource deployment levels supplied by vendors, interconnection queue information and the PJM Load Forecast.

[126] Proposed RAA, Schedule 9.2, section H.

[127] Proposed RAA, Schedule 9.2, section H.

requirement is discussed below. It is reasonable for PJM to consider all resources that will submit offers in an upcoming RPM Auction, in performing the ELCC analysis.

Finally, expanding on the existing approach of scaling the model inputs to meet PJM's annual reliability criteria,[128] PJM proposes that "[t]he model inputs shall be scaled to meet the annual reliability criteria of the Office of the Interconnection," with "[t]he resulting expected unserved energy constitutes the Portfolio EUE for the Delivery Year."[129] The scaling process is performed due to the fact that the set of ELCC Resources expected to offer may fall long or short in meeting the annual reliability criteria given forecasted peak loads and associated forecasted load uncertainty. Therefore, specifically, the load scenarios are scaled, without altering the relationship between the hourly loads in the scenarios, until the annual reliability criteria is met. Upon completing this step, PJM will determine the Portfolio EUE required to evaluate how an additional increment of a given resource may address resource adequacy risk.

B. PJM's Risk Modeling Should Be Updated to Evaluate Risk on a More Granular, Hourly Level.

Complementing PJM's adoption of an accreditation methodology that uses an hourly model to examine resources' ability to address resource adequacy risk, PJM proposes to use an hourly model to determine the PJM system's resource adequacy risk, i.e., the Reserve Requirement Study. In fact, as Dr. Rocha-Garrido explains, PJM proposes

[128] *See* RAA, Schedule 9.1, section H ("In performing this analysis, the model inputs shall be scaled to meet the annual loss of load expectation of the Office of the Interconnection.").

[129] Proposed RAA, Schedule 9.2, section H.

to use the same model for both the ELCC accreditation and the Reserve Requirement Study.[130]

1. Updating the Model Used to Determine the Installed Reserve Margin and Forecast Pool Requirement to the More Granular ELCC.

The Reserve Requirement Study models load uncertainty and resource performance uncertainty "to determine the amount of installed capacity reserves, i.e., the IRM, and the corresponding amount of UCAP (determined using the [Forecast Pool Requirement]) required to meet expected energy demand and procuring sufficient reserves to meet the 1-day-in-10-years target reliability criteria by analyzing load and resource performance scenarios."[131] The Unforced Capacity equivalent of the Installed Reserve Margin is known as the Forecast Pool Requirement, which is in turn employed to calculate the PJM Region Reliability Requirement. The PJM Region Reliability Requirement effectively represents the level of unforced capacity targeted to be procured in RPM consistent with reliability standards.[132] The PJM Region Reliability Requirement for a future delivery year is defined as the Forecast Pool Requirement times the median ("50/50") peak load forecast for the PJM region less the sum of FRR Entities Unforced Capacity Obligations. Because the Reserve Requirement Study uses the LOLE criterion of 1-day-in-10 years, the Forecast

[130] *See* Rocha-Garrido Aff. ¶ 18.

[131] Rocha-Garrido Aff. ¶ 17.

[132] *See* Tariff, Definitions O- P -Q ("'PJM Region Reliability Requirement' shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region."); *see also* Capacity Market & Demand Response Operations, *PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C., section 2.4.1 (July 26, 2023), https://www.pjm.com/-/media/documents/manuals/m18.ashx.

Pool Requirement can be described as the level of Unforced Capacity reserves above the median ("50/50") peak load forecast required to meet this LOLE criterion.

There are many similarities between the Reserve Requirement Study and the ELCC methodology. Both studies model load and resource performance uncertainty at the PJM Region level and use the LOLE criterion of 1-day-in-10-years as the reliability standard.[133] While the Reserve Requirement Study is concerned with calculating the PJM Region Reliability Requirement for an RPM Auction, the ELCC is concerned with determining the megawatt valuation that ELCC Resources can offer into an auction to meet that PJM Region Reliability Requirement. Thus, the calculations of the Installed Reserve Margin, Forecast Pool Requirement, and ELCC Class Ratings each rely on the same set of inputs used for the ELCC analysis. Dr. Rocha-Garrido explains that today "a full overlap between the ELCC and the RRS model" is precluded only "by the fact that only a subset of all Capacity Resources are evaluated and accredited through the ELCC analysis and thus included in the ELCC model (i.e., Variable Resources, Combination Resources and Limited Duration Resources)."[134]

PJM's proposal in this filing to accredit all Capacity Resources except Energy Efficiency Resources through the ELCC model resolves that issue and allows for PJM to use the same model for both determination of the amount of capacity required and the amount of capacity each resource is capable of providing.[135] Accordingly, it is appropriate

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[133] *See* Rocha-Garrido Aff. ¶ 17.

[134] Rocha-Garrido Aff. ¶ 17.

[135] *See* Rocha-Garrido Aff. ¶ 17 ("As a result, the ELCC and RRS models will fully overlap, and the same model that accredits the capacity capability of almost all Capacity Resources also will determine the IRM.").

to use the same model for the ELCC and Reserve Requirement Study analyses. Using the same model for both analyses would also allow the Reserve Requirement Study to benefit from the hourly interval modeling of all 8760 hours in a year that is part of the ELCC model, instead of just analyzing the peak hour of each day that the current Reserve Requirement Study models.[136]

In addition to and consistent with using the same model for the ELCC and Reserve Requirement Study analyses, PJM also proposes to use the same model for determining the Forecast Pool Requirement. As noted, the Forecast Pool Requirement is used to convert the Installed Reserve Margin to an Unforced Capacity value. Under the existing rules, the Forecast Pool Requirement is determined as a product of one plus the Installed Reserve Margin and one minus the average EFORd of the pool of Capacity Resources for which EFORd is determined.[137] But, reliance on the "pool-wide EFORd" "will no longer be appropriate" given the declining relevance of EFORd, as, going forward, it will not be used to accredit Capacity Resources.[138] Accordingly, PJM proposes to use "Pool-wide average Accredited UCAP Factor" to determine the Forecast Pool Requirement, as it is the analog to one minus EFORd under PJM's proposal.[139] The resulting Forecast Pool Requirement

[136] *See* Rocha-Garrido Aff. ¶ 20.

[137] *See* Rocha-Garrido Aff. ¶ 18 ("[T]he Forecast Pool Requirement is currently calculated as the product of '*one plus IRM'* and '*one minus pool wide average EFORd,'* where '*one minus pool wide average EFORd'* provides a means to convert the IRM quantity, denominated in installed capacity, to UCAP." (citing RAA, Schedule 4.1)).

[138] *See* proposed RAA, Schedule 5, sections B and C.

[139] *See* Rocha-Garrido Aff. ¶ 38 ("Pool-wide average Accredited UCAP is an appropriate replacement for one minus pool-wide average EFORd. Given that pool-wide average EFORd generally represents the forced outage rate of the vast majority of resources in PJM, pool-wide average Accredited UCAP Factor should provide a comparable ratio of UCAP to installed capacity, allowing PJM's existing calculations.").

equals the product of [one plus the Installed Reserve Margin] and the pool-wide average Accredited UCAP Factor.[140] Thus, starting with the 2025/2026 Delivery Year, the Forecast Pool Requirement will be calculated based solely on inputs determined through the new ELCC/RRS model.[141] Also, to allow time for updated information on planned generation resource participation (e.g., the binding notice of participation discussed in Part III.A below) and incorporation of other relevant data, PJM proposes to post the Forecast Pool Requirement Installed Reserve Margin 75 days in advance of each Base Residual Auction for a Delivery Year, instead of the current three months in advance.[142]

Because the Forecast Pool Requirement, Installed Reserve Margin, and ELCC values will be determined using the same model with the same inputs, PJM is revising the inputs RAA, Schedule 4 states are considered in the determination of the Forecast Pool Requirement. Specifically, PJM is updating the inputs listed in RAA, Schedule 4, section C to: (1) state that PJM is considering at "seasonal peak diversities" and no longer just "summer peak diversities;"[143] (2) remove the forecast seasonal and weekly peak load shapes, as this input is obsolete in the face of the hourly modeling PJM will utilize;[144] (3) make clear that weekly load variability will be considered through the 2024/2025 Delivery Year, but hourly load shapes will be used starting with the 2025/2025 Delivery

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[140] *See* proposed RAA, Schedule 4.1, section C.

[141] *See* proposed RAA, Schedule 4.1. Because the determination of the Forecast Pool Requirement will now be determined using the capacity capability of Generation Capacity Resources *and* Demand Resources, PJM is revising RAA, Schedule 7.1 to state that it provides for the unavailability of all Capacity Resources, not just Generation Capacity Resources. *See* proposed RAA, Schedule 7.1, section (a).

[142] Proposed RAA, Schedule 4.B.

[143] Proposed RAA, Schedule 4.C.1.

[144] *See* proposed RAA, Schedule 4.C.

Year;[145] (4) state that the model will consider recent "and historical" generator forced outage experiences, consistent with now using performance starting in 2012;[146] (5) clarify that the model will look at planned outage "factors," not "schedules," determined "based on forecasts and historical data;"[147] and finally, (6) clarify that weather shall be considered a factor in the analysis.[148]

2. Adoption of EUE in the Reserve Requirement Study Appropriately Tracks the Changing Resource Mix.

To further enhance its resource adequacy modeling, PJM plans to assess its resource adequacy risk using the EUE metric, keyed to meeting the traditional 1-day-in-10-years loss of load event metric that PJM has historically employed.[149] Dr. Rocha-Garrido explains that "EUE measures the expected megawatt-hours of load that a system cannot meet due to resource adequacy insufficiency, while LOLE measures the number of days that are expected to have some level of resource adequacy insufficiency, regardless of the duration and magnitude of the loss of load events."[150] As a result, inclusion of an EUE analysis would provide PJM information about the depth of loss of load events and therefore a more useful characterization of the events for resource adequacy planning purposes than relying solely on LOLE. And, PJM will therefore be able to better provide the resources needed to maintain resource adequacy at reasonable cost to consumers.

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[145] Proposed RAA, Schedule 4.C.2.

[146] Proposed RAA, Schedule 4.C.4

[147] Proposed RAA, Schedule 4.C.5.

[148] Proposed RAA, Schedule 4.C.6.

[149] *See* Rocha-Garrido Aff. ¶ 22.

[150] Rocha-Garrido Aff. ¶ 22.

The current 1-day-in-10-years LOLE reliability criterion "does not fully represent the three typical reliability dimensions: magnitude (MW), duration (hours) and frequency (number of events/time period),"[151] Indeed, LOLE only provides a measure of average days with shortfalls over a study period, without consideration of the magnitude (in megawatts) or duration of specific outage events. Thus relying solely on the current 1-day-in-10-years LOLE metric limits PJM's resource adequacy modeling.

In contrast, EUE provides a much more granular metric that measures the average amount of energy shortfalls—both in terms of duration and number of megawatts—as opposed to just the number of days with shortfalls. As a result, EUE allows the resource adequacy analysis to clearly differentiate among events (e.g., by duration and especially, magnitude) and better identify the scope of loss of load risk throughout the year. Dr. Rocha-Garrido finds that "by providing information about the [duration and number of megawatts] of loss of load events, EUE provides a more useful characterization of the events for resource adequacy planning purposes than LOLE."[152]

The changing resource mix, which increasingly will be composed of resources with greater hourly performance variability (e.g., wind and solar resources) further supports the need to include EUE in resource adequacy risk modeling, as "the expected future resource mix is likely to have a significant impact on the nature of the loss of load events (at the RTO level and more so, because of their smaller size, at the LDA levels)."[153] That is, as

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[151] *Resource Adequacy, A Comparison of Reliability Metrics*, Alberta Electric System Operator, 4 (July 7, 2017), https://www.aeso.ca/assets/Uploads/Capital-Power-Reliability-Target-Summary-CM.pdf (selections from EDC Associates' 2017 Annual Report and Second Quarter 2017 Forecast Update).

[152] Rocha-Garrido Aff. ¶ 22.

[153] Rocha-Garrido Aff. ¶ 22.

the level of renewable resources increases, shortage events may be caused by sustained lulls in wind or solar generation rather than random outages of Unlimited Resources, the system will experience shortage events outside of peak load events (see, e.g., California brownouts in August of 2020[154]). Indeed, PJM can expect that "there likely will be (i) shorter loss of load events in the summer evening in a summer peaking LDA due to reduction of solar output in an LDA with high solar penetration; (ii) longer but shallower loss of load events in the summer afternoon in a summer peaking LDA due to load patterns in an LDA with no solar penetration, and (iii) extended and deeper loss of load events in the winter due to no solar output and high thermal correlated forced outages in a winter peaking LDA with high penetration of solar and gas units."[155] Thus, EUE will help measure the shift in load shed risk caused by greater amounts of renewable resources. Accordingly, "the resource mix changes compel a prudent operator to use a resource adequacy metric that can provide information at a more granular level about expected loss of load events,"[156] and using a reliability metric that explicitly tracks unserved energy is important to allow PJM to procure sufficient capacity to meet the region's needs.

To be clear, PJM is not moving on from the 1-day-in-10-years LOLE reliability criterion; PJM is simply incorporating the EUE metric into its analysis. PJM will still plan to 1-day-in-10-years LOLE, but will calculate the associated level of EUE that results from PJM meeting the 1-day-in-10-years LOLE criterion. However, given the adoption of EUE

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[154] *Root Cause Analysis Mid-August 2020 Extreme Heat Wave*, California Independent System Operator Corp. (Jan. 13, 2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[155] Rocha-Garrido Aff. ¶ 22.

[156] Rocha-Garrido Aff. ¶ 22.

in the reliability planning, PJM proposes to revise the definition of "Reliability Principles and Standards," which is used in various places throughout the RAA and Tariff to make clear that it is PJM and not "NERC or an Applicable Regional Entity" that defines the "acceptable probabilistic loss of load criteria" PJM will use.[157]

3. Using the New ELCC Model, Including the Use of EUE, for Determining the Installed Reserve Margin and Forecast Pool Requirement Will Improve the Accuracy of, and Confidence in, Those Values.

PJM's new model for ELCC and the Reserve Requirement Study "includes several improvements that better capture and reflect the range of uncertainties faced by the PJM system relative to the current average ELCC model that PJM implemented in 2021 and the current RRS model."[158] The current Reserve Reliability Study models load uncertainty using, in key part, the PJM load forecast and resource performance uncertainty for Unlimited Resources using, in key part, PJM's Generator Availability Data System data from the most recent five-year period. However, as discussed above, PJM's new ELCC/RRS model will include (1) weather history dating from June 1, 1993, providing greater confidence in the modelled load patterns and weather-dependent resource performance patterns; (2) correlated forced outage patterns of Unlimited Resources; (3) forced outage modeling of Unlimited Resources dating from June 1, 2012; and (4) modeling historical correlations (or lack thereof) between forced outages of Unlimited Resources and the unavailability of Variable Resources.[159]

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[157] Proposed RAA, Article 1 - Definitions (defining Reliability Principles and Standards).

[158] Rocha-Garrido Aff. ¶ 20.

[159] *See* Rocha-Garrido Aff. ¶ 20.

Further, because the Reserve Requirement Study currently is performed by only analyzing the peak hour of each day, switching to the hourly modeling approach of the new ELCC/RRS model in the determination of the Installed Reserve Margin provides a significant improvement, as it "will enable the [Reserve Requirement Study] to capture both load variability and resource performance variations over the full 8760-hour period."[160]

Finally, the addition of the EUE reliability metric further enhances the model's ability to accurately identify the appropriate amount of capacity each resource can contribute and the amount of capacity the region requires to maintain reliability at reasonable cost.

These improvements to the Reserve Requirement Study (and ELCC) model will improve the relative accuracy of the model's outputs, e.g., the Installed Reserve Margin, which will allow for PJM and others to have greater confidence in those values. In turn, this will provide greater confidence in RPM Auctions and their ability to procure proper amounts of capacity, which should enhance price formation and efficient market outcomes.[161]

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[160] Rocha-Garrido Aff. ¶ 20(e).

[161] Graf Aff. ¶¶ 35-38 (observing the reliability and efficiency benefits from the improvements to the ELCC/RRS model, based on simulation results).

4. *Evidence Shows the Enhanced Risk Modeling and Marginal ELCC Accreditation Will Improve PJM's Ability to Maintain Resource Adequacy Concerns at Reasonable Cost.*

a. Simulations re-running 2024/2025 Base Residual Auction under proposed risk modeling and marginal ELCC accreditation approaches shows clearing different sets of resources and improving reliability

Dr. Graf performed a "simulation analysis to compare potential clearing results under the status quo Base Residual Auction design with those under the proposed capacity market with risk modeling and accreditation enhancements."[162] Using data from the 2024/2025 Base Residual Auction that PJM conducted in December 2022, including offers, load forecasts, and an assumed resource mix (for risk modeling) and removing constraints related to LDAs and Capacity Emergency Transfer Limits, Dr. Graf "re-cleared the auction to yield an 'unconstrained' RTO price."[163] Dr. Graf also re-ran the 2024/2025 Base Residual Auction but with the modeling and accreditation enhancements PJM proposes in this filing—i.e., employing the proposed ELCC/RRS model, run by Dr. Rocha-Garrido, to determine resource accreditation and RPM Auction inputs, e.g., the Forecast Pool Requirement. He found that "the auction results clear a different set of resources and improve reliability" relative to a status quo case, and this is due to the combined effect of several moving pieces. Specifically, he found that:

- Some resources have higher accreditation under the enhanced modeling than under status quo; these offer more UCAP megawatts at lower prices. Others (most) receive lower accreditation than before, and offer less UCAP megawatts at higher prices.

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[162] *See* Graf Aff. ¶ 32.

[163] Graf Aff. ¶ 33.

- Total costs to consumers increase modestly from $2.2 billion in the status quo case to $2.4 billion in the enhanced design case.

- Further, the total supply cost (that is, total offered cost of cleared resources, equivalent to production costs in the energy market) actually *falls,* from $330 million to $310 million.

- These results suggest that the risk modeling and accreditation enhancements allow for more efficient clearing outcomes, improving reliability (25% decrease in EUE) at moderate customer costs (10% increase) and slight savings (5% decrease) in overall system-wide costs of supply by enabling PJM to identify and procure the low-hanging fruit of reliability beyond the margin.[164]

Evaluating the results, Dr. Graf concluded that "this is a reasonable representation of the potential benefits of the proposed approach under relatively over-supplied capacity market conditions such as those that persisted in PJM in the early 2020s."[165] Dr. Graf also ran a simulation under tighter system conditions, and found the results to be "consistent with those of other similar scenarios I tested (with different assumptions regarding the contraction of the supply curve)," and his simulations "indicate that the proposed design enhancements could substantially improve efficiency in clearing outcomes when the system is tight."[166] In sum, Dr. Graf's analysis demonstrates that application of PJM's proposed risk modeling and accreditation approaches to a "potential set of market conditions, as recently observed," is expected to provide "reliability and efficiency benefits."[167]

[164] Graf Aff. ¶¶ 35-36.

[165] Graf. Aff. ¶ 36.

[166] Graf. Aff. ¶ 37.

[167] Graf Aff. ¶ 32.

b. The ELCC/RRS model runs supporting Dr. Graf's simulations show uneven distribution of risk throughout the Delivery Year, underscoring the reasonableness of using the same model for marginal ELCC accreditation and the Reserve Requirement Study

Dr. Rocha-Garrido ran the ELCC/RRS model, including all the proposed model enhancements concerning expanding weather history and modeling correlated outages,[168] using scenarios for Delivery Year 2024/2025 until the 1-day-in-10-years annual LOLE criteria was met, resulting in an associated illustrative Portfolio EUE, of 1,135 MWh/year.[169] An analysis of that Portfolio EUE showed that, in these illustrative results, "approximately 64% of the EUE was observed in the winter period," with 36% in the summer period, and conversely "around 65% of the LOLE was observed during the summer period while the remaining 35% of the LOLE was observed during the winter period."[170] Dr. Rocha-Garrido analyzed the illustrative distribution of the EUE throughout the Delivery Year, and found that summer EUE to be concentrated in July, with a little in August, and during the late afternoon/early evening hours, and the winter EUE to be concentrated in January, with some in February, but the winter EUE to be "significantly more distributed from a daily perspective (i.e., multiple hours in the morning and multiple hours in the evening show a non-negligible share of EUE)."[171]

Recent PJM experience during extreme weather events such as Winter Storm Elliott is more consistent with the above risk distribution than the results from the current ELCC

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[168] Rocha-Garrido Aff. ¶ 20.

[169] Rocha-Garrido Aff. ¶ 44.

[170] Rocha-Garrido Aff. ¶ 45.

[171] Rocha-Garrido Aff. ¶ 46.

and RRS models. Thus, as Dr. Rocha-Garrido explains, the illustrative EUE patterns for Delivery Year 2024/205 calculated by the proposed ELCC/RRS model provide a "more accurate quantification of seasonal and hourly risk."[172]

As a result, PJM's approach provides that "a resource that performs well in summer and poor in winter will receive an annual accreditation that is reflective of this [the resource's] disparate seasonal performance and *also* of the distribution of seasonal risk in the model, 64% of the EUE in winter and 36% of the EUE in summer."[173] Stated another way, because the supply (accreditation) side considers all risks, including winter risk, resources that have lower availability during winter hours (and therefore lower winter RA value) receive lower accreditation when more of the RTO's annual risks occur in winter. Thus, resources are de-rated, i.e., reducing the extent to which PJM relies on a resource, by exactly the right amount to correspond to their reduction in overall resource adequacy contribution. In turn, this improves the "accuracy of the total amount of annually accredited capacity that the system requires [i.e., the PJM Region Reliability Requirement] to meet reliability standards."[174]

Importantly, given the interplay between the calculation of the supply and demand sides, improving the accuracy of the accreditation assures that "the annual reliability requirement calculated for the system, expressed in megawatts of accredited UCAP, will be representative of the seasonal and hourly risk patterns expected for the system."[175]

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[172] Rocha-Garrido Aff. ¶ 47.

[173] Rocha-Garrido Aff. ¶ 47(a).

[174] Rocha-Garrido Aff. ¶ 47(b).

[175] Rocha-Garrido Aff. ¶ 47(b).

Further, under PJM's proposed annual construct, the annual accreditation provides a reliability-neutral exchange rate such that any resource can be replaced – MW for MW on an accredited UCAP basis – without impacting overall annual risk, i.e., as Dr. Graf states, this creates a "substitutable product definition where accredited capacity can be exchanged on the margin with no expected change in reliability."[176] This provides a tangible benefit. For example, resources that provide winter resource adequacy value in a winter-risk heavy system cannot be replaced, except by another resource that provides equivalent EUE reliability contribution in either summer or winter. Plus, this approach provides that resources are compensated for their contribution to reliability in a manner that is proportional to such contribution. In sum, PJM's simulations and illustrative ELCC/RRS modeling show that PJM's annual model identifies risk whenever it occurs, and aligns resource adequacy risk with capacity accreditation and the expected occurrence of the risk, improving the accuracy of both.

5. Updating the Capacity Emergency Transfer Objective Studies to Employ the ELCC/RRS Model and Switch to an EUE-based Metric is Just and Reasonable.

PJM also proposes to employ the ELCC/RRS model in the studies of the Capacity Emergency Transfer Objective ("CETO"). CETO represents the import capability required by a Locational Deliverability Area ("LDA"), as determined largely by the capacity located within the LDA, resource performance, and load shape characteristics, to meet the current reliability standard of a 0.04 LOLE, or 1-event-in-25-years.[177] PJM performs CETO

[176] Graf Aff. ¶ 28.

[177] *See* proposed RAA, Article 1 – Definitions (defining Capacity Emergency Transfer Objective (CETO)).

studies for each LDA for the purpose of determining the megawatt amount of imports required by that LDA to meet specified reliability targets and that LDA's specific Reliability Requirement.

Furthering the adoption of EUE as a reliability metric used to maintain resource adequacy at reasonable cost, PJM proposes to switch the stated requirement 1-day-in-25-years LOLE metric with an EUE-based metric. Dr. Rocha-Garrido explains that the explicit adoption of an EUE metric is appropriate for CETOs, because "[a]t the LDA level, given the heterogeneity of load profiles (e.g., summer peaking vs. winter peaking LDAs), resource mix (e.g., LDAs with high penetration of renewables of a certain type vs. LDAs with low penetration of renewables vs. LDAs with high penetration of renewables of a different type) and the resulting loss of load risk profiles, . . . an EUE-based value provides a higher degree of comparability between the targeted reliability of LDAs relative to the comparability provided by an LOLE-based criteria."[178] That is, EUE provides greater comparability because the EUE metric is denominated in megawatt-hour terms, and therefore identifies the *amount* of load that cannot be served regardless of how many loss of load events are underneath the EUE metric; in contrast, the LOLE metric identifies the number of events, without consideration of the amount of unserved load.

Specifically, starting with the 2025/2026 Delivery Year, PJM proposes that the CETO studies solve for a megawatt "amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at

[178] Rocha-Garrido Aff. ¶ 22(b).

the annual reliability criteria."[179] To ensure clarity, PJM also proposes to state that "normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals."[180]

As Dr. Rocha-Garrido explains, the 40% EUE metric is comparable to the current 1-day-in-25-years LOLE-based criteria used in the current CETO studies.[181] In fact, it is a translation of the current LOLE metric to EUE, as it "corresponds to the ratio of the current LOLE criteria for an LDA (1-in-25, or 0.04 days/year) and the current LOLE criteria for the RTO (1-in-10, or 0.1 days/year)."[182]

Moreover, by employing the same model as used for the Reserve Requirement Study and ELCC analyses and an EUE-based metric, PJM "seeks to maintain the principle that the transmission/imports risk of an LDA should be small enough relative to the RTO resource adequacy risk so that the total risk that an LDA could face under a worse reserve case scenario (i.e., the sum of the LDA's transmission/import risk criteria and the RTO's resource adequacy risk criteria) is not large."[183] As such, PJM's proposed updating of the CETO definition to correspond with its other modeling changes is just and reasonable.

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[179] Proposed RAA, Article 1 – Definitions (defining Capacity Emergency Transfer Objective (CETO)).

[180] Proposed RAA, Article 1 – Definitions (defining Capacity Emergency Transfer Objective (CETO)).

[181] *See* Rocha-Garrido Aff. ¶ 42.

[182] Rocha-Garrido Aff. ¶ 42. *See also id.* ("In other words, the current and proposed transmission/imports risk criteria for an LDA is 40% of the current and proposed RTO's resource adequacy criteria.").

[183] Rocha-Garrido Aff. ¶ 42.

III. OTHER QUALITATIVE REFORMS ARE APPROPRIATE TO SUPPORT RESOURCE ADEQUACY

A. PJM Proposes Enhancements to Properly Account for Planned Generation Capacity Resources in the Calculation of the Locational Deliverability Area Reliability Requirement.

This filing also proposes to enhance the existing methodology to account for Planned Generation Capacity Resources that are not offered in the RPM Auction for purposes of calculating the Locational Deliverability Area Reliability Requirement.

PJM's capacity market is a locational market, meaning there are defined areas, i.e., LDAs, within PJM that recognize limits on the amount of capacity they can import. Which LDAs are modeled is determined by, inter alia, comparing the import limit of an LDA (also known as the Capacity Emergency Transfer Limit or "CETL") to the amount of capacity that needs to be imported into a LDA to meet the CETO reliability criterion.[184]

For each modeled LDA, PJM determines a Locational Deliverability Area Reliability Requirement, which is the amount of capacity that must be deliverable to an LDA to maintain the desired level of reliability, determined based, in part, on the LDA's CETO and its "projected internal capacity."[185] Planned Generation Capacity Resources are included in the preliminary Locational Deliverability Area Reliability Requirement as projected internal capacity and offset by decreases in the CETO. Specifically, the PJM Manuals explain that any "planned generation resource addition or planned increase in rating that has executed an Interconnection Service Agreement (ISA) is modeled" for

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[184] An LDA is modeled when the CETL is less than 1.15 times the CETO of an area. *See* RAA, Schedule 10.1, section B.

[185] Tariff, Definitions L – M – N (defining Locational Deliverability Area Reliability Requirement).

purposes of determining what planned resources are included in the Locational Deliverability Area Reliability Requirement as projected internal capacity and the CETO modeling.[186] Thus, PJM currently includes all resources with an executed ISA that specifies a commercial operation date that falls on or before the first day of the Delivery Year (June 1) being analyzed in the Locational Deliverability Area Reliability Requirement prior to the auction. Thereafter, if a materiality threshold is reached, Planned Generation Capacity Resources that do not participate in the auction are excluded from the Locational Deliverability Area Reliability Requirement when employing the optimization algorithm during the conduct of the RPM Auction.[187] This allows PJM to more closely align the Locational Deliverability Area Reliability Requirement with actual reliability needs of an LDA based on which Planned Generation Capacity Resources participated in the RPM Auctions. As the Commission previously explained, this process "help[s to] ensure that load-serving entities are charged for capacity based on an LDA Reliability Requirement that reflects actual reliability needs in a manner consistent with supply and demand fundamentals."[188] This is because including Planned Generation Capacity Resources in the Locational Deliverability Area Reliability Requirement when such resources do not

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[186] PJM Manual 18: PJM Capacity Market refers to "PJM Manual 20: PJM Resource Adequacy Analysis, Section 4 PJM Capacity Emergency Transfer Objective Analysis, Subsection 4.3 Modeling Specifics for further details on the resources included in projected internal capacity." Capacity Market & Demand Response Operations, *PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C., 26 (July 26, 2023), https://www.pjm.com/-/media/documents/manuals/m18.ashx. In turn, PJM Manual 20: PJM Resource Adequacy Analysis, Section 4.3 explains that in modeling CETO, "planned generation resource addition or planned increase in rating that has executed an Interconnection Service Agreement (ISA) is modeled." Resource Adequacy Planning, *PJM Manual 20: PJM Resource Adequacy Analysis*, PJM Interconnection, L.L.C. (July 26, 2023), https://www.pjm.com/-/media/documents/manuals/m20.ashx.

[187] *See* Tariff, Attachment DD, sections 5.12(a) and (b).

[188] *PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,109, at P 150.

actually participate in the RPM Auction may result in a reliability requirement that reflects a need for more resources than the actual reliability needs for the LDA.

While the existing Tariff provisions address the aforementioned issue by allowing PJM to revise the Locational Deliverability Area Reliability Requirement based on excluding Planned Generation Capacity Resources that are not offered into the RPM Auction when a materiality threshold is reached, PJM believes that an alternative approach previously suggested by the Market Monitor is preferred. More particularly, consistent with the Market Monitor's prior comments,[189] PJM proposes to require all Capacity Market Sellers of any Planned Generation Capacity Resource to provide a binding notice of intent if such resource will be offered into in the relevant RPM Auction before the auction parameters are posted.[190] Existing Generation Capacity Resources that are not subject to the capacity must offer requirement would not be subject to this requirement because, as the Commission recently explained, "these resources are likely to be producing energy in the Delivery Year and should therefore be included in the [Locational Deliverability Area] Reliability Requirement as internal capacity that may be available during a local capacity emergency."[191]

Capacity Market Sellers of Planned Generation Capacity Resources will be required to submit a notice of intent to offer such resource into the Base Residual Auction

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[189] *See PJM Interconnection, L.L.C.*, Comments of the Independent Market Monitor of PJM, Docket Nos. ER23-729-000 & EL23-19-000, at 5 (Jan. 20, 2023).

[190] *See* proposed Tariff, Attachment DD, section 5.5.

[191] *PJM Interconnection, L.L.C.*, 184 FERC ¶ 61,055, at P 115 (2023).

by December 1 prior to such auction.[192] This is necessary so that PJM has adequate time to model such Planned Generation Capacity Resources in the ELCC/RRS model, which is used in the calculation the Locational Deliverability Area Reliability Requirement. PJM must run this analysis and post the results in advance of the Base Residual Auction, and therefore, PJM must start the analysis by the end of each calendar year. Therefore, PJM must have such information in time and requiring Capacity Market Sellers to submit the binding notice of intent to offer by December 1 prior to each Base Residual Auction is appropriate.[193] For the Incremental Auctions, PJM will not need to complete a new ELCC analysis and will only use the notice of intent to participate for purposes of calculating the Locational Deliverability Area Reliability Requirement. Thus, Capacity Market Sellers of Planned Generation Capacity Resources would need to provide a binding notice of intent to participate no later than 90 days prior to the conduct of an Incremental Auction.[194]

Planned Generation Capacity Resources that are the subject of such binding notice of intent would then be required to be offered into the applicable RPM Auction.[195] Conversely, Planned Generation Capacity Resources that are not the subject of a binding

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[192] *See* proposed Tariff, Attachment DD, section 5.5. It is acknowledged that for the 2025/2026 Base Residual Auction, this deadline would mean Capacity Market Sellers of Planned Generation Capacity Resources would be required to provide their binding notice of intent on or before December 1, 2023, and before an expected Commission order on this filing. As with prior filings where a proposed deadline occurs before an expected order date, PJM will accept such notices of intent to participate by the December 1, 2023 deadline, contingent upon Commission acceptance of this filing.

[193] PJM also proposes that "for the 2026/2027 and 2028/2029 Delivery Years, such notice shall be submitted by 180 days prior to the commencement of the offer period." *See* proposed Tariff, Attachment DD, section 5.5. This is reasonable, given the compressed timelines for conducting Base Residual Auctions for these Delivery Years.

[194] *See* proposed Tariff, Attachment DD, section 5.5.

[195] *See* proposed Tariff, Attachment DD, sections 6.6(a) and 6.6A(a).

notice of intent to participate would not be allowed to be offered as capacity into the relevant RPM Auction. This approach will result in a Locational Deliverability Area Reliability Requirement that reflects the reliability needs of an LDA without having to recalculate the reliability requirement during the conduct of the RPM Auction based on actual participation.[196] To enforce this requirement, PJM proposes that for any Planned Generation Capacity Resource that is associated with a notice of intent to offer, but is not offered into the auction, such resource will not be allowed to be offered in each of the subsequent Incremental Auctions associated with that Delivery Year.[197] This approach is consistent with the enforcement provision in the existing Tariff that precludes any Capacity Resources that are subject to the must offer requirement, but that do not meet any of the must offer exceptions and did not offer into the auction.[198] In this way, PJM proposes to preclude Planned Generation Capacity Resources that are associated with a notice of intent to offer with the same existing rules that are applied to Generation Capacity Resources that are subject to the must offer requirement that do not offer with a valid exception request.

Such a solution is an improvement over the existing rules as it will not require PJM to recalculate the Locational Deliverability Area Reliability Requirement during the conduct of the RPM Auction. This will ultimately provide greater transparency to Market Participants while reducing the administrative tasks that are needed for PJM to complete in running the optimization algorithm during the conduct of the RPM Auctions. Therefore,

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[196] *See* proposed Tariff, Attachment DD, section 5.5.

[197] *See* proposed Tariff, Attachment DD, section 6.6(h).

[198] Tariff, Attachment DD, section 6.6(g).

this approach is just and reasonable and preferable to the status quo of having to adjust the Locational Deliverability Area Reliability Requirement during the conduct of the auction.

B. Without Changing Its Shape, PJM Proposes to Update the Inputs Used in Determining the VRR Curve.

In PJM's last quadrennial review of the VRR Curve used to clear Base Residual Auctions, PJM proposed, and the Commission accepted, changes to the metric inputs used to determine the VRR Curve starting with the 2026/2027 Delivery Year. Specifically, to simplify and provide stability to the curve, PJM proposed to state in the VRR Curve formula set percentages to be applied directly against the Reliability Requirement, in place of the pre-existing mode of using factors to convert the Installed Reserve Margin to Unforced Capacity.[199] PJM explained that "[r]eplacing the [Installed Reserve Margin]-based formula with the Reliability Requirement is reasonable, as both metrics represent the 'target level of reserves required' to meet reliability standards, but are expressed in different capacity values."[200]

In this filing, PJM proposes changes in the same vein to the determination of the VRR Curve for the Base Residual Auction for the 2025/2026 Delivery Year. PJM proposes to bring forward by a year the use of set percentages that are applied directly against the Reliability Requirement rather than against the Installed Reserve Margin. This change will allow the revised formula for each x-axis point of the VRR Curve to more concisely define

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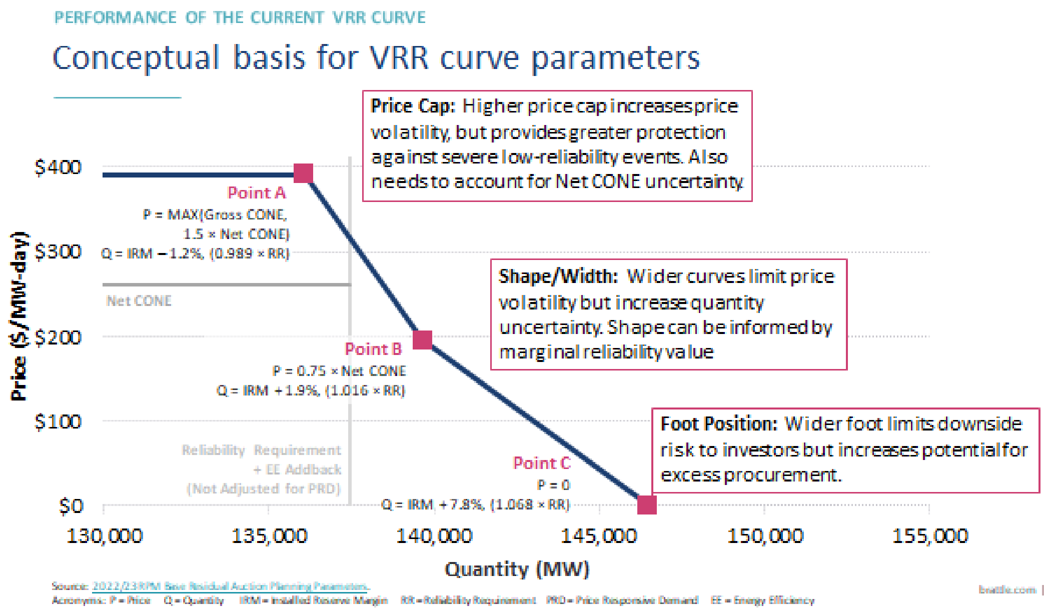
[199] Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters of PJM Interconnection, L.L.C., Docket No. ER22-2984-000, at 16 (Sept. 30, 2022) ("Quadrennial Review Filing"); *PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073, at P 157 (2023).

[200] Quadrennial Review Filing at 16 (quoting *PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C., 28 (Sept. 21, 2022), https://www.pjm.com/-/media/documents/manuals/m18.ashx).

the PJM Region Reliability Requirement percentage as a direct percentage as opposed to a formula, based on Installed Reserve Margin, that yields the same PJM Region Reliability Requirement percentage. PJM proposes to use the percentages that are the PJM Region Reliability Requirement of the current IRM-based ratio to determine VRR Curve Points (1), (2), and (3), which are shown as Points A, B, and C in Figure 2 below.

Figure 2: Current PJM VRR Curve



Under this change, for example, PJM proposes in the determination of the Unforced Capacity at Point A to replace

> [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 1.2%) divided by (100% plus IRM%)]

with

> [the PJM Region Reliability Requirement multiplied by 98.9%].[201]

[201] Proposed Tariff, Attachment DD, section 5.10(a)(i).

PJM proposes similar simplifications for Points (2) and (3), where PJM proposes to set the Unforced Capacity quantity of Point (2) at 101.6% of the PJM Region Reliability Requirement, and Point (3) at 106.8% of the PJM Region Reliability Requirement.[202]

In addition, for the determination of the point on the y-axis, PJM proposes to discontinue using a percentage based on "one minus the pool-wide EFORd" as the factor to convert the net Cost of New Entry ("CONE") price from a $/MW-day on an installed capacity basis to be on an Unforced Capacity basis. In its place PJM proposes to use the Reference Resource's ELCC Class Rating.[203] The availability of an ELCC Class Rating specific to the Reference Resource will provide for a more accurate determination of the net CONE $/MW-day UCAP value at Points (1) and (2).[204] (The price at Point (3) remains set to zero.) PJM proposes to make this change effective with the 2025/2026 Delivery Year and continue it going forward.[205]

C. PJM Proposes Revisions to its Sell Offer Requirements to Align with Its Proposed ELCC/Modeling Changes.

Consistent with its proposal to discontinue use of EFORd in favor of PJM's proposed marginal ELCC approach to determine each Generation Capacity Resource's capacity accreditation, PJM proposes to modify its Sell Offer requirements to require Generation Capacity Resources to specify their Accredited UCAP Factor, beginning with

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[202] Proposed Tariff, Attachment DD, section 5.10(a)(i).

[203] *See* proposed Tariff, Attachment DD, section 5.10(a)(i).

[204] PJM proposes this same change for use in the New Entry Price Adjustment determination. *See* Tariff, Attachment DD, section 5.14(c)(3).

[205] *See* proposed Tariff, Attachment DD, section 5.10(a)(i).

the 2025/2026 Delivery Year.[206] The Accredited UCAP Factor will be established by PJM prior to the applicable RPM Auction, and will be multiplied by the ICAP offered to convert the ICAP offered into the UCAP offered.[207] If a Capacity Market Seller is committing the resource as Self-Supply, the Accredited UCAP Factor determined by PJM shall apply to that commitment.[208]

To calculate the Nominated Demand Resource Value included in a Demand Resource's Sell Offer, PJM proposes to convert the nominated Demand Resource value to a UCAP basis by multiplying such value by the applicable ELCC Class Rating beginning with the 2025/2026 Delivery Year.[209]

IV. REVISIONS TO THE CAPACITY PERFORMANCE CONSTRUCT ARE APPROPRIATE TO ACHIEVE RESOURCE ADEQUACY AT LEAST COST

A. PJM Proposes to Enhance Its Resource Testing Requirements to Ensure that Capacity Resources Are Physically Capable of Responding During Performance Assessment Intervals.

To strengthen the Capacity Performance framework,[210] PJM proposes to enhance its testing requirements for Capacity Resources that are committed through an RPM Auction or included in an FRR Plan by (1) adding a requirement for such resources to physically perform a capability test in both the winter and summer seasons; (2) assessing

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[206] *See* proposed Tariff, Attachment DD, section 5.5.

[207] *See* proposed Tariff, Attachment DD, section 5.6.1(e)(i).

[208] *See* proposed Tariff, Attachment DD, section 5.6.1(e)(ii).

[209] Energy Efficiency Resources will continue to convert the Nominated Energy Efficiency Value to UCAP by multiplying the value times the Forecast Pool Requirement. *See* RAA, Schedule 6, section L.3.

[210] The suite of capacity market reforms accepted in *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015), *order on reh'g & compliance*, 155 FERC ¶ 61,157, *aff'd sub nom. Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656 (D.C. Cir. 2017), installed the "Capacity Performance" construct.

any testing shortfalls, in the form of capacity test failure charges, for each day of the season by comparing the seasonal test value against the resource's daily committed installed capacity, rather than the average seasonal committed installed capacity; (3) creating a new test, referred to as the Generator Operation Test, to test resource capability and operating parameter accuracy prior to periods of the year where PJM may experience extreme weather conditions; and (4) conforming the testing requirements for Demand Resources.[211] As Mr. Keech explains, "the purpose of making these changes is to better balance the financial incentives for performance conveyed through Capacity Performance with actual demonstrations of capacity resource capability prior to the Performance Assessment Intervals where Non-Performance Charges and bonus payments may apply."[212]

PJM's recent experience with Winter Storm Elliot demonstrates that the current annual testing obligations set forth in Tariff, Attachment DD, sections 7 and 11A, could be enhanced to better test generators' and Demand Resources' physical capability when called upon during a Performance Assessment Interval. Specifically, Mr. Keech explains that "resources that had run within a month of Winter Storm Elliott experienced a forced outage rate that was 25% percentage points lower than those that had not run as recently."[213] In fact, resources that had last run more than four weeks prior to Winter Storm Elliott had a forced outage rate of more than 70%, providing clear evidence that resources that ran more recently performed better relative to those that ran more than four weeks before the

[211] Keech Aff. ¶ 22.

[212] Keech Aff. ¶ 21.

[213] Keech Aff. ¶ 27.

event.[214] Additionally, as Mr. Keech explains, "over 80% of the outages experienced during Winter Storm Elliott were mechanical in nature" and not due to a lack of fuel supply.[215]

Thus, this data demonstrates that there is an opportunity to enhance testing and better balance the demonstration of performance through testing with the financial incentives conveyed through Capacity Performance. Given these findings, PJM and its stakeholders evaluated opportunities to improve testing rules to complement assessments during actual reliability events, including frequency of the tests, defined guidelines for test success/failure, and penalties for test failure.

As discussed below, PJM's proposed enhancements to its testing requirements increase reliability by better testing the physical capabilities of committed resources and incentivizing resources to maintain their operational status. The proposal should therefore be accepted as filed.

1. Generation Resource Capacity Tests Should Be Required in Both the Summer and Winter Seasons.

PJM's current generator capacity capability test rules require only a single test to be conducted in the summer and permits the use of ambient temperature adjustments from the summer test result to demonstrate winter capability. However, in light of recent experience, these existing testing requirements should be updated for PJM to have greater confidence that committed Capacity Resources are physically capable of performing when called upon during an emergency. Specifically, Mr. Keech explains that, "empirical

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[214] *See* Keech Aff. ¶ 27.

[215] Keech Aff. ¶ 29.

observations from Winter Storm Elliott and similar extreme events in other ISO/RTOs, as well as the analysis performed by Dr. Rocha-Garrido to determine the ELCC for Capacity Resources, clearly demonstrate that generators operate differently in the summer and winter. These observations and analyses indicate that the current method of extrapolating winter capability from summer capability through ambient temperature adjustments is not suitable to determine the true winter capability of a generation resource."[216]

To address these concerns, PJM believes that the best way to assess both summer and winter capability is by requiring physical demonstrations of this capability in each season.[217] Therefore, PJM is proposing to require the generator capacity capability test to be conducted in both the summer and winter seasons during the Delivery Year for any Generation Capacity Resource, excluding Variable Resources,[218] that is committed through the RPM Auctions or in an FRR Plan.[219] Consistent with the existing rules, the resource owner or operator may rely upon an unlimited number of tests or operational data during each seasonal testing period to demonstrate the capability of the resource. This is appropriate because the purpose of the capacity capability test is to verify that committed Generation Capacity Resources are capable of generating up to their committed megawatt amount of installed capacity.[220]

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[216] Keech Aff. ¶ 24.

[217] Keech Aff. ¶ 24.

[218] As part of this filing, PJM is clarifying in Tariff, Attachment DD, section 7(a) that Variable Resources are not subject to the Generation Resource Rating Test Failure Charge, as currently noted in the PJM Manuals. This is appropriate given the varying nature of the resource's capability as a function of its energy source, along with the fact that the capacity accreditation of these resources largely relies upon such Variable Resource's historical output rather than a claimed installed capacity level that may be committed.

[219] *See* proposed Tariff, Attachment DD, section 7.1(a).

[220] Keech Aff. ¶ 25.

Consistent with the existing rules, a Generation Capacity Resource that fails the generator capacity capability test will continue to be assessed a test failure charge for each day of the Delivery Year.[221] However, PJM is proposing to modify the manner in which it assesses charges for failure to satisfy seasonal generator capability testing requirements under the Tariff. Specifically, under the current capability testing construct, the Generation Resource Rating Test Failure Charge is calculated at the end of each Delivery Year and includes MW shortfall calculation based on the annual average of the installed capacity committed on each resource minus the highest installed capacity rating determined for the resource during the relevant summer or winter testing period. That MW shortfall is then multiplied by the Daily Deficiency Rate.[222]

Effective with the 2025/2026 Delivery Year, PJM proposes to assess the resource's MW shortfall on the daily installed capacity commitment of the resource in calculating the MW shortfall rather than annual average of the installed capacity committed on the resource.[223] This will allow for a more precise determination of whether the installed capacity that a committed Generation Capacity Resource is committed for each day aligns with its demonstrated capability. As Mr. Keech explains, "[t]he current process of using an annual average is directionally reasonable but can miss scenarios where on any given day, a resource's committed installed capacity is higher than its demonstrated seasonal capability but when averaged annually is missed."[224] Thus, this enhancement effectively

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[221] *See* proposed Tariff, Attachment DD, section 7.1(b).

[222] Keech Aff. ¶ 25, see Tariff, Attachment DD, section 7.1(b).

[223] *See* proposed Tariff, Attachment DD, section 7.1(a).

[224] Keech Aff. ¶ 25.

requires Generation Capacity Resources to demonstrate that they are able to meet their capacity commitment for every single day of the Delivery Year. If they cannot, such Generation Capacity Resources will be assessed as deficient and subject to a generation resource rating test failure charge.

2. Generator Operational Testing Will Better Test a Resource's Operational Capabilities.

Beyond the enhancements to the generator capacity capability test described above, this filing proposes to conduct seasonal generator operational testing.[225] This includes up to two PJM-initiated tests of a generator's availability status, per season every Delivery Year, to better gauge the operating capability of such resources if and when they are needed for reliability.[226] As Mr. Keech explains, seasonal testing, up to twice in each season, will mean resources are required to run more often, so that when there is an emergency, the likelihood of a forced outage should be significantly reduced.[227] The timing of the tests and re-tests are subject to PJM's dispatch discretion, as the goal is to issue the test during system conditions that are directionally close to those faced during a reliability event.[228]

PJM's selection of resources for operational testing and the timing of such tests will be based on a number of factors, including the period of time since a unit last operated, the system conditions under which the unit has recently operated, the expected system conditions during the operational test, and the recent performance of units with respect to

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[225] *See* proposed Tariff, Attachment DD, section 7A(a).

[226] *See* proposed Tariff, Attachment DD, section 7A(a).

[227] Keech Aff. ¶ 27.

[228] Keech Aff. ¶ 31.

successfully starting and operating within the specified parameters.[229] While PJM is proposing these factors for when resources may be tested, the language is intentionally crafted in a manner that would allow PJM to conduct operational tests with an element of surprise. Such "real world" testing will better help to verify the resource's stated operational capabilities and will identify potential problems before an actual capacity emergency. As Mr. Keech explains, "the Generation Capacity Resource Operational Test will result in better operational performance of the generation fleet during capacity emergencies because it specifically creates an opportunity to test the operating capability of a resource prior to the event itself. This will help to identify any operational issues with a Generation Capacity Resource before an actual emergency condition arises."[230] Thus, the proposed generation operational testing will increase reliability by giving PJM a direct view into a resource's physical capabilities.

Under the proposed generator operational test, PJM will initiate a test that respects the operating parameter limits of the available schedule on which the unit is committed.[231] A unit will be considered to have passed its test if it is synchronized to the grid within the start-up times specified in the schedule that PJM tests the unit on and operates for its minimum run time. To be clear, the schedule that PJM could test the unit on would not be limited to a cost offer so that PJM can have the flexibility of electing to test resources based

[229] *See* proposed Tariff, Attachment DD, section 7A(a).

[230] Keech Aff. ¶ 34.

[231] *See* proposed Tariff, Attachment DD, section 7A(a).

on the most flexible schedule (which could be a resource's non-parameter limited price schedule). If the unit fails the test, PJM may schedule a re-test of the unit.[232]

PJM may issue re-tests (at the unit owner's cost) following any failed test.[233] A PJM-initiated re-test has the same requirements as the initial test. Units will receive make-whole payments for costs associated for initial tests; however, units are not eligible to be made whole for PJM-initiated re-tests following a failed test.[234] Mr. Keech clarifies that "[t]his allows PJM to continue re-testing resources that fail, without subjecting load to further uplift payments, which improves PJM's visibility of the operational capabilities of resources, and provides an incentive for generation owners to be accurate in the operating parameters submitted to PJM and used for scheduling."[235]

For the generator operational tests, the Generation Capacity Resource will be dispatched and settled the same as any other resource operating in the PJM energy market and any uplift required to ensure the resource has recovered its operating cost will be covered by PJM's existing uplift provisions detailed in Tariff, Attachment K-Appendix, section 3.2.3 and the parallel provisions of Operating Agreement, Schedule 1, section 3.2.3.[236] However, if the resource fails its initial test, the resource will not be eligible for any uplift payments incurred during any re-tests.[237] If the retest is also failed, regardless of

[232] Keech Aff. ¶ 32.

[233] Proposed Tariff, Attachment DD, section 7A(a).

[234] Re-tests do not count against the limit of two tests that PJM may initiate per season. *See* proposed Tariff, Attachment DD, section 7A(a).

[235] Keech Aff. ¶ 32.

[236] Keech Aff. ¶ 32.

[237] *See* proposed Tariff, Attachment DD, section 7A(a).

the reason, a Generation Capacity Resource Operational Test Failure Charge will apply from the point at which the Generation Capacity Resource failed the re-test until it can successfully synchronize to the grid after such a failed test, regardless of whether the re-test is initiated by PJM or another entity.[238]

Any Generation Capacity Resource that fails a retest of the resource operational test will be subject to a Generation Capacity Resource operational test failure charge equal to the Daily Deficiency Rate multiplied by the applicable daily committed unforced capacity MW of that Generation Capacity Resource.[239] To avoid being potentially overly-punitive, the operational test failure charge is only assessed when resources fail to come online after a retest. However, once such operational test failure charge is assessed, it will continue to be assessed on a daily basis until such time the Capacity Resource is able to successfully demonstrate that it is operational again and synchronizes back to the grid.[240] Additionally, because it is also important that generators are able to operate in a manner consistent with the parameters specified in their offers, when a resource fails to pass the test due to operating parameters, PJM continues to reserve the right to continue issuing a re-test of the resource (without the ability to receive uplift) until they demonstrate they can operate within the provided parameters.

The operational test failure charge will apply during Performance Assessment Intervals; however, the resource will be charged only if it is equal to or greater than the

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[238] *See* proposed Tariff, Attachment DD, section 7A(a).

[239] *See* proposed Tariff, Attachment DD, section 7.1(b-1); Keech Aff. ¶ 33.

[240] *See* proposed Tariff, Attachment DD, section 7A(a); Keech Aff. ¶ 32.

charges assessed for Performance Shortfalls under Tariff, Attachment DD, section 10A.[241] The operational test failure charge will not apply if a resource is assessed for unavailability under Tariff, Attachment DD, section 8.[242] Mr. Keech explains that the proposed operational test failure charge incentivizes physical performance while preventing the resource from being double-charged for failure to operate.[243] Finally, similar to the existing generation resource rating test failure charge, all revenues collected from the operational test failure charge will be "distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Generation Capacity Resource Operational Test Failure Charge was assessed."[244]

3. Conforming Revisions to Testing and Failure Charge Requirements for Demand Resources Will Similarly Help to Prepare These Resources for Performance Assessment Intervals.

In addition to the above-described changes, PJM proposes to revise Tariff, Attachment DD, section 11A, to conform the testing requirements for Demand Resources and to clarify how failure charges apply to Demand Resources that fail to perform.[245] Specifically, the proposed revisions state that if a Demand Resource is not dispatched for a Load Management event in a Delivery Year and assessed for performance during Performance Assessment Intervals,[246] then the resource will be tested, at a date and time to

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[241] *See* proposed Tariff, Attachment DD, section 7A(b).

[242] *See* proposed Tariff, Attachment DD, section 7A(b).

[243] Keech Aff. ¶ 34.

[244] *See* proposed Tariff, Attachment DD, section 7A(c).

[245] *See* proposed Tariff, Attachment DD, section 11A.

[246] Under the currently effective Tariff, Demand Resources are not capability tested in the same manner as other Capacity resources. Instead, Demand Resources are "tested" when they perform (or do not) during a Performance Assessment Interval. *See* Tariff, Attachment DD, section 11A.

be determined by PJM, for a two-hour period during the relevant Delivery Year.[247] This change is merely a conforming change given that the existing rules were developed based on the prior Emergency Action definition where being dispatched for a Load Management event was deemed an Emergency Action (and automatically triggered a Performance Assessment Interval). Now that the definition of Emergency Action has recently been amended, a Load Management action does not automatically result in a Performance Assessment Interval where Demand Resource performance would be assessed. As a result, PJM is now simply clarifying that beginning with the 2024/2025 Delivery Year, Demand Resource test would not be required if there is a Load Management event and such Demand Resource is assessed for performance during a Performance Assessment Interval in a Delivery Year.

Notwithstanding these requirements, a Capacity Market Seller may elect to utilize performance data from a Load Management event in the Delivery Year that was not assessed for performance during Performance Assessment Intervals to be considered in the Demand Resource test requirement, as long as the event is at least 30 minutes of a clock hour.[248] If an Annual Demand Resource is dispatched for a Load Management event during the Delivery Year, and assessed for performance during Performance Assessment Intervals, then no test will be required.[249]

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[247] Annual Demand Resources may be tested during June through October or November through March of the relevant Delivery Year. Proposed Tariff, Attachment DD, section 11A(b)(iii)(A-1). Summer-Period Demand Resources may be tested June through October of the relevant Delivery Year. Proposed Tariff, Attachment DD, section 11A(b)(iii)(B-1).

[248] For Summer-Period Demand Resources, the Load Management must occur in the summer.

[249] *See* proposed Tariff, Attachment DD, section 11A(b)(iii)(A).

Consistent with the existing rules, Committed Demand Resources that do not satisfy these testing requirements will be assessed a Demand Resources Test Failure Charge equal to the net capability testing shortfall for such products tested in a Zone during such test in the aggregate of all of such Seller's Demand Resources tested in such Zone times the Demand Resources Test Failure Charge Rate.[250] The net capability testing shortfall in a Zone will be a MW quantity, converted to an Unforced Capacity basis using the applicable Forecast Pool Requirement prior to 2025/2026 Delivery Year, and the applicable ELCC Class Rating beginning with the 2025/2026 Delivery Year.[251]

The proposed Demand Resource testing and failure charge revisions are necessary to reflect that emergency load management no longer automatically triggers a Performance Assessment Interval. As the Commission recently recognized, "it is appropriate to remove the deployment of pre-emergency load response and emergency load response from the trigger for a [Performance Assessment Interval ("PAI")] because PJM cannot verify the amount of response these resources are providing until 60 days after an event, and therefore it may be prudent for PJM operators to maintain load response even after capacity shortage conditions pass."[252] Because deployment of Demand Resources no longer produces a Performance Assessment Interval, annual testing is necessary to increase the likelihood that Demand Resources will actually perform as expected during a Performance Assessment Interval.

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[250] *See* Tariff, Attachment DD, section 11A(c).

[251] *See* proposed Tariff, Attachment DD, section 11A(c).

[252] *PJM Interconnection, L.L.C.*, 184 FERC ¶ 61,058, at P 34 (2023); *see* Graf Aff. ¶ 48.

B. The Stop-Loss Limit Should Be Reduced in Connection with a Decreased Risk of Non-Performance Along with Enhanced Generator Testing Requirements.

The stop-loss limit (referred to in the Tariff as the "Non-Performance Charge Limit") caps the amount any Capacity Performance Resource can lose in Non-Performance Charges during a delivery year.[253] Under the current Tariff, a resource's stop-loss is capped at 1.5 times the net CONE, multiplied by the committed MW of Unforced Capacity times the number of days in the Delivery Year.[254] In accepting the currently effective stop-loss limit, the Commission found that it "protects resources against exceedingly large penalties resulting from an unforeseen event."[255] The Commission further found that "[t]he stop-loss provision is designed to provide some protection to capacity resources while not unduly limiting the performance incentive underlying the Non-Performance Charge provisions,"[256] while still retaining the appropriate incentive for each resource to respond during an emergency—"[s]ince each unit's performance may be crucial and all units need to have sufficient incentive to make investments and perform when needed.[257]

Thus, the stop-loss limit caps the financial exposure for each Delivery Year a Capacity Resource may encounter. In economic parlance, the stop-loss acts as a hedge for Capacity Market Sellers to mitigate the risk of incurring exceedingly large Non-Performance Charges during Performance Assessment Intervals over a Deliver Year. It is

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[253] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 164.

[254] Graf Aff. ¶ 48.

[255] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at P 78.

[256] *Id*. at P 80.

[257] *Id*. at P 80.

designed to work in concert with other aspects of the Capacity Performance construct to allow Capacity Market Sellers and Locational UCAP Sellers to appropriately assess their risk of exposure during a particular Delivery Year.[258] As such, any changes to the stop-loss limit should be evaluated in conjunction with other elements of the Capacity Performance construct and capacity reforms more generally.

Here, PJM is proposing to revise how the stop-loss limit is determined by changing the index price to the Base Residual Auction clearing price rather than to the net CONE.[259] This would result in a reduction of the stop-loss limit in years that the capacity prices fall below net CONE, as has been the case in recent history.

Indexing the stop-loss limit to the Base Residual Auction clearing price is just and reasonable. Making the stop-loss a function of the clearing price on which Capacity Resources are compensated provides a total net charge liability that is in better proportion to their capacity revenues and the risks associated with taking on a capacity commitment. During periods of relatively low capacity prices (as seen in recent years), such relationship between revenues and exposure serves to reduce the likelihood that Capacity Performance risk would make it uneconomic for otherwise willing market sellers to accept the obligations – and associated risks – of taking on a capacity obligation.

Winter Storm Elliott illustrated that indexing the stop-loss to net CONE exposes resources to a level of annual Non-Performances Charges that may equal many years of capacity revenues, and is disproportionate to the revenues associated with an annual

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[258] Graf Aff. ¶ 49.

[259] *See* proposed Tariff, Attachment DD, section 10A(f-1).

capacity commitment. For example, the net CONE for the RTO in the 2022/2023 Delivery Year was roughly $90,000/MW-year, providing for an annual stop-loss of $135,000/MW-year, meaning that the stop-loss was about 7.5 times higher than the RTO Base Residual Auction clearing price for that year ($50/MW-day, or $18,250/MW-year). In other words, the existing stop-loss provisions allow for a resource to lose about 7.5 years of capacity revenues from a single event. The number of years of capacity revenues at stake would increase at even lower clearing price levels. This high level of exposure relative to compensation in the market may not represent the best balance between incentives and risk, and results in significant tail risk for Capacity Market Sellers, which could have an impact of chilling future investment in PJM's capacity market or even inducing premature retirements.

As an alternative, the proposed stop-loss that is indexed to the Base Residual Auction clearing price significantly reduces the low-probability, high-impact, tail risk by providing an explicit link between the capacity revenues that resources receive and their maximum exposure to Non-Performance Charges in a year. PJM's proposal would still expose resources to an annual net loss in capacity revenue from poor performance, and would thereby maintain the balance recognized by the Commission of "provid[ing] some protection" to Capacity Market Sellers, and their investors, while still maintaining the necessary financial performance incentives.[260]

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[260] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at P 80.

As Dr. Graf explains, adjusting the stop-loss "reduce[s] the tail-end risk of the most extreme non-performance charges that could harm the investability of the PJM markets."[261] Dr. Graf further explains that a "high stop-loss places substantial idiosyncratic risk on Capacity Market Sellers," which is reasonable without the adoption of PJM's proposed modeling, accreditation, and testing changes.[262] But, with those changes, such high stop-loss limit maintains "the potential, however unlikely, for a Capacity Market Seller to lose multiple years of capacity revenues for non-performance in a single event may deter future investments in PJM's markets, ultimately undermining the competition that the capacity market needs to meet the twin objectives of reliability and efficiency."[263] Lowering the stop-loss limit helps maintain robust competition in the Capacity market by safeguarding against the potential for loss of multiple years of capacity revenues, which could in turn deter or chill future investments in PJM's capacity market.[264] With regard to preserving performance incentives, PJM is confident that the proposed change in the stop-loss limit will not affect resource performance during emergency conditions. Several factors support this conclusion.

First, PJM is making no changes to the Non-Performance Charge Rate despite requests from certain stakeholders to do so and a proposal from the Market Monitor to discard the Non-Performance Charges entirely. Thus, the Non-Performance Charge rate

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[261] Graf. Aff. ¶ 49.

[262] Graf. Aff. ¶ 49.

[263] Graf. Aff. ¶ 49.

[264] Graf Aff. ¶ 49.

will still be tied to net CONE, which will continue to serve as a strong impetus for resource performance during emergency conditions.

Second, the proposed modifications to Capacity Resource accreditation and risk modeling, proposed as part of this filing, provide increased confidence that PJM will procure resources that are capable of providing capacity during emergencies. Further, the proposed intra-Delivery Year testing requirements will enhance the likelihood that resources with capacity commitments will actually perform during Performance Assessment Intervals.[265] This strengthening of the likelihood of actual performance and maintenance of the existing Non-Performance Charge rate is appropriately balanced with a reduction in the cap on exposure to Non-Performance Charges are that tied to actual performance.[266] Plus, PJM's proposed stop-limit retains the essential element that a Capacity Market Seller's capacity revenues can go negative if the resource underperforms during emergencies.

Finally, the refined definition of Emergency Action recently accepted by the Commission[267] limits the likelihood of actually exceeding the stop-loss limit by more

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[265] *See* Keech Aff. ¶ 27 (providing analysis demonstrating that resources that had run within a month of Winter Storm Elliott experienced a forced outage rate that was 25% percentage points lower than those that had run less recently).

[266] Graf Aff. ¶ 50.

[267] *See PJM Interconnection, L.LC.*, 184 FERC ¶ 61,058, at P 1. An Emergency Action is defined as "(1) any megawatt shortage of the Primary Reserve Requirement (as specified in the PJM Manuals) in a Reserve Zone or Reserve Sub-zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of non-essential building loads and Voltage Reduction Warning that encompasses such Reserve Zone or Reserve Sub-zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for an entire Reserve Zone or Reserve Sub-zone." Tariff, Definitions – E - F.

narrowly defining the event that triggers a Performance Assessment Interval, and thus reducing the probability of any Capacity Resource being assessed total Non-Performance Charges that exceed the stop-loss. For example, had this new definition been in place during Winter Storm Elliott, the total number of Performance Assessment Intervals would have fallen from 277 (~23 hours) down to 73 Performance Assessment Intervals (~6 hours).[268] As a result, the change to the triggers to focus on the most extreme risk periods lowers the probability of a PAI occurring, let alone enough PAIs to make the current stop-loss binding for any Capacity Market Seller, all other things held equal.[269] And, in the event a resource hits its annual stop-loss limit, the scarcity pricing that will be in effect during the Emergency Action would continue to provide some financial incentive for resource performance.

In making this proposal, PJM accounted for the need to balance the elements of risk while also strengthening resource performance. As the Board explained in its letter, "the combination of the enhanced testing requirements in the PJM proposal, retention of the Non-Performance Charge Rate calculation, the recent changes to the triggers for PAIs to align with more severe emergency conditions, and a reduction in the stop-loss from 1.5 × net CONE × 365 to 1.5 × [Base Residual Auction] Clearing Price × 365 provides a reasonable balance between additional requirements, strong performance incentives during system emergencies and risk to capacity suppliers."[270]

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[268] *See* Graf Aff. ¶ 51.

[269] *See* Graf Aff. ¶ 51.

[270] Letter from Mark Takahashi, Chair, PJM Board of Managers, to PJM Interconnection, L.L.C. Stakeholders, 3 (Sept. 27, 2023) (https://pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230927-pjm-board-letter-re-its-decision-within-the-cifp-ra.ashx).

V. PJM PROPOSES REVISIONS TO BETTER SYNCHRONIZE THE FIXED RESOURCE REQUIREMENT ALTERNATIVE RULES WITH THE RELIABILITY PRICING MODEL

A. PJM Proposes to Adjust the FRR Insufficiency and Deficiency Charges so that FRR Capacity Shortfalls Are Priced Equal to RPM Capacity Shortfalls, Thereby Providing Stronger Incentives to Procure Sufficient Capacity to Meet FRR Obligations.

Because FRR Entities are solely responsible for acquiring and committing sufficient capacity to meet the Reliability Requirements specific to their Zones, the FRR Alternative rules impose charges whenever an FRR Entity's capacity level falls below the required amount. Specifically, FRR Entities are required to have all required capacity under commitment at least 30 days before the Base Residual Auction for the relevant Delivery Year, and submit an FRR Plan detailing such capacity commitments. If the FRR Plan is short, then after a five-day notice and cure period, PJM assesses the FRR Entity an FRR Commitment Insufficiency Charge equal to two times the CONE (in $/MW-day) for the relevant location times the megawatt shortfall below applicable capacity obligation.[271]

Once the Delivery Year starts, any capacity shortfall is subject to an FRR Capacity Deficiency Charge. Under the existing rules, for each day an FRR Entity fails to have enough committed capacity to satisfy the applicable Daily Unforced Capacity Obligation, the FRR Entity will be assessed an FRR capacity deficiency charge equal to 120% the applicable Base Residual Auction clearing price.[272]

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[271] RAA, Schedule 8.1.D(7).

[272] *See* RAA, Schedule 8.1.F(2) ("FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times (1.20 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 quantities cleared in such auctions).").

PJM proposes to revise these charges so that shortfall charges provide the correct financial incentive for FRR Entities, without being punitive.[273] Specifically, PJM proposes that these capacity shortfall rates should be equal to the RPM clearing price if RPM was facing a capacity shortfall. Thus, both the RPM and FRR rules would send similar incentives with regard to the willingness to pay to alleviate a capacity shortfall. To accomplish this, beginning with the 2025/2026 Delivery Year, PJM proposes to set the deficiency and insufficiency charge rates for FRR Entities at the price-level corresponding to Point 1 on the LDA VRR curve where the FRR obligation exists. As an example, when RPM is short of capacity, starting with the 2026/2027 Delivery Year, the clearing price is set at the greater of gross CONE or 1.75 times net CONE.[274] As Mr. Keech states in his affidavit, "PJM selected the price-level of Point 1 on the applicable LDA VRR curve because the obligation of an FRR Entity is set based on the [Forecast Pool Requirement] which represents the amount of UCAP required to maintain the one-day-in-ten-years Loss of Load Expectation standard. Failure to meet that falls short of the target level of reliability and should correspond to a high penalty rate to incentivize curing the shortfall expeditiously. Additionally, the price associated with Point 1 on the applicable LDA VRR curve" also generally corresponds to the maximum price level loads participating in the

[273] *See* Keech Aff. ¶ 40 ("Two times gross CONE for the insufficiency charge is higher than any point on the VRR Curve used in the RPM Auctions and is inappropriately high and punitive.").

[274] *See* Tariff, Attachment DD, section 5.10(a)(i) ("For the 2026/2027 Delivery Year and subsequent Delivery Years, . . . 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)]}"); proposed RAA, Schedule 8.1.D(7) & Schedule 8.1.F(2).

Base Residual Auction would pay if the RPM auction cleared short of the reliability target.[275]

Further, this change in the deficiency charge is particularly necessary as Base Residual Auction clearing prices have recently cleared as low as $34.13/MW-day in certain Locational Deliverability Areas for the 2023/2024 Delivery Year. Such low clearing price levels means that it may be less expensive for FRR Entities to pay the deficiency charges (set at 1.2 times clearing price) than to procure sufficient capacity to meet the resource adequacy requirements.[276] In other words, an FRR Entity could make the economic choice *not* to procure enough capacity to meet reliability needs, and instead pay the lesser cost (the deficiency charge) and lean on the RPM portion of the RTO to maintain reliability. This is unacceptable, both from reliability/resource adequacy and equity perspectives. Indeed, "[f]ailure to meet that falls short of the target level of reliability and should correspond to a high penalty rate to incentivize curing the shortfall expeditiously."[277] Keying the deficiency charge to the RPM shortfall price will correct these improper incentives and better incentivize FRR Entities to build or contract with resources in a timely manner to meet their capacity obligations.[278]

PJM proposes to apply this rate to determining the Deficiency Charge starting with the 2025/2026 Delivery Year and is proposing to align the deficiency and insufficiency charge rates with Point 1 on the VRR curve rather than a set value because it would allow

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[275] Keech Aff. ¶ 41.

[276] Keech Aff. ¶ 38.

[277] Keech Aff. ¶ 41.

[278] Keech Aff. ¶ 40.

it to remain consistent over time even as the price-level or methodology to determine the price-level of Point 1 changes. PJM proposes to start applying this rate to determine the Insufficiency Charge for FRR Plans beginning with the 2029/2030 Delivery Year. The delay in application of the Insufficiency Charge accommodates the four-Delivery Year transition period for FRR Entities to adjust to the other new rules.

B. PJM Proposes a Transition Period to Allow FRR Entities Time to Align with New Capacity Accreditation Rules.

The changes PJM proposes will enhance the operation of the capacity market and supporting processes so that PJM may meet resource adequacy requirements at reasonable cost.[279] However, the proposed marginal ELCC accreditation approach and its broad application to almost all Capacity Resources is expected to result in many existing Capacity Resources having less Unforced Capacity available to meet reliability requirements. In recognition of (1) this and the other significant changes proposed in the filing, (2) the longer lead time capacity planning in FRR regions, (3) the relatively short timeframe in which such changes will be implemented, and (4) the unique circumstances facing FRR Entities are in due to their inability to purchase capacity through RPM Auctions, PJM proposes two transition mechanisms to smoothen the synchronization with RPM for FRR Entities.[280] The transition mechanisms are designed "ultimately to procure all the resource adequacy needs of the entire PJM Region, either through RPM Auctions or through FRR Plans."[281]

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[279] *See* Keech Aff. ¶ 43.

[280] Keech Aff. ¶ 43.

[281] Keech Aff. ¶ 44.

One option, available to FRR Entities that in the midst of a minimum five-year commitment of the FRR election, is the opportunity to re-join the RPM beginning with the 2025/2026 Delivery Year.[282] This would allow for FRR Entities concerned about being able to meet their capacity obligation the option to "sell their resources in RPM Auctions and purchase capacity from the pool."[283] To prevent flip-flopping, FRR Entities electing this option must commit to a five year minimum commitment period to stay in RPM, and will be not be free to "jump in and out of the market."[284] FRR Entities electing this option must provide written notice of the termination of its election of the FRR Alternative at least two months prior to the Base Residual Auction through the 2028/2029 Delivery Year.[285]

For FRR Entities that elect to remain in the FRR option, PJM proposes to suspend any potential insufficiency charges through the end of the 2028/2029 Delivery Year.[286] This charge applies when an FRR Entity is unable to demonstrate in its preliminary FRR Plan that they have contracted for sufficient megawatts of Unforced Capacity to meet their capacity obligation. Mr. Keech explains that the "magnitude of the [capacity accreditation and other] changes [proposed in this filing] and the relatively quick implementation schedule" dictates that FRR Entities should be afforded a period to adjust their capacity planning without being subject to insufficiency charges.[287] Thus, the FRR Alternative rules should provide that "no FRR Commitment Insufficiency Charge shall be assessed" for the

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[282] *See* Keech Aff. ¶ 43.a; Proposed RAA, Schedule 8.1.C(5).

[283] Keech Aff. ¶ 44.

[284] *See* Keech Aff. ¶ 43.a.

[285] Proposed RAA, Schedule 8.1.C(5).

[286] *See* proposed RAA, Schedule 8.1.D(7).

[287] Keech Aff. ¶ 44.

"Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year."[288]

Importantly, as noted above, the insufficiency charge is based on an FRR Entity's FRR Plan that is submitted at least one month prior to the Base Residual Auction and does not contain sufficient resources to meet such FRR Entity's resource adequacy requirements. Thus, insufficiency charges are assessed based only on an FRR Plan that is submitted *before* the Base Residual Auction and *before* the relevant Delivery Year. It is only this insufficiency charge that is being proposed to be waived between the 2025/2026 Delivery Year and 2028/2029 Delivery Year. Once a Delivery Year starts, an FRR Entity will continue to be assessed a deficiency charge if an FRR Entity still has not secured sufficient capacity during the actual Delivery Year.[289] In this way, an FRR Entity will still be incentivized to secure sufficient capacity to meet its load requirements before the actual start of the Delivery Year. This dichotomy is appropriate during the transition period because it will provide FRR Entities with additional time to procure or build additional Capacity Resources before the Delivery Year begins, while incentivizing them to do so given the potential for deficiency charges if an FRR Entity is still short capacity once the Delivery Year begins.

VI. PJM PROPOSES CERTAIN CLERICAL, MINISTERIAL, AND NON-SUBSTANTIVE REVISIONS TO THE TARIFF IN THIS FILING

Finally, as part of this filing, PJM is proposing limited clerical, ministerial, and non-substantive revisions to the sections of the Tariff that are impacted by this filing. In

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[288]Proposed RAA, Schedule 8.1.D(7).

[289] *Compare* RAA, Schedule 8.1.D(7), *with* RAA, Schedule 8.1.F(2).

reviewing the Tariff and RAA sections that PJM proposes to revise through this filing, PJM identified a number of outdated provisions that are generally limited to removing capacity market rules that have been sunset and are no longer applicable.[290]

VII. SUBSTANTIVE CHANGES PROPOSED IN THIS FILING GENERALLY ARE TO BE EFFECTIVE STARTING WITH THE 2025/2026 DELIVERY YEAR AND WILL NOT DISTURB THE 2024/2025 DELIVERY YEAR

As discussed, PJM is proposing to implement all the changes proposed in this filing starting with the 2025/2026 Delivery Year and for all subsequent Delivery Years, except for the changes to the Demand Resource testing charge provisions in Tariff, Attachment DD, section 11A, which PJM requests to become effective for the 2024/2025 Delivery Year. Generally speaking, the current-effective Tariff capacity market rules will all remain in effect through the end of the 2024/2025 Delivery Year, and will govern issues related to Delivery Years prior to the 2025/2026 Delivery Year, including the Third Incremental Auction conducted for the 2024/2025 Delivery Year. The Tariff revisions PJM is proposing clearly specify this delineation and state that the changes proposed in this filing apply only beginning with the 2025/2026 Delivery Year and all subsequent Delivery Years.

VIII. EFFECTIVE DATE

PJM requests an effective date of December 12, 2023, which is 60 days from the date of filing. Timely Commission action is needed on this filing given that the Base Residual Auction associated with the 2025/2026 Delivery Year is scheduled to commence

[290] *See* Tariff, Attachment DD, sections 5.4(c)(2)(i) & (d); Tariff, Attachment DD, section 5.5; Tariff, Attachment DD, sections 5.6.1(d)(i), (e), (g); Tariff, Attachment DD, sections 5.10(a), (c); Tariff, Attachment DD, sections 5.12 (a), (b); Tariff, Attachment DD, section 6.6(g); Tariff, Attachment DD, sections 11A (b), (c); RAA, Schedule 5, sections (B), (C); RAA, Schedule 6, sections (A)(1), (B)(1), (I), (J), (K), (L); RAA, Schedule 8.1.D(2); RAA, Schedule 8.1.G(1).

on June 1, 2024,[291] with many pre-auction deadlines associated with this upcoming in mid-January, 2024.[292] Thus, acceptance of this filing by the requested effective date is necessary to provide for an orderly conduct of the next Base Residual Auction.

IX. CORRESPONDENCE

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

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[291] Tariff, Attachment DD, section 5.4(a).

[292] *See RPM Auction Schedule*, PJM Interconnection, L.L.C. (Sept. 25, 2023), https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.

X. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;
2. Revisions to the Tariff and RAA in redline format, as Attachment A;
3. Revisions to the Tariff and RAA in clean format, as Attachment B;
4. Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C., as Attachment C;
5. Affidavit of Dr. Walter Graf on Behalf of PJM Interconnection, L.L.C., as Attachment D; and
6. Affidavit of Dr. Patricio Rocha-Garrido on Behalf of PJM Interconnection, L.L.C., as Attachment E.

XI. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[293] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region[294] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through

[293] *See* 18 C.F.R. §§ 35.2(e) & 385.2010(f)(3).

[294] PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

XII. CONCLUSION

Based on the foregoing, PJM requests that the Commission accept the enclosed Tariff and RAA revisions effective December 12, 2023. As noted above, this section 205 filing is part of an overall suite of reforms to PJM's capacity rules. PJM is also proposing a companion section 205 filing that proposes reforms to better align the Market Seller Offer Cap with the risks of committing a Capacity Resource, while also aligning bonus eligibility to match the risks and obligations of resources that take on a capacity obligation. Both filings are just and reasonable on a standalone basis, as explained and supported by the records PJM has presented in each proceeding. However, the combined revisions contained within the two section 205 filings together would provide greater synergies and is preferable as a just and reasonable capacity construct for the PJM Region. Thus, given the complementary, but independent, nature of the two filings, PJM urges that the Commission accept both sets of filings concurrently so that the reforms set forth in this filing align with the changes proposed in PJM's concurrent filing on risk modeling and accreditation. Such acceptance will allow the synergies between the filings to be realized. Acceptance of both filings concurrently and without delay will allow for an orderly implementation of these enhancements beginning with the upcoming Base Residual Auction associated with the 2025/2026 Delivery Year.

Respectfully submitted,

/s/ Ryan J. Collins

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Attachment A

Revisions to the
PJM Open Access Transmission Tariff
and
PJM Reliability Assurance Agreement

(Marked / Redline Format)

Sections of the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

Definitions – C - D

Canadian Guaranty:

"Canadian Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Export Transmission Customer:

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

“Capacity Interconnection Rights” shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

“Capacity Market Buyer” shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

“Capacity Market Seller” shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:

“Capacity Performance Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

“Capacity Resource with State Subsidy” shall mean (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 Resource Clearing Price:

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

Capacity Transmission Injection Rights:

"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cleared Capacity Resource with State Subsidy:

"Cleared Capacity Resource with State Subsidy" shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Closed-Loop Hybrid Resource:

"Closed-Loop Hybrid Resource" shall mean a Hybrid Resource that is physically or contractually incapable of charging from the grid.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

“Collateral” shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. “Collateral” shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

“Collateral Call” shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Co-Located Resource:

“Co-Located Resource” shall mean a component of a Mixed Technology Facility that operates in the capacity, energy, and/or ancillary services market(s) as a separate resource from the other components of such facility.

Commencement Date:

“Commencement Date” shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The “Committed Offer” shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

"Completed Application" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Composite Energy Offer:

"Composite Energy Offer" for generation resources shall mean the sum (in $/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in $/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

Conditional Incremental Auction:

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

Conditioned State Support:

"Conditioned State Support" shall mean 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 in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

"CONE Area" shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an

Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

"Construction Service Agreement" shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

"Contingent Facilities" shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

"Continuous Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(1) 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);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

"Control Zone" shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

"Controllable A.C. Merchant Transmission Facilities" shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

"Corporate Guaranty" shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

Cost of New Entry:

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own load.

Credit Affiliate:

“Credit Affiliate” shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

“Credit Available for Export Transactions” shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

“Credit Available for Virtual Transactions” shall mean the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

“Credit Breach” shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

Critical Natural Gas Infrastructure:

"Critical Natural Gas Infrastructure" shall mean locations with electrical loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility as defined by NERC/FERC standard(s); and until such NERC/FERC standard(s) is developed, is defined as electric loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility, which if curtailed, will impact the delivery of natural gas to bulk-power system natural gas-fired generation.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the

Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

"Customer Facility" shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

"Customer-Funded Upgrade" shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

"Customer Interconnection Facilities" shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges as detailed under Tariff, Attachment DD, section 7~~, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13~~.

Daily Unforced Capacity Obligation:

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

"Deactivation" shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

"Deactivation Avoidable Cost Credit" shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

"Deactivation Avoidable Cost Rate" shall mean the formula rate established pursuant to Tariff, Part V, section 115.

Deactivation Date:

"Deactivation Date" shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

"Decrement Bid" shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, "Default" shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

"Delivering Party" shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

"Delivery Year" shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

Demand Resource Factor or DR Factor:

"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate:

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

"Dispatched Charging Energy" shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

"Dynamic Schedule" shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

"Dynamic Transfer" shall have the same meaning provided in the Operating Agreement.

Definitions – L – M – N

Legacy Policy:

"Legacy Policy" shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource 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.

Limited Demand Resource:

"Limited Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

"Limited Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:
"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

"Load Interest" shall mean, 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.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area. Notwithstanding the foregoing, ~~effective with~~ for the 2024/2025 Delivery Year, during the auction process, the Office of Interconnection shall exclude from the Locational Deliverability Area Reliability Requirement any Planned Generation Capacity Resource in an LDA that does not participate in the relevant RPM Auction as projected internal capacity and in the Capacity Emergency Transfer Objective model where the Locational Deliverability Area Reliability Requirement for the Base Residual Auction increases by more than one percent over the reliability requirement used from the prior Delivery Year's Base Residual Auction (for Incremental Auctions the Locational Deliverability Area Reliability Requirement would be compared with the reliability requirement used in the prior relevant RPM Auction associated with the same Delivery Year) for that LDA due to the cumulative addition of such Planned Generation Capacity Resources.

Locational Price Adder:

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

"Marginal Value" shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

"Market Monitor**"** means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

"Market Monitoring Unit Advisory Committee" or "MMU Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

"Market Participant" shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

"Market Participant Energy Injection" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

"Market Participant Energy Withdrawal" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

"Market Revenue Neutrality Offset" shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Suspension:

"Market Suspension" shall mean the inability of the Office of the Interconnection to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances, as further described in Operating Agreement, Schedule 1, section 1.10.8(d) and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.8(d), or the inability of the Office of the Interconnection to produce Zonal Dispatch Rates for a total of seven (7) or more Real-time Settlement Intervals within a clock hour, for the purposes of the Real-time Energy Market, as further described in Operating Agreement, Schedule 1, section 1.11.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.11.6.

Market Violation:

"Market Violation" shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

"Material Modification" shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

"Maximum Daily Starts" shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource

Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero to the time of the last generator breaker opening as measured by PJM’s State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

“Mixed Technology Facility” shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III.

Network Load:

"Network Load" shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer's Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

"Network Operating Agreement" shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

"Network Operating Committee" shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

"Network Resource" shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

"Network Service User" shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

"New Services Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

"Non-Performance Charge" shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

"Nonincumbent Developer" shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

"Non-Retail Behind The Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

"Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data

or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Operating Agreement, section 18.17.

B. <u>Required Disclosure</u>:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Tariff, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the Market Monitoring Unit using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the Market Monitoring Unit from a third party which is not, to the Office of the Interconnection's or Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. <u>Disclosure to FERC and CFTC</u>:

1. Notwithstanding anything in this section I to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC") or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in section I.B.

D. <u>Disclosure to Authorized Commissions</u>:

1. Notwithstanding anything in this section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member

is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member’s confidential information to any other Member.

(iii) Notwithstanding section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit’s receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a “fast track” complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. [Reserved]

II. <u>DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION</u>

A. <u>Offer Price Caps</u>:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Operating Agreement, Schedule 1, section 6.4.2and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Operating Agreement, Schedule 2.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated

under Operating Agreement, Schedule 1, section 6.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2 is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Operating Agreement, Schedule 1, section 6.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. <u>Minimum Generator Operating Parameters</u>:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Operating Agreement, Schedule 1, section 6.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6 and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Tariff, Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Tariff, Attachment DD, section 6.6.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under Tariff, Attachment DD.

3. Through the 2024/2025 Delivery Year, t~~T~~he Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Tariff, Attachment DD, section 6.6(b). If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORd to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Tariff, Attachment DD, section 5.6.6, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in section II.C.4 above, or (iii) through the

2024/2025 Delivery Year, a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level determined under section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Tariff, Attachment DD, section 6.6.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Tariff, Attachment DD, section 6.6(g), to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Tariff, Attachment DD, section 6.6(i), and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. <u>Unit Specific Minimum Sell Offers:</u>

1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, section*s* 5.14(h) *and 5.14(h-1)*, the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.

2. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

E. <u>Market Seller Offer Caps</u>:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Tariff, Attachment DD, section 6.7(d), the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller

Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Tariff, Attachment DD, section 6.5, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. Data Submission:

Pursuant to Tariff, Attachment DD, section 6.7, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Tariff, Attachment DD, section 6.7(c) and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Tariff, Attachment DD, section 6.7, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in Tariff, Attachment DD, section 6.7(d).

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Tariff, Attachment DD, section 6.8(d), and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Tariff, Attachment DD, section 6.7(d)(ii). The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Tariff, Schedule 6A and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Tariff, Part V from the Office of the Interconnection forwarded pursuant to Tariff, Part V, section 113.1, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (or, if applicable, its designated agent) if a market power issue has been identified. The Market Monitoring Unit shall provide such notice by the following date: (a) May 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between January 1 and March 31; (b) August 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between April 1 and June 30; (c) November 30 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between July 1 and September 30; or (d) February 28 of the following calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between October 1 and December 31. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Tariff, Part V, section 114 and Tariff, Part V, section 119.

V. <u>OPPORTUNITY COST CALCULATION</u>

The Market Monitoring Unit shall review requests for opportunity cost compensation under Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.
3B(h), discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the paralelle provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.3B9H).

VI. <u>FTR FORFEITURE RULE</u>

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Operating Agreement, Schedule 1, section 5.2.1(b) and Tariff, Attachment K-Appendix, section 5.2.1(b), including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Tariff, Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. Notwithstanding, the Base Residual Auction for the 2025/2026 Delivery Year shall be conducted in June 2024; the Base Residual Auction for the 2026/2027 Delivery Year shall be conducted in December 2024; the Base Residual Auction for the 2027/2028 Delivery Year shall be conducted in June 2025; and the Base Residual Auction for the 2028/2029 Delivery Year shall be conducted in December 2025. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. Notwithstanding, for the 2025/2026 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2025; for the 2026/2027 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2026; for the 2027/2028 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which will commence on July 2026 and February 2027, respectively; for the 2028/2029 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which shall commence on July 2027 and February 2028, respectively.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement ~~less, for Delivery Years through May 31, 2018, the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year,~~ or ~~if~~ the LDA Reliability Requirement ~~less, for Delivery Years through May 31, 2018, the LDA Short Term Resource Procurement Target~~ applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource~~, Extended Summer Demand Resource, or Limited Demand Resource~~. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, decrease in Accredited UCAP Factor, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.5 Eligibility for Participation in RPM Auctions

A Capacity Market Seller may submit a Sell Offer for a Capacity Resource in a Base Residual Auction~~,~~ or Incremental Auction~~, or Capacity Performance Transition Incremental Auction~~ only if such seller owns or has the contractual authority to control the output or load reduction capability of such resource and has not transferred such authority to another entity prior to submitting such Sell Offer. Capacity Resources must satisfy the capability and deliverability requirements of RAA, Schedule 9 and RAA, Schedule 10, the requirements for Demand Resources or Energy Efficiency Resources in Tariff, Attachment DD-1 and RAA, Schedule 6, as applicable, and, ~~for the 2018/2019 Delivery Year and subsequent Delivery Years,~~ the criteria in Tariff, Attachment DD, section 5.5A. Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, a Planned Generation Capacity Resource may be included in a Sell Offer for an RPM Auction only if the Capacity Market Seller of such resource provides a binding notice of intent, as further detailed in the PJM Manuals, to submit a Sell Offer in such auction to the Office of the Interconnection no later than (a) the immediately preceding December 1 for a Base Residual Auction (except that for the 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.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered through the 2024/2025 Delivery Year.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered.

i) The Office of the Interconnection shall~~, in both cases,~~ convert ~~such~~ Nominated Energy Efficiency V~~v~~alue to an Unforced Capacity basis by multiplying such value by ~~the DR Factor (for Delivery Years through May 31, 2018) times~~ the Forecast Pool Requirement.

ii) The Office of the Interconnection shall convert the nominated Demand Resource value to a UCAP basis by multiplying such value by, the Forecast Pool Requirement through the 2024/2025 Delivery Year, and starting with the 2025/2026 Delivery Year and for subsequent Delivery Years, the applicable ELCC Class Rating.

iii) Demand Resources and Energy Efficiency Resources shall specify the LDA in which the ~~Demand R~~resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on RAA, Schedule 10.1.

e) ~~For Delivery Years through May 31, 2018, a Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.~~Accredited UCAP Factor for Generation Capacity Resources beginning with the 2025/2026 Delivery Year and subsequent Delivery Years.

i) The Accredited UCAP Factor shall be the value established by the Office of the Interconnection in accordance with RAA, Schedule 9.2, prior to the applicable RPM Auction. Such Accredited UCAP Factor shall be multiplied by the ICAP offered to convert the ICAP offered into the UCAP offered.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Accredited UCAP Factor determined by the Office of the Interconnection shall apply to such commitment.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

~~g) For the 2018/2019 and 2019/2020 Delivery Years, each Capacity Market Seller owning or controlling a resource that qualifies as both a Base Capacity Resource and a Capacity Performance Resource may submit separate but coupled Sell Offers for such resource as a Base Capacity Resource and as a Capacity Performance Resource, at different prices, and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Submission of a coupled Base Capacity Resource Sell Offer shall be mandatory for any Capacity Performance Resource Sell Offer that exceeds a Sell Offer Price equal to the applicable Net Cost of New Entry times the Balancing Ratio as provided for in Tariff, Attachment DD, section 6.4. For such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer.~~

(g~~h~~) A Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods, ~~but for ELCC Resources, for the 2023/2024 Delivery Year and subsequent Delivery Years, such MW quantity shall~~ not to exceed the Accredited UCAP of ~~the~~ such resource, as applicable. Alternatively, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its *Capacity Exchange* tools. If any of the commercially aggregated resources in such Sell Offer are subject to the Minimum Floor Offer Price pursuant to Tariff, Attachment DD, sections 5.14(h) and 5.14(h-1), the Capacity Market Seller that owns or controls such resources may submit a Sell Offer with a Minimum Floor Offer Price of no lower than the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer.

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Tariff, Attachment Q, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Tariff, Attachment DD, section 6.6, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Tariff, Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Tariff, Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Tariff, Attachment DD, section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement ~~(for Delivery Years through May 31, 2018, less the Short-Term Resource Procurement Target)~~ or Locational Deliverability Area Reliability Requirement ~~(for Delivery Year through May 31, 2018, less the Short-Term Resource Procurement Target for the Zones associated with such LDA)~~ for such Delivery Year. For any auction, the Updated Forecast Peak Load~~, and Short-Term Resource Procurement Target~~ applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- For the 2022/2023 Delivery Year through and including the Delivery Year commencing June 1, ~~2025~~2024, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 1.2%) divided by (100% plus IRM%)];

- For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1.9%) divided by (100% plus IRM%)]; and

- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 7.8%) divided by (100% plus IRM%)].

- For the 2025/2026 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 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 98.9%];

  - 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 101.6%]; and

  - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 106.8%].

- For the 2026/2027 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) 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 (~~one minus the pool-wide average EFORd~~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~~one minus the pool-wide average EFORd~~) 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%].

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year~~ commencing on June 1, 2012~~, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement~~ and, for Delivery Years through May 31, 2018, the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target~~. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, ~~for the 2018/2019 Delivery Year and subsequent Delivery Years,~~ the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA. ~~The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.~~

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the

FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Incremental Auctions, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for each corresponding Delivery Year and LDA. For the Delivery Year commencing on June 1, 2022 through and including the Delivery Year commencing on June 1, 2025, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in \$/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	108,000
BGE, PEPCO ("CONE Area 2")	109,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3")	105,500
PPL, MetEd, Penelec ("CONE Area 4")	105,500

B) Beginning with the 2023/2024 Delivery Year through and including the 2025/2026 Delivery Year, the CONE 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 then adjusted further by a factor of 1.022 to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law, in accordance with the following:

(1) The Applicable BLS Composite Index for any 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 Price Index for Construction Materials and Components (weighted 55%), and the BLS

Producer Price Index Turbines and Turbine Generator Sets (weighted 25%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area, and then multiplying the result by 1.022.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2022/2023 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years), and then multiplying the result by 1.022.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

C) For the 2026/2027 Delivery Year and for subsequent Delivery Years, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(C)(1).

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year (ICAP)**
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	198,200
BGE, PEPCO (“CONE Area 2”)	193,100
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC,	197,800

Dominion, OVEC ("CONE Area 3")	
PPL, MetEd, Penelec ("CONE Area 4")	199,700

(1) Beginning with the 2027/2028 Delivery Year, the CONE 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, in accordance with the following:

(a) The Applicable BLS Composite Index for any 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 Price Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 15%), as each such index is further specified for each CONE Area in the PJM Manuals.

(b) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2026/2027 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(c) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset for 2023/2024 Delivery Year through and including the 2025/2026 Delivery Years (except that the calculation of the MOPR Floor Price pursuant to Tariff, Attachment DD, section 5.14(h-2) for combustion turbine resources shall remain applicable beyond the 2025/2026 Delivery Year):

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (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 time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.93 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

v-1) Net Energy and Ancillary Services Revenue Offset for the 2026/2027 Delivery Year and subsequent Delivery Years:

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (1) the average of the net energy and ancillary services revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such 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. Each net energy and ancillary services revenue simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of $2.10 per MWh, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis; plus (2) reactive service revenues of $2,546 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the Forward Hourly LMPs for such Zone shall be used in place of the Forward Hourly LMP for the PJM Region; (2) if such Zone was not integrated into the PJM Region for the entire three calendar years preceeding the time of the determination for the RPM Auction, then simulations shall rely on only those whole calendar years during which the Zone was integrated; and (3) Forward Daily Natural Gas Prices for the fuel pricing point mapped to such Zone.

C) "Forward Hourly LMPs" shall be determined as follows:

(1) Identify the liquid hub to which each Zone is mapped, as specified in the PJM Manuals.

(2) For each liquid hub, calculate the average day-ahead on-peak and day-ahead off-peak energy prices for each month during the Delivery Year over the most recent thirty trading days as of 180 days prior to the Base Residual Auction. For each of the remaining steps, the historical prices used herein shall be taken from the most recent three calendar years preceding the time of the determination for the RPM Auction:

(3) Determine and add monthly basis differentials between the hub and each of its mapped Zones to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. This differential is developed using the prices for the Planning Period closest in time to the Delivery Year from the most recent long-term Financial Transmission Rights auction conducted prior to the Base Residual Auction. The difference between the annual long-term Financial Transmission Rights auction prices for the Zone and the hub are converted to monthly values by adding, for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials between the Zone and hub. This step is only used when developing forward prices for locations other than the liquid hubs;

(4) Determine and add marginal loss differentials to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. For each month of the year, calculate the marginal loss differential, which is the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of (a) the forward monthly average on-peak or off-peak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period. This step is only used when developing forward prices for locations other than the liquid hubs;

(5) Shape the forward monthly day-ahead on-peak and off-peak prices to (a) forward hourly day-ahead LMPs using historic hourly day-ahead LMP shapes for the Zone and (b) forward hourly real-time LMPs using historic hourly real-time LMP shapes for the Zone. The historic hourly shapes are based on the ratio of the historic day-ahead or real-time LMP for the Zone for each given hour in a monthly on-peak or off-peak period to the average of the historic day-ahead or real-time LMP for the Zone for all hours in such monthly on-peak or off-peak period. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction;

(6) For unit-specific energy and ancillary service offset calculations, determine and apply basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone. The differential for each hour of the year is developed using the difference between the historical DA or RT LMP for the generation bus and the historical DA or RT LMP for the Zone in which the generation bus is located for that same hour; and

(7) Develop the Forward Hourly LMPs for the PJM Region pricing point. Calculate the load-weighted average of the monthly on-peak and off-peak Zonal LMPs developed in step (4) above, using the historical average load within each monthly on-peak or off-peak period. The load-weighted average monthly on-peak or off-peak Zonal LMPs are then shaped to forward hourly day-ahead and real-time LMPs using the same procedure as defined in step (5) above, except using historical LMPs for the PJM Region pricing point.

D) Forward Hourly Ancillary Services Prices shall include prices for Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve and shall be determined as follows. The historical prices used herein shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction:

(1) For Synchronized Reserve, the forward real-time Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year;

(2) For Non-Synchronized Reserve, the forward real-time Non-Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Non-Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year; and

(3) For Secondary Reserve, the forward day-ahead and real-time Secondary Reserve market clearing price shall be $0.00/MWh for all hours.

E) Forward Daily Natural Gas Prices shall be determined as follows:

(1) Map each Zone to the appropriate natural gas hub in the PJM Region, as listed in the PJM Manuals;

(2) Map each natural gas hub lacking sufficient liquidity to the liquid hub to which it has the highest historic price correlation;

(3) For each sufficiently liquid natural gas hub, calculate the simple average natural gas monthly settlement prices over the most recent thirty trading days as of 180 days prior to the Base Residual Auction;

(4) Calculate the forward monthly prices for each illiquid hub by scaling the forward monthly price of the mapped liquid hub by the average ratio of historical monthly prices at the insufficiently liquid hub to the historical monthly prices at the sufficiently liquid over the most recent three calendar years preceding the time of determination for the RPM Auction;

(5) Shape the forward monthly prices for each hub to Forward Daily Natural Gas Prices using historic daily natural gas price shapes for the hub. The historic daily shapes are based on the ratio of the historic price for the hub for each given day in a month to the average of the historic prices for the hub for all days in such month. The daily prices are then assigned to each hour starting 10am Eastern Prevailing Time each day. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and

Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the Reliability Assurance Agreement.

c) [Reserved]~~Resource Requirements and Constraints~~

~~Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for the 2017/2018 Delivery Year, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year.~~

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, (through the 2024/2025 Delivery Year), the pool-wide average Accredited UCAP Factor (beginning with the 2025/2026 Delivery Year), the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year , the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in Tariff, Attachment DD, section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results for each Base Residual Auction shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price.

If PJM discovers a potential error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, along with a description detailing the cause and scope of the error, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. The provided description will not contain information that is market sensitive or confidential. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- ~~for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a);~~
- ~~For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;~~
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;
- For the 2024/2025 ~~and subsequent~~ Delivery Year~~s~~, the Locational Deliverability Requirement Reliability Requirement, including any revised Locational Deliverability Area Reliability Requirement based on the actual participation of Planned Generation Capacity Resources in the relevant Base Residual Auction; and
- For the 2020/2021 Delivery Year and subsequent Delivery Years, 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 optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. For the 2020/2021 Delivery Year and subsequent Delivery Years, the supply curve formed by the Sell Offers submitted within an LDA for which a separate VRR Curve is established, shall only consider the quantity of MW 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 LDA's reliability requirement.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year. The Capacity Resource clearing results and Capacity Resource Clearing Prices determined for Summer-Period Capacity Performance Resources shall be applicable for the calendar months of June through October and the following May of such Delivery Year; and shall be applicable for Winter-Period Capacity Performance Resources for the calendar months of November through April of such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- ~~For the Delivery years through May 31, 2018, the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;~~

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;

- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;

- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- ~~For the Delivery Years through May 31, 2018, for each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;~~

- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement, and for the 2024/2025 Delivery Year ~~and subsequent Delivery Years~~, including any revised Locational Deliverability Area Reliability Requirement based on the actual participation of Planned Generation Capacity Resources in the relevant Incremental Auction;

- ~~For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a);~~

- For the 2020/2021 Delivery Year and subsequent Delivery Years, 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;

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and
- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(2), the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(1), and the conditions stated in Tariff, Attachment DD, section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction~~, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction,~~ minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C*,* 5.14E*,* and 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9~~, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 and 2017/2018 Delivery Years associated with the transition provisions in Tariff, Attachment DD, section 5.14D where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E~~. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, ~~with exception for the Third Incremental Auction for the 2017/2018 Delivery Year,~~ the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. ~~In seeking to sell back such quantity for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a curve represented by a straight line connecting two points with the first point located at 0 megawatts and at a price set to the lowest price point of the Updated VRR Curve Decrement and the second point located at a megawatt amount corresponding to the negative quantity defined above and at a price set to the Resource Clearing Price of the 2017/2018 Base Residual Auction.~~

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction,~~ plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, ~~ minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by Tariff, Attachment DD, section 5.4(c)(3)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C*,* 5.14E*,* and 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9, ~~minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 and 2017/2018 Delivery Years associated with the transition provisions in Tariff, Attachment DD, section 5.14D where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E; ~~provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, ~~with exception for the Third Incremental Auction for the 2017/2018 Delivery Year, ~~the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. ~~In seeking to sell back such quantity for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a curve represented by a straight line connecting two points with the first point located at 0 megawatts and at a price set to the lowest price point of the Updated VRR Curve Decrement and the second point located at a megawatt amount corresponding to the negative quantity defined above and at a price set to the Resource Clearing Price of the 2017/2018 Base Residual Auction.~~

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, ~~plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, ~~minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. ~~For the Delivery Years through May 31, 2018, if more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction~~

(v) ~~If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.~~ (reserved)

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

(A) [Reserved]~~For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;~~

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and

- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

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 LDAs 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 level constrained LDA, where they are considered in a similar manner for compensation.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the 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.

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with Tariff, Attachment DD, section 5.12(a) and section 5.14(a) above.

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b) above; or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in Tariff, Attachment DD, section 5.12(a), and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) above that is entitled to compensation pursuant to section 5.14(b) above; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) above shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with section 5.14(b) above. Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in section 5.14(a) above.

6. The failure to submit a Sell Offer consistent with section 5.14(c)(i)-(iii) above in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) above in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Tariff, Attachment DD, section 5.10(a)(ii).

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under Tariff, Attachment DD, section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in Tariff, Attachment DD, section 5.14B, Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D, Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain New Generation Capacity Resources that are not Capacity Resources with State Subsidy for up to the 2022/2023 Delivery Year.

(1) The provisions of this section 5.14(h) shall not be effective after the 2022/2023 Delivery Year. For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Tariff, Attachment DD, section 5.10(a)(iv)(A) of this Attachment. This section only applies to new Generation Capacity Resources that do not receive or are not entitled to receive a State Subsidy, meaning that such resources are not Capacity Resources with State Subsidy. To the extent a new Generation Capacity Resource is a Capacity Resource with State Subsidy, then the provisions in Tariff, Attachment DD, section 5.14(h-1) apply.

The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), and a combined cycle generator ("CC") respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT $/MW-yr	132,200	130,300	128,990	130,300
CC $/MW-yr	185,700	176,000	172,600	179,400

(2) The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in Tariff, Attachment DD, section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For the 2022/2023 Delivery Year, for purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by Tariff, Attachment DD, section 5.10(a)(v-1)(A), provided that the energy and ancillary services revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.501 MMbtu/MWh, the variable operations and maintenance expenses for such resource shall be $2.11 per MWh, a 10% adder will not be included in the energy offer, and the reactive service revenues shall be $3,350 per MW-year.

(4) Any Sell Offer that is based on either (i) or (ii), and (iii):

i) a Generation Capacity Resource located in the PJM Region that is submitted in an RPM Auction for a Delivery Year unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM auction for that or any subsequent Delivery Year; or

ii) a Generation Capacity Resource located outside the PJM Region (where such Sell Offer is based solely on such resource) that requires sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region, unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM Auction for that or any subsequent Delivery Year;

iii) in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.

(5) Unit-Specific Exception. A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following process and requirements shall apply to requests for such determinations:

i) The Capacity Market Seller may request such a determination by no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the minimum offer level expected to be established under subsection (4). If the minimum offer level subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues, or, sufficient data for the Office of the Interconnection and the Market Monitoring Unit to produce such an estimate. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer. The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for an exception hereunder.

The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above.

For the 2022/2023 Delivery Year, in making such demonstration, the Capacity Market Seller may rely upon revenues projected by well defined, forward-looking dispatch models, designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance costs, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors and ancillary service capabilities.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, and plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

iii) A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4). Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of an exception hereunder by the Office of the Interconnection.

iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, the Capacity Market Seller Shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.

h-1) Minimum Offer Price Rule for Capacity Resources with State Subsidy for the 2022/2023 Delivery Year.

(1) **General Rule.** The provisions of this section 5.14(h-1) shall not be effective after the 2022/2023 Delivery Year. For the 2022/2023 Delivery Year, any Sell Offer based on either a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with a State Subsidy submitted in any RPM Auction shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the Capacity Market Seller qualifies for an exemption with respect to such Capacity Resource with a State Subsidy prior to the submission of such offer.

(A) Effect of Exemption. To the extent a Sell Offer in any RPM Auction is based on a Capacity Resource with State Subsidy that qualifies for any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h-1)(4)-(8), the Sell Offer for such resource shall not be limited by the MOPR Floor Offer Price, unless otherwise specified.

(B) Effect of Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a Capacity Resource with State Subsidy for which the Capacity Market Seller obtains, prior to the submission of such offer, a resource-specific exception, such offer may include an offer price below the default MOPR Floor Offer Price applicable to such resource type, but no lower than the resource-specific MOPR Floor Offer Price determined in such exception process.

(C) Process for Establishing a Capacity Resource with a State Subsidy.

(i) By no later than one hundred and twenty (120) days prior to the commencement of the offer period of any RPM Auction conducted for the 2022/2023 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not each Capacity Resource (other than Demand Resource and Energy Efficiency Resource) that the Capacity Market Seller intends to offer into the RPM Auction qualifies as a Capacity Resource with a State Subsidy (including by way of Jointly Owned Cross-Subsidized Capacity Resource) and identify (with specificity) any State Subsidy. Capacity Market Sellers that intend to offer a Demand Resource or an Energy Efficiency Resource into the RPM Auction shall certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not such Demand Resource or Energy Efficiency Resource qualifies as a Capacity Resource with a State Subsidy no later than thirty (30) days prior to the commencement of the offer period of any RPM Auction conducted for the 2022/2023 Delivery Year. All Capacity Market Sellers shall be responsible for each certification irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit. A Capacity Resource shall be deemed a Capacity Resource with State Subsidy if the Capacity Market Seller fails to timely certify whether or not a Capacity Resource is entitled to a State Subsidy, unless the Capacity Market Seller receives a waiver from the Commission. Notwithstanding, if a Capacity Market Seller submits a timely resource-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) for the relevant Delivery Year, and PJM approves the resource-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely certified whether or not the resource is a Capacity Resource with State Subsidy.

(ii) The requirements in subsection (i) above do not apply to Capacity Resources for which the Market Seller designated whether or not it is subject to a State Subsidy and the associated subsidies to which the Capacity Resource is entitled in a prior Delivery Year, unless there has been a change in the set of those State Subsidy(ies), or for those which are eligible for the Demand Resource or Energy Efficiency exemption, Capacity Storage Resource exemption, Self-Supply Entity exemption, or the Renewable Portfolio Standard exemption.

(iii) Once a Capacity Market Seller has certified a Capacity Resource as a Capacity Resource with a State Subsidy, 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 shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Capacity Resource's material change in status as a Capacity Resource with State Subsidy within 30 days of such material change, unless such material change occurs within 30 days of the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year, in which case the Market Seller must notify PJM no later than 5 days prior to the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection whether its resource meets the criteria of a Capacity Resource with State Subsidy pursuant to Tariff, Attachment DD, section 5.14(h-1)(1)(C)(i).

(2) **Minimum Offer Price Rule.** Any Sell Offer for a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with State Subsidy that does not qualify for any of the exemptions, as defined in Tariff, Attachment DD, sections 5.14(h-1)(4)-(8), shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Resource with State Subsidy must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process to participate in an RPM Auction.

(A) New Entry MOPR Floor Offer Price. For a New Entry Capacity Resource with State Subsidy the applicable MOPR Floor Offer Price, based on the net cost of new entry for each resource type, shall be, at the election of the Capacity Market Seller, (i) the resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Gross Cost of New Entry (2022/2023 $/ MW-day) (Nameplate)**
Nuclear	$2,000
Coal	$1,068
Combined Cycle	$320
Combustion Turbine	$294
Fixed Solar PV	$271
Tracking Solar PV	$290
Onshore Wind	$420
Offshore Wind	$1,155
Battery Energy Storage	$532
Diesel Backed Demand Resource	$254

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For Delivery Years through the 2022/2023 Delivery Year, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types and battery energy storage resource types, the applicable class average EFORd; for wind and solar generation resource types, the applicable class average capacity value factor; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. For the 2023/2024 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types, the applicable class average EFORd; for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

The default New Entry MOPR Floor Offer Price for load-backed Demand Resources (i.e., the MW portion of Demand Resources that is not supported by generation) shall be separately determined for each Locational Deliverability Area as the MW-weighted average offer price of load-backed Demand Resources from the most recent three Base Residual Auctions, where the MW weighting shall be determined based on the portion of each Sell Offer for a load-backed portion of the Demand Resource that is supported by end-use customer locations on the registrations used in the pre-registration process for such Base Residual Auctions, as described in the PJM Manuals.

For generation-backed Demand Resources that are not powered by diesel generators, the default New Entry MOPR Floor Offer Price shall be the default New Entry MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.

The default gross cost of new entry for Energy Efficiency Resources shall be $644/ICAP MW-Day, which shall be offset by projected wholesale energy savings, as well as transmission and distribution savings of $95/ICAP MW-Day, to determine the default New Entry MOPR Floor Offer Price (Net Cost of New Entry), where the projected wholesale energy savings are determined utilizing the cost and performance data of relevant programs offered by representative energy efficiency programs with sufficiently detailed publicly available data. The wholesale energy savings, in $/ICAP MW-day, shall be calculated prior to each RPM Auction and be equal to the average annual energy savings of 6,221 MWh/ICAP MW times the weighted average of the annual real-time Forward Hourly LMPs of the Zones of the representative energy efficiency programs, where the weighting is developed from the annual energy savings in the relevant Zones, divided by 365.

To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types except for load-backed Demand Resources and Energy Efficiency Resources, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, combine cycle, and generation-backed Demand 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. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue shall be the average of the net energy and ancillary services revenues that the resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of each 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. Each net energy and ancillary services revenue simulation shall be conducted in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus reactive services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $3,350/MW-year;

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,350/MW-year; and

(ix) for generation-backed Demand Resource, the net energy and ancillary services revenue estimate shall be zero dollars.

New Entry Capacity Resource with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices.

(i) For a Cleared Capacity Resource with State Subsidy, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the resource-specific MOPR Floor Offer Price , as determined in accordance with Tariff, Attachment DD, section 5.14(h-1)(3) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, net of projected PJM market revenues equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with subsection (ii) below.

Existing Resource Type	**Default Gross ACR (2022/2023 ($/MW-day) (Nameplate)**
Nuclear - single	$697
Nuclear - dual	$445
Coal	$80
Combined Cycle	$56
Combustion Turbine	$50
Solar PV (fixed and tracking)	$40
Wind Onshore	$83
Diesel-backed Demand Response	$3
Load-backed Demand Response	$0
Energy Efficiency	$0

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on: for Delivery Years through the 2022/2023 Delivery Year, the resource-specific EFORd for thermal generation resource types, resource-specific capacity value factor for solar and wind generation resource types (based on the ratio of Capacity Interconnection Rights to nameplate capacity, appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction, and for the 2023/2024 Delivery Year and subsequent Delivery Years, the resource-specific EFORd for thermal generation resource types and on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resources with State Subsidies that have cleared in an RPM Auction for any prior Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

For generation-backed Demand Resources that are not powered by diesel generators, the default Cleared MOPR Floor Offer Price shall be the default Cleared MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.

Cleared Capacity Resources with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(ii) The net energy and ancillary services revenue is equal to forecasted net revenues which shall be determined in accordance with the applicable resource type net energy and ancillary services revenue determination methodology set forth in Tariff, Attachment DD, section 5.14(h-1)(2)(A)(i) through (ix) and using the subject resource's operating parameters as determined in accordance with the PJM Manuals based on (a) offers submitted in the Day-ahead Energy Market and Real-time Energy Market over the calendar year preceding the time of the determination for the RPM Auction; (b) the resource-specific operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs); (c) the resource's EFORd; (d) Forward Hourly LMPs at the generation bus as determined in accordance with Tariff, Attachment DD, section 5.10(a)(v-1)(C)(6); and (e) the resource's stated annual revenue requirement for reactive services; plus any unit-specific bilateral contract. In addition, the following resource type-specific parameters shall be considered; (f) for combustion turbine, combined cycle, and coal resource types: the installed capacity rating, ramp rate (which shall be equal to the maximum ramp rate included in the resource's energy offers over the most recent previous calendar year preceding the determination for the RPM Auction), and the heat rate as determined as the resource's average heat rate at full load as submitted to the Market Monitoring Unit and the Office of the Interconnection, where for combined cycle resources heat rates will be determined at base load and at peak load (e.g., without duct burners and with duct burners), as applicable; (g) for nuclear resource type: an average equivalent availability factor of all PJM nuclear resources to account for refueling outages; (h) for solar and wind resource types: the resource's output profiles for the most recent three calendar years, as available; and (i) for battery storage resource type: the nameplate capacity rating (on a MW / MWh basis).

To the extent the resource has not achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Cleared Capacity Resource with State Subsidy based on a net energy and ancillary services revenue determination that does not use the foregoing methodology or parameter inputs stated for that resource type shall, at its election, submit a request for a resource-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) below.

(3) Resource-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with State Subsidy below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a resource-specific exception for such Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the resource-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The resource-specific MOPR Floor Offer Price determined under this provision shall be based on the resource-specific EFORd for thermal generation resource types, on the resource-specific Accredited UCAP value for ELCC Resources (where for solar and wind generation resource types the Accredited UCAP shall be appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost were the resource to rely solely on revenues exclusive of any State Subsidy. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the resource-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-1)(2)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(B) For a resource-specific exception for a New Entry Capacity Resource with State Subsidy, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources and generation-backed Demand Resources 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.

Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a resource-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any State Subsidies) 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, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

The default assumptions for calculating resource-specific Cost of New Entry for Energy Efficiency Resources shall be based on, as supported by documentation provided by the Capacity Market Seller: the nominal-levelized annual cost to implement the Energy Efficiency program or to install the Energy Efficiency measure reflective of the useful life of the implemented Energy Efficiency equipment, and the offsetting savings associated with avoided wholesale energy costs and other claimed savings provided by implementing the Energy Efficiency program or installing the Energy Efficiency measure.

The default assumptions for calculating resource-specific Cost of New Entry for load-backed Demand Resources shall be based on, as supported by documentation provided by the Capacity Market Seller, program costs required for the resource to meet the capacity obligations of a Demand Resource, including all fixed operating and maintenance cost and weighted average cost of capital based on the actual cost of capital for the entity proposing to develop the Demand Resource.

For generation-backed Demand Resources, the determination of a resource-specific MOPR Floor Offer Price shall consider all costs associated with the generation unit supporting the Demand Resource, and demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include, but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit.

(C) For a Resource-Specific Exception for a Cleared Capacity Resource with State Subsidy that is a generation resource, the Capacity Market Seller shall submit a Sell Offer 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 shall, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any State Subsidies) 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, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not avaliable, publicly avaliable estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

The resource-specific MOPR Floor Offer Price for a Cleared Capacity Resource with State Subsidy that is a generation-backed Demand Resource will be determined based on all costs associated with the generation unit supporting the Demand Resource, and demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit.

(D) A Sell Offer evaluated at the resource-specific exception 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 default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a resource-specific exception by the Office of the Interconnection.

(E) 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 his/her 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.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the resource-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the resource-specific determination unless and until ordered to do otherwise by FERC.

(4) Competitive Exemption.

(A) A Capacity Resource with State Subsidy may be exempt from the Minimum Offer Price Rule under this subsection 5.14(h-1) in any RPM Auction if the Capacity Market Seller certifies to the Office of Interconnection, in accordance with the PJM Manuals, that the Capacity Market Seller of such Capacity Resource elects to forego receiving any State Subsidy for the applicable Delivery Year no later than thirty (30) days prior to the commencement of the offer period for the relevant RPM Auction. Notwithstanding the foregoing, the competitive exemption is not available to Capacity Resources with State Subsidy that (A) are owned or offered by Self-Supply Entities unless the Self-Supply Entity certifies, subject to PJM and Market Monitor review, that the Capacity Resource will not accept a State Subsidy, including any financial benefit that is the result of being owned by a regulated utility, such that retail ratepayers are held harmless, (B) are no longer entitled to receive a State Subsidy but are still considered a Capacity Resource with State Subsidy solely because they have not cleared an RPM Auction since last receiving a State Subsidy, or (C) are Jointly Owned Cross-Subsidized Capacity Resources or is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) and not all Capacity Market Sellers of the supporting facility unanimously elect the competitive exemption and certify that no State Subsidy will be received associated with supporting the resource (unless the underlying Capacity Resource that is the subject of a bilateral transaction has not received, is not receiving, and is not entitled to receive any State Subsidy except those that are assigned (i.e., renewable energy credits) to the off-takers of a bilateral transaction and the Capacity Market Seller of such Capacity Resource can demonstrate and certify that the Capacity Market Seller's rights and obligations of its share of the capacity, energy, and assignable State Subsidy associated with the underlying Capacity Resource are in pro rata shares). A new Generation Capacity Resource that is a Capacity Resource with State Subsidy may elect the competitive exemption; however, in such instance, the applicable MOPR Floor Offer Price will be determined in accordance with the minimum offer price rules for certain new Generation Capacity Resources as provided in Tariff, Attachment DD, section 5.14(h), which apply the minimum offer price rule to the new Generation Capacity Resources located in an LDA where a separate VRR Curve is established as provided in Tariff, Attachment DD, section 5.14(h)(4).

(B) The Capacity Market Seller shall not receive a State Subsidy for any part of the relevant Delivery Year in which it elects a competitive exemption or certifies that it is not a Capacity Resource with State Subsidy.

(5) Self-Supply Entity exemption. A Capacity Resource that was owned, or bilaterally contracted, by a Self-Supply Entity on December 19, 2019, shall be exempt from the

Minimum Offer Price Rule if such Capacity Resource remains owned or bilaterally contracted by such Self-Supply Entity and satisfies at least one of the criteria specified below:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(6) Renewable Portfolio Standard Exemption. A Capacity Resource with State Subsidy shall be exempt from the Minimum Offer Price Rule if such Capacity Resource (1) receives or is entitled to receive State Subsidies through renewable energy credits or equivalent credits associated with a state-mandated or state-sponsored renewable portfolio standard ("RPS") program or equivalent program as of December 19, 2019 and (2) satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(7) Demand Resource and Energy Efficiency Resource Exemption.

(A) A Capacity Resource with State Subsidy that is Demand Resource or an Energy Efficiency Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Resource satisfies at least one of the following criteria:

(i) has successfully cleared an RPM Auction prior to December 19, 2019. For purposes of this subsection (A), individual customer location registrations that participated as Demand Resource and cleared in an RPM Auction prior to December 19, 2019, and were submitted to PJM no later than 45 days prior to the BRA for the

2022/2023 Delivery Year shall be deemed eligible for the Demand Resource and Energy Efficiency Resource Exemption; or

(ii) has completed registration on or before December 19, 2019; or

(iii) is supported by a post-installation measurement and verification report for Energy Efficiency Resources approved by PJM on or before December 19, 2019 (calculated for each installation period, Zone and Sub-Zone by using the greater of the latest approved post-installation measurement and verification report prior to December 19, 2019 or the maximum MW cleared for a Delivery Year across all auctions conducted prior to December 19, 2019).

(B) All registered locations that qualify for the Demand Resource and Energy Efficiency Resource exemption shall continue to remain exempt even if the MW of nominated capacity increases between RPM Auctions unless any MW increase in the nominated capacity is due to an investment made for the sole purpose of increasing the curtailment capability of the location in the capacity market. In such case, the MW of increased capability will not be qualified for the Demand Resource and Energy Efficiency Resource exemption.

(8) Capacity Storage Resource Exemption. A Capacity Resource with State Subsidy that is a Capacity Storage Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Storage Resource satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(9) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with State Subsidy. In the event the Office of the Interconnection, with advice and input from the Market Monitoring Unit, reasonably believes that a certification of a Capacity Resource's status contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource is a Capacity Resource with a State Subsidy (including whether the Capacity Resource is a Jointly Owned Cross-Subsidized Capacity Resource) or does not qualify for a competitive exemption or contains information that is inconsistent with the resource-specific exception, then:

(A) A Capacity Market Seller shall, within five (5) business days upon receipt of the request for additional information, provide any supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate whether such Capacity Resource is a Capacity Resource with State Subsidy or whether the Capacity Market Seller is eligible for the competitive exemption. If the Office of the Interconnection determines that the Capacity Resource's status as a Capacity Resource with State Subsidy is different from that specified by the Capacity Market Seller or is not eligible for a competitive exemption pursuant to subsection (4) above, the Office of the Interconnection shall notify, in writing, the Capacity Market Seller of such determination by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, if the Office of Interconnection determines that the subject resource is a Capacity Resource with State Subsidy or is not eligible for a competitive exemption pursuant to subsection (4) above, such Capacity Resource shall be subject to the Minimum Offer Price Rule, unless and until ordered to do otherwise by FERC.

(B) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least sixty-five (65) days before the start of the relevant RPM Auction, then the Office of the Interconnection may file the certification that contains any alleged fraudulent or material misrepresentation or omission with FERC. In such event, if the Office of Interconnection determines that a resource is a Capacity Resource with State Subsidy that is subject to the Minimum Offer Price Rule, the Office of the Interconnection will proceed with administration of the Tariff and market rules on that basis unless and until ordered to do otherwise by FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(C) prior to applying the Minimum Offer Price Rule, the Office of the Interconnection, with advice and input of the Market Monitoring Unit, shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged fraudulent or material misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may submit a revised certification for that Capacity Resource for subsequent RPM Auctions, including RPM Auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

h-2) Minimum Offer Price Rule Effective with the 2023/2024 Delivery Year

(1) **Certification Requirement.**

(A) By no later than one hundred and fifty (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 to the Office of Interconnection for each Generation Capacity Resource the Capacity Market Seller intends to offer into the RPM Auction, in accordance with the PJM Manuals:

(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.

(B) All Capacity Market Sellers shall be responsible for the accuracy of each certification and its conformance with the Tariff irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.

(C) Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the certification requirements in subsection (A)(i) above do not apply and the status of such Generation Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller of the underlying resource) that owns or controls such Generation 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 shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

(2) **Determining Generation Capacity Resources Subject to the Minimum Offer Price Rule.**

(A) Conditioned State Support.

(i) If the Office of the Interconnection 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, the Office of Interconnection shall submit, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, a filing at FERC indicating the Office of the Interconnection's 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 reasonably expected to receive such Conditioned State Support. If FERC has already ruled on whether a specific government program or policy constitutes Conditioned State Support and such policy or program is listed in Tariff, Attachment DD-3, the Office of the Interconnection shall not be required to submit the filing described in the preceding sentence.

(ii) 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.

(iii) Upon FERC acceptance (whether by order or operation of law) that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i) that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, will be subject to the provisions of the Minimum Offer Price Rule.

(B) Exercise of Buyer-Side Market Power

(i) 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, then the underlying Capacity Resource shall be subject to the MOPR pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i). If the Office of the Interconnection and/or the Market Monitoring Unit reasonably suspects that a certification submitted under Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii) contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource 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 may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. 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 would not be an Exercise of Buyer-Side Market Power. The Office of the Interconnection and/or the Market Monitoring Unit 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, the Office of the Interconnection and/or the Market Monitoring Unit shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. The Office of the Interconnection and/or the Market Monitoring Unit may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, the Office of the Interconnection and the Market Monitoring Unit 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 the Office of the Interconnection and/or the Market Monitoring Unit, 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 Office of the Interconnection, 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 that could be an Exercise of Buyer-Side Market Power, as follows:

(a) To determine whether a Capacity Market Seller may have Buyer Side Market Power associated with the Generation Capacity Resource for the applicable RPM Auction, the Office of the Interconnection and/or the Market Monitoring Unit will perform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.

(b) To determine whether the Capacity Market Seller's submission of a Sell Offer at any given price level for such Generation Capacity Resource may constitute an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall perform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically. In this analysis, the Office of Interconnection and/or the Market Monitoring Unit shall consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices. If the expected benefit outweighs the expected cost, the Capacity Market Seller shall be deemed to have the incentive to exercise Buyer Side Market Power. If a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not to have the incentive to exercise Buyer Side Market Power with respect to that resource. Out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review.

(ii) The following nonexhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review initiated pursuant to subsection (i) above: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource 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 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 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.

(iii) Based on the foregoing tests and fact-specific review, including the facts and circumstances of the Generation Capacity Resource, the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, determines that a Generation Capacity Resource 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, the Office of the Interconnection shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the Office of the Interconnection's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on its determination hereunder unless FERC by order directs otherwise.

(C) Failure to timely submit a certification. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications required under Tariff, Attachment DD, section 5.14(h-2)(1) 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 pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) 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.

(3) **Minimum Offer Price Rule.** Any Sell Offer for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process, and the unit-specific MOPR Floor Offer Price shall establish the offer level for such resource.

(A) New Entry MOPR Floor Offer Price. For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource, or any uprate of such Generation Capacity Resource participating in the generation interconnection process under Tariff, Part IV, Subpart A, that has not cleared an RPM Auction for any Delivery Year, the applicable MOPR Floor Offer Price, based on the net cost of new entry for the resource type, shall be, at the election of the Capacity Market Seller, (i) the unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-2)(4) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Through the 2025/2026 Delivery Years: Gross Cost of New Entry (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	$427
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

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For the 2023/2024 and 2024/2025 Delivery Years~~ and subsequent Delivery Years, to determine the applicable UCAP MW-day value~~, the net cost of new entry is adjusted ~~as follows~~using: for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for all other generation resource types, the applicable class average EFORd. For the 2025/2026 Delivery Year and subsequent Delivery Years, the net cost of new entry is adjusted by the applicable class average Accredited UCAP Factor. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle 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. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue is equal to the average of the annual net revenues of the three most recent calendar years preceding the Base Residual Auction, where such annual net revenues shall be determined in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus an ancillary services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate shall be determined by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using applicable coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,553 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in Peak-Hour Dispatch, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary services revenue shall be $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate shall be the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%], plus an ancillary services revenue of $3,350/MW-year; and

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily twenty-four hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same twenty-four hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has not previously cleared an RPM Auction for that or any prior Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices.

For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-

2)(2) 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 shall be, at the election of the Capacity Market Seller, (a) based on the unit-specific MOPR Floor Offer Price, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(4) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent for the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of projected PJM market revenues equal to the resource's historical net energy and ancillary service revenues consistent with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	**Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate)**	**For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/ MW-day) Nameplate**
Nuclear - single	$697	$591
Nuclear - dual	$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
Wind Onshore	$83	$147

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. Through the 2024/2025 Delivery Year, ~~F~~for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on the ~~2023/2024 Delivery Year and subsequent Delivery Years, the~~ resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights) or the resource-specific EFORd for all other generation resource types ~~and on~~. Effective for the 2025/2026 Delivery Year and subsequent Delivery Years, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, based on the resource's Accredited UCAP Factor. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default Avoidable Cost Rates in the table above, and post the adjusted values on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted Avoidable Cost Rates, the Office of the Interconnection shall utilize the 10-year average Handy-Whitman Index in order to adjust the Gross ACR values to account for expected inflation. Updated estimates of the net energy and ancillary service revenues shall be determined on a resource-specific basis in accordance with Tariff, Attachment DD, section 6.8(d) and the PJM Manuals.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction for any Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(4) **Unit-Specific Exception**. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Capacity Resource. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is under a fact-specific review for Buyer-Side Market Power pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), and where the offer is below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Generation Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the unit-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The unit-specific MOPR Floor Offer Price determined under this provision shall be based on the unit-specific Accredited UCAP value for battery energy storage resource types and for solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights) or on the unit-specific EFORd for all other generation resource types, and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell

Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of the resource. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the unit-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-2)(3)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(B) For a unit-specific exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has never cleared an RPM Auction, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources 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 or any other revenues outside of PJM markets that do not constitute Conditioned State Support), 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.

Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a unit-specific exception hereunder. The request also 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, evidence of compensation outside the PJM market not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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, with the standard prescribed above. 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, which may include Maintenance Adders, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to 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.

(C) For a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, the Capacity Market Seller shall submit a Sell Offer 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 for an exception under this subsection 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, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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, with the standard prescribed above. 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, which may include Maintenance Adders, and emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to 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 revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

(D) A Sell Offer evaluated at the unit-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall 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, and that out-of-market compensation is not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices. Failure to adequately support such claimed cost advantages or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in the elimination of consideration of the unsupported element(s) of a unit-specific exception by the Office of the Interconnection.

(E) 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 his/her 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.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market

Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the unit-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the unit-specific determination unless and until ordered to do otherwise by FERC.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) above also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under Tariff, Attachment DD, section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) above times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h) below, all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. 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. Through the 2024/2025 Delivery Year, ~~T~~the Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in section 6.6(b). Starting with the 2025/2026 Delivery Year, the Unforced Capacity of such resource is determined using the effective Accredited UCAP Factor for that resource. If a resource should be included on the list of Existing Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, section II.C.1, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) Through the 2024/2025 Delivery Year, ~~F~~for each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under this section 6.6 to establish the maximum EFORd applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORd for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORd, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORd, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. As further described in Tariff, Attachment M-Appendix, section II.C, the Market

Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORd or, if no agreement has been reached, specifying the level of alternate maximum EFORd to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORd prior to the specified deadlines, the maximum EFORd for the applicable RPM Auction shall be deemed to be the default EFORd calculated pursuant to this section.

The maximum EFORd that may be used in a Sell Offer for Third Incremental Auction, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) Through the 2024/2025 Delivery Year, ~~I~~in the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, the Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORd based on the requirements of the Tariff and the PJM Manuals, per Tariff, Attachment DD, section 5.8, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Through the 2024/2025 Delivery Year, ~~N~~nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Through the 2024/2025 Delivery Year, ~~N~~notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses for an RPM Auction held prior to the date on which the final EFORd used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, Attachment M-Appendix, section II.C, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity

Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than ~~(a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year,~~ (~~b~~a) the September 1 that last precedes the Base Residual Auction ~~for the 2018/2019 and subsequent Delivery Years,~~ and (~~c~~b) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) Business Days after *the notification deadline for* any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after *the notification deadline for* such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from Capacity Resource status shall first submit a preliminary request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to remove the Capacity Resource status of such resource to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) the September 1 that last precedes the Base Residual Auction, and (b) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. ~~For the Base Residual Auction for the 2023/2024 Delivery Year, a Capacity Market Seller that seeks to remove a Generation Capacity Resource from Capacity Resource status shall first submit such preliminary request by no later~~

~~than November 1, 2019.~~ By no later than five (5) Business Days after *the notification deadline for* any such preliminary requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall, by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is either (a) withdrawing its preliminary request and explaining the changes to its analysis that support its decision to withdraw, or (b) confirming its preliminary decision to remove the Generation Capacity Resource from Capacity Resource status. By no later than five (5) Business Days after *the notification deadline for* such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests to remove its Capacity Resource status, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

The Market Monitoring Unit shall analyze the effects of the proposed removal of a Generation Capacity Resource from Capacity Resource status with regard to potential market power issues and shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the request to remove the Generation Capacity Resource from Capacity Resource status, and whether a market power issue has been identified, by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. Such notice shall include the specific market power impact resulting from the proposed removal of the Generation Capacity Resource from Capacity Resource status, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

A Capacity Market Seller may only remove the Generation Capacity Resource from Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Tariff, Attachment DD, sections 5.6.6 and this section 6.6 and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource, or (iii) it is required as set forth in Tariff, Attachment DD, section 6.6A(c). Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of this section 6.6. A Generation Capacity Resource that is removed from Capacity Resource status shall no longer qualify as an Existing Generation Capacity Resource, and the Capacity Interconnection Rights associated with such facility shall be subject to termination in accordance with the rules described in Tariff, Part VI, section 230.3.3. The Office of the Interconnection shall amend the applicable Interconnection Service Agreement or wholesale market participation agreement to reflect any such removal of the Capacity Interconnection Rights, and shall report the amended agreement to the Commission in the same manner as the original (e.g., FERC filing or Electronic Quarterly Reports). The Office of the Interconnection shall file the amended agreement unexecuted if the Interconnection Customer or wholesale market participant does not sign the amended Interconnection Service Agreement or wholesale market participation agreement.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource may be removed from Capacity Resource status, or whether the resource meets one of the exceptions thereto, and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Tariff, Attachment M-Appendix, section II.C.4, the Office of the Interconnection shall approve or deny the request. The request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn't timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any Planned Generation Capacity Resource associated with a notice of intent to offer into a particular RPM Auction that is not offered into the associated RPM Auction and ~~A~~all Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Tariff, Attachment M and Tariff, Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. 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.

(b) Determinations of EFORd, Accredited UCAP, and Unforced Capacity made under this Tariff, Attachment DD, section 6.6 as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

Effective with the 2023/2024 Delivery Year, Capacity Market Sellers seeking an exception for a Base Residual Auction on the basis that a resource is incapable of meeting the Capacity Performance Resource requirement shall include a documented plan with the submission of their 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. Such plan shall include (i) a timeline for design, permitting, procurement, and construction milestones, as applicable, where such timeline shall not exceed one Base Residual Auction exception, and (ii) evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment). Periodic updates on the progress, shall be provided by the Capacity Market Seller to the Office of the Interconnection and the Market Monitoring Unit for their review by no later than (i) one hundred twenty (120) days prior to the commencement of the offer period for subsequent Incremental Auctions for the applicable Delivery Years, and (ii) the December 1 that last precedes subsequent Base Residual Auctions. The Capacity Market Seller shall also immediately notify the Office of the Interconnection and the Market Monitoring Unit of any material changes to the plan that may occur. Upon request by a Capacity Market Seller, a one year extension to the plan timeline shall be permissible only for delays not caused by the Capacity Market Seller, and that could not have been remedied through the exercise of due diligence by the Capacity Market Seller. In no event may an exception be requested by the Capacity Market Seller for more than two Base Residual Auctions.

Failure to submit a documented plan, or lack of good faith effort by a Capacity Market Seller to make an Existing Generation Capacity Resource physically capable of meeting the requirements of a Capacity Performance Resource in accordance with a documented plan, shall result in the removal of the resource's Capacity Resource status effective with the first future Delivery Year for which the resource was granted an exception, no earlier than the 2023/2024 Delivery Year. The Office of the Interconnection shall amend the applicable Interconnection Service Agreement or wholesale market participation agreement to reflect any such removal of the Capacity Interconnection Rights, and shall report the amended agreement to the Commission in the same manner as the original (e.g. FERC Filing or Electronic Quarterly Reports). The Office of the Interconnection shall file the amended agreement unexecuted if the Interconnection Customer or wholesale market participant does not sign the amended Interconnection Service Agreement or wholesale market participation agreement. The required change in Capacity Resource status shall only apply to those Generation Capacity Resources that are shown to be physically incapable of satisfying the requirements of a Capacity Performance Resource.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

7. GENERATION RESOURCE RATING TEST FAILURE CHARGE

7.1 Generation Resource Rating Test Failure Charges

A Generation Resource Rating Test Failure Charge shall be assessed on any Market Seller that commits a Generation Capacity Resource for a Delivery Year, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, if such resource fails a generation resource capacity test, as provided herein.

a) Generation Resource Fails Capacity Test in Delivery Year

Each Generation Capacity Resource committed through RPM Auctions or included in a FRR Plan for a Delivery Year, with the exception of Variable Resources, shall be obligated to complete a generation resource capacity test, as described in the PJM Manuals. The Market Seller that committed the resource, or Locational UCAP Seller that sold the resource, may perform an unlimited number of tests during each such period. If none of the tests during a testing period certify full delivery of the megawatt amount of installed capacity the Market Seller committed, or Locational UCAP Seller sold, for such Delivery Year, the Market Seller or Locational UCAP Seller shall be assessed a daily Generation Resource Rating Test Failure Charge for each day from the first day of the Summer or Winter Season in which such resource failed the rating test through the last day of such Delivery Year, provided, however, that such a seller that fails or is expected to fail a rating test may obtain and commit Unforced Capacity from a replacement Capacity Resource meeting the same locational requirements. Such Unforced Capacity may include uncommitted or uncleared Sell Offer blocks from Generation Capacity Resources that were otherwise committed. Any such commitment of replacement capacity shall be effective upon no less than one day's notice to the Office of the Interconnection, and shall reduce the amount of installed capacity committed from the Generation Capacity Resource, that failed or was expected to fail such rating test, in accordance with the determination prescribed by subsection (b) below. Effective with the 2025/2026 Delivery Year, such charge shall be evaluated and assessed for each day of the Delivery Year in which the seasonal rating test for such resource fails to certify full delivery of the megawatt amount of installed capacity committed for such day.

b) Generation Resource Rating Test Failure Charge

Through the 2024/2025 Delivery Year, ~~T~~the Generation Resource Rating Test Failure Charge shall equal the Daily Deficiency Rate multiplied by the following megawatt quantity, converted to an Unforced Capacity basis using the Generation Capacity Resource's EFORD for the twelve months ending the September 30 last preceding the Delivery Year: (i) the annual average of the installed capacity committed for each day of such Delivery Year as a result of all cleared Sell Offers in all RPM Auctions for such Delivery Year relying on such resource, reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource, minus (ii) the highest installed capacity rating determined for such resource in any test during the relevant testing period. Effective with the 2025/2026 Delivery Year, the Generation Resource Rating Test Failure Charge shall be determined for each day of the Delivery Year and shall be equal to the Daily Deficiency Rate multiplied by the following megawatt quantity shortfall, converted to an Unforced Capacity basis using the Generation Capacity Resource's final Accredited UCAP Factor for such Delivery Year: (i) the installed capacity committed for such day of the Delivery Year (adjusted for any replacement capacity), minus (ii) the highest installed capacity rating determined for such resource in any test during the relevant testing period.

b-1) Daily Deficiency Rate

The Daily Deficiency Rate shall equal the Capacity Resource Clearing Price (weighted as necessary to reflect the clearing prices in all RPM Auctions that resulted in installed capacity commitments from such resource), in $/MW-day, applicable to the Generation Capacity Resource (for purposes of replacement capacity, including Locational UCAP transactions, the applicable Capacity Resource Clearing Price shall be the clearing price for the Locational Deliverability Area in which such resource is located) plus the greater of (iii) 0.20 times such weighted average Capacity Resource Clearing Price; or (iv) $20/MW-Day, provided, however, if a resource is unavailable during the Delivery Year at less than the level committed in the Market Seller's cleared Sell Offer or Locational UCAP Seller's Locational UCAP sale due to derating, delay, or retirement, then such seller shall not be assessed a charge under this section to the extent (i.e., for the same megawatts and time period) that such seller is assessed a charge under Tariff, Attachment DD, section 8 for such unavailability; and provided further that a resource that is subject to a charge under Tariff, Attachment DD, section 7A (i.e., for the same megawatts and time period) shall not also be subject to a charge under this section; and provided further that a resource that is subject to a charge under this section that is also subject to a charge under Tariff, Attachment DD, section 10A hereof for a Performance Shortfall during one or more Performance Assessment Intervals occurring during the period of resource capacity rating deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Tariff, Attachment DD, section 10A, but shall not be assessed a charge under both this section and Tariff, Attachment DD, section 10A for such simultaneous occurrence of a resource capacity rating deficiency and Performance Shortfall. If a single resource is the basis for installed capacity commitments of multiple Capacity Market Sellers or Locational UCAP Sellers, the installed capacity shortfall determined under (i) and (ii) above shall be assessed upon such sellers on a pro-rata basis in accordance with the megawatts of capacity from such resource in their cleared Sell Offers, Locational UCAP sales, or other commitment as replacement capacity.

c) Allocation of Revenue Collected from Generation Resource Rating Test Failure Charges.

The revenue collected from Generation Resource Rating Test Failure Charges shall be distributed on a pro-rata basis to LSEs that were charged a Locational Reliability Charge for the Delivery Year for which the Generation Resource Rating Test Failure Charge was assessed. The charges shall be allocated on a pro-rata basis to LSEs based on their Daily Unforced Capacity Obligation.

7A. GENERATION OPERATIONAL TESTING AND CHARGES

a) Generation Capacity Resource Operational Testing

To preserve and maintain the reliability of the PJM Region, and to improve the likelihood that Generation Capacity Resources will be capable of operating within their specified operating parameters during a reliability event, Generation Capacity Resources that are committed in RPM Auctions or are included in a FRR Plan 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, and as further detailed in the PJM Manuals. The selection of Generation Capacity Resources and the timing of an operational test shall be determined by the Office of the Interconnection, and may consider a number of factors, including the period of time since a unit last operated, the system conditions under which the unit has recently operated, the expected system conditions during the operational test, and the recent performance of units with respect to successfully starting and operating within the specified parameters when scheduled by the Office of the Interconnection. Such tests will respect operating parameter limits of the available schedule that the Office of the Interconnection selects for purposes of testing the resource. Capacity Market Sellers of Generation Capacity Resources that are tested by the Office of the Interconnection under this provision shall be eligible for make whole payments in accordance with Tariff, Attachment K-Appendix, section 3.2.3(e). A committed Generation Capacity Resource shall be deemed to pass a test initiated by the Office of the Interconnection if the resource successfully starts and synchronizes to the grid within the specified notification and startup time (plus the greater of 10% time to start or ten minutes) and operates for the unit's minimum run time as specified in the selected schedule; otherwise, such resource shall be deemed to fail the test. Following a failed test or a failed re-test, the Office of Interconnection may issue a re-test of the resource once the resource is made available for scheduling. A re-test initiated by the Office of the Interconnection has the same requirements as the initial test. The re-test is considered to be part of the same operational test, and does not count as a second test initiated by the Office of Interconnection for the relevant season. Resources shall not be eligible to be made whole for PJM initiated re-tests following a failed test. If a re-test is issued by PJM and the unit fails to successfully start and synchronize to the grid during such re-test, a Generation Capacity Resource operational test failure charge shall be assessed until such time as the unit successfully starts and synchronizes to the grid.

b) Generation Capacity Resource Operational Test Failure Charge

The Generation Capacity Resource operational test failure charge shall equal the Daily Deficiency Rate multiplied by the applicable daily committed UCAP MW of that Generation Resource; provided however, a Capacity Market Seller shall not be assessed a charge under this section to the extent (i.e., for the same megawatts and time period) that such seller is assessed a charge under Tariff, Attachment DD, section 8 for such resource's unavailability; and provided further that a resource that is subject to a charge under this section that is also subject to a charge under Tariff, Attachment DD, section 10A hereof for a Performance Shortfall during one or more

Performance Assessment Intervals occurring during the period of resource operational test deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Tariff, Attachment DD, section 10A, but shall not be assessed a charge under both this section and Tariff, Attachment DD, section 10A for such simultaneous occurrence of a resource operational test deficiency and Performance Shortfall.

c) Allocation of Revenue Collected from Generation Operational Deficiency Rate Failure Charges.

The revenue collected from Generation Capacity Resource Operational Test Failure Charges shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Generation Capacity Resource Operational Test Failure Charge was assessed. Such revenues shall be allocated on a pro-rata basis to LSEs based on their Daily Unforced Capacity Obligation.

10A. CHARGES FOR NON-PERFORMANCE AND CREDITS FOR PERFORMANCE

(a) For the 2018/2019 Delivery Year and any subsequent Delivery Year (and for certain purposes for the 2016/2017 and 2017/2018 Delivery Years as provided in subsections (h) and (i) hereof), each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, and for the 2022/2023 Delivery Year and subsequent Delivery Years each PRD Provider that commits Price Responsive Demand for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources or Price Responsive Demand during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation, demand response resources, or Price Responsive Demand that perform during such hour in excess of the level expected based on commitments (if any) of such resources.

(b) Performance shall be measured for purposes of this assessment during each Performance Assessment Interval.

(c) For each Performance Assessment Interval, the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource and Locational UCAP has fallen short of the performance expected of such committed Capacity Resource, and the magnitude of any such shortfall, based on the following formula:

Performance Shortfall = Expected Performance - Actual Performance

Where the result of such formula is a positive number and where:
Expected Performance =

for Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve a declared Emergency Action; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and Capacity Storage Resources: [(Resource Committed Capacity * the Balancing Ratio)];

where

Resource Committed Capacity = the total megawatts of Unforced Capacity of the Capacity Resource committed by such Capacity Market Seller or Locational UCAP Seller; and

The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports, Price Responsive Demand Bonus Performance effective with the 2022/2023 Delivery Year, and Demand Response Bonus

Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Interval for which performance by any external Generation Capacity Resource would have helped resolve the Emergency Action that was the subject to the Performance Assessment Hour; and provided further that for any Delivery Year up to and including the 2019/2020 Delivery Year, Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

All Committed Generation and Storage Capacity = the total megawatts of Unforced Capacity of all Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and all Capacity Storage Resources committed by all Capacity Market Sellers, FRR Entities, Locational UCAP Sellers;

All Actual Generation Performance and Storage Resource Performance = the total amount of Actual Performance for all generation resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and storage resources during the interval;

Net Energy Imports = the sum of interchange transactions importing energy into PJM (not including those associated with external Generation Capacity Resources and therefore included in All Actual Generation Performance) minus the sum of interchange transactions exporting energy out of PJM, but not less than zero;

Demand Response Bonus Performance = the sum of Bonus performance provided by Demand Response resources as calculated in (g) below;

Price Responsive Demand Bonus Performance = the sum of Bonus performance provided by Price Responsive Demand as calculated in (g) below;

and for Demand Resources, Energy Efficiency Resources, and Qualifying Transmission

Upgrades: Resource Committed Capacity;

where

Resource Committed Capacity = the total megawatts of capacity committed from such Capacity Resource committed capacity without making any adjustment for the Forecast Pool Requirement

and for PRD Provider: Price Responsive Demand Committed

where

Price Responsive Demand Committed = the Nominal PRD Value committed by the PRD Provider in the area defined by the Performance Assessment Interval, adjusted to account for any PRD registrations in such area that were not subject to compliance measurement.

and

Actual Performance =

for each generation resource, the metered output of energy delivered to PJM by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each storage resource, the metered output of energy delivered to PJM by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each Demand Resource, the demand response provided to PJM by such resource, plus such resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval, as established through the PJM demand response settlement procedure consistent with the standards specified in RAA, Schedule 6;

for each PRD Provider, the actual load reduction provided by the PRD Provider during a Performance Assessment Interval, determined in accordance with RAA, Schedule 6.1.N and the PJM Manuals;

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; and

for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Interval, and zero if it is not in service during such Performance

Assessment Interval.

Such calculation shall encompass all resources and Price Responsive Demand located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. 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 purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval. For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Interval shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.

(d) Notwithstanding subsection (c) above, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, or was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the Interconnection, based on a determination by the Office of the Interconnection that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM Region. Such a resource shall be considered in the calculation of a Performance Shortfall if it otherwise was needed and would have been scheduled by the Office of the Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to: (i) any operating parameter limitations submitted in the resource's offer, or (ii) the seller's submission of a market-based offer higher than its cost-based. In addition, notwithstanding subsection (c) above, a Price Responsive Demand registration shall not be considered in the calculation of a Performance Shortfall or Bonus Performance for a Performance Assessment Interval when the PRD Curve associated with such registration in the PJM 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.

(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:

Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate

Where

For Capacity Performance Resources and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour).

and for Base Capacity Resources the Non-Performance Charge Rate = (Weighted Average Resource Clearing Price applicable to the resource * (the number of days in the Delivery Year / 30) (the number of Real-Time Settlement Intervals in an hour)

(f) The Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource or such PRD Provider times the number of days in the Delivery Year. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. The total Non-Performance Charges for each Base Capacity Resource (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to the total payments due such Capacity Resource or Locational UCAP under Tariff, Attachment DD, section 5.14 for such Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.

(f-1) Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource or such PRD Provider, where such megawatts shall be based on the maximum Unforced Capacity committed up through the end of the month in which the PAI occurs, times the number of days in the Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource, where such megawatts shall be based on maximum Unforced Capacity committed up through the end of the month in which the Performance Assessment Interval occurs, times the number of days in the season applicable to such resource.

(g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval, that provided energy or load reductions above the levels expected for such resource during such interval. For purposes of this provision, the performance expected of a resource, and the revenue distribution payment, if any, for a resource, shall be determined in accordance with the following formulae:

Formula 1: Market Participant Bonus Performance = Actual Performance – Expected Performance

and

Formula 2: Performance Payment = (Market Participant Bonus Performance / All Market Participants Bonus Performance) * Non-Performance Charge Revenues.

Where the result of Formula 1 is a positive number and where:

Actual Performance is as defined in subsection (c), provided, however, that Actual Performance for purposes of this calculation shall not exceed the megawatt level at which such resource was scheduled by the Office of the Interconnection during the Performance Assessment Intervals; and provided further that Actual Performance for a Market Participant that imports energy into the PJM Region during such Performance Assessment Interval shall be the net import, if any, from all interchange transactions scheduled by such Market Participant during such Performance Assessment Interval;

Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the resource's capacity obligation period, including, without limitation, a Base Capacity Demand Resource providing demand response during non-summer months; and

All Market Participants Bonus Performance is the sum of the results of calculating Formula 1 of this subsection (g) for all Market Participants that have Bonus Performance during such Performance Assessment Interval.

(h) The provisions of this section 10A shall apply during the 2016/2017 Delivery Year, provided that:

(i) Non-Performance Charges shall be determined solely for and assessed solely on, Capacity Performance Resources committed for such Delivery Year;

(ii) The Non-Performance Charge shall be 0.5 times the Non-Performance Charge calculated under subsection (e) hereof; and

(iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.75 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(i) The provisions of this section 10A shall apply during the 2017/2018 Delivery Year, provided that:

(i) Non-Performance Charges shall be determined solely for, and assessed solely on, Capacity Performance Resources committed for such Delivery Year;

(ii) The Non-Performance Charge shall be 0.6 times the Non-Performance Charge calculated under subsection (e) hereof; and

(iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.9 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(j) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year. Notwithstanding, if there are less than six months remaining in the current Delivery Year for which no invoice has been issued, the Office of the Interconnection may, with prior notice to PJM Members, allocate in equal amounts any Non-Performance Charge in the remaining monthly bills for the current Delivery Year plus up to six monthly bills into the following Delivery Year for all Capacity Market Sellers that incur such a Non-Performance Charge (but in no event shall the total Non-Performance Charge be divided in more than nine monthly bills). Provided, for any Non-Performance Charges associated with Performance Assessment Intervals from December 23, 2022 and December 24, 2022, a Capacity Market Seller may elect, by providing notice to the Office of Interconnection by March 17, 2023, to divide the total amount of Non-Performance Charges by either (i) the number of remaining monthly bills in the current Delivery Year (i.e., 3 bills) or (ii) the number of remaining monthly bills in the current Delivery Year plus six additional monthly bills into the following Delivery Year (i.e., 9 bills); provided further, however, that for an election under subsection (ii) above, the monthly Non-Performance Charge shall be levelized to include interest for the six month period following the current Delivery Year, such interest amount being determined at the electric interest rate established by the Federal Energy Regulatory Commission at the time of such election. All interest collected in accordance with this provision shall be allocated to the total pool of bonus performance payments and distributed in accordance with Tariff, Attachment DD, section 10A(g).

11A DEMAND RESOURCES TEST FAILURE CHARGE

a) ~~Beginning with the Delivery Year that commences on June 1, 2009,~~ Capacity Market Sellers that commit Demand Resources may be charged to the extent their committed resources fail performance tests, as set forth herein.

b)

(i) [Reserved]~~For Demand Resources not committed as Capacity Performance Resources for Delivery Years through May 31, 2018:~~

~~For Limited Demand Resources: If a registration for a Limited Demand Resource committed by a Capacity Market Seller is not dispatched by the Office of the Interconnection for a Load Management event prior to August 15 of the relevant Delivery Year, then such registration must demonstrate that it was tested as described below in (iii), in a zone for a one-hour period during any hour when a PJM Load Management event may be called between June 1 and September 30, inclusive. If a registration for a Limited Demand Resource committed by a Capacity Market Seller is dispatched by the Office of the Interconnection for a PJM Load Management event in a zone between August 16 and September 30, no test will be required. If a registration for a Limited Demand Resource committed by a Capacity Market Seller is dispatched by the Office of Interconnection for a PJM Load Management event in a subzone between June 1 and September 30 of the 2012/2013 and 2013/2014 Delivery Years, and such registration performs at or above the nominated amount of capacity on the registration, no test will be required and no Demand Resources Test Failure Charges will be assessed for such registrations. If a registration for a Limited Demand Resource committed by a Capacity Market Seller is dispatched by the Office of the Interconnection for a PJM Load Management event in a zone between June 1 and September 30, inclusive, then Demand Resources Test Failure Charges will not be assessed.~~

~~For Annual Demand Resources: if an Annual Demand Resource registration is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year, then the Annual Demand Resource registration committed by a Capacity Market Seller must demonstrate that the Annual Demand Resource registration committed in a zone was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through October or the following May of the relevant Delivery Year. If an Annual Demand Resource registration is dispatched by the Office of the Interconnection for a Load~~

~~Management event during the Delivery Year, then no test will be required.~~

~~For Extended Summer Demand Resources: if an Extended Summer Demand Resource registration is not dispatched by the Office of the Interconnection for a Load Management event during June through October or the following May, then the Extended Summer Demand Resource registration committed by a Capacity Market Seller must demonstrate that the Extended Summer Demand Resource registration was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through October or the following May of the relevant Delivery Year.~~

(ii) [Reserved]~~For Demand Resources committed as Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years and for all Demand Resources for the 2018/2019 Delivery Year through the 2022/2023 Delivery Year:~~

~~For Base Capacity Demand Resources: if an Base Capacity Demand Resource registration is not dispatched by the Office of the Interconnection for a Load Management event during June through September, then the Base Capacity Demand Resource registration committed by a Capacity Market Seller must demonstrate that the Base Capacity Demand Resource registration was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through September of the relevant Delivery Year.~~

~~For Demand Resources that commit as Capacity Performance Resources: if a Demand Resource that is a Capacity Performance Resource registration is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year, then that Demand Resource registration committed by a Capacity Market Seller must demonstrate that that Demand Resource registration committed in a zone was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through October or the following May of the relevant Delivery Year. If an Annual Demand Resource registration is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year, then no test will be required.~~

~~For Summer-Period Demand Resources: if a Summer-Period Demand Resource registration 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, then the~~

~~registration committed by a Capacity Market Seller must demonstrate that it was tested as described below in (iii), for a one-hour period during any hour when a PJM Load Management event may be called during June through October or the following May of the relevant Delivery Year.~~

~~All registrations in a zone required to test must be tested simultaneously for each product except that, when less than 25 percent (by megawatts) of a provider's Demand Resources in a zone fail a test, the provider may conduct a re-test limited to all registrations that failed to meet their seasonal nominated ICAP in 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 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 provider chooses to conduct a retest, the provider may elect to maintain the performance compliance result for registration(s) achieved during the test if provider: (1) notifies the Office of the Interconnection 48 hours prior to the retest under this election; and (2) the provider retests affiliated registrations under this election as set forth in the PJM Manual.~~

(iii) [Reserved]~~For Demand Resources committed for the 2023/2024 Delivery Year and subsequent Delivery Years:~~

A. Through the 2023/2024 Delivery Years, ~~F~~for Annual Demand Resources: if an Annual Demand Resource registration is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year, then the registration committed by a Capacity Market Seller in a zone shall be tested as described below in section iii(c), 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 below in section iii(d). If an Annual Demand Resource registration is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year, then no test will be required.

A-1. Effective with the 2024/2025 Delivery Year and subsequent Delivery Years, for Annual Demand Resources: if an Annual Demand Resource registration 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, then the registration committed by a Capacity Market Seller in a zone shall be tested as described below in section iii(c), 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 below in section iii(d). Notwithstanding the foregoing, a Capacity Market Seller may elect to utilize performance data from a Load Management event in the Delivery Year that was not assessed for performance during Performance Assessment Intervals to be considered in the annual Demand Resource test requirement , as long as the event is at least 30 minutes of a clock hour. If an Annual Demand Resource registration is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year, and assessed for performance during Performance Assessment Intervals, then no test will be required.

B. Through the 2023/2024 Delivery Year, ~~F~~for Summer-Period Demand Resources: if a Summer-Period Demand Resource registration 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, then the registration committed by a Capacity Market Seller must demonstrate that it was tested as described below in section iii(c), 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.

B-1. Effective with the 2024/2025 Delivery Year and subsequent Delivery Years, for Summer-Period Demand Resources: if a Summer Period Demand Resource registration is not dispatched and assessed for performance during Performance Assessment Intervals, by the Office of the Interconnection for a Load Management event during June through October or the following May of the Delivery Year, then the registration committed by a Capacity Market Seller must demonstrate that it was tested as described below in section iii(c), 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. Notwithstanding the foregoing, a Capacity Market Seller may elect to utilize performance data from a Load Management event in the Delivery Year that was not assessed for performance during Performance Assessment Intervals to be considered in the annual Demand Resource test requirement, as long as the event is at least 30 minutes of a clock hour and the Load Management event occurred in the summer.

C. 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.

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.

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.

D. Notification of the initial Office of the Interconnection scheduled test will be provided based on the following procedure. 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. 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.

Notification of any scheduled retest by the Office of the Interconnection will be provided based on the following procedure. 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.

c) a Capacity Market Seller that committed Demand Resources shall be assessed a Demand Resources Test Failure Charge equal to the net capability testing shortfall for such products tested in a Zone during such test in the aggregate of all of such Seller's Demand Resources tested in such Zone times the Demand Resources Test Failure Charge Rate. The net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable ~~DR Factor and~~ Forecast Pool Requirement prior to 2025/2026 Delivery Year and applicable ELCC Class Rating beginning with the 2025/2026 Delivery Year: (i) the summer daily average of the megawatts of load reduction capability committed by such seller in such Zone for such product(s) tested minus (ii) the megawatts of load reduction actually provided by all such Demand Resources in such Zone during such test. The net capability 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.

d) the Demand Resources Test Failure Charge Rate shall equal such Seller's Weighted Daily Revenue Rate in such Zone for the product(s) 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). The Daily Demand Resources Test Failure Charge in a zone for the product(s) tested shall be equal to the net capability testing shortfall in such Zone for such product(s) tested times the Demand Resources Test Failure Charge Rate. 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.

e) revenues collected from assessment of Demand Resources Test Failure Charges shall be distributed to Load Serving Entities that were charged a Locational Reliability Charge for the Delivery Year for which the Demand Resources Test Failure Charge was assessed, pro-rata based on such Load Serving Entities' Daily Unforced Capacity Obligations.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of RAA, Schedule 6. Capitalized terms used herein that are not otherwise defined in Tariff, Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to ~~a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource,~~ a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand

Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) 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;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or 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 Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are 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 Demand Resource Sell

Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but 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 Demand Resource customers within this market and the potential for

other Demand Resource Providers targeting the same customers; and

- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

(1) for ~~the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource,~~

~~times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent~~ Delivery Years through the 2024/2025 Delivery Year, ~~or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years,~~ as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. ~~The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.~~

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service 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.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

● A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

● Supplemental status reports, detailing Demand Resources available, as requested by PJM;

● Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

● Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or ~~Provider initiated~~ test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

● Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer~~,~~ or winter~~ or annual~~) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor. ~~The annual Nominated Value for or Firm Service Level customer(s) on a registration shall equal the lesser of i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.~~

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider. ~~The annual Nominated Value for a Guaranteed Load Drop customer on a registration shall be the lesser of the i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.~~

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer~~,~~ or winter~~, or annual~~ Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

~~The daily Nominated Value for the Delivery Year for a Limited Demand Resource, Extended Summer Demand Resource, Base Capacity Demand Resource, and Annual~~

~~Demand Resource without a Capacity Performance commitment shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource. For the 2017/2018 and 2018/2019 Delivery Years, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the sum of the annual Nominated Values of the registrations linked to such Demand Resource. For the 2019/2020 Delivery Year, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource. Effective with the 2020/2021 Delivery Year, t~~The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and ~~Curtailment Service Provider initiated~~ tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and ~~Curtailment Service Provider initiated~~ test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable prior to the 2025/2026 Delivery Year, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

(PLC) - (Load *LF)

Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:

(WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is ~~averaged over the Load Management Event for a Demand Resource Registration linked to a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource without a Capacity Performance commitment or~~ determined on an hourly basis for a Demand Resource Registration linked to ~~a Base Capacity Demand Resource or~~ an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). ~~The registered capacity commitment for a Demand Resource Registration without a Base or Capacity Performance commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals.~~ Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. 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 in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

~~Compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a committed Limited Demand Resource, Extended Summer Demand Resource, and Annual Demand Resource without a Capacity Performance commitment to determine a net compliance position for the event for each Provider by Compliance Aggregation Area and such net compliance position shall be allocated to the underlying registrations, in accordance with PJM Manuals. Load Management Event deficiencies shall be as further determined in accordance with Tariff, Attachment DD, section 11 and PJM Manuals.~~

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's ~~Base Capacity Demand Resource or to an~~ Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-

Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- ~~For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 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;~~

- ~~For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 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; and~~

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource~~ for the 2016/2017 and 2017/2018 Delivery Years~~, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 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.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. ~~For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, t~~The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. ~~For Incremental Auctions conducted for the 2019/2020 and 2020/2021 Delivery Years, and f~~For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) ~~For Incremental Auctions that will be conducted for the 2019/2020 and 2020/2021 Delivery Years, and f~~For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller’s deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

Sections of the
PJM Reliability Assurance Agreement

(Marked / Redline Format)

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

"Accredited UCAP" shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

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

Agreement:

"Agreement" shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

"Annual Demand Resource" shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

"Applicable Regional Entity" shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

"Base Capacity Demand Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

"Base Capacity Energy Efficiency Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

"Base Capacity Resource" shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

"Base Residual Auction" shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of 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 Capacity Resource or (ii) in any 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.

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit" or "CETL" shall mean 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 Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating 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 all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

"Capacity Only Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

"Capacity Performance Resource" shall have the same meaning as in Tariff, Attachment DD.

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.

Capacity Storage Resource Class:

"Capacity Storage Resource Class" shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours. The characteristic duration of an Energy Storage Resource Class is the ratio of the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

"Capacity Transfer Right" shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

"Coal Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

"Combination Resource" shall mean a Generation Capacity 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.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall have the same meaning as in the Tariff.

Complex Hybrid Class:

"Complex Hybrid Class" shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Daily Unforced Capacity Obligation:

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

"Delivery Year" shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

"Demand Resource" or "DR" shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity 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 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

"Demand Resource Factor" or "DR Factor" shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6

Demand Resource Officer Certification Form:

"Demand Resource Officer Certification Form" shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

"Demand Resource Registration" shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

"Demand Resource Sell Offer Plan" shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

Effective Nameplate Capacity:

"Effective Nameplate Capacity" shall mean (i) for each Variable Resource and Combination Resource, the resource's Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility's Maximum Facility Output); (ii) for each Limited Duration Resource, the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource's capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility's Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

"Effective UCAP" shall mean 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 Class:

"ELCC Class" shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

"ELCC Class Rating" shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

"ELCC Class UCAP" shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

"ELCC Portfolio UCAP" shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

"ELCC Resource" shall mean, through the 2024/2025 Delivery Year, a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource, and beginning with the 2025/2026 Delivery Year, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

"ELCC Resource Performance Adjustment" shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

"Electric Cooperative" shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

"Electric Distributor" shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

"Emergency" shall mean (i) 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; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

″End-Use Customer″ shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Members Committee sector classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Efficiency Resource:

"Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

"Exigent Water Storage" shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

"Existing Demand Resource" shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery

Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

“Extended Summer Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

“Facilities Study Agreement” shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall have the meaning specified in the Tariff.

Firm Service Level:

"Firm Service Level" or "FSL" of Price Responsive Demand for the 2022/2023 Delivery Year and subsequent Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when an Emergency Action that triggers a Performance Assessment Interval is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. "Firm Service Level" or "FSL" of Demand Resource shall mean the pre-determined level for which an end-use customer's load shall be reduced, upon notification from the Curtailment Service Provider's market operations center or its agent.

Firm Transmission Service:

"Firm Transmission Service" shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

"Fixed Resource Requirement Alternative" or "FRR Alternative" shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

"Fixed-Tilt Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

"Forecast Pool Requirement" or "FPR" shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

"FRR Capacity Plan" or "FRR Plan" shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

"FRR Entity" shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

"FRR Service Area" shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. 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 Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

"Full Program Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

"Full Requirements Service" shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

"Gas Combined Cycle Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

"Gas Combined Cycle Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start and operate independently on an alternate, onsite fuel source up to its maximum capacity level during the winter season of the applicable Delivery

Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

"Gas Combustion Turbine Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

"Gas Combustion Turbine Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start and operate independently on an alternate, onsite fuel source up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

"Generation Capacity Resource" shall mean 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 Capacity Resource Provider:

"Generation Capacity Resource Provider" shall mean a Member that owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity.

Generation Owner:

"Generation Owner" shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, 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 shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, 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 pursuant to the PJM Manuals.

Generator Planned Outage:

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hybrid Resource Class:

"Hybrid Resource Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in a Capacity Storage Resource Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

"Hydropower With Non-Pumped Storage" shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

"Hydropower With Non-Pumped Storage Class" shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

Incremental Auction:

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, Accredited UCAP Factor decrease, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Intermittent Hydropower Class:

"Intermittent Hydropower Class" shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

"IOU" shall mean an investor-owned utility 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.

Intermittent Landfill Gas Class:

"Intermittent Landfill Gas Class" shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Limited Demand Resource:

"Limited Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Limited Duration Resource:

"Limited Duration Resource" shall mean a Generation Capacity 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 Serving Entity or LSE:

"Load Serving Entity" or "LSE" shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been 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 Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

"Locational Reliability Charge" shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

"Markets and Reliability Committee" shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

"Maximum Emergency Service Level" or "MESL" of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Members Committee:

"Members Committee" shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

"Network Resources" shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Nominal PRD Value:

"Nominal PRD Value" shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

"Non-Retail Behind the Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Nuclear Class:

"Nuclear Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

"Obligation Peak Load" shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Offshore Wind Class:

"Offshore Wind Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

“Onshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean that agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C, on file with the Commission.

Operating Day:

“Operating Day” shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Ordinary Water Storage:

“Ordinary Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

“Other Limited Duration Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

“Other Limited Duration Combination Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

"Other Supplier" shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM's governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

"Other Unlimited Resource Class" shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

"Other Variable Resource Class" shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

"Partial Requirements Service" shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

"Party" shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

"Peak Shaving Adjustment" shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Base Capacity Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall mean, 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 such LDA.

Performance Assessment Interval:

"Performance Assessment Interval" shall have the meaning specified in Tariff, Attachment DD.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Region:

"PJM Region" shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

"PJM Region Installed Reserve Margin" shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T., "OATT" or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Planned Demand Resource:

"Planned Demand Resource" shall mean any 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 such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned External Generation Capacity Resource:

"Planned External Generation Capacity Resource" shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has a fully executed system impact study agreement (or other documentation which is functionally equivalent to a System Impact Study Agreement under the PJM Tariff) or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to a Facilities Study Agreement under the PJM Tariff), with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to an Interconnection Service Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

"Planned Generation Capacity Resource" shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, a System Impact Study Agreement (or, for resources for which a System Impact Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a System Impact Study Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, a Facilities Study Agreement (or, for resources for which a Facilities Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a Facility Studies Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

"Planning Period" shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

"Portfolio Expected Unserved Energy" shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

"PRD Curve" shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

“PRD Provider” shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider’s Zonal Expected Peak Load Value of PRD:

“PRD Provider’s Zonal Expected Peak Load Value of PRD” shall mean the expected contribution to Delivery Year peak load of a PRD Provider’s Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year’s peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection’s load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

“PRD Reservation Price” shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

“PRD Substation” shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

“Price Responsive Demand” or “PRD” shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection (prior to 2022/2023Delivery Year) or a Performance Assessment Interval that triggers a PRD performance assessment (effective with 2022/2023 Delivery Year), and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

“Price Responsive Demand Credit” shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

"Price Responsive Demand Plan" or "PRD Plan" shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider's Nominal PRD Value.

Public Power Entity:

"Public Power Entity" shall mean 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 foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

"Qualifying Transmission Upgrades" shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" or "RERRA" shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

"Reliability Principles and Standards" shall mean the principles and standards established by ~~NERC or an Applicable Regional Entity~~ the Office of the Interconnection that~~to~~ define, among other things, an acceptable probabilistic~~probability~~ of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

"Required Approvals" shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

"Self-Supply" shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

"Small Commercial Customer" shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

"State Regulatory Structural Change" shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

Steam Class:

"Steam Class" shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, 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 the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM 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 a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

"Supervisory Control" shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

"Threshold Quantity" shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Reliability Assurance Agreement, Schedule 8.1).

Tracking Solar Class:

"Tracking Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the 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:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity:

"Unforced Capacity" shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

"Unlimited Resource" shall mean 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, ~~A~~an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource:

"Variable Resource" shall mean a Generation Capacity 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.

Winter Peak Load (or WPL):

"Winter Peak Load" or "WPL" shall mean 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 the Delivery Year for which the registration is submitted. Notwithstanding, 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. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

Zonal Capacity Price:

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity

Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

Zone or Zonal:

"Zone" or "Zonal" shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

"Zonal Winter Weather Adjustment Factor" or "ZWWAF" shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

7.1 Forecast Pool Requirement and Unforced Capacity Obligations.

(a) The Forecast Pool Requirement shall be established to ensure a sufficient amount of capacity to meet the forecast load plus reserves adequate to provide for the unavailability of ~~Generation~~ Capacity Resources, load forecasting uncertainty, and planned and maintenance outages. RAA, Schedule 4 sets forth guidelines with respect to the Forecast Pool Requirement.

(b) Unless the Party and its customer that is also a Load Serving Entity agree that such customer is to bear direct responsibility for the obligations set forth in this Agreement, (i) any Party that supplies Full Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for all of that Load Serving Entity's capacity obligations under this Agreement for the period of such Full Requirements Service and (ii) any Party that supplies Partial Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for such portion of the capacity obligations of that Load Serving Entity as agreed by the Party and the Load Serving Entity so long as the Load Serving Entity's full capacity obligation under this Agreement is allocated between or among Parties to this Agreement.

B. Forecast Pool Requirement and PJM Region Installed Reserve Margin To Be Determined Annually

No later than ~~three months~~ 75 days in advance of each Base Residual Auction for a Delivery Year, based on the projections described in section C of this Schedule, and after consideration of the recommendation of the Members Committee, the PJM Board shall establish the Forecast Pool Requirement, including the PJM Region Installed Reserve Margin for all Parties, including FRR Entities, for such Delivery Year. Unless otherwise agreed by the PJM Board, the Forecast Pool Requirement and PJM Region Installed Reserve Margin for such Planning Period shall be considered firm and not subject to re-determination thereafter.

C. Methodology

Each year, the Forecast Pool Requirement for at least each of the next five Planning Periods shall be projected by applying suitable probability methods to the data and forecasts provided by the Parties and obtained from Electric Distributors, as described in RAA, Schedule 11, the Operating Agreement and in the PJM Manuals. The projection of the Forecast Pool Requirement shall consider the following data and forecasts as necessary:

1. Seasonal peak load forecasts for each Planning Period as calculated by PJM in accordance with the PJM Manuals reflecting (a) load forecasts with a 50 percent probability of being too high or too low and (b) ~~summer~~ seasonal peak diversities determined by the Office of the Interconnection ~~from recent experience~~.

~~2. Forecasts of aggregate seasonal load shape of the Parties which are consistent with forecast averages of 52 weekly peak loads prepared by the Parties and obtained from Electric Distributors for their respective systems.~~

~~3~~2. Variability of loads within each week through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, hourly load shapes and variability, due to weather and other recurring and random factors, as determined by the Office of the Interconnection.

~~4~~3. Generating unit capability and types for every existing and proposed unit.

~~5~~4. Generator Forced Outage rates for existing mature generating units, as determined by the Office of the Interconnection, based on data submitted by the Parties for their respective systems, from recent and historical experience, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

~~6~~5. Generator Maintenance Outage factors and planned outage factors ~~schedules~~ as determined by the Office of the Interconnection based on forecasts and historical data submitted by the Parties for their respective systems.

~~7~~6. Miscellaneous adjustments to capacity due to all causes, including weather, as determined by the Office of the Interconnection, based on forecasts submitted by the Parties for their respective systems.

~~8~~7. The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, as limited by the capacity benefit margin considered in the determination of available transfer capability and the probable availability of generation in excess of load requirements in such areas.

SCHEDULE 4.1

DETERMINATION OF THE FORECAST POOL REQUIREMENT

A. Through the 2024/2025 Delivery Year, the Forecast Pool Requirement shall be determined in accordance with the following:

Based on the guidelines set forth in RAA, Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

FPR = (1 + IRM~~/100~~) * (1- Pool-wide average $EFOR_D$~~/100~~)

where

average $EFOR_D$ = the average equivalent demand forced outage rate for the PJM Region, stated in percent and determined in accordance with Section B hereof

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent. Studies by the Office of the Interconnection to determine IRM shall not exclude outages that are deemed to be outside plant management control under NERC guidelines.

B. Through the 2024/2025 Delivery Year, ~~T~~the PJM Region equivalent demand forced outage rate ("average $EFOR_D$") shall be determined as the capacity weighted $EFOR_D$ for all units expected to serve loads within the PJM Region during the Delivery Year, as determined pursuant to RAA, Schedule 5.

C. Beginning with the 2025/2026 Delivery Year, the Forecast Pool Requirement shall be determined in accordance with the following:

Based on the guidelines set forth in RAA, Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

FPR = (1 + IRM) * (Pool-wide average Accredited UCAP Factor)

where

Pool-wide average Accredited UCAP Factor = 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

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent.

SCHEDULE 5

FORCED OUTAGE RATE CALCULATION

A. The equivalent demand forced outage rate ("$EFOR_D$") shall be calculated as follows:

$$EFOR_D\ (\%) = \{(f_f * FOH + f_p * EFPOH) / (SH + f_f * FOH)\} * 100$$

where

f_f = full outage factor
f_p = partial outage factor
FOH = full forced outage hours
EFPOH = equivalent forced partial outage hours
SH = service hours

B. Calculation of $EFOR_D$ for individual Generation Capacity Resources.

For ~~each~~ Delivery Years through the 2024/2025 Delivery Year, $EFOR_D$ shall be calculated at least one month prior to the start of the Third Incremental Auction for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third Incremental Auction; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to an FRR Capacity Plan or prior auctions for such Delivery Year.

Such calculation shall be based upon such resource's service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit. For purposes of the calculations under this Paragraph B, ~~for Delivery Years through May 31, 2018, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered, and for the 2018/2019 Delivery Year and all subsequent Delivery Years,~~ outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered.

1. The $EFOR_D$ of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

2. The $EFOR_D$ of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the $EFOR_D$ experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be

based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average $EFOR_D$ for the PJM Region

For Delivery Years through the 2024/2025 Delivery Year, ~~T~~the forecast average $EFOR_D$ for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average $EFOR_D$ shall be the average of the capacity-weighted $EFOR_D$s of all units committed to serve load in the PJM Region; and for purposes of the $EFOR_D$ calculations under this Paragraph C ~~for any Delivery Year beginning after May 31, 2010, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered, and for the 2018/2019 Delivery Year and all subsequent Delivery Years,~~ outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered. All rates shall be in percent.

1. The $EFOR_D$ of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.

2. The $EFOR_D$ of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.

3. The $EFOR_D$ of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar Years of Service	
1	One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate.
2	Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate.

3	Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
4	Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to ~~a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource,~~ a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) 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;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or 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 Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are 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 Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but 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 Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined ~~as~~:

(1) for ~~the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent~~ Delivery Years through the 2024/2025 Delivery Year~~, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years~~, as the

product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. ~~The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.~~

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service 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.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

● A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

● Supplemental status reports, detailing Demand Resources available, as requested by PJM;

● Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

● Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or ~~Provider initiated~~ test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

● Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer~~,~~ or winter~~ or annual~~) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor. ~~The annual Nominated Value for or Firm Service Level customer(s) on a registration shall equal the lesser of i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.~~

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider. ~~The annual Nominated Value for a Guaranteed Load Drop customer on a registration shall be the lesser of the i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.~~

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer~~,~~ or winter~~, or annual~~ Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

~~The daily Nominated Value for the Delivery Year for a Limited Demand Resource, Extended Summer Demand Resource, Base Capacity Demand Resource, and Annual Demand Resource without a Capacity Performance commitment shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource. For the 2017/2018 and 2018/2019 Delivery Years, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall~~

~~equal the sum of the annual Nominated Values of the registrations linked to such Demand Resource. For the 2019/2020 Delivery Year, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource. Effective with the 2020/2021 Delivery Year, t~~The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and ~~Curtailment Service Provider initiated~~ tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and ~~Curtailment Service Provider initiated~~ test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable prior to the 2025/2026 Delivery Year, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:

(WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is ~~averaged over the Load Management Event for a Demand Resource Registration linked to a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource without a Capacity Performance commitment or~~ determined on an hourly basis for a Demand Resource Registration linked to ~~a Base Capacity Demand Resource or~~ an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). ~~The registered capacity commitment for a Demand Resource Registration without a Base or Capacity Performance commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals.~~ Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. 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 in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

~~Compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a committed Limited Demand Resource, Extended Summer Demand Resource, and Annual Demand Resource without a Capacity Performance commitment to determine a net compliance position for the event for each Provider by Compliance Aggregation Area and such net compliance position shall be allocated to the underlying registrations, in accordance with PJM Manuals. Load Management Event deficiencies shall be as further determined in accordance with Tariff, Attachment DD, section 11 and PJM Manuals.~~

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's ~~Base Capacity Demand Resource or to an~~ Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that

is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- ~~For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 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;~~

- ~~For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 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; and~~

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource~~ for the 2016/2017 and 2017/2018 Delivery Years~~, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 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.

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. ~~For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, t~~The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and

accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. ~~For Incremental Auctions conducted for the 2019/2020 and 2020/2021 Delivery Years, and f~~For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) ~~For Incremental Auctions that will be conducted for the 2019/2020 and 2020/2021 Delivery Years, and f~~For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

C. Election, and Termination of Election, of FRR Alternative

1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. No later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources, Seasonal Capacity Performance Resources, and Base Capacity Resources, as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment 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 such Delivery Year. An FRR Entity 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.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, except a new FRR Entity's initial election, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

5. Notwithstanding subsections C.1 and C.2 of this Schedule, 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 the 2028/2029 Delivery Year.

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

1.1 Beginning with the 2020/2021 Delivery Year and for all subsequent Delivery Years, the FRR Capacity Plan shall comprise only Capacity Performance Resources and Seasonal Capacity Performance Resources.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. ~~For the 2016/2017 Delivery Year and prior Delivery Years, the set of Capacity Resources designated in the FRR Capacity Plan must meet the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation. For the 2017/2018 and 2018/2019 Delivery Years, the set of Capacity Resources designated in the FRR Capacity Plan must satisfy the Limited Resource Constraints and the Sub-Annual Resource Constraints applicable to the FRR Entity's capacity obligation. For the 2019/2020 Delivery Year, the set of Capacity Resources designated in the FRR Capacity Plan must satisfy the Base Capacity Resource Constraints and Base Capacity Demand Resource Constraints applicable to the FRR Entity's capacity obligation.~~ If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved

pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement, the PJM Tariff, and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted 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 FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan, subject to applicable demand resource constraints for the relevant Delivery Year, submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity. Without limiting the generality of the foregoing, the FRR Entity must submit a Demand Resource Sell Offer Plan 15 business days before the deadline for submitting an FRR Capacity Plan as to any Demand Resources it intends to include in such FRR Capacity Plan and may only include in such FRR Capacity Plan Demand Resources that are approved by PJM following review of such Demand Resource Sell Offer Plan. The requirements, standards, and procedures for a Demand Resource Sell Offer Plan shall be as set forth in Schedule 6 of this Agreement, provided that all references (including deadlines) in Schedule 6, section A-1 to submission or clearing of a Demand Resource offer in an RPM Auction shall be understood for purposes of FRR Entities as referring to inclusion of a Demand

Resource in an FRR Capacity Plan, and a distinct Demand Resource Officer Certification Form shall be applicable to FRR Entities, as shown in the PJM Manuals and provided on the PJM website.

5. For each LDA for which the Office of the Interconnection is required to establish a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a Percentage Internal Resources Required, subject to subsections D.1.1 and D.2 of this Schedule. The Percentage Internal Resources Required will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement. Notwithstanding the provisions of Sections C.1 and C.2 of this Schedule 8.1, 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 its minimum five year FRR commitment for which the Office of the Interconnection will be required to establish a separate Variable Resource Requirement Curve by giving written notice two months prior to the Base Residual Auction for the Delivery Year. The Office of the Interconnection shall be deemed to be required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), or Mid-Atlantic Region ("MAR"), or for other LDAs if the separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the Tariff.

6. An FRR Entity may reduce the Percentage Internal Resources Required as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the CETL for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days *after* the submittal *deadline* of the FRR Capacity Plan. Through the 2024/2025 Delivery Year, ~~I~~if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold

Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan. 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, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to the price level corresponding to point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the relevant Locational Deliverability Area, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for such Delivery Year.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement, the PJM Tariff, and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

F. FRR Daily Unforced Capacity Obligations and Deficiency Charges

1. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = [(OPL * Final Zonal FRR Scaling Factor) – Nominal PRD Value committed by the FRR Entity] * FPR

where:

OPL =Obligation Peak Load, defined as:

> the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal FRR Scaling Factor = FZPLDY/FZWNSP;

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

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

2. An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in such entity's FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Through the 2024/2025 Delivery Year, ~~S~~such FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times (1.20 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 quantities cleared in such auctions). Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, such FRR Capacity Deficiency Charge shall equal the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times the price level corresponding to Point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the Locational Deliverability Area encompassing the Zone of the FRR Entity.

3. If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of this Schedule.

4. The shortages in meeting the minimum requirement within the constrained zones and the shortage in meeting the total obligation are first calculated. The shortage in the unconstrained area is calculated as the total shortage less shortages in constrained zones and excesses in

constrained zones (the shortage is zero if this is a negative number). The Capacity Deficiency Charge is charged to the shortage in each zone and in the unconstrained area separately. This procedure is used to allow the use of capacity excesses from constrained zones to reduce shortage in the unconstrained area and to disallow the use of capacity excess from unconstrained area to reduce shortage in constrained zones.

~~5. For Delivery Years during the period starting June 1, 2014 and ending May 31, 2017, the shortages in meeting the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation are calculated separately. For such period, the applicable penalty rate is calculated for Annual Resources, Extended Summer Demand Resources, and Limited Resources as (1.20 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 quantities cleared in such auctions). For Delivery Years beginning June 1, 2017, the FRR Entity shall receive no credit for Limited Demand Resources to the extent committed in excess of the applicable Limited Resource Constraint and shall receive no credit for the sum of Limited Demand Resources and Extended Summer Demand Resources to the extent the sum of the Unforced Capacity of such resources exceeds the applicable Sub-Annual Resource Constraint.~~

G. Capacity Resource Performance

1. Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A~~Tariff, Attachment DD, section 9, Tariff, Attachment DD, section 10~~, Tariff, Attachment DD, section 10A, ~~Tariff Attachment DD, section 11,~~ Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A~~Tariff, Attachment DD, section 9~~, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, ~~only for the 2019/2020 and subsequent Delivery Years and~~ however, through the 2024/2025 Delivery Year, only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1~~and the charge rates under section 10A thereof for Base Capacity Resources shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above; and (iii) the charge rates under Tariff, Attachment DD, section 10 and Tariff, Attachment DD, section 11, shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above~~. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, ~~Tariff, Attachment DD, section 9, Tariff, Attachment DD, section 10,~~ Tariff, Attachment DD, section 10A, ~~Tariff, Attachment DD, section 11,~~ and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

2. For any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources or Seasonal Capacity Performance Resources determined in accordance with the following: For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's FRR Capacity Plan or Price Responsive Demand committed to reduce the FRR Entity's unforced capacity obligation (for the 2022/2023 Delivery Year and subsequent Delivery Years) will be determined in the same fashion as prescribed by the Tariff, Attachment DD, section 10A, and for such hour, a net Performance Shortfall shall be determined separately for Capacity Performance Resources and for Base Capacity Resources. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) exceeds the Expected Performance of such resources or Price Responsive Demand, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Base Capacity Resources for such hour. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR

Entity's committed Base Capacity Resources exceeds the Expected Performance of such resources, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such hour. For the 2020/2021 Delivery Year, the net Performance Shortfall determined for Capacity Performance Resources and Price Responsive Demand shall include the performance of Seasonal Capacity Performance Resources contained in the FRR Capacity Plan.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources or Price Responsive Demand, if any, for each such Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval to establish the additional MW quantities of Capacity Performance Resources, Seasonal Capacity Performance Resources, or Price Responsive Demand that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Capacity Performance Resources in any Delivery Year shall not exceed a MW quantity equal to 0.5 times the MW quantity of the Capacity Performance Resources and Seasonal Capacity Performance Resources that were committed in the FRR Capacity Plan for such Delivery Year and Price Responsive Demand committed such Delivery Year (for the 2022/2023 Delivery Year and subsequent Delivery Years). The FRR Entity's net Performance Shortfall among Base Capacity Resources, if any, for each such Performance Assessment Interval shall be multiplied by a rate of [(0.00139 MWs/Performance Assessment Interval) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)] to establish the additional MW quantities of Capacity Performance Resources or Seasonal Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Base Capacity Resources in any Delivery Year shall not exceed a MW quantity equal to [(0.5 times the MW quantity of the Base Capacity Resources that were committed in the FRR Capacity Plan for such Delivery Year) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)].

An FRR Entity that elects the physical option shall not be eligible for, or subject to, the revenue allocation described in Tariff, Attachment DD, section 10A(g).

SCHEDULE 9

PROCEDURES FOR
ESTABLISHING THE CAPABILITY OF GENERATION CAPACITY RESOURCES

A. Such rules and procedures as may be required to determine and demonstrate the capability of Generation Capacity Resources for the purposes of meeting a Load Serving Entity's obligations under the Agreement shall be developed by the Office of the Interconnection and maintained in the PJM Manuals.

B. The rules and procedures shall recognize the difference in the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow and/or reservoir storage for hydro units, energy storage capability for Energy Storage Resources, energy source variability and intermittency, mechanical limitations, and system operating policies. For this purpose, the basis for determining and demonstrating the capability of a particular generating unit shall be described in RAA, Schedule 9.~~.1~~.

C. **For Delivery Years through the 2024/2025 Delivery Year~~Provisions for Unlimited Resources~~**

For Unlimited Resources, the capability of the generating unit is based on the level of output that the unit can provide under the site conditions expected to exist at the time of PJM system peak load where such conditions include, but are not limited to, ambient air temperature, humidity, barometric pressure, intake water temperature, and cooling system performance. Generating units with the ability to operate continuously across all hours of an Operating Day without interruption if needed include, but are not limited to, nuclear and fossil-fired steam units, combined cycle units, combustion turbine units, reciprocating engine units, and fuel cell units.

~~**D. Provisions for ELCC Resources**~~

For ELCC Resources, ~~T~~the Office of the Interconnection shall determine the capability of ~~ELCC Resources~~the resource to meet a Load Serving Entity's obligations under the Agreement using an effective load carrying capability analysis, as set forth in RAA, Schedule 9.1, with additional implementation details provided in the PJM Manuals.

D. For the 2025/2026 Delivery Year and Subsequent Delivery Years

The Office of the Interconnection shall determine the capability of Generation Capacity Resources to meet a Load Serving Entity's obligations under the Agreement using an effective load carrying capability analysis, as set forth in RAA, Schedule 9.2, with additional implementation details provided in the PJM Manuals.

SCHEDULE 9.1:

EFFECTIVE LOAD CARRYING CAPABILITY ANALYSIS
FOR DELIVERY YEARS THROUGH THE 2024/2025 DELIVERY YEAR

A. Overview of Effective Load Carrying Capability Analysis

The inputs of the effective load carrying capability analysis include:

-Historical weather and load data;
-Historical output of existing Variable Resources;
-Estimates of putative historical output for planned Variable Resources;
-Forced outage patterns for Unlimited Resources;
-Resource deployment forecast; and
-Modeling parameters for Limited Duration Resources and Combination Resources.

The outputs of the effective load carrying capability analysis include:

-The ELCC Portfolio UCAP, in MW;
-ELCC Class UCAP values, in MW; and
-ELCC Class Rating values, in percent.

B. ELCC Classes

(1) (a) The following are the ELCC Classes for Variable Resources:

- Tracking Solar Class
- Fixed-Tilt Solar Class
- Onshore Wind Class
- Offshore Wind Class
- Landfill Gas Class
- Intermittent Hydropower Class
- Other Variable Resource Class

(b) The following are the types of ELCC Classes for Limited Duration Resources:

- The type of Capacity Storage Resource Classes
- The type of Other Limited Duration Resource Classes

Within those types, the following are the specific ELCC Classes for Limited Duration Resources:

- Capacity Storage Resource Class (4-Hour Duration)
- Capacity Storage Resource Class (6-Hour Duration)
- Capacity Storage Resource Class (8-Hour Duration)
- Capacity Storage Resource Class (10-Hour Duration)
- Other Limited Duration Class (4-Hour Duration)
- Other Limited Duration Class (6-Hour Duration)

- Other Limited Duration Class (8-Hour Duration)
- Other Limited Duration Class (10-Hour Duration)

(c) The following are the ELCC Classes for Combination Resources:

- The types of Hybrid Resource Classes, as further specified below
- Hydropower With Non-Pumped Storage Class
- Complex Hybrid Class
- The types of Other Limited Duration Combination Classes, as further specified below

(2) PJM shall establish Hybrid Resource Classes for all "open-loop" combinations of each Capacity Storage Resource class and each Variable Resource class, as well as all "closed-loop" combinations of each Capacity Storage Resource class and each Variable Resource class. An "open-loop" resource is physically and contractually capable of charging from the grid, while a "closed-loop" resource is not.

(3) PJM shall establish "Other Limited Duration Combination Classes" for all combinations of each Variable Resource Class and each Other Limited Duration Resource Class, and for combinations of an Unlimited Resource with each Other Limited Duration Resource Class.

(4) For a given Delivery Year, ELCC Class Ratings will not be calculated for any ELCC Class to the extent that no member of the class is expected to provide, or offer to provide capacity, in the applicable Delivery Year. PJM will determine the ELCC Class Ratings for an ELCC Class when any one of the following criteria are met:

(a) An Existing Generation Capacity Resource is in such class; or
(b) A Planned Generation Capacity Resource has submitted timely and valid data through the ELCC data submission process and is in such class; or
(c) The resource deployment forecast contains a resource in such class.

(5) (a) For each ELCC Resource, except an ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine the ELCC Class of which such resource is a member by matching the physical characteristics of such resource with the definition of the ELCC Class.

(b) For each ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine, by matching the physical characteristics of such resource with the definition of the ELCC Class, the type of ELCC Class of which such resource is a member; provided however, the Generation Capacity Resource Provider shall choose the specific ELCC Class within the type ELCC Class identified by PJM that corresponds to the chosen characteristic duration.

If the Generation Capacity Resource Provider fails to choose, PJM will choose a specific ELCC Class to assign to such resource. The election of the specific ELCC Class corresponding to the chosen characteristic duration shall be for a term of five consecutive Delivery Years. ~~During~~ After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in the ELCC Class, based on choosing a different characteristic duration, by submitting to the Office of the Interconnection a written request to switch ELCC Classes and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the ~~2026/2027~~2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource shall be considered in the new ELCC Class starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(6) Mixed-technology resources are composed of components with different generation technologies, at least one of which would be an ELCC Resource, behind a single Point of Interconnection. For a mixed-technology resource composed of components that do not have significant interaction, the components are eligible to participate as separate resources. A mixed-technology resource composed of components that have significant interaction must participate as a single Combination Resource (or, if the components would all be Variable Resources, then as a single Variable Resource).

The Generation Capacity Resource Provider of a mixed-technology resource eligible to participate as either a single ELCC Resource or as multiple stand-alone resources shall elect, for a term of five consecutive Delivery Years, whether PJM is to model it as a single ELCC Resource or as multiple stand-alone resources. ~~During~~After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in such modelling approach by submitting to the Office of the Interconnection a written request to change the modelling approach and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource(s) intend(s) to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the ~~2026/2027~~2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource(s) shall be modelled as requested starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

C. Calculation of ELCC Portfolio UCAP

The effective load carrying capability analysis shall identify a scenario in which the aggregate installed capacity "Y" of a group of Unlimited Resources with no outages yields the same annual loss of load expectation as the one produced by the scenario with all ELCC Resources that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year being analyzed. The ELCC Portfolio UCAP shall be the value "Y".

D. Allocation from ELCC Portfolio UCAP to ELCC Class UCAP

The ELCC Portfolio UCAP shall be allocated, as specified in the PJM Manuals, to each ELCC Class UCAP according to:

(1) The reliability value of the subject ELCC Class evaluated in the absence of other ELCC Classes, minus

(2) a quantity that is proportional to the product of:

(a) the difference between the reliability value of the subject ELCC Class when evaluated in the presence of the entire portfolio of ELCC Classes and the reliability value of the subject ELCC Class when evaluated in the absence of the other ELCC Classes, and

(b) the difference between the total reliability value of all the ELCC Classes in the model when evaluated jointly and the sum of the reliability values determined individually for each ELCC Class by evaluating the subject ELCC Class in the absence of other ELCC Classes.

E. Calculation of ELCC Class Rating

(1) The ELCC Class Rating of Variable Resources and Limited Duration Resources shall be the ratio of the applicable ELCC Class UCAP to the aggregate Effective Nameplate Capacity of the modeled ELCC Resources of that ELCC Class that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year being analyzed.

(2) For Combination Resources, there shall be an ELCC Class Rating for each component.

(i) For a Combination Resource with a Limited Duration Resource component and a Variable Resource component, the Limited Duration Resource component ELCC Class Rating shall be equal to the quotient of (1) the Combination Resource ELCC Class UCAP minus the [product of the Variable Resource ELCC Class Rating and the aggregate Effective Nameplate Capacity of all the Variable Resource components within the subject Combination Resource class] divided by (2) the aggregate equivalent Effective Nameplate Capacity of all the Limited Duration Resource components within the subject Combination Resource class, and the Variable Resource component ELCC Class Rating shall be equal to the ELCC Class Rating for the ELCC Class to which the Variable Resource component would belong if it were not a component of the Combination Resource.

(ii) For a Combination Resource with a Limited Duration Resource component and an Unlimited Resource component, the Limited Duration Resource component ELCC Class Rating shall be equal to the ELCC Class Rating for the ELCC Class to which the Limited Duration Resource component would belong if it were not a component of the Combination Resource, and the Unlimited Resource component would not have an ELCC Class Rating.

(3) For ELCC Resources in the Hydropower with Non-Pumped Storage Class and in the Complex Hybrid Class, no ELCC Class Rating is determined. A resource-specific ELCC rating is determined for each such resource.

F. Calculation of Accredited UCAP and ELCC Resource Performance Adjustment

(1) (a) For Variable Resources and Limited Duration Resources, Accredited UCAP values shall be equal to the product of:

(i) the Effective Nameplate Capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(b) For Combination Resources, Accredited UCAP values shall be equal to the sum of the Accredited UCAP of each component, but not to exceed the Maximum Facility Output of the resource, where:

(i) The value for a Variable Resource component shall be determined in accordance with subsection (a) above.

(ii) The value for a Limited Duration Resource component shall be equal to the product of:

(A) the Effective Nameplate Capacity determined for the Limited Duration Resource component;

(B) [one minus the EFORd for the Limited Duration Resource component]; and

(C) the applicable Limited Duration Resource component ELCC Class Rating as determined in Section E(2)(i).

(iii) The value for an Unlimited Resource component shall be equal to the product of the installed capacity of the Unlimited Resource component and [one minus the EFORd for the Unlimited Resource component].

(iv) The Accredited UCAP for Hydropower With Non-Pumped Storage, and for each member of an ELCC Class whose members are so distinct from one another that a single ELCC Class Rating fails to capture their physical characteristics, shall be based on a resource-specific effective load carrying capability analysis based on the resource's unique parameters.

(2) The ELCC Resource Performance Adjustment shall be calculated according to the following methods, as further detailed in the PJM Manuals:

(a) For a Variable Resource: based on a metric consisting of the average of (1) actual output during the 200 highest coincident peak load hours over the preceding ten years, regardless of the years in which they occur, and (2) actual output during the 200 highest coincident peak putative net load hours over the preceding ten years, regardless of the years in which they occur, where putative net load is actual load minus the putative hourly output of Variable Resources based on the resource mix of the target year. For Planned Resources or resources less than 10 years old, estimated hypothetical historical output will be used to develop this metric. For a given resource or component, the Performance Adjustment shall equal the ratio of such metric to the average (weighted by the Effective Nameplate Capacity) of such metrics for all units in the applicable Variable Resource ELCC Class.

~~In determining the ELCC Resource Performance Adjustment for the 2025/2026 Delivery Year and subsequent Delivery Years, the actual output of a Variable Resource shall be adjusted to reflect historical curtailments, and output in any hour shall be capped at: (i) *the greater of* the Variable Resource's Capacity Interconnection Rights*, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year,* for hours in the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's winter deliverability MW as defined in the PJM Manuals for hours in the months of November through April of the Delivery Year.~~

(b) For Limited Duration Resources: based on EFORd.

(c) For Combination Resources with only an Unlimited Resource component and a Limited Duration Resource component: based on EFORd.

(d) For Combination Resources with a Variable Resource component (except for Hydropower With Non-Pumped Storage): (1) based on the direct metered or estimated output of the Variable Resource component, which is then assessed according to the methodology described in subsection (a) above for Variable Resources and in accordance with the PJM Manuals; and (2) based on the EFORd that is applicable to the Limited Duration Resource component.

~~In determining the ELCC Resource Performance Adjustment for the 2025/2026 Delivery Year and subsequent Delivery Years, actual output of the Variable Resource component of a Combination Resource shall be adjusted to reflect historical curtailments, and output shall be capped at: (i) *the greater of* the Combination Resource's Capacity Interconnection Rights*, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year,* for hours in the months of June through October and the following May of the Delivery Year minus the Effective Nameplate Capacity of the Limited Duration Resource component of the Combination Resource, and (ii) the Combination Resource's winter deliverability MW as defined in the PJM Manuals for hours in the months of November through April of the Delivery Year minus the Effective Nameplate Capacity of the Limited Duration Resource component of the Combination Resource. Notwithstanding the foregoing, in the case where the *greater of the* total Capacity Interconnection Rights*, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year,* of the Combination Resource is equal to the Maximum Facility Output of the Combination Resource, the hourly output of the Variable Resource and Limited Duration Resource components of the Combination Resource shall not be capped.~~

(e) For Hydropower With Non-Pumped Storage and other Combination Resources that do not fall into the above categories: based on EFORd.

G. Installed Capacity of ELCC Resources

Rules and procedures for technically determining and demonstrating the installed capacity of ELCC Resources shall be developed by the Office of the Interconnection and maintained in the PJM Manuals. The installed capacity of a Limited Duration Resource is based on the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, as described in the PJM Manuals. The installed capacity of a Combination Resource (other than Hydropower With Non-Pumped Storage) is based on the lesser of the Maximum Facility Output or the sum of the equivalent Effective Nameplate Capacity values of the resource's constituent components considered on a stand-alone basis.

H. Details of the Effective Load Carrying Capability Methodology

The effective load carrying capability analysis shall compare expected hourly load levels (based on historical weather) with the expected hourly output of the expected future resource mix in order to identify the relative resource adequacy value of the portfolio of all ELCC Classes, as well of each individual ELCC Class, compared to a group of Unlimited Resources with no outages. In performing this analysis, the model inputs shall be scaled to meet the annual loss of load expectation of the Office of the Interconnection. The effective load carrying capability analysis shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; and (iii) expected output of Limited Duration Resources and of Combination Resources as described below. These expected quantities are based on actual values for load and actual and putative values for Variable Resource output (standalone or as a component of Combination Resources) after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist. For resources that have not existed each year since June 1, 2012, putative output is an estimate of the hourly output that resource would have produced in a historical hour if that resource had existed in that hour. This putative output estimate is developed based on historical weather data consistent with the particular site conditions for each such resource in accordance with the PJM Manuals.

~~For the 2025/2026 Delivery Year and subsequent Delivery Years, Variable Resource actual output shall be adjusted in the ELCC analysis to reflect historical curtailments, and output shall be capped in any hour at: (i) *the greater of* the Variable Resource's Capacity Interconnection Rights*, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year,* during the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's winter deliverability MW, as defined in the PJM Manuals, during the months of November through April of the Delivery Year.~~

The effective load carrying capability analysis shall simulate forced outages of Unlimited Resources based on actual historical data, and shall simulate the output of Limited Duration Resources and Combination Resources based on their Office of the Interconnection-validated parameters, including the putative output of the Variable Resource component of Combination Resources, as described above. Forced outages of Limited Duration Resources and Combination Resources shall not be simulated in the effective load carrying capability analysis.

The quantity of deployed resources studied in the analysis shall be based on resource deployment forecasts and, where applicable, on available information based on Sell Offers submitted in RPM Auctions or Fixed Resource Requirement plans for the applicable Delivery Year.

The ELCC Class UCAP and other results of the effective load carrying capability analysis shall be based on the total Effective UCAP of the ELCC Class as a whole.

The ELCC Class UCAP and corresponding ELCC Class Rating values may increase or decrease from year to year as the expected resource mix and load shape change.

Energy Resources are not included in the effective load carrying capability analysis. Generating units that are expected to only offer or otherwise provide a portion of their Accredited UCAP for that Delivery Year are represented in the analysis in proportion to the expected quantity offered or delivered divided by the Accredited UCAP.

I. Methodology to Simulate Output of Certain Resources in the Effective Load Carrying Capability Model

The effective load carrying capability analysis shall simulate the output of Limited Duration Resources and Combination Resources based on their physical parameters, including limited storage capability, and shall simulate the deployment of Demand Resources. The analysis shall simulate output from the subject Limited Duration Resources and Combination Resources in hours in which all output from Unlimited Resources and available output from Variable Resources is insufficient to meet load. The output of the subject Limited Duration Resources and Combination Resources shall be simulated on an hour-by-hour basis in proportion to their Effective Nameplate Capacity without foresight to future hours. ~~For the 2025/2026 Delivery Year and subsequent Delivery Years, output of Combination Resources shall be capped in any hour at: (i)~~ ~~*the greater of*~~ ~~the Combination Resource's Capacity Interconnection Rights~~~~*, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year,*~~ ~~during the months of June through October and the following May of the Delivery Year, and (ii) the Combination Resource's winter deliverability MW, as defined in the PJM Manuals, during the months of November through April of the Delivery Year.~~ The simulated deployment of Demand Resources shall be such that there is adequate Primary Reserves provided by economic resources, if sufficient simulated Demand Resources are available. Primary Reserves shall be assigned to generation resources in order to maximize simulated reliability, provided that assignments to Limited Duration Resources and Combination Resources shall be pro rata according to their Effective Nameplate Capacity. Primary Reserves shall be exhausted prior to identifying a loss of load event in the analysis. Energy Storage Resource charging is during hours with sufficient margin, including between daily peaks if necessary.

J. Administration of Effective Load Carrying Capability Analysis

The Office of the Interconnection shall post final ~~ELCC Class UCAP and~~ ELCC Class Rating values at least once per year in a report that also includes appropriate details regarding methodology and inputs. The Office of the Interconnection shall post this report and shall communicate ELCC Resource Performance Adjustment values to applicable Generation Capacity Resource Providers no later than five months prior to the start of the target Delivery Year, as described in the PJM Manuals. Starting with the 2023/2024 Delivery Year, Accredited UCAP values for the applicable Delivery Year shall establish the maximum Unforced Capacity that an ELCC Resource can physically provide or offer to provide in the applicable Delivery Year.

The Office of the Interconnection shall also post preliminary ELCC Class Rating values for nine subsequent Delivery Years. For any Delivery Year for which a final ELCC Class Rating has not been posted and a preliminary ELCC Class Rating has been posted, the Accredited UCAP of an ELCC Resource for such Delivery Year shall be based on the most recent preliminary ELCC Class Rating value for that Delivery Year, together with the most recently calculated ELCC Resource Performance Adjustment value for that ELCC Resource. Except to the extent specified above or otherwise specified, the preliminary ELCC Class Rating values for future years are non-binding and are only for indicative purposes. A Generation Capacity Resource Provider can offer or provide capacity from an ELCC Resource that is not subject to a capacity market must offer obligation (as specified in Tariff, Attachment DD, Section 6.6) at a level less than the Accredited UCAP for such resource.

In order to facilitate the effective load carrying capability analysis, the Generation Capacity Resource Provider of each ELCC Resource must submit to the Office of the Interconnection the required information as specified in the PJM Manuals by no later than August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2026/2027 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The required information may include relevant physical parameters, relevant historical data such as weather data and actual or estimated historical energy output, and documentation supporting such parameters and historical data. The relevant physical parameters are those that are incorporated into the effective load carrying capability analysis. The parameters required for Hydropower With Non-Pumped Storage shall include Ordinary Water Storage and any applicable Exigent Water Storage. Submitted parameters must indicate the expected duration for which any submitted physical parameters are valid.

The Office of the Interconnection shall evaluate, validate, and approve the foregoing information in accordance with the process set forth in the PJM Manuals. In evaluating the validity of submitted information, the Office of the Interconnection may assess the consistency of such information with observed conditions. If the Office of the Interconnection observes that the information provided by the Generation Capacity Resource Provider of the ELCC Resource is inconsistent with observed conditions, the Office of the Interconnection will coordinate with the Generation Capacity Resource Provider of the ELCC Resource to understand the information and observed conditions before making a determination regarding the validity of the applicable parameters. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the foregoing information.

After the Office of the Interconnection has completed its evaluation of the foregoing information, the Office of the Interconnection shall notify the Generation Capacity Resource Provider in writing whether the submitted information is considered invalid by no later than September 1 following the submission of the information. The Office of the Interconnection's determination on the validity of the foregoing information shall continue for the applicable Delivery Year and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

In the event that the Office of the Interconnection is unable to validate any of the required information, physical parameters, supporting documentation, or other related information submitted by the Generation Capacity Resource Provider of an ELCC Resource, then the Office of the Interconnection shall calculate Accredited UCAP values for that ELCC Resource based only on the validated information. Such ELCC Resource shall not be permitted to offer or otherwise provide capacity above such Accredited UCAP values until the Office of the Interconnection determines new Accredited UCAP values for such resource.

Generation Capacity Resource Providers of ELCC Resources that are hydropower plants with water storage must provide documentation to support the physical parameters provided for expected load carrying capability analysis modeling, as specified in the PJM Manuals. This documentation must: (a) support the plant's physical capabilities; (b) demonstrate that the parameters do not violate any federal, state, river basin, or other applicable authority operating limitations of the plant; and (c) demonstrate full authorization from FERC, any river basin commissions, and any other applicable authorities to meet those capabilities.

SCHEDULE 9.2:

EFFECTIVE LOAD CARRYING CAPABILITY ANALYSIS FOR THE 2025/2026 DELIVERY YEAR AND SUBSEQUENT DELIVERY YEARS

A. Overview of Effective Load Carrying Capability Analysis

The inputs of the effective load carrying capability analysis shall consider similar data and forecasts as that used in development of the FPR, as described in Schedule 4.C, and will include:

-Historical weather and load data;
-Historical output of existing Variable Resources;
-Estimates of putative historical output for planned Variable Resources;
-Forced outage patterns for Unlimited Resources, including consideration of correlated outage risks;
-Resource deployment forecast; and
-Modeling parameters for Limited Duration Resources, Combination Resources, and Demand Resources.

The outputs of the effective load carrying capability analysis include:

-ELCC Class Rating values, in percent.

B. ELCC Classes

(1) (a) The following are the ELCC Classes for Variable Resources:

- Tracking Solar Class
- Fixed-Tilt Solar Class
- Onshore Wind Class
- Offshore Wind Class
- Intermittent Landfill Gas Class
- Intermittent Hydropower Class
- Other Variable Resource Class

(b) The following are the types of ELCC Classes for Limited Duration Resources:

- The type of Capacity Storage Resource Classes
- The type of Other Limited Duration Resource Classes

Within those types, the following are the specific ELCC Classes for Limited Duration Resources:

- Capacity Storage Resource Class (4-Hour Duration)
- Capacity Storage Resource Class (6-Hour Duration)
- Capacity Storage Resource Class (8-Hour Duration)
- Capacity Storage Resource Class (10-Hour Duration)

- Other Limited Duration Class (4-Hour Duration)
- Other Limited Duration Class (6-Hour Duration)
- Other Limited Duration Class (8-Hour Duration)
- Other Limited Duration Class (10-Hour Duration)

(c) The following are the ELCC Classes for Combination Resources:

- The types of Hybrid Resource Classes, as further specified in subpart (2) below
- Hydropower With Non-Pumped Storage Class
- Complex Hybrid Class
- The types of Other Limited Duration Combination Classes, as further specified in subpart (3).

(d) The following are the ELCC Classes for Unlimited Resources

- Nuclear Class
- Coal Class
- Gas Combined Cycle Class
- Gas Combustion Turbine Class
- Gas Combined Cycle Dual Fuel Class
- Gas Combustion Turbine Dual Fuel Class
- Diesel Utility Class
- Steam Class
- Other Unlimited Resource Class

(e) The following are the ELCC Classes for Demand Resources

- Demand Resource Class

(2) PJM shall establish Hybrid Resource Classes for all "open-loop" combinations of each Capacity Storage Resource class and each Variable Resource class, as well as all "closed-loop" combinations of each Capacity Storage Resource class and each Variable Resource class. An "open-loop" resource is physically and contractually capable of charging from the grid, while a "closed-loop" resource is not.

(3) PJM shall establish "Other Limited Duration Combination Classes" for all combinations of each Variable Resource Class and each Other Limited Duration Resource Class, and for combinations of an Unlimited Resource with each Other Limited Duration Resource Class.

(4) For a given Delivery Year, ELCC Class Ratings will not be calculated for any ELCC Class to the extent that no member of the class is expected to provide, or offer to provide capacity, in the applicable Delivery Year. PJM will determine the ELCC Class Ratings for an ELCC Class when any one of the following criteria are met:

(a) An Existing Generation Capacity Resource is in such class; or
(b) A Planned Generation Capacity Resource has submitted timely and valid data through the ELCC data submission process and is in such class; or
(c) The resource deployment forecast contains a resource in such class.

(5) (a) For each ELCC Resource, except an ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine the ELCC Class of which such resource is a member by matching the physical characteristics of such resource with the definition of the ELCC Class.

(b) For each ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine, by matching the physical characteristics of such resource with the definition of the ELCC Class, the type of ELCC Class of which such resource is a member; provided however, the Generation Capacity Resource Provider shall choose the specific ELCC Class within the type ELCC Class identified by PJM that corresponds to the chosen characteristic duration.

If the Generation Capacity Resource Provider fails to choose, PJM will choose a specific ELCC Class to assign to such resource. The election of the specific ELCC Class corresponding to the chosen characteristic duration shall be for a term of five consecutive Delivery Years. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in the ELCC Class, based on choosing a different characteristic duration, by submitting to the Office of the Interconnection a written request to switch ELCC Classes and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource shall be considered in the new ELCC Class starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(6) Mixed-technology resources are composed of components with different generation technologies, at least one of which would be an ELCC Resource, behind a single Point of Interconnection. For a mixed-technology resource composed of components that do not have significant interaction, the components are eligible to participate as separate resources. A mixed-technology resource composed of components that have significant interaction must participate as a single Combination Resource (or, if the components would all be Variable Resources, then as a single Variable Resource).

The Generation Capacity Resource Provider of a mixed-technology resource eligible to participate as either a single ELCC Resource or as multiple stand-alone resources shall elect, for a term of five consecutive Delivery Years, whether PJM is to model it as a single ELCC Resource or as multiple stand-alone resources. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in such modelling approach by submitting to the Office of the Interconnection a written request to change the modelling approach and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource(s) intend(s) to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource(s) shall be modelled as requested starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

C. Calculation of ELCC Class Rating

ELCC Class Ratings for a Delivery Year are calculated by adding to the forecasted resource portfolio incremental quantities of resources belonging to the subject ELCC Class, depending on the resource type:

(1) The ELCC Class Rating of Variable Resources, Limited Duration Resources, Unlimited Resources (except Other Unlimited Resources), and Demand Resources shall be the ratio of the expected unserved energy improvement resulting from adding an incremental quantity of the subject ELCC Class to the expected unserved energy improvement resulting from adding an incremental quantity of an Unlimited Resource with no outages, where expected unserved energy improvement is calculated relative to the Portfolio EUE for the Delivery Year.

(2) No ELCC Class Rating is determined for Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class, and in any ELCC Class whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics.

D. Calculation of Accredited UCAP and ELCC Resource Performance Adjustment

(1) (a) For Variable Resources and Limited Duration Resources, Accredited UCAP values shall be equal to the lesser of the resource's Capacity Interconnection Right or the product of:

(i) the Effective Nameplate Capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(b) For any resource in an ELCC Class for which no Class Rating has been calculated pursuant to C(2), the Accredited UCAP shall be based on a resource-specific effective load carrying capability analysis based on the resource's unique parameters.

(c) For Unlimited Resources that have an ELCC Class Rating determined pursuant to C(1), Accredited UCAP values shall be equal to the product of:

(i) the installed capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(d) For Demand Resources, Accredited UCAP values shall be equal to the product of:

(i) the Nominated Value of the Demand Resource; and
(ii) the applicable ELCC Class Rating.

(2) The ELCC Resource Performance Adjustment shall be calculated according to the following methods, as further detailed in the PJM Manuals:

(a) For a Variable Resource, a Limited Duration Resource, and an Unlimited Resource: based on a metric consisting of the weighted average expected hourly output of the resource in the ELCC model during hours of loss of load risk where: (i) the weights correspond to the modeled probability of losing load in such hour and (ii) the expected hourly output is based on the resource's modeled output during the same hour on days since June 1st, 2012 identified as having similar weather from an RTO-perspective. For a given resource or component, the Performance Adjustment shall equal the ratio of such metric to the average (weighted by the Effective Nameplate Capacity) of such metrics for all units in the applicable Variable Resource ELCC Class or applicable Unlimited Resource ELCC Class.

In determining the ELCC Resource Performance Adjustment, the actual output of a Variable Resource shall be adjusted to reflect historical curtailments, and output in any hour shall be capped at: (i) the greater of the Variable Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, for hours in the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's assessed deliverability, as defined in the PJM Manuals, for hours in the months of November through April of the Delivery Year. The output of an Unlimited Resource in any hour shall be capped at the greater of the resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year..

E. Calculation of Accredited UCAP Factor

For Generation Capacity Resources, PJM shall determine an Accredited UCAP Factor, which is the ratio of the resource's Accredited UCAP to the resource's installed capacity.

G. Installed Capacity of ELCC Resources

Rules and procedures for technically determining and demonstrating the installed capacity of ELCC Resources shall be developed by the Office of the Interconnection and maintained in the PJM Manuals. The installed capacity of a Limited Duration Resource is based on the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, as described in the PJM Manuals. The installed capacity of a Combination Resource (other than Hydropower With Non-Pumped Storage) is based on the lesser of the Maximum Facility Output or the sum of the equivalent Effective Nameplate Capacity values of the resource's constituent components considered on a stand-alone basis. The installed capacity of an Unlimited Resource and Variable Resource shall be determined in accordance with the PJM Manuals. The installed capacity of Demand Resources, for purposes of the ELCC analysis, is based on the forecasted deployment level in the PJM Load Forecast.

H. Details of the Effective Load Carrying Capability Methodology

The effective load carrying capability analysis shall compare expected hourly load levels (based on historical weather) with the expected hourly output of the expected future resource mix in order to identify the relative marginal resource adequacy value of each individual ELCC Class compared to an Unlimited Resource with no outages. In performing this analysis, the model inputs shall be scaled to meet the annual reliability criteria of the Office of the Interconnection. The effective load carrying capability analysis shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; (iii) expected output of Limited Duration Resources and of Combination Resources as described below; (iv) expected Unlimited Resource output; and (v) expected Demand Resource output. These expected quantities are based on forecasted load and actual and putative values for Variable Resource output (standalone or as a component of Combination Resources) and Unlimited Resource output after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist. For resources that have not existed each year since June 1, 2012, putative output is an estimate of the hourly output that resource would have produced in a historical hour if that resource had existed in that hour. For Variable Resources, this putative output estimate is developed based on historical weather data consistent with the particular site conditions for each such resource in accordance with the PJM Manuals; for Unlimited Resources, the putative output is developed based on actual performance of similar units in accordance with the PJM Manuals.

Variable Resource actual output shall be adjusted in the ELCC analysis to reflect historical curtailments, and output shall be capped in any hour at: (i) the greater of the Variable Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, during the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's assessed deliverability, as defined in the PJM Manuals, during the months of November through April of the Delivery Year. The output of Unlimited Resources shall not exceed the greater of the Unlimited Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

The effective load carrying capability analysis shall simulate performance of Demand Resources, and shall simulate the output of Limited Duration Resources and Combination Resources based on their Office of the Interconnection-validated parameters, including the putative output of the Variable Resource component of Combination Resources, as described above.

The quantity of deployed resources studied in the analysis shall be based on resource deployment forecasts and, where applicable, on available information based on Sell Offers submitted in RPM Auctions or Fixed Resource Requirement plans for the applicable Delivery Year, and, where applicable, information provided to the Office of the Interconnection regarding intent to offer in an RPM Auction, pursuant to the requirements in the Tariff, Attachment DD, section 5.5.

The model inputs, including the set of ELCC Resources that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year, shall be scaled to meet the annual reliability criteria of the Office of the Interconnection. The resulting expected unserved energy constitutes the Portfolio EUE for the Delivery Year. Energy Resources are not included in the effective load carrying capability analysis. Generating units that are expected to only offer or otherwise provide a portion of their Accredited UCAP for that Delivery Year are represented in the analysis in proportion to the expected quantity offered or delivered divided by the Accredited UCAP.

I. Methodology to Simulate Output of Certain Resources in the Effective Load Carrying Capability Model

The effective load carrying capability analysis shall simulate the output of Limited Duration Resources and Combination Resources based on their physical parameters, including limited storage capability, and shall simulate the deployment of Demand Resources. The analysis shall simulate output from the subject Limited Duration Resources, Combination Resources, and Demand Resources in hours in which all output from Unlimited Resources and available output from Variable Resources is insufficient to meet load. The analysis shall first simulate the output of Demand Resources. If the simulated output of Demand Resources is insufficient to meet load, then the output of the subject Limited Duration Resources and Combination Resources shall be simulated on an hour-by-hour basis based on their relative duration, starting from longer duration resources to shorter duration resources. The output of Combination Resources shall be capped in any hour at: (i) the Combination Resource's Capacity Interconnection Rights during the months of June through October and the following May of the Delivery Year, and (ii) the Combination Resource's assessed deliverability, as defined in the PJM Manuals, during the months of November through April of the Delivery Year. Energy Storage Resource charging is during hours with sufficient margin, including between daily peaks if necessary.

J. Administration of Effective Load Carrying Capability Analysis

The Office of the Interconnection shall post final ELCC Class Rating values at least once per year in a report that also includes appropriate details regarding methodology and inputs. The Office of the Interconnection shall post this report and shall communicate ELCC Resource Performance Adjustment values to applicable Generation Capacity Resource Providers no later than five months prior to the start of the target Delivery Year, as described in the PJM Manuals. Accredited UCAP values for the applicable Delivery Year shall establish the maximum Unforced Capacity that an ELCC Resource can physically provide or offer to provide in the applicable Delivery Year.

The Office of the Interconnection shall also post preliminary ELCC Class Rating values for nine subsequent Delivery Years. For any Delivery Year for which a final ELCC Class Rating has not been posted and a preliminary ELCC Class Rating has been posted, the Accredited UCAP of an ELCC Resource for such Delivery Year shall be based on the most recent preliminary ELCC Class Rating value for that Delivery Year, together with the most recently calculated ELCC Resource Performance Adjustment value for that ELCC Resource. Except to the extent specified above or otherwise specified, the preliminary ELCC Class Rating values for future years are non-binding and are only for indicative purposes. A Generation Capacity Resource Provider can offer or provide capacity from an ELCC Resource that is not subject to a capacity market must offer obligation (as specified in Tariff, Attachment DD, Section 6.6) at a level less than the Accredited UCAP for such resource.

In order to facilitate the effective load carrying capability analysis, the Generation Capacity Resource Provider of each ELCC Resource must submit to the Office of the Interconnection the required information as specified in the PJM Manuals by no later than August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Years such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The required information may include relevant physical parameters, relevant historical data such as weather data and actual or estimated historical energy output, and documentation supporting such parameters and historical data. The relevant physical parameters are those that are incorporated into the effective load carrying capability analysis. The parameters required for Hydropower With Non-Pumped Storage shall include Ordinary Water Storage and any applicable Exigent Water Storage. Submitted parameters must indicate the expected duration for which any submitted physical parameters are valid.

The Office of the Interconnection shall evaluate, validate, and approve the foregoing information in accordance with the process set forth in the PJM Manuals. In evaluating the validity of submitted information, the Office of the Interconnection may assess the consistency of such information with observed conditions. If the Office of the Interconnection observes that the information provided by the Generation Capacity Resource Provider of the ELCC Resource is inconsistent with observed conditions, the Office of the Interconnection will coordinate with the Generation Capacity Resource Provider of the ELCC Resource to understand the information and observed conditions before making a determination regarding the validity of the applicable parameters. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the foregoing information.

After the Office of the Interconnection has completed its evaluation of the foregoing information, the Office of the Interconnection shall notify the Generation Capacity Resource Provider in writing whether the submitted information is considered invalid by no later than September 1 following the submission of the information. The Office of the Interconnection's determination on the validity of the foregoing information shall continue for the applicable Delivery Year and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

In the event that the Office of the Interconnection is unable to validate any of the required information, physical parameters, supporting documentation, or other related information submitted by the Generation Capacity Resource Provider of an ELCC Resource, then the Office of the Interconnection shall calculate Accredited UCAP values for that ELCC Resource based only on the validated information. Such ELCC Resource shall not be permitted to offer or otherwise provide capacity above such Accredited UCAP values until the Office of the Interconnection determines new Accredited UCAP values for such resource.

Generation Capacity Resource Providers of ELCC Resources that are hydropower plants with water storage must provide documentation to support the physical parameters provided for expected load carrying capability analysis modeling, as specified in the PJM Manuals. This documentation must: (a) support the plant's physical capabilities; (b) demonstrate that the parameters do not violate any federal, state, river basin, or other applicable authority operating limitations of the plant; and (c) demonstrate full authorization from FERC, any river basin commissions, and any other applicable authorities to meet those capabilities.

Attachment B

Revisions to the
PJM Open Access Transmission Tariff
and
PJM Reliability Assurance Agreement

(Clean Format)

Sections of the
PJM Open Access Transmission Tariff

(Clean Format)

Definitions – C - D

Canadian Guaranty:

"Canadian Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Export Transmission Customer:

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

“Capacity Interconnection Rights” shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

“Capacity Market Buyer” shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

“Capacity Market Seller” shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:

“Capacity Performance Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

“Capacity Resource with State Subsidy” shall mean (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 Resource Clearing Price:

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

Capacity Transmission Injection Rights:

"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cleared Capacity Resource with State Subsidy:

"Cleared Capacity Resource with State Subsidy" shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Closed-Loop Hybrid Resource:

"Closed-Loop Hybrid Resource" shall mean a Hybrid Resource that is physically or contractually incapable of charging from the grid.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

"Collateral" shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. "Collateral" shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

"Collateral Call" shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Co-Located Resource:

"Co-Located Resource" shall mean a component of a Mixed Technology Facility that operates in the capacity, energy, and/or ancillary services market(s) as a separate resource from the other components of such facility.

Commencement Date:

"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The "Committed Offer" shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

“Completed Application” shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Composite Energy Offer:

“Composite Energy Offer” for generation resources shall mean the sum (in $/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in $/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

Conditional Incremental Auction:

“Conditional Incremental Auction” shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

Conditioned State Support:

“Conditioned State Support” shall mean 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 in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

"CONE Area" shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an

Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

“Construction Party” shall mean a party to a Construction Service Agreement. “Construction Parties” shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

“Contingent Facilities” shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request’s costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(1) 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);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

"Control Zone" shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

"Controllable A.C. Merchant Transmission Facilities" shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

"Corporate Guaranty" shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

Cost of New Entry:

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own load.

Credit Affiliate:

“Credit Affiliate” shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

“Credit Available for Export Transactions” shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

“Credit Available for Virtual Transactions” shall mean the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

“Credit Breach” shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

Critical Natural Gas Infrastructure:

"Critical Natural Gas Infrastructure" shall mean locations with electrical loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility as defined by NERC/FERC standard(s); and until such NERC/FERC standard(s) is developed, is defined as electric loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility, which if curtailed, will impact the delivery of natural gas to bulk-power system natural gas-fired generation.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the

Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

"Customer Facility" shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

"Customer-Funded Upgrade" shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

"Customer Interconnection Facilities" shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges as detailed under Tariff, Attachment DD, section 7.

Daily Unforced Capacity Obligation:

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York

Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

"Deactivation" shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

"Deactivation Avoidable Cost Credit" shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, Part V, section 115.

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating

Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

Demand Resource Factor or DR Factor:

"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

“Discharge Economic Maximum Megawatts” shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

“Discharge Economic Minimum Megawatts” shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

“Discharge Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate:

“Discharge Ramp Rate” shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

“Dispatch Rate” shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

“Dynamic Transfer” shall have the same meaning provided in the Operating Agreement.

Definitions – L – M – N

Legacy Policy:

"Legacy Policy" shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource 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.

Limited Demand Resource:

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

"Load Interest" shall mean, 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.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area. Notwithstanding the foregoing, for the 2024/2025 Delivery Year, during the auction process, the Office of Interconnection shall exclude from the Locational Deliverability Area Reliability Requirement any Planned Generation Capacity Resource in an LDA that does not participate in the relevant RPM Auction as projected internal capacity and in the Capacity Emergency Transfer Objective model where the Locational Deliverability Area Reliability Requirement for the Base Residual Auction increases by more than one percent over the reliability requirement used from the prior Delivery Year's Base Residual Auction (for Incremental Auctions the Locational Deliverability Area Reliability Requirement would be compared with the reliability requirement used in the prior relevant RPM Auction associated with the same Delivery Year) for that LDA due to the cumulative addition of such Planned Generation Capacity Resources.

Locational Price Adder:

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

"Marginal Value" shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

"Market Monitor**"** means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Suspension:

“Market Suspension” shall mean the inability of the Office of the Interconnection to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances, as further described in Operating Agreement, Schedule 1, section 1.10.8(d) and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.8(d), or the inability of the Office of the Interconnection to produce Zonal Dispatch Rates for a total of seven (7) or more Real-time Settlement Intervals within a clock hour, for the purposes of the Real-time Energy Market, as further described in Operating Agreement, Schedule 1, section 1.11.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.11.6.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:

"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource

Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero to the time of the last generator breaker opening as measured by PJM’s State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

“Mixed Technology Facility” shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

"New Services Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

"Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has

delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Operating Agreement, section 18.17.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Tariff, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the Market Monitoring Unit using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the Market Monitoring Unit from a third party which is not, to the Office of the Interconnection's or Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. **<u>Disclosure to FERC and CFTC</u>:**

1. Notwithstanding anything in this section I to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC") or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in section I.B.

D. **<u>Disclosure to Authorized Commissions</u>:**

1. Notwithstanding anything in this section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market

Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a “fast track” complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission’s ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission’s Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that “exceptional circumstances,” as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute “exceptional circumstances” as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as “Confidential,” challenging such designation. Any complaints filed at FERC objecting to the designation of information as “Confidential” shall be designated by the party as a “fast track” complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit “Confidential” status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with “publicly available” not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. [Reserved]

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Operating Agreement, Schedule 1, section 6.4.2and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2) included in the Offer Price Cap of a generating unit in order to ensure

that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Operating Agreement, Schedule 2.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Operating Agreement, Schedule 1, section 6.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2 is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Operating Agreement, Schedule 1, section 6.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. <u>Minimum Generator Operating Parameters</u>:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Operating Agreement, Schedule 1, section 6.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6 and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Tariff, Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Tariff, Attachment DD, section 6.6.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under Tariff, Attachment DD.

3. Through the 2024/2025 Delivery Year, the Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Tariff, Attachment DD, section 6.6(b). If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORd that may be used in a Sell Offer for RPM Auctions held prior to the

date on which the final EFORds used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORd to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the

Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Tariff, Attachment DD, section 5.6.6, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in section II.C.4 above, or (iii) through the 2024/2025 Delivery Year, a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level determined under section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Tariff, Attachment DD, section 6.6.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Tariff, Attachment DD, section 6.6(g), to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Tariff, Attachment DD, section 6.6(i), and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. <u>Unit Specific Minimum Sell Offers:</u>

1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, section*s* 5.14(h) *and 5.14(h-1)*, the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.

2. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

E. <u>Market Seller Offer Caps</u>:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Tariff, Attachment DD,

section 6.7(d), the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

F. <u>Mitigation of Offers from Planned Generation Capacity Resources</u>:

Pursuant to Tariff, Attachment DD, section 6.5, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. <u>Data Submission</u>:

Pursuant to Tariff, Attachment DD, section 6.7, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. <u>Determination of Default Avoidable Cost Rates</u>:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Tariff, Attachment DD, section 6.7(c) and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Tariff, Attachment DD, section 6.7, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in Tariff, Attachment DD, section 6.7(d).

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Tariff, Attachment DD, section 6.8(d), and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Tariff, Attachment DD, section 6.7(d)(ii). The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Tariff, Schedule 6A and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Tariff, Part V from the Office of the Interconnection forwarded pursuant to Tariff, Part V, section 113.1, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (or, if applicable, its designated agent) if a market power issue has been identified. The Market Monitoring Unit shall provide such notice by the following date: (a) May 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between January 1 and March 31; (b) August 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between April 1 and June 30; (c) November 30 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between July 1 and September 30; or (d) February 28 of the following calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between October 1 and December 31. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Tariff, Part V, section 114 and Tariff, Part V, section 119.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.
3B(h), discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the paralelle provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.3B9H).

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Operating Agreement, Schedule 1, section 5.2.1(b) and Tariff, Attachment K-Appendix, section 5.2.1(b), including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit’s capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Tariff, Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. Notwithstanding, the Base Residual Auction for the 2025/2026 Delivery Year shall be conducted in June 2024; the Base Residual Auction for the 2026/2027 Delivery Year shall be conducted in December 2024; the Base Residual Auction for the 2027/2028 Delivery Year shall be conducted in June 2025; and the Base Residual Auction for the 2028/2029 Delivery Year shall be conducted in December 2025. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. Notwithstanding, for the 2025/2026 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2025; for the 2026/2027 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2026; for the 2027/2028 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which will commence on July 2026 and February 2027, respectively; for the 2028/2029 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which shall commence on July 2027 and February 2028, respectively.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement or the LDA Reliability Requirement applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, decrease in Accredited UCAP Factor, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from

Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.5 Eligibility for Participation in RPM Auctions

A Capacity Market Seller may submit a Sell Offer for a Capacity Resource in a Base Residual Auction or Incremental Auction only if such seller owns or has the contractual authority to control the output or load reduction capability of such resource and has not transferred such authority to another entity prior to submitting such Sell Offer. Capacity Resources must satisfy the capability and deliverability requirements of RAA, Schedule 9 and RAA, Schedule 10, the requirements for Demand Resources or Energy Efficiency Resources in Tariff, Attachment DD-1 and RAA, Schedule 6, as applicable, and, the criteria in Tariff, Attachment DD, section 5.5A. Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, a Planned Generation Capacity Resource may be included in a Sell Offer for an RPM Auction only if the Capacity Market Seller of such resource provides a binding notice of intent, as further detailed in the PJM Manuals, to submit a Sell Offer in such auction to the Office of the Interconnection no later than (a) the immediately preceding December 1 for a Base Residual Auction (except that for the 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.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered through the 2024/2025 Delivery Year.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered.

i) The Office of the Interconnection shall convert Nominated Energy Efficiency Value to an Unforced Capacity basis by multiplying such value by the Forecast Pool Requirement.

ii) The Office of the Interconnection shall convert the nominated Demand Resource value to a UCAP basis by multiplying such value by, the Forecast Pool Requirement through the 2024/2025 Delivery Year, and starting with the 2025/2026 Delivery Year and for subsequent Delivery Years, the applicable ELCC Class Rating.

iii) Demand Resources and Energy Efficiency Resources shall specify the LDA in which the resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on RAA, Schedule 10.1.

e) Accredited UCAP Factor for Generation Capacity Resources beginning with the 2025/2026 Delivery Year and subsequent Delivery Years.

i) The Accredited UCAP Factor shall be the value established by the Office of the Interconnection in accordance with RAA, Schedule 9.2, prior to the applicable RPM Auction. Such Accredited UCAP Factor shall be multiplied by the ICAP offered to convert the ICAP offered into the UCAP offered.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Accredited UCAP Factor determined by the Office of the Interconnection shall apply to such commitment.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

(g) A Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods, not to exceed the Accredited UCAP of such resource, as applicable. Alternatively, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its *Capacity Exchange* tools. If any of the commercially aggregated resources in such Sell Offer are subject to the Minimum Floor Offer Price pursuant to Tariff, Attachment DD, sections 5.14(h) and 5.14(h-1), the Capacity Market Seller that owns or controls such resources may submit a Sell Offer with a Minimum Floor Offer Price of no lower than the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer.

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Tariff, Attachment Q, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Tariff, Attachment DD, section 6.6, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Tariff, Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Tariff, Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Tariff, Attachment DD, section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement or Locational Deliverability Area Reliability Requirement for such Delivery Year. For any auction, the Updated Forecast Peak Load applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- For the 2022/2023 Delivery Year through and including the Delivery Year commencing June 1, 2024, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 1.2%) divided by (100% plus IRM%)];

  - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability

Requirement multiplied by (100% plus IRM% plus 1.9%) divided by (100% plus IRM%)]; and

- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 7.8%) divided by (100% plus IRM%)].

- For the 2025/2026 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 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 98.9%];

  - 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 101.6%]; and

  - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 106.8%].

- For the 2026/2027 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) 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%].

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Incremental Auctions, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for each corresponding Delivery Year and LDA. For the Delivery Year commencing on June 1, 2022 through and including the Delivery Year commencing on June 1, 2025, the Cost of New Entry for the PJM Region shall be the average of the

Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	108,000
BGE, PEPCO (“CONE Area 2”)	109,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	105,500
PPL, MetEd, Penelec (“CONE Area 4”)	105,500

B) Beginning with the 2023/2024 Delivery Year through and including the 2025/2026 Delivery Year, the CONE 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 then adjusted further by a factor of 1.022 to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law, in accordance with the following:

(1) The Applicable BLS Composite Index for any 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 Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area, and then multiplying the result by 1.022.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2022/2023 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years), and then multiplying the result by 1.022.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

C) For the 2026/2027 Delivery Year and for subsequent Delivery Years, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(C)(1).

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year (ICAP)**
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	198,200
BGE, PEPCO (“CONE Area 2”)	193,100
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	197,800
PPL, MetEd, Penelec (“CONE Area 4”)	199,700

(1) Beginning with the 2027/2028 Delivery Year, the CONE 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, in accordance with the following:

(a) The Applicable BLS Composite Index for any 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 Price Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 15%), as each such index is further specified for each CONE Area in the PJM Manuals.

(b) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2026/2027 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(c) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset for 2023/2024 Delivery Year through and including the 2025/2026 Delivery Years (except that the calculation of the MOPR Floor Price pursuant to Tariff, Attachment DD, section 5.14(h-2) for combustion turbine resources shall remain applicable beyond the 2025/2026 Delivery Year):

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (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 time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.93 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

v-1) Net Energy and Ancillary Services Revenue Offset for the 2026/2027 Delivery Year and subsequent Delivery Years:

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (1) the average of the net energy and ancillary services revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such 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. Each net energy and ancillary services revenue simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of $2.10 per MWh, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward

Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis; plus (2) reactive service revenues of $2,546 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the Forward Hourly LMPs for such Zone shall be used in place of the Forward Hourly LMP for the PJM Region; (2) if such Zone was not integrated into the PJM Region for the entire three calendar years preceeding the time of the determination for the RPM Auction, then simulations shall rely on only those whole calendar years during which the Zone was integrated; and (3) Forward Daily Natural Gas Prices for the fuel pricing point mapped to such Zone.

C) "Forward Hourly LMPs" shall be determined as follows:

(1) Identify the liquid hub to which each Zone is mapped, as specified in the PJM Manuals.

(2) For each liquid hub, calculate the average day-ahead on-peak and day-ahead off-peak energy prices for each month during the Delivery Year over the most recent thirty trading days as of 180 days prior to the Base Residual Auction. For each of the remaining steps, the historical prices used herein shall be taken from the most recent three calendar years preceding the time of the determination for the RPM Auction:

(3) Determine and add monthly basis differentials between the hub and each of its mapped Zones to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. This differential is developed using the prices for the Planning Period closest in time to the Delivery Year from the most recent long-term Financial Transmission Rights auction conducted prior to the Base Residual Auction. The difference between the annual long-term Financial Transmission Rights auction prices for the Zone and the hub are converted to monthly values by adding, for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials

between the Zone and hub. This step is only used when developing forward prices for locations other than the liquid hubs;

(4) Determine and add marginal loss differentials to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. For each month of the year, calculate the marginal loss differential, which is the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of (a) the forward monthly average on-peak or off-peak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period. This step is only used when developing forward prices for locations other than the liquid hubs;

(5) Shape the forward monthly day-ahead on-peak and off-peak prices to (a) forward hourly day-ahead LMPs using historic hourly day-ahead LMP shapes for the Zone and (b) forward hourly real-time LMPs using historic hourly real-time LMP shapes for the Zone. The historic hourly shapes are based on the ratio of the historic day-ahead or real-time LMP for the Zone for each given hour in a monthly on-peak or off-peak period to the average of the historic day-ahead or real-time LMP for the Zone for all hours in such monthly on-peak or off-peak period. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction;

(6) For unit-specific energy and ancillary service offset calculations, determine and apply basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone. The differential for each hour of the year is developed using the difference between the historical DA or RT LMP for the generation bus and the historical DA or RT LMP for the Zone in which the generation bus is located for that same hour; and

(7) Develop the Forward Hourly LMPs for the PJM Region pricing point. Calculate the load-weighted average of the monthly on-peak and off-peak Zonal LMPs developed in step (4) above, using the historical average load within each monthly on-peak or off-peak period. The load-weighted average monthly on-peak or off-peak Zonal LMPs are then

shaped to forward hourly day-ahead and real-time LMPs using the same procedure as defined in step (5) above, except using historical LMPs for the PJM Region pricing point.

D) Forward Hourly Ancillary Services Prices shall include prices for Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve and shall be determined as follows. The historical prices used herein shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction:

(1) For Synchronized Reserve, the forward real-time Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year;

(2) For Non-Synchronized Reserve, the forward real-time Non-Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Non-Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year; and

(3) For Secondary Reserve, the forward day-ahead and real-time Secondary Reserve market clearing price shall be $0.00/MWh for all hours.

E) Forward Daily Natural Gas Prices shall be determined as follows:

(1) Map each Zone to the appropriate natural gas hub in the PJM Region, as listed in the PJM Manuals;

(2) Map each natural gas hub lacking sufficient liquidity to the liquid hub to which it has the highest historic price correlation;

(3) For each sufficiently liquid natural gas hub, calculate the simple average natural gas monthly settlement prices over

the most recent thirty trading days as of 180 days prior to the Base Residual Auction;

(4) Calculate the forward monthly prices for each illiquid hub by scaling the forward monthly price of the mapped liquid hub by the average ratio of historical monthly prices at the insufficiently liquid hub to the historical monthly prices at the sufficiently liquid over the most recent three calendar years preceding the time of determination for the RPM Auction;

(5) Shape the forward monthly prices for each hub to Forward Daily Natural Gas Prices using historic daily natural gas price shapes for the hub. The historic daily shapes are based on the ratio of the historic price for the hub for each given day in a month to the average of the historic prices for the hub for all days in such month. The daily prices are then assigned to each hour starting 10am Eastern Prevailing Time each day. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the

Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the

Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the Reliability Assurance Agreement.

c) [Reserved]

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, (through the 2024/2025 Delivery Year), the pool-wide average Accredited UCAP Factor (beginning with the 2025/2026 Delivery Year), the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year , the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in Tariff, Attachment DD, section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results for each Base Residual Auction shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price.

If PJM discovers a potential error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, along with a description detailing the cause and scope of the error, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. The provided description will not contain information that is market sensitive or confidential. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;
- For the 2024/2025 Delivery Year, the Locational Deliverability Requirement Reliability Requirement, including any revised Locational Deliverability Area Reliability Requirement based on the actual participation of Planned Generation Capacity Resources in the relevant Base Residual Auction; and
- For the 2020/2021 Delivery Year and subsequent Delivery Years, 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 optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. For the 2020/2021 Delivery Year and subsequent Delivery Years, the supply curve formed by the Sell Offers submitted within an LDA for which a separate VRR Curve is established, shall only consider the quantity of MW 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 LDA's reliability requirement.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year. The Capacity Resource clearing results and Capacity Resource Clearing Prices determined for Summer-Period Capacity Performance Resources shall be applicable for the calendar months of June through October and the following May of such Delivery Year; and shall be applicable for Winter-Period Capacity Performance Resources for the calendar months of November through April of such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;

- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;

- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement, and for the 2024/2025 Delivery Year, including any revised Locational Deliverability Area Reliability Requirement based on the actual participation of Planned Generation Capacity Resources in the relevant Incremental Auction;

- For the 2020/2021 Delivery Year and subsequent Delivery Years, 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;

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and

- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(2), the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(1), and the conditions stated in Tariff, Attachment DD, section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14E, and 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by Tariff, Attachment DD, section 5.4(c)(3)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14E, and 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9, provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(v) (reserved)

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

(A) [Reserved]

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and

- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

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 LDAs 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 level constrained LDA, where they are considered in a similar manner for compensation.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the 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.

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with Tariff, Attachment DD, section 5.12(a) and section 5.14(a) above.

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b) above; or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in Tariff, Attachment DD, section 5.12(a), and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) above that is entitled to compensation pursuant to section 5.14(b) above; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) above shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with section 5.14(b) above. Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in section 5.14(a) above.

6. The failure to submit a Sell Offer consistent with section 5.14(c)(i)-(iii) above in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) above in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Tariff, Attachment DD, section 5.10(a)(ii).

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under Tariff, Attachment DD, section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in Tariff, Attachment DD, section 5.14B, Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D, Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain New Generation Capacity Resources that are not Capacity Resources with State Subsidy for up to the 2022/2023 Delivery Year.

(1) The provisions of this section 5.14(h) shall not be effective after the 2022/2023 Delivery Year. For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Tariff, Attachment DD, section 5.10(a)(iv)(A) of this Attachment. This section only applies to new Generation Capacity Resources that do not receive or are not entitled to receive a State Subsidy, meaning that such resources are not Capacity Resources with State Subsidy. To the extent a new Generation Capacity Resource is a Capacity Resource with State Subsidy, then the provisions in Tariff, Attachment DD, section 5.14(h-1) apply.

The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), and a combined cycle generator ("CC") respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT $/MW-yr	132,200	130,300	128,990	130,300
CC $/MW-yr	185,700	176,000	172,600	179,400

(2) The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in Tariff, Attachment DD, section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For the 2022/2023 Delivery Year, for purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by Tariff, Attachment DD, section 5.10(a)(v-1)(A), provided that the energy and ancillary services revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.501 MMbtu/MWh, the variable operations and maintenance expenses for such resource shall be $2.11 per MWh, a 10% adder will not be included in the energy offer, and the reactive service revenues shall be $3,350 per MW-year.

(4) Any Sell Offer that is based on either (i) or (ii), and (iii):

i) a Generation Capacity Resource located in the PJM Region that is submitted in an RPM Auction for a Delivery Year unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM auction for that or any subsequent Delivery Year; or

ii) a Generation Capacity Resource located outside the PJM Region (where such Sell Offer is based solely on such resource) that requires sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region, unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM Auction for that or any subsequent Delivery Year;

iii) in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.

(5) Unit-Specific Exception. A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following process and requirements shall apply to requests for such determinations:

i) The Capacity Market Seller may request such a determination by no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the minimum offer level expected to be established under subsection (4). If the minimum offer level subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues, or, sufficient data for the Office of the Interconnection and the Market Monitoring Unit to produce such an estimate. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer. The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for an exception hereunder.

The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above.

For the 2022/2023 Delivery Year, in making such demonstration, the Capacity Market Seller may rely upon revenues projected by well defined, forward-looking dispatch models, designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance costs, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors and ancillary service capabilities.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, and plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

iii) A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4). Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of an exception hereunder by the Office of the Interconnection.

iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, the Capacity Market Seller Shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.

h-1) Minimum Offer Price Rule for Capacity Resources with State Subsidy for the 2022/2023 Delivery Year.

(1) **General Rule.** The provisions of this section 5.14(h-1) shall not be effective after the 2022/2023 Delivery Year. For the 2022/2023 Delivery Year, any Sell Offer based on either a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with a State Subsidy submitted in any RPM Auction shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the Capacity Market Seller qualifies for an exemption with respect to such Capacity Resource with a State Subsidy prior to the submission of such offer.

(A) Effect of Exemption. To the extent a Sell Offer in any RPM Auction is based on a Capacity Resource with State Subsidy that qualifies for any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h-1)(4)-(8), the Sell Offer for such resource shall not be limited by the MOPR Floor Offer Price, unless otherwise specified.

(B) Effect of Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a Capacity Resource with State Subsidy for which the Capacity Market Seller obtains, prior to the submission of such offer, a resource-specific exception, such offer may include an offer price below the default MOPR Floor Offer Price applicable to such resource type, but no lower than the resource-specific MOPR Floor Offer Price determined in such exception process.

(C) Process for Establishing a Capacity Resource with a State Subsidy.

(i) By no later than one hundred and twenty (120) days prior to the commencement of the offer period of any RPM Auction conducted for the 2022/2023 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not each Capacity Resource (other than Demand Resource and Energy Efficiency Resource) that the Capacity Market Seller intends to offer into the RPM Auction qualifies as a Capacity Resource with a State Subsidy (including by way of Jointly Owned Cross-Subsidized Capacity Resource) and identify (with specificity) any State Subsidy. Capacity Market Sellers that intend to offer a Demand Resource or an Energy Efficiency Resource into the RPM Auction shall certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not such Demand Resource or Energy Efficiency Resource qualifies as a Capacity Resource with a State Subsidy no later than thirty (30) days prior to the commencement of the offer period of any RPM Auction conducted for the 2022/2023 Delivery Year. All Capacity Market Sellers shall be responsible for each certification irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit. A Capacity Resource shall be deemed a Capacity Resource with State Subsidy if the Capacity Market Seller fails to timely certify whether or not a Capacity Resource is entitled to a State Subsidy, unless the Capacity Market Seller receives a waiver from the Commission. Notwithstanding, if a Capacity Market Seller submits a timely resource-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) for the relevant Delivery Year, and PJM approves the resource-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely certified whether or not the resource is a Capacity Resource with State Subsidy.

(ii) The requirements in subsection (i) above do not apply to Capacity Resources for which the Market Seller designated whether or not it is subject to a State Subsidy and the associated subsidies to which the Capacity Resource is entitled in a prior Delivery Year, unless there has been a change in the set of those State Subsidy(ies), or for those which are eligible for the Demand Resource or Energy Efficiency exemption, Capacity Storage Resource exemption, Self-Supply Entity exemption, or the Renewable Portfolio Standard exemption.

(iii) Once a Capacity Market Seller has certified a Capacity Resource as a Capacity Resource with a State Subsidy, 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 shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Capacity Resource's material change in status as a Capacity Resource with State Subsidy within 30 days of such material change, unless such material change occurs within 30 days of the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year, in which case the Market Seller must notify PJM no later than 5 days prior to the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection whether its resource meets the criteria of a Capacity Resource with State Subsidy pursuant to Tariff, Attachment DD, section 5.14(h-1)(1)(C)(i).

(2) **Minimum Offer Price Rule.** Any Sell Offer for a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with State Subsidy that does not qualify for any of the exemptions, as defined in Tariff, Attachment DD, sections 5.14(h-1)(4)-(8), shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Resource with State Subsidy must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process to participate in an RPM Auction.

(A) New Entry MOPR Floor Offer Price. For a New Entry Capacity Resource with State Subsidy the applicable MOPR Floor Offer Price, based on the net cost of new entry for each resource type, shall be, at the election of the Capacity Market Seller, (i) the resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Gross Cost of New Entry (2022/2023 $/ MW-day) (Nameplate)**
Nuclear	$2,000
Coal	$1,068
Combined Cycle	$320
Combustion Turbine	$294
Fixed Solar PV	$271
Tracking Solar PV	$290
Onshore Wind	$420
Offshore Wind	$1,155
Battery Energy Storage	$532
Diesel Backed Demand Resource	$254

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For Delivery Years through the 2022/2023 Delivery Year, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types and battery energy storage resource types, the applicable class average EFORd; for wind and solar generation resource types, the applicable class average capacity value factor; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. For the 2023/2024 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types, the applicable class average EFORd; for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

The default New Entry MOPR Floor Offer Price for load-backed Demand Resources (i.e., the MW portion of Demand Resources that is not supported by generation) shall be separately determined for each Locational Deliverability Area as the MW-weighted average offer price of load-backed Demand Resources from the most recent three Base Residual Auctions, where the MW weighting shall be determined based on the portion of each Sell Offer for a load-backed portion of the Demand Resource that is supported by end-use customer locations on the registrations used in the pre-registration process for such Base Residual Auctions, as described in the PJM Manuals.

For generation-backed Demand Resources that are not powered by diesel generators, the default New Entry MOPR Floor Offer Price shall be the default New Entry MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.

The default gross cost of new entry for Energy Efficiency Resources shall be $644/ICAP MW-Day, which shall be offset by projected wholesale energy savings, as well as transmission and distribution savings of $95/ICAP MW-Day, to determine the default New Entry MOPR Floor Offer Price (Net Cost of New Entry), where the projected wholesale energy savings are determined utilizing the cost and performance data of relevant programs offered by representative energy efficiency programs with sufficiently detailed publicly available data. The wholesale energy savings, in $/ICAP MW-day, shall be calculated prior to each RPM Auction and be equal to the average annual energy savings of 6,221 MWh/ICAP MW times the weighted average of the annual real-time Forward Hourly LMPs of the Zones of the representative energy efficiency programs, where the weighting is developed from the annual energy savings in the relevant Zones, divided by 365.

To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types except for load-backed Demand Resources and Energy Efficiency Resources, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, combine cycle, and generation-backed Demand 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. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue shall be the average of the net energy and ancillary services revenues that the resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of each 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. Each net energy and ancillary services revenue simulation shall be conducted in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus reactive services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $3,350/MW-year;

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,350/MW-year; and

(ix) for generation-backed Demand Resource, the net energy and ancillary services revenue estimate shall be zero dollars.

New Entry Capacity Resource with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices.

(i) For a Cleared Capacity Resource with State Subsidy, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the resource-specific MOPR Floor Offer Price , as determined in accordance with Tariff, Attachment DD, section 5.14(h-1)(3) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, net of projected PJM market revenues equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with subsection (ii) below.

Existing Resource Type	**Default Gross ACR (2022/2023 ($/MW-day) (Nameplate)**
Nuclear - single	$697
Nuclear - dual	$445
Coal	$80
Combined Cycle	$56
Combustion Turbine	$50
Solar PV (fixed and tracking)	$40
Wind Onshore	$83
Diesel-backed Demand Response	$3
Load-backed Demand Response	$0
Energy Efficiency	$0

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on: for Delivery Years through the 2022/2023 Delivery Year, the resource-specific EFORd for thermal generation resource types, resource-specific capacity value factor for solar and wind generation resource types (based on the ratio of Capacity Interconnection Rights to nameplate capacity, appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction, and for the 2023/2024 Delivery Year and subsequent Delivery Years, the resource-specific EFORd for thermal generation resource types and on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resources with State Subsidies that have cleared in an RPM Auction for any prior Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

For generation-backed Demand Resources that are not powered by diesel generators, the default Cleared MOPR Floor Offer Price shall be the default Cleared MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.

Cleared Capacity Resources with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(ii) The net energy and ancillary services revenue is equal to forecasted net revenues which shall be determined in accordance with the applicable resource type net energy and ancillary services revenue determination methodology set forth in Tariff, Attachment DD, section 5.14(h-1)(2)(A)(i) through (ix) and using the subject resource's operating parameters as determined in accordance with the PJM Manuals based on (a) offers submitted in the Day-ahead Energy Market and Real-time Energy Market over the calendar year preceding the time of the determination for the RPM Auction; (b) the resource-specific operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs); (c) the resource's EFORd; (d) Forward Hourly LMPs at the generation bus as determined in accordance with Tariff, Attachment DD, section 5.10(a)(v-1)(C)(6); and (e) the resource's stated annual revenue requirement for reactive services; plus any unit-specific bilateral contract. In addition, the following resource type-specific parameters shall be considered; (f) for combustion turbine, combined cycle, and coal resource types: the installed capacity rating, ramp rate (which shall be equal to the maximum ramp rate included in the resource's energy offers over the most recent previous calendar year preceding the determination for the RPM Auction), and the heat rate as determined as the resource's average heat rate at full load as submitted to the Market Monitoring Unit and the Office of the Interconnection, where for combined cycle resources heat rates will be determined at base load and at peak load (e.g., without duct burners and with duct burners), as applicable; (g) for nuclear resource type: an average equivalent availability factor of all PJM nuclear resources to account for refueling outages; (h) for solar and wind resource types: the resource's output profiles for the most recent three calendar years, as available; and (i) for battery storage resource type: the nameplate capacity rating (on a MW / MWh basis).

To the extent the resource has not achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Cleared Capacity Resource with State Subsidy based on a net energy and ancillary services revenue determination that does not use the foregoing methodology or parameter inputs stated for that resource type shall, at its election, submit a request for a resource-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) below.

(3) Resource-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with State Subsidy below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a resource-specific exception for such Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the resource-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The resource-specific MOPR Floor Offer Price determined under this provision shall be based on the resource-specific EFORd for thermal generation resource types, on the resource-specific Accredited UCAP value for ELCC Resources (where for solar and wind generation resource types the Accredited UCAP shall be appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost were the resource to rely solely on revenues exclusive of any State Subsidy. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the resource-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-1)(2)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(B) For a resource-specific exception for a New Entry Capacity Resource with State Subsidy, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources and generation-backed Demand Resources 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.

Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a resource-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any State Subsidies) 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, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

The default assumptions for calculating resource-specific Cost of New Entry for Energy Efficiency Resources shall be based on, as supported by documentation provided by the Capacity Market Seller: the nominal-levelized annual cost to implement the Energy Efficiency program or to install the Energy Efficiency measure reflective of the useful life of the implemented Energy Efficiency equipment, and the offsetting savings associated with avoided wholesale energy costs and other claimed savings provided by implementing the Energy Efficiency program or installing the Energy Efficiency measure.

The default assumptions for calculating resource-specific Cost of New Entry for load-backed Demand Resources shall be based on, as supported by documentation provided by the Capacity Market Seller, program costs required for the resource to meet the capacity obligations of a Demand Resource, including all fixed operating and maintenance cost and weighted average cost of capital based on the actual cost of capital for the entity proposing to develop the Demand Resource.

For generation-backed Demand Resources, the determination of a resource-specific MOPR Floor Offer Price shall consider all costs associated with the generation unit supporting the Demand Resource, and demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include, but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit.

(C) For a Resource-Specific Exception for a Cleared Capacity Resource with State Subsidy that is a generation resource, the Capacity Market Seller shall submit a Sell Offer 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 shall, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any State Subsidies) 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, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not avaliable, publicly avaliable estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

The resource-specific MOPR Floor Offer Price for a Cleared Capacity Resource with State Subsidy that is a generation-backed Demand Resource will be determined based on all costs associated with the generation unit supporting the Demand Resource, and demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit.

(D) A Sell Offer evaluated at the resource-specific exception 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 default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a resource-specific exception by the Office of the Interconnection.

(E) 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 his/her 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.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the resource-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the resource-specific determination unless and until ordered to do otherwise by FERC.

(4) Competitive Exemption.

(A) A Capacity Resource with State Subsidy may be exempt from the Minimum Offer Price Rule under this subsection 5.14(h-1) in any RPM Auction if the Capacity Market Seller certifies to the Office of Interconnection, in accordance with the PJM Manuals, that the Capacity Market Seller of such Capacity Resource elects to forego receiving any State Subsidy for the applicable Delivery Year no later than thirty (30) days prior to the commencement of the offer period for the relevant RPM Auction. Notwithstanding the foregoing, the competitive exemption is not available to Capacity Resources with State Subsidy that (A) are owned or offered by Self-Supply Entities unless the Self-Supply Entity certifies, subject to PJM and Market Monitor review, that the Capacity Resource will not accept a State Subsidy, including any financial benefit that is the result of being owned by a regulated utility, such that retail ratepayers are held harmless, (B) are no longer entitled to receive a State Subsidy but are still considered a Capacity Resource with State Subsidy solely because they have not cleared an RPM Auction since last receiving a State Subsidy, or (C) are Jointly Owned Cross-Subsidized Capacity Resources or is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) and not all Capacity Market Sellers of the supporting facility unanimously elect the competitive exemption and certify that no State Subsidy will be received associated with supporting the resource (unless the underlying Capacity Resource that is the subject of a bilateral transaction has not received, is not receiving, and is not entitled to receive any State Subsidy except those that are assigned (i.e., renewable energy credits) to the off-takers of a bilateral transaction and the Capacity Market Seller of such Capacity Resource can demonstrate and certify that the Capacity Market Seller's rights and obligations of its share of the capacity, energy, and assignable State Subsidy associated with the underlying Capacity Resource are in pro rata shares). A new Generation Capacity Resource that is a Capacity Resource with State Subsidy may elect the competitive exemption; however, in such instance, the applicable MOPR Floor Offer Price will be determined in accordance with the minimum offer price rules for certain new Generation Capacity Resources as provided in Tariff, Attachment DD, section 5.14(h), which apply the minimum offer price rule to the new Generation Capacity Resources located in an LDA where a separate VRR Curve is established as provided in Tariff, Attachment DD, section 5.14(h)(4).

(B) The Capacity Market Seller shall not receive a State Subsidy for any part of the relevant Delivery Year in which it elects a competitive exemption or certifies that it is not a Capacity Resource with State Subsidy.

(5) Self-Supply Entity exemption. A Capacity Resource that was owned, or bilaterally contracted, by a Self-Supply Entity on December 19, 2019, shall be exempt from the

Minimum Offer Price Rule if such Capacity Resource remains owned or bilaterally contracted by such Self-Supply Entity and satisfies at least one of the criteria specified below:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(6) Renewable Portfolio Standard Exemption. A Capacity Resource with State Subsidy shall be exempt from the Minimum Offer Price Rule if such Capacity Resource (1) receives or is entitled to receive State Subsidies through renewable energy credits or equivalent credits associated with a state-mandated or state-sponsored renewable portfolio standard ("RPS") program or equivalent program as of December 19, 2019 and (2) satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(7) Demand Resource and Energy Efficiency Resource Exemption.

(A) A Capacity Resource with State Subsidy that is Demand Resource or an Energy Efficiency Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Resource satisfies at least one of the following criteria:

(i) has successfully cleared an RPM Auction prior to December 19, 2019. For purposes of this subsection (A), individual customer location registrations that participated as Demand Resource and cleared in an RPM Auction prior to December 19, 2019, and were submitted to PJM no later than 45 days prior to the BRA for the

2022/2023 Delivery Year shall be deemed eligible for the Demand Resource and Energy Efficiency Resource Exemption; or

(ii) has completed registration on or before December 19, 2019; or

(iii) is supported by a post-installation measurement and verification report for Energy Efficiency Resources approved by PJM on or before December 19, 2019 (calculated for each installation period, Zone and Sub-Zone by using the greater of the latest approved post-installation measurement and verification report prior to December 19, 2019 or the maximum MW cleared for a Delivery Year across all auctions conducted prior to December 19, 2019).

(B) All registered locations that qualify for the Demand Resource and Energy Efficiency Resource exemption shall continue to remain exempt even if the MW of nominated capacity increases between RPM Auctions unless any MW increase in the nominated capacity is due to an investment made for the sole purpose of increasing the curtailment capability of the location in the capacity market. In such case, the MW of increased capability will not be qualified for the Demand Resource and Energy Efficiency Resource exemption.

(8) Capacity Storage Resource Exemption. A Capacity Resource with State Subsidy that is a Capacity Storage Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Storage Resource satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(9) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with State Subsidy. In the event the Office of the Interconnection, with advice and input from the Market Monitoring Unit, reasonably believes that a certification of a Capacity Resource's status contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource is a Capacity Resource with a State Subsidy (including whether the Capacity Resource is a Jointly Owned Cross-Subsidized Capacity Resource) or does not qualify for a competitive exemption or contains information that is inconsistent with the resource-specific exception, then:

(A) A Capacity Market Seller shall, within five (5) business days upon receipt of the request for additional information, provide any supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate whether such Capacity Resource is a Capacity Resource with State Subsidy or whether the Capacity Market Seller is eligible for the competitive exemption. If the Office of the Interconnection determines that the Capacity Resource's status as a Capacity Resource with State Subsidy is different from that specified by the Capacity Market Seller or is not eligible for a competitive exemption pursuant to subsection (4) above, the Office of the Interconnection shall notify, in writing, the Capacity Market Seller of such determination by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, if the Office of Interconnection determines that the subject resource is a Capacity Resource with State Subsidy or is not eligible for a competitive exemption pursuant to subsection (4) above, such Capacity Resource shall be subject to the Minimum Offer Price Rule, unless and until ordered to do otherwise by FERC.

(B) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least sixty-five (65) days before the start of the relevant RPM Auction, then the Office of the Interconnection may file the certification that contains any alleged fraudulent or material misrepresentation or omission with FERC. In such event, if the Office of Interconnection determines that a resource is a Capacity Resource with State Subsidy that is subject to the Minimum Offer Price Rule, the Office of the Interconnection will proceed with administration of the Tariff and market rules on that basis unless and until ordered to do otherwise by FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(C) prior to applying the Minimum Offer Price Rule, the Office of the Interconnection, with advice and input of the Market Monitoring Unit, shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged fraudulent or material misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may submit a revised certification for that Capacity Resource for subsequent RPM Auctions, including RPM Auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

h-2) Minimum Offer Price Rule Effective with the 2023/2024 Delivery Year

(1) **Certification Requirement.**

(A) By no later than one hundred and fifty (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 to the Office of Interconnection for each Generation Capacity Resource the Capacity Market Seller intends to offer into the RPM Auction, in accordance with the PJM Manuals:

(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.

(B) All Capacity Market Sellers shall be responsible for the accuracy of each certification and its conformance with the Tariff irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.

(C) Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the certification requirements in subsection (A)(i) above do not apply and the status of such Generation Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller of the underlying resource) that owns or controls such Generation 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 shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

(2) **Determining Generation Capacity Resources Subject to the Minimum Offer Price Rule.**

(A) Conditioned State Support.

(i) If the Office of the Interconnection 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, the Office of Interconnection shall submit, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, a filing at FERC indicating the Office of the Interconnection's 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 reasonably expected to receive such Conditioned State Support. If FERC has already ruled on whether a specific government program or policy constitutes Conditioned State Support and such policy or program is listed in Tariff, Attachment DD-3, the Office of the Interconnection shall not be required to submit the filing described in the preceding sentence.

(ii) 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.

(iii) Upon FERC acceptance (whether by order or operation of law) that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i) that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, will be subject to the provisions of the Minimum Offer Price Rule.

(B) Exercise of Buyer-Side Market Power

(i) 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, then the underlying Capacity Resource shall be subject to the MOPR pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i). If the Office of the Interconnection and/or the Market Monitoring Unit reasonably suspects that a certification submitted under Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii) contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource 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 may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. 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 would not be an Exercise of Buyer-Side Market Power. The Office of the Interconnection and/or the Market Monitoring Unit 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, the Office of the Interconnection and/or the Market Monitoring Unit shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. The Office of the Interconnection and/or the Market Monitoring Unit may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, the Office of the Interconnection and the Market Monitoring Unit 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 the Office of the Interconnection and/or the Market Monitoring Unit, 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 Office of the Interconnection, 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 that could be an Exercise of Buyer-Side Market Power, as follows:

(a) To determine whether a Capacity Market Seller may have Buyer Side Market Power associated with the Generation Capacity Resource for the applicable RPM Auction, the Office of the Interconnection and/or the Market Monitoring Unit will perform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.

(b) To determine whether the Capacity Market Seller's submission of a Sell Offer at any given price level for such Generation Capacity Resource may constitute an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall perform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically. In this analysis, the Office of Interconnection and/or the Market Monitoring Unit shall consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices. If the expected benefit outweighs the expected cost, the Capacity Market Seller shall be deemed to have the incentive to exercise Buyer Side Market Power. If a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not to have the incentive to exercise Buyer Side Market Power with respect to that resource. Out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review.

(ii) The following nonexhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review initiated pursuant to subsection (i) above: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource 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 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 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.

(iii) Based on the foregoing tests and fact-specific review, including the facts and circumstances of the Generation Capacity Resource, the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, determines that a Generation Capacity Resource 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, the Office of the Interconnection shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the Office of the Interconnection's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on its determination hereunder unless FERC by order directs otherwise.

(C) Failure to timely submit a certification. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications required under Tariff, Attachment DD, section 5.14(h-2)(1) 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 pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) 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.

(3) **Minimum Offer Price Rule.** Any Sell Offer for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process, and the unit-specific MOPR Floor Offer Price shall establish the offer level for such resource.

(A) New Entry MOPR Floor Offer Price. For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource, or any uprate of such Generation Capacity Resource participating in the generation interconnection process under Tariff, Part IV, Subpart A, that has not cleared an RPM Auction for any Delivery Year, the applicable MOPR Floor Offer Price, based on the net cost of new entry for the resource type, shall be, at the election of the Capacity Market Seller, (i) the unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-2)(4) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Through the 2025/2026 Delivery Years: Gross Cost of New Entry (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	$427
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

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For the 2023/2024 and 2024/2025 Delivery Years, the net cost of new entry is adjusted using: for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for all other generation resource types, the applicable class average EFORd. For the 2025/2026 Delivery Year and subsequent Delivery Years, the net cost of new entry is adjusted by the applicable class average Accredited UCAP Factor. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle 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. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue is equal to the average of the annual net revenues of the three most recent calendar years preceding the Base Residual Auction, where such annual net revenues shall be determined in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus an ancillary services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate shall be determined by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using applicable coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,553 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in Peak-Hour Dispatch, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary services revenue shall be $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate shall be the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%], plus an ancillary services revenue of $3,350/MW-year; and

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily twenty-four hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same twenty-four hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has not previously cleared an RPM Auction for that or any prior Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices.

For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) 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 shall be, at the election of the Capacity Market Seller, (a) based on the unit-specific MOPR Floor Offer Price, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(4) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent for the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of projected PJM market revenues equal to the resource's historical net energy and ancillary service revenues consistent with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	**Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate)**	**For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/ MW-day) Nameplate**
Nuclear - single	$697	$591
Nuclear - dual	$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
Wind Onshore	$83	$147

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. Through the 2024/2025 Delivery Year, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights) or the resource-specific EFORd for all other generation resource types. Effective for the 2025/2026 Delivery Year and subsequent Delivery Years, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, based on the resource's Accredited UCAP Factor. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default Avoidable Cost Rates in the table above, and post the adjusted values on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted Avoidable Cost Rates, the Office of the Interconnection shall utilize the 10-year average Handy-

Whitman Index in order to adjust the Gross ACR values to account for expected inflation. Updated estimates of the net energy and ancillary service revenues shall be determined on a resource-specific basis in accordance with Tariff, Attachment DD, section 6.8(d) and the PJM Manuals.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction for any Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(4) **Unit-Specific Exception**. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Capacity Resource. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is under a fact-specific review for Buyer-Side Market Power pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), and where the offer is below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Generation Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the unit-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The unit-specific MOPR Floor Offer Price determined under this provision shall be based on the unit-specific Accredited UCAP value for battery energy storage resource types and for solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights) or on the unit-specific EFORd for all other generation resource types, and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of the resource. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the unit-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-2)(3)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(B) For a unit-specific exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has never cleared an RPM Auction, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources 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 or any other revenues outside of PJM markets that do not constitute Conditioned State Support), 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.

Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a unit-specific exception hereunder. The request also 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, evidence of compensation outside the PJM market not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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, with the standard prescribed above. 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, which may include Maintenance Adders, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to 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.

(C) For a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, the Capacity Market Seller shall submit a Sell Offer 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 for an exception under this subsection 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, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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, with the standard prescribed above. 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, which may include Maintenance Adders, and emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to 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 revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

(D) A Sell Offer evaluated at the unit-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall 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, and that out-of-market compensation is not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices. Failure to adequately support such claimed cost advantages or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in the elimination of consideration of the unsupported element(s) of a unit-specific exception by the Office of the Interconnection.

(E) 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 his/her 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.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the unit-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the unit-specific determination unless and until ordered to do otherwise by FERC.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) above also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under Tariff, Attachment DD, section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) above times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h) below, all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. 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. Through the 2024/2025 Delivery Year, the Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in section 6.6(b). Starting with the 2025/2026 Delivery Year, the Unforced Capacity of such resource is determined using the effective Accredited UCAP Factor for that resource. If a resource should be included on the list of Existing Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, section II.C.1, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) Through the 2024/2025 Delivery Year, for each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under this section 6.6 to establish the maximum EFORd applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORd for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORd, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORd, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. As further described in Tariff, Attachment M-Appendix, section II.C, the Market

Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORd or, if no agreement has been reached, specifying the level of alternate maximum EFORd to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORd prior to the specified deadlines, the maximum EFORd for the applicable RPM Auction shall be deemed to be the default EFORd calculated pursuant to this section.

The maximum EFORd that may be used in a Sell Offer for Third Incremental Auction, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) Through the 2024/2025 Delivery Year, in the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, the Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORd based on the requirements of the Tariff and the PJM Manuals, per Tariff, Attachment DD, section 5.8, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Through the 2024/2025 Delivery Year, nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Through the 2024/2025 Delivery Year, notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses for an RPM Auction held prior to the date on which the final EFORd used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, Attachment M-Appendix, section II.C, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity

Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) the September 1 that last precedes the Base Residual Auction and (b) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) Business Days after *the notification deadline for* any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after *the notification deadline for* such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from Capacity Resource status shall first submit a preliminary request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to remove the Capacity Resource status of such resource to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) the September 1 that last precedes the Base Residual Auction, and (b) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) Business Days after *the notification deadline for* any such preliminary requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall, by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is either (a) withdrawing its preliminary request and explaining the changes to its analysis that support its decision to withdraw, or (b) confirming its preliminary decision to remove the Generation Capacity Resource from Capacity Resource status. By no later than five (5) Business Days after *the notification deadline for* such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests to remove its Capacity Resource status, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

The Market Monitoring Unit shall analyze the effects of the proposed removal of a Generation Capacity Resource from Capacity Resource status with regard to potential market power issues and shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the request to remove the Generation Capacity Resource from Capacity Resource status, and whether a market power issue has been identified, by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. Such notice shall include the specific market power impact resulting from the proposed removal of the Generation Capacity Resource from Capacity Resource status, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

A Capacity Market Seller may only remove the Generation Capacity Resource from Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Tariff, Attachment DD, sections 5.6.6 and this section 6.6 and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource, or (iii) it is required as set forth in Tariff, Attachment DD, section 6.6A(c). Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of this section 6.6. A Generation Capacity Resource that is removed from Capacity Resource status shall no longer qualify as an Existing Generation Capacity Resource, and the Capacity Interconnection Rights associated with such facility shall be subject to termination in accordance with the rules described in Tariff, Part VI, section 230.3.3. The Office of the Interconnection shall amend the applicable Interconnection Service Agreement or wholesale market participation agreement to reflect any such removal of the Capacity Interconnection Rights, and shall report the amended agreement to the Commission in the same manner as the original (e.g., FERC filing or Electronic Quarterly Reports). The Office of the Interconnection shall file the amended agreement unexecuted if the Interconnection Customer or wholesale market participant does not sign the amended Interconnection Service Agreement or wholesale market participation agreement.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource may be removed from Capacity Resource status, or whether the resource meets one of the exceptions thereto, and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Tariff, Attachment M-Appendix, section II.C.4, the Office of the Interconnection shall approve or deny the request. The request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn’t timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any Planned Generation Capacity Resource associated with a notice of intent to offer into a particular RPM Auction that is not offered into the associated RPM Auction and all Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Tariff, Attachment M and Tariff, Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant

RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. 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.

(b) Determinations of EFORd, Accredited UCAP, and Unforced Capacity made under this Tariff, Attachment DD, section 6.6 as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

Effective with the 2023/2024 Delivery Year, Capacity Market Sellers seeking an exception for a Base Residual Auction on the basis that a resource is incapable of meeting the Capacity Performance Resource requirement shall include a documented plan with the submission of their 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. Such plan shall include (i) a timeline for design, permitting, procurement, and construction milestones, as applicable, where such timeline shall not exceed one Base Residual Auction exception, and (ii) evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment). Periodic updates on the progress, shall be provided by the Capacity Market Seller to the Office of the Interconnection and the Market Monitoring Unit for their review by no later than (i) one hundred twenty (120) days prior to the commencement of the offer period for subsequent Incremental Auctions for the applicable Delivery Years, and (ii) the December 1 that last precedes subsequent Base Residual Auctions. The Capacity Market Seller shall also immediately notify the Office of the Interconnection and the Market Monitoring Unit of any material changes to the plan that may occur. Upon request by a Capacity Market Seller, a one year extension to the plan timeline shall be permissible only for delays not caused by the Capacity Market Seller, and that could not have been remedied through the exercise of due diligence by the Capacity Market Seller. In no event may an exception be requested by the Capacity Market Seller for more than two Base Residual Auctions.

Failure to submit a documented plan, or lack of good faith effort by a Capacity Market Seller to make an Existing Generation Capacity Resource physically capable of meeting the requirements of a Capacity Performance Resource in accordance with a documented plan, shall result in the removal of the resource's Capacity Resource status effective with the first future Delivery Year for which the resource was granted an exception, no earlier than the 2023/2024 Delivery Year. The Office of the Interconnection shall amend the applicable Interconnection Service Agreement or wholesale market participation agreement to reflect any such removal of the Capacity Interconnection Rights, and shall report the amended agreement to the Commission in the same manner as the original (e.g. FERC Filing or Electronic Quarterly Reports). The Office of the Interconnection shall file the amended agreement unexecuted if the Interconnection Customer or wholesale market participant does not sign the amended Interconnection Service Agreement or wholesale market participation agreement. The required change in Capacity Resource status shall only apply to those Generation Capacity Resources that are shown to be physically incapable of satisfying the requirements of a Capacity Performance Resource.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

7. GENERATION RESOURCE RATING TEST FAILURE CHARGE

7.1 Generation Resource Rating Test Failure Charges

A Generation Resource Rating Test Failure Charge shall be assessed on any Market Seller that commits a Generation Capacity Resource for a Delivery Year, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, if such resource fails a generation resource capacity test, as provided herein.

a) Generation Resource Fails Capacity Test in Delivery Year

Each Generation Capacity Resource committed through RPM Auctions or included in a FRR Plan for a Delivery Year, with the exception of Variable Resources, shall be obligated to complete a generation resource capacity test, as described in the PJM Manuals. The Market Seller that committed the resource, or Locational UCAP Seller that sold the resource, may perform an unlimited number of tests during each such period. If none of the tests during a testing period certify full delivery of the megawatt amount of installed capacity the Market Seller committed, or Locational UCAP Seller sold, for such Delivery Year, the Market Seller or Locational UCAP Seller shall be assessed a daily Generation Resource Rating Test Failure Charge for each day from the first day of the Summer or Winter Season in which such resource failed the rating test through the last day of such Delivery Year, provided, however, that such a seller that fails or is expected to fail a rating test may obtain and commit Unforced Capacity from a replacement Capacity Resource meeting the same locational requirements. Such Unforced Capacity may include uncommitted or uncleared Sell Offer blocks from Generation Capacity Resources that were otherwise committed. Any such commitment of replacement capacity shall be effective upon no less than one day's notice to the Office of the Interconnection, and shall reduce the amount of installed capacity committed from the Generation Capacity Resource, that failed or was expected to fail such rating test, in accordance with the determination prescribed by subsection (b) below. Effective with the 2025/2026 Delivery Year, such charge shall be evaluated and assessed for each day of the Delivery Year in which the seasonal rating test for such resource fails to certify full delivery of the megawatt amount of installed capacity committed for such day.

b) Generation Resource Rating Test Failure Charge

Through the 2024/2025 Delivery Year, the Generation Resource Rating Test Failure Charge shall equal the Daily Deficiency Rate multiplied by the following megawatt quantity, converted to an Unforced Capacity basis using the Generation Capacity Resource's EFORD for the twelve months ending the September 30 last preceding the Delivery Year: (i) the annual average of the installed capacity committed for each day of such Delivery Year as a result of all cleared Sell Offers in all RPM Auctions for such Delivery Year relying on such resource, reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource, minus (ii) the highest installed capacity rating determined for such resource in any test during the relevant testing period. Effective with the 2025/2026

Delivery Year, the Generation Resource Rating Test Failure Charge shall be determined for each day of the Delivery Year and shall be equal to the Daily Deficiency Rate multiplied by the following megawatt quantity shortfall, converted to an Unforced Capacity basis using the Generation Capacity Resource's final Accredited UCAP Factor for such Delivery Year: (i) the installed capacity committed for such day of the Delivery Year (adjusted for any replacement capacity), minus (ii) the highest installed capacity rating determined for such resource in any test during the relevant testing period.

b-1) Daily Deficiency Rate

The Daily Deficiency Rate shall equal the Capacity Resource Clearing Price (weighted as necessary to reflect the clearing prices in all RPM Auctions that resulted in installed capacity commitments from such resource), in $/MW-day, applicable to the Generation Capacity Resource (for purposes of replacement capacity, including Locational UCAP transactions, the applicable Capacity Resource Clearing Price shall be the clearing price for the Locational Deliverability Area in which such resource is located) plus the greater of (iii) 0.20 times such weighted average Capacity Resource Clearing Price; or (iv) $20/MW-Day, provided, however, if a resource is unavailable during the Delivery Year at less than the level committed in the Market Seller's cleared Sell Offer or Locational UCAP Seller's Locational UCAP sale due to derating, delay, or retirement, then such seller shall not be assessed a charge under this section to the extent (i.e., for the same megawatts and time period) that such seller is assessed a charge under Tariff, Attachment DD, section 8 for such unavailability; and provided further that a resource that is subject to a charge under Tariff, Attachment DD, section 7A (i.e., for the same megawatts and time period) shall not also be subject to a charge under this section; and provided further that a resource that is subject to a charge under this section that is also subject to a charge under Tariff, Attachment DD, section 10A hereof for a Performance Shortfall during one or more Performance Assessment Intervals occurring during the period of resource capacity rating deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Tariff, Attachment DD, section 10A, but shall not be assessed a charge under both this section and Tariff, Attachment DD, section 10A for such simultaneous occurrence of a resource capacity rating deficiency and Performance Shortfall. If a single resource is the basis for installed capacity commitments of multiple Capacity Market Sellers or Locational UCAP Sellers, the installed capacity shortfall determined under (i) and (ii) above shall be assessed upon such sellers on a pro-rata basis in accordance with the megawatts of capacity from such resource in their cleared Sell Offers, Locational UCAP sales, or other commitment as replacement capacity.

c) Allocation of Revenue Collected from Generation Resource Rating Test Failure Charges.

The revenue collected from Generation Resource Rating Test Failure Charges shall be distributed on a pro-rata basis to LSEs that were charged a Locational Reliability Charge for the Delivery Year for which the Generation Resource Rating Test Failure Charge was assessed. The charges shall be allocated on a pro-rata basis to LSEs based on their Daily Unforced Capacity Obligation.

7A. GENERATION OPERATIONAL TESTING AND CHARGES

a) Generation Capacity Resource Operational Testing

To preserve and maintain the reliability of the PJM Region, and to improve the likelihood that Generation Capacity Resources will be capable of operating within their specified operating parameters during a reliability event, Generation Capacity Resources that are committed in RPM Auctions or are included in a FRR Plan 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, and as further detailed in the PJM Manuals. The selection of Generation Capacity Resources and the timing of an operational test shall be determined by the Office of the Interconnection, and may consider a number of factors, including the period of time since a unit last operated, the system conditions under which the unit has recently operated, the expected system conditions during the operational test, and the recent performance of units with respect to successfully starting and operating within the specified parameters when scheduled by the Office of the Interconnection. Such tests will respect operating parameter limits of the available schedule that the Office of the Interconnection selects for purposes of testing the resource. Capacity Market Sellers of Generation Capacity Resources that are tested by the Office of the Interconnection under this provision shall be eligible for make whole payments in accordance with Tariff, Attachment K-Appendix, section 3.2.3(e). A committed Generation Capacity Resource shall be deemed to pass a test initiated by the Office of the Interconnection if the resource successfully starts and synchronizes to the grid within the specified notification and startup time (plus the greater of 10% time to start or ten minutes) and operates for the unit's minimum run time as specified in the selected schedule; otherwise, such resource shall be deemed to fail the test. Following a failed test or a failed re-test, the Office of Interconnection may issue a re-test of the resource once the resource is made available for scheduling. A re-test initiated by the Office of the Interconnection has the same requirements as the initial test. The re-test is considered to be part of the same operational test, and does not count as a second test initiated by the Office of Interconnection for the relevant season. Resources shall not be eligible to be made whole for PJM initiated re-tests following a failed test. If a re-test is issued by PJM and the unit fails to successfully start and synchronize to the grid during such re-test, a Generation Capacity Resource operational test failure charge shall be assessed until such time as the unit successfully starts and synchronizes to the grid.

b) Generation Capacity Resource Operational Test Failure Charge

The Generation Capacity Resource operational test failure charge shall equal the Daily Deficiency Rate multiplied by the applicable daily committed UCAP MW of that Generation Resource; provided however, a Capacity Market Seller shall not be assessed a charge under this section to the extent (i.e., for the same megawatts and time period) that such seller is assessed a charge under Tariff, Attachment DD, section 8 for such resource's unavailability; and provided further that a resource that is subject to a charge under this section that is also subject to a charge under Tariff, Attachment DD, section 10A hereof for a Performance Shortfall during one or more

Performance Assessment Intervals occurring during the period of resource operational test deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Tariff, Attachment DD, section 10A, but shall not be assessed a charge under both this section and Tariff, Attachment DD, section 10A for such simultaneous occurrence of a resource operational test deficiency and Performance Shortfall.

c) Allocation of Revenue Collected from Generation Operational Deficiency Rate Failure Charges.

The revenue collected from Generation Capacity Resource Operational Test Failure Charges shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Generation Capacity Resource Operational Test Failure Charge was assessed. Such revenues shall be allocated on a pro-rata basis to LSEs based on their Daily Unforced Capacity Obligation.

10A. CHARGES FOR NON-PERFORMANCE AND CREDITS FOR PERFORMANCE

(a) For the 2018/2019 Delivery Year and any subsequent Delivery Year (and for certain purposes for the 2016/2017 and 2017/2018 Delivery Years as provided in subsections (h) and (i) hereof), each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, and for the 2022/2023 Delivery Year and subsequent Delivery Years each PRD Provider that commits Price Responsive Demand for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources or Price Responsive Demand during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation, demand response resources, or Price Responsive Demand that perform during such hour in excess of the level expected based on commitments (if any) of such resources.

(b) Performance shall be measured for purposes of this assessment during each Performance Assessment Interval.

(c) For each Performance Assessment Interval, the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource and Locational UCAP has fallen short of the performance expected of such committed Capacity Resource, and the magnitude of any such shortfall, based on the following formula:

Performance Shortfall = Expected Performance - Actual Performance

Where the result of such formula is a positive number and where:
Expected Performance =

for Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve a declared Emergency Action; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and Capacity Storage Resources: [(Resource Committed Capacity * the Balancing Ratio)];

where

Resource Committed Capacity = the total megawatts of Unforced Capacity of the Capacity Resource committed by such Capacity Market Seller or Locational UCAP Seller; and

The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports, Price Responsive Demand Bonus Performance effective with the 2022/2023 Delivery Year, and Demand Response Bonus Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Interval for which performance by any external Generation Capacity Resource would have helped resolve the Emergency Action that was the subject to the Performance Assessment Hour; and provided further that for any Delivery Year up to and including the 2019/2020 Delivery Year, Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

All Committed Generation and Storage Capacity = the total megawatts of Unforced Capacity of all Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and all Capacity Storage Resources committed by all Capacity Market Sellers, FRR Entities, Locational UCAP Sellers;

All Actual Generation Performance and Storage Resource Performance = the total amount of Actual Performance for all generation resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and storage resources during the interval;

Net Energy Imports = the sum of interchange transactions importing energy into PJM (not including those associated with external Generation Capacity Resources and therefore included in All Actual Generation Performance) minus the sum of interchange transactions exporting energy out of PJM, but not less than zero;

Demand Response Bonus Performance = the sum of Bonus performance provided by Demand Response resources as calculated in (g) below;

Price Responsive Demand Bonus Performance = the sum of Bonus performance provided by Price Responsive Demand as calculated in (g) below;

and for Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades: Resource Committed Capacity;

where

Resource Committed Capacity = the total megawatts of capacity committed from such Capacity Resource committed capacity without making any adjustment for the Forecast Pool Requirement

and for PRD Provider: Price Responsive Demand Committed

where

Price Responsive Demand Committed = the Nominal PRD Value committed by the PRD Provider in the area defined by the Performance Assessment Interval, adjusted to account for any PRD registrations in such area that were not subject to compliance measurement.

and

Actual Performance =

for each generation resource, the metered output of energy delivered to PJM by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each storage resource, the metered output of energy delivered to PJM by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each Demand Resource, the demand response provided to PJM by such resource, plus such resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval, as established through the PJM demand response settlement procedure consistent with the standards specified in RAA, Schedule 6;

for each PRD Provider, the actual load reduction provided by the PRD Provider during a Performance Assessment Interval, determined in accordance with RAA, Schedule 6.1.N and the PJM Manuals;

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; and for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Interval, and zero if it is not in service during such Performance Assessment Interval.

Such calculation shall encompass all resources and Price Responsive Demand located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. 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 purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval. For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Interval shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.

(d) Notwithstanding subsection (c) above, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, or was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the Interconnection, based on a determination by the Office of the Interconnection that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM Region. Such a resource shall be considered in the calculation of a Performance Shortfall if it otherwise was needed and would have been scheduled by the Office of the Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to: (i) any operating parameter limitations submitted in the resource's offer, or (ii) the seller's submission of a market-based offer higher than its cost-based. In addition, notwithstanding subsection (c) above, a Price Responsive Demand registration shall not be considered in the calculation of a Performance Shortfall or Bonus Performance for a

Performance Assessment Interval when the PRD Curve associated with such registration in the PJM 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.

(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:

Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate

Where

For Capacity Performance Resources and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour).

and for Base Capacity Resources the Non-Performance Charge Rate = (Weighted Average Resource Clearing Price applicable to the resource * (the number of days in the Delivery Year / 30) (the number of Real-Time Settlement Intervals in an hour)

(f) The Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource or such PRD Provider times the number of days in the Delivery Year. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. The total Non-Performance Charges for each Base Capacity Resource (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to the total payments due such Capacity Resource or Locational UCAP under Tariff, Attachment DD, section 5.14 for such Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.

(f-1) Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource or such PRD Provider, where such megawatts shall be based on the maximum Unforced

Capacity committed up through the end of the month in which the PAI occurs, times the number of days in the Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource, where such megawatts shall be based on maximum Unforced Capacity committed up through the end of the month in which the Performance Assessment Interval occurs, times the number of days in the season applicable to such resource.

(g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval, that provided energy or load reductions above the levels expected for such resource during such interval. For purposes of this provision, the performance expected of a resource, and the revenue distribution payment, if any, for a resource, shall be determined in accordance with the following formulae:

Formula 1: Market Participant Bonus Performance = Actual Performance – Expected Performance

and

Formula 2: Performance Payment = (Market Participant Bonus Performance / All Market Participants Bonus Performance) * Non-Performance Charge Revenues.

Where the result of Formula 1 is a positive number and where:

Actual Performance is as defined in subsection (c), provided, however, that Actual Performance for purposes of this calculation shall not exceed the megawatt level at which such resource was scheduled by the Office of the Interconnection during the Performance Assessment Intervals; and provided further that Actual Performance for a Market Participant that imports energy into the PJM Region during such Performance Assessment Interval shall be the net import, if any, from all interchange transactions scheduled by such Market Participant during such Performance Assessment Interval;

Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the resource's capacity obligation period, including, without limitation, a Base Capacity Demand Resource providing demand response during non-summer months; and

All Market Participants Bonus Performance is the sum of the results of calculating Formula 1 of this subsection (g) for all Market Participants that have Bonus Performance during such Performance Assessment Interval.

(h) The provisions of this section 10A shall apply during the 2016/2017 Delivery Year, provided that:

- (i) Non-Performance Charges shall be determined solely for and assessed solely on, Capacity Performance Resources committed for such Delivery Year;
- (ii) The Non-Performance Charge shall be 0.5 times the Non-Performance Charge calculated under subsection (e) hereof; and
- (iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.75 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(i) The provisions of this section 10A shall apply during the 2017/2018 Delivery Year, provided that:

- (i) Non-Performance Charges shall be determined solely for, and assessed solely on, Capacity Performance Resources committed for such Delivery Year;
- (ii) The Non-Performance Charge shall be 0.6 times the Non-Performance Charge calculated under subsection (e) hereof; and
- (iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.9 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(j) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year. Notwithstanding, if there are less than six months remaining in the current Delivery Year for which no invoice has been issued, the Office of the Interconnection may, with prior notice to PJM Members, allocate in equal amounts any Non-Performance Charge in the remaining monthly bills for the current Delivery Year plus up to six monthly bills into the following Delivery Year for all Capacity Market Sellers that incur such a Non-Performance Charge (but in no event shall the total Non-Performance Charge be divided in more than nine monthly bills). Provided, for any Non-Performance Charges associated with Performance Assessment Intervals from December 23, 2022 and December 24, 2022, a Capacity Market Seller may elect, by providing notice to the Office of Interconnection by March 17, 2023, to divide the total amount of Non-Performance Charges by either (i) the number of remaining monthly bills in the current Delivery Year (i.e., 3 bills) or (ii) the number of remaining monthly bills in the current Delivery Year plus six additional monthly bills into the following Delivery Year (i.e., 9 bills); provided further, however, that for an election under subsection (ii) above, the monthly Non-Performance Charge shall be levelized to include interest for the six month period following the current Delivery Year, such interest amount being determined at the electric interest rate established by the Federal Energy Regulatory Commission at the time of such election. All interest collected in accordance with this provision shall be allocated to the total pool of bonus performance payments and distributed in accordance with Tariff, Attachment DD, section 10A(g).

11A DEMAND RESOURCES TEST FAILURE CHARGE

a) Capacity Market Sellers that commit Demand Resources may be charged to the extent their committed resources fail performance tests, as set forth herein.

b)

(i) [Reserved]
(ii) [Reserved]
(iii) [Reserved]

A. Through the 2023/2024 Delivery Years, for Annual Demand Resources: if an Annual Demand Resource registration is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year, then the registration committed by a Capacity Market Seller in a zone shall be tested as described below in section iii(c), 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 below in section iii(d). If an Annual Demand Resource registration is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year, then no test will be required.

A-1. Effective with the 2024/2025 Delivery Year and subsequent Delivery Years, for Annual Demand Resources: if an Annual Demand Resource registration 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, then the registration committed by a Capacity Market Seller in a zone shall be tested as described below in section iii(c), 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 below in section iii(d). Notwithstanding the foregoing, a Capacity Market Seller may elect to utilize performance data from a Load Management event in the Delivery Year that was not assessed for performance during Performance Assessment Intervals to be considered in the annual Demand Resource test requirement , as long as the event is at least 30 minutes of a clock hour. If an Annual Demand Resource registration is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year, and assessed for performance during Performance Assessment Intervals, then no test will be required.

B. Through the 2023/2024 Delivery Year, for Summer-Period Demand Resources: if a Summer-Period Demand Resource registration 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, then the registration committed by a Capacity Market Seller must demonstrate that it was tested as described below in section iii(c), 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.

B-1. Effective with the 2024/2025 Delivery Year and subsequent Delivery Years, for Summer-Period Demand Resources: if a Summer Period Demand Resource registration is not dispatched and assessed for performance during Performance Assessment Intervals, by the Office of the Interconnection for a Load Management event during June through October or the following May of the Delivery Year, then the registration committed by a Capacity Market Seller must demonstrate that it was tested as described below in section iii(c), 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. Notwithstanding the foregoing, a Capacity Market Seller may elect to utilize performance data from a Load Management event in the Delivery Year that was not assessed for performance during Performance Assessment Intervals to be considered in the annual Demand Resource test requirement, as long as the event is at least 30 minutes of a clock hour and the Load Management event occurred in the summer.

C. 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.

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.

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.

D. Notification of the initial Office of the Interconnection scheduled test will be provided based on the following procedure. 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. 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.

Notification of any scheduled retest by the Office of the Interconnection will be provided based on the following procedure. 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.

c) a Capacity Market Seller that committed Demand Resources shall be assessed a Demand Resources Test Failure Charge equal to the net capability testing shortfall for such products tested in a Zone during such test in the aggregate of all of such Seller's Demand Resources tested in such Zone times the Demand Resources Test Failure Charge Rate. The net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable Forecast Pool Requirement prior to 2025/2026 Delivery Year and applicable ELCC Class Rating beginning with the 2025/2026 Delivery Year: (i) the summer daily average of the megawatts of load reduction capability committed by such seller in such Zone for such product(s) tested minus (ii) the megawatts of load reduction actually provided by all such Demand Resources in such Zone during such test. The net capability 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.

d) the Demand Resources Test Failure Charge Rate shall equal such Seller's Weighted Daily Revenue Rate in such Zone for the product(s) 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). The Daily Demand Resources Test Failure Charge in a zone for the product(s) tested shall be equal to the net capability testing shortfall in such Zone for such product(s) tested times the Demand Resources Test Failure Charge Rate. 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.

e) revenues collected from assessment of Demand Resources Test Failure Charges shall be distributed to Load Serving Entities that were charged a Locational Reliability Charge for the Delivery Year for which the Demand Resources Test Failure Charge was assessed, pro-rata based on such Load Serving Entities' Daily Unforced Capacity Obligations.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of RAA, Schedule 6. Capitalized terms used herein that are not otherwise defined in Tariff, Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) 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;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or 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 Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three

(3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are 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 Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned

Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but 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 Demand Resource customers within this market and the potential for

other Demand Resource Providers targeting the same customers; and

- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

(1) for Delivery Years through the 2024/2025 Delivery Year, as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service 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.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

● A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

● Supplemental status reports, detailing Demand Resources available, as requested by PJM;

● Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

● Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

● Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer or winter) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer or winter Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place.

Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable prior to the 2025/2026 Delivery Year, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)
>
> Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:
>
> (WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. 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 in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or

systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 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.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the

Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver

Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

Sections of the
PJM Reliability Assurance Agreement

(Clean Format)

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

"Accredited UCAP" shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

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

Agreement:

"Agreement" shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

"Annual Demand Resource" shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

"Applicable Regional Entity" shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

"Base Capacity Demand Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

"Base Capacity Energy Efficiency Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

"Base Capacity Resource" shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

"Base Residual Auction" shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of 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 Capacity Resource or (ii) in any 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.

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit" or "CETL" shall mean 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 Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating 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 all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

"Capacity Only Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

"Capacity Performance Resource" shall have the same meaning as in Tariff, Attachment DD.

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.

Capacity Storage Resource Class:

"Capacity Storage Resource Class" shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours. The characteristic duration of an Energy Storage Resource Class is the ratio of the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

"Capacity Transfer Right" shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

"Coal Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

"Combination Resource" shall mean a Generation Capacity 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.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall have the same meaning as in the Tariff.

Complex Hybrid Class:

"Complex Hybrid Class" shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

“Delivery Year” shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

“Demand Resource” or “DR” shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity 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 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or “DR Factor” shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

“Demand Resource Registration” shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

Effective Nameplate Capacity:

“Effective Nameplate Capacity” shall mean (i) for each Variable Resource and Combination Resource, the resource’s Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output); (ii) for each Limited Duration Resource, the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource’s capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

“Effective UCAP” shall mean 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 Class:

“ELCC Class” shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

"ELCC Class Rating" shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

"ELCC Class UCAP" shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

"ELCC Portfolio UCAP" shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

"ELCC Resource" shall mean, through the 2024/2025 Delivery Year, a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource, and beginning with the 2025/2026 Delivery Year, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

"ELCC Resource Performance Adjustment" shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

"Electric Cooperative" shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

"Electric Distributor" shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

"Emergency" shall mean (i) 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; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

"End-Use Customer" shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Members Committee sector classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Efficiency Resource:

"Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

"Exigent Water Storage" shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

"Existing Demand Resource" shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery

Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing Generation Capacity Resource:

"Existing Generation Capacity Resource" shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

"Extended Summer Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

"Facilities Study Agreement" shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall have the meaning specified in the Tariff.

Firm Service Level:

“Firm Service Level” or “FSL” of Price Responsive Demand for the 2022/2023 Delivery Year and subsequent Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when an Emergency Action that triggers a Performance Assessment Interval is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. “Firm Service Level” or “FSL” of Demand Resource shall mean the pre-determined level for which an end-use customer’s load shall be reduced, upon notification from the Curtailment Service Provider’s market operations center or its agent.

Firm Transmission Service:

“Firm Transmission Service” shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

“Fixed Resource Requirement Alternative” or “FRR Alternative” shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

“Fixed-Tilt Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

“Forecast Pool Requirement” or “FPR” shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

“FRR Capacity Plan” or “FRR Plan” shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

“FRR Entity” shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

“FRR Service Area” shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. 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 Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

“Full Program Option” shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

“Full Requirements Service” shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

“Gas Combined Cycle Class” shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

“Gas Combined Cycle Dual Fuel Class” shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start and operate independently on an alternate, onsite fuel source up to its maximum capacity level during the winter season of the applicable Delivery

Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

"Gas Combustion Turbine Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

"Gas Combustion Turbine Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start and operate independently on an alternate, onsite fuel source up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

"Generation Capacity Resource" shall mean 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 Capacity Resource Provider:

"Generation Capacity Resource Provider" shall mean a Member that owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity.

Generation Owner:

"Generation Owner" shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, 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 shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, 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 pursuant to the PJM Manuals.

Generator Planned Outage:

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hybrid Resource Class:

"Hybrid Resource Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in a Capacity Storage Resource Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

"Hydropower With Non-Pumped Storage" shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

"Hydropower With Non-Pumped Storage Class" shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

Incremental Auction:

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, Accredited UCAP Factor decrease, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Intermittent Hydropower Class:

"Intermittent Hydropower Class" shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

"IOU" shall mean an investor-owned utility 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.

Intermittent Landfill Gas Class:

"Intermittent Landfill Gas Class" shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Limited Demand Resource:

"Limited Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Limited Duration Resource:

"Limited Duration Resource" shall mean a Generation Capacity 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 Serving Entity or LSE:

"Load Serving Entity" or "LSE" shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been 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 Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

“Locational Reliability Charge” shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

“Markets and Reliability Committee” shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

“Maximum Emergency Service Level” or “MESL” of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

“Network Resources” shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Nominal PRD Value:

"Nominal PRD Value" shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

"Non-Retail Behind the Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Nuclear Class:

"Nuclear Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

"Obligation Peak Load" shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Offshore Wind Class:

"Offshore Wind Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

“Onshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean that agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C, on file with the Commission.

Operating Day:

“Operating Day” shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Ordinary Water Storage:

“Ordinary Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

“Other Limited Duration Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

“Other Limited Duration Combination Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

"Other Supplier" shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM's governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

"Other Unlimited Resource Class" shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

"Other Variable Resource Class" shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

"Partial Requirements Service" shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

"Party" shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

"Peak Shaving Adjustment" shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Base Capacity Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

“Percentage Internal Resources Required” shall mean, 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 such LDA.

Performance Assessment Interval:

“Performance Assessment Interval” shall have the meaning specified in Tariff, Attachment DD.

PJM:

“PJM” shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Region:

“PJM Region” shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T., “OATT” or “PJM Open Access Transmission Tariff” shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Planned Demand Resource:

"Planned Demand Resource" shall mean any 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 such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned External Generation Capacity Resource:

"Planned External Generation Capacity Resource" shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has a fully executed system impact study agreement (or other documentation which is functionally equivalent to a System Impact Study Agreement under the PJM Tariff) or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to a Facilities Study Agreement under the PJM Tariff), with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to an Interconnection Service Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

“Planned Generation Capacity Resource” shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, a System Impact Study Agreement (or, for resources for which a System Impact Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a System Impact Study Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, a Facilities Study Agreement (or, for resources for which a Facilities Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a Facility Studies Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

“Portfolio Expected Unserved Energy” shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

“PRD Curve” shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

"PRD Provider" shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider's Zonal Expected Peak Load Value of PRD:

"PRD Provider's Zonal Expected Peak Load Value of PRD" shall mean the expected contribution to Delivery Year peak load of a PRD Provider's Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year's peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection's load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

"PRD Reservation Price" shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

"PRD Substation" shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

"Price Responsive Demand" or "PRD" shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection (prior to 2022/2023Delivery Year) or a Performance Assessment Interval that triggers a PRD performance assessment (effective with 2022/2023 Delivery Year), and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

"Price Responsive Demand Credit" shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

“Price Responsive Demand Plan” or “PRD Plan” shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider’s Nominal PRD Value.

Public Power Entity:

“Public Power Entity” shall mean 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 foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

“Qualifying Transmission Upgrades” shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” or “RERRA” shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

“Reliability Principles and Standards” shall mean the principles and standards established by the Office of the Interconnection that define, among other things, an acceptable probabilistic of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

“Required Approvals” shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

“Self-Supply” shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

“Small Commercial Customer” shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

“State Regulatory Structural Change” shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party’s default service rules that materially affect whether retail choice is economically viable.

Steam Class:

“Steam Class” shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, 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 the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM 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 a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

"Supervisory Control" shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

"Threshold Quantity" shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Reliability Assurance Agreement, Schedule 8.1).

Tracking Solar Class:

"Tracking Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the 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:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity:

“Unforced Capacity” shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

“Unlimited Resource” shall mean 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:

“Variable Resource” shall mean a Generation Capacity 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.

Winter Peak Load (or WPL):

“Winter Peak Load” or “WPL” shall mean 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 the Delivery Year for which the registration is submitted. Notwithstanding, 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. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

Zonal Capacity Price:

“Zonal Capacity Price” shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity

Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

Zone or Zonal:

"Zone" or "Zonal" shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

"Zonal Winter Weather Adjustment Factor" or "ZWWAF" shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

7.1 Forecast Pool Requirement and Unforced Capacity Obligations.

(a) The Forecast Pool Requirement shall be established to ensure a sufficient amount of capacity to meet the forecast load plus reserves adequate to provide for the unavailability of Capacity Resources, load forecasting uncertainty, and planned and maintenance outages. RAA, Schedule 4 sets forth guidelines with respect to the Forecast Pool Requirement.

(b) Unless the Party and its customer that is also a Load Serving Entity agree that such customer is to bear direct responsibility for the obligations set forth in this Agreement, (i) any Party that supplies Full Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for all of that Load Serving Entity's capacity obligations under this Agreement for the period of such Full Requirements Service and (ii) any Party that supplies Partial Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for such portion of the capacity obligations of that Load Serving Entity as agreed by the Party and the Load Serving Entity so long as the Load Serving Entity's full capacity obligation under this Agreement is allocated between or among Parties to this Agreement.

B. Forecast Pool Requirement and PJM Region Installed Reserve Margin To Be Determined Annually

No later than 75 days in advance of each Base Residual Auction for a Delivery Year, based on the projections described in section C of this Schedule, and after consideration of the recommendation of the Members Committee, the PJM Board shall establish the Forecast Pool Requirement, including the PJM Region Installed Reserve Margin for all Parties, including FRR Entities, for such Delivery Year. Unless otherwise agreed by the PJM Board, the Forecast Pool Requirement and PJM Region Installed Reserve Margin for such Planning Period shall be considered firm and not subject to re-determination thereafter.

C. Methodology

Each year, the Forecast Pool Requirement for at least each of the next five Planning Periods shall be projected by applying suitable probability methods to the data and forecasts provided by the Parties and obtained from Electric Distributors, as described in RAA, Schedule 11, the Operating Agreement and in the PJM Manuals. The projection of the Forecast Pool Requirement shall consider the following data and forecasts as necessary:

1. Seasonal peak load forecasts for each Planning Period as calculated by PJM in accordance with the PJM Manuals reflecting (a) load forecasts with a 50 percent probability of being too high or too low and (b) seasonal peak diversities determined by the Office of the Interconnection.

2. Variability of loads within each week through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, hourly load shapes and variability, due to weather and other recurring and random factors, as determined by the Office of the Interconnection.

3. Generating unit capability and types for every existing and proposed unit.

4. Generator Forced Outage rates for existing mature generating units, as determined by the Office of the Interconnection, based on data submitted by the Parties for their respective systems, from recent and historical experience, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

5. Generator Maintenance Outage factors and planned outage factors as determined by the Office of the Interconnection based on forecasts and historical data submitted by the Parties for their respective systems.

6. Miscellaneous adjustments to capacity due to all causes, including weather, as determined by the Office of the Interconnection, based on forecasts submitted by the Parties for their respective systems.

7. The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, as limited by the capacity benefit margin considered in the determination of available transfer capability and the probable availability of generation in excess of load requirements in such areas.

SCHEDULE 4.1

DETERMINATION OF THE FORECAST POOL REQUIREMENT

A. Through the 2024/2025 Delivery Year, the Forecast Pool Requirement shall be determined in accordance with the following:

Based on the guidelines set forth in RAA, Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (1 + IRM) * (1 - \text{Pool-wide average } EFOR_D)$$

where

average $EFOR_D$ = the average equivalent demand forced outage rate for the PJM Region, stated in percent and determined in accordance with Section B hereof

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent. Studies by the Office of the Interconnection to determine IRM shall not exclude outages that are deemed to be outside plant management control under NERC guidelines.

B. Through the 2024/2025 Delivery Year, the PJM Region equivalent demand forced outage rate ("average $EFOR_D$") shall be determined as the capacity weighted $EFOR_D$ for all units expected to serve loads within the PJM Region during the Delivery Year, as determined pursuant to RAA, Schedule 5.

C. Beginning with the 2025/2026 Delivery Year, the Forecast Pool Requirement shall be determined in accordance with the following:

Based on the guidelines set forth in RAA, Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (1 + IRM) * (\text{Pool-wide average Accredited UCAP Factor})$$

where

Pool-wide average Accredited UCAP Factor = 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

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent.

SCHEDULE 5

FORCED OUTAGE RATE CALCULATION

A. The equivalent demand forced outage rate ("$EFOR_D$") shall be calculated as follows:

$$EFOR_D (\%) = \{(f_f * FOH + f_p * EFPOH) / (SH + f_f * FOH)\} * 100$$

where

f_f = full outage factor
f_p = partial outage factor
FOH = full forced outage hours
EFPOH = equivalent forced partial outage hours
SH = service hours

B. Calculation of $EFOR_D$ for individual Generation Capacity Resources.

For Delivery Years through the 2024/2025 Delivery Year, $EFOR_D$ shall be calculated at least one month prior to the start of the Third Incremental Auction for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third Incremental Auction; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to an FRR Capacity Plan or prior auctions for such Delivery Year.

Such calculation shall be based upon such resource's service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit. For purposes of the calculations under this Paragraph B, outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered.

1. The $EFOR_D$ of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

2. The $EFOR_D$ of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the $EFOR_D$ experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average $EFOR_D$ for the PJM Region

For Delivery Years through the 2024/2025 Delivery Year, the forecast average $EFOR_D$ for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average $EFOR_D$ shall be the average of the capacity-weighted $EFOR_D$s of all units committed to serve load in the PJM Region; and for purposes of the $EFOR_D$ calculations under this Paragraph C outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered. All rates shall be in percent.

1. The $EFOR_D$ of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.

2. The $EFOR_D$ of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.

3. The $EFOR_D$ of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar Years of Service	
1	One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate.
2	Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate.
3	Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
4	Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand

Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) 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;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or 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 Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are 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 Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the

Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but 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 Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined:

(1) for Delivery Years through the 2024/2025 Delivery Year, as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service 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.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer or winter) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter

Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer or winter, Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable prior to the 2025/2026 Delivery Year, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

(PLC) - (Load *LF)

Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:

(WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. 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 in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and

winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 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.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

   (a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric

Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

C. Election, and Termination of Election, of FRR Alternative

1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. No later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources, Seasonal Capacity Performance Resources, and Base Capacity Resources, as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment 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 such Delivery Year. An FRR Entity 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.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, except a new FRR Entity's initial election, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

5. Notwithstanding subsections C.1 and C.2 of this Schedule, 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 the 2028/2029 Delivery Year.

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

1.1 Beginning with the 2020/2021 Delivery Year and for all subsequent Delivery Years, the FRR Capacity Plan shall comprise only Capacity Performance Resources and Seasonal Capacity Performance Resources.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and

quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement, the PJM Tariff, and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted 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 FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan, subject to applicable demand resource constraints for the relevant Delivery Year, submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity. Without limiting the generality of the foregoing, the FRR Entity must submit a Demand Resource Sell Offer Plan 15 business days before the deadline for submitting an FRR Capacity Plan as to any Demand Resources it intends to include in such FRR Capacity Plan and may only include in such FRR Capacity Plan Demand Resources that are approved by PJM following review of such Demand Resource Sell Offer Plan. The requirements, standards, and procedures for a Demand Resource Sell Offer Plan shall be as set forth in Schedule 6 of this Agreement, provided that all references (including deadlines) in Schedule 6, section A-1 to submission or clearing of a Demand Resource offer in an RPM Auction shall be understood for purposes of FRR Entities as referring to inclusion of a Demand Resource in an FRR Capacity Plan, and a distinct Demand Resource Officer Certification Form shall be applicable to FRR Entities, as shown in the PJM Manuals and provided on the PJM website.

5. For each LDA for which the Office of the Interconnection is required to establish a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a Percentage Internal Resources Required, subject to subsections D.1.1 and D.2 of this Schedule. The Percentage Internal Resources Required will be

calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement. Notwithstanding the provisions of Sections C.1 and C.2 of this Schedule 8.1, 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 its minimum five year FRR commitment for which the Office of the Interconnection will be required to establish a separate Variable Resource Requirement Curve by giving written notice two months prior to the Base Residual Auction for the Delivery Year. The Office of the Interconnection shall be deemed to be required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), or Mid-Atlantic Region ("MAR"), or for other LDAs if the separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the Tariff.

6. An FRR Entity may reduce the Percentage Internal Resources Required as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the CETL for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days *after* the submittal *deadline* of the FRR Capacity Plan. Through the 2024/2025 Delivery Year, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan. 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, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to the price level corresponding to point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the relevant Locational Deliverability Area, in $/MW-

day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for such Delivery Year.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement, the PJM Tariff, and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

F. FRR Daily Unforced Capacity Obligations and Deficiency Charges

1. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = [(OPL * Final Zonal FRR Scaling Factor) – Nominal PRD Value committed by the FRR Entity] * FPR

where:

OPL =Obligation Peak Load, defined as:

> the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal FRR Scaling Factor = FZPLDY/FZWNSP;

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

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

2. An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in such entity's FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Through the 2024/2025 Delivery Year, such FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times (1.20 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 quantities cleared in such auctions). Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, such FRR Capacity Deficiency Charge shall equal the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times the price level corresponding to Point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the Locational Deliverability Area encompassing the Zone of the FRR Entity.

3. If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of this Schedule.

4. The shortages in meeting the minimum requirement within the constrained zones and the shortage in meeting the total obligation are first calculated. The shortage in the unconstrained area is calculated as the total shortage less shortages in constrained zones and excesses in

constrained zones (the shortage is zero if this is a negative number). The Capacity Deficiency Charge is charged to the shortage in each zone and in the unconstrained area separately. This procedure is used to allow the use of capacity excesses from constrained zones to reduce shortage in the unconstrained area and to disallow the use of capacity excess from unconstrained area to reduce shortage in constrained zones.

G. Capacity Resource Performance

1. Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, however, through the 2024/2025 Delivery Year, only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

2. For any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources or Seasonal Capacity Performance Resources determined in accordance with the following: For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's FRR Capacity Plan or Price Responsive Demand committed to reduce the FRR Entity's unforced capacity obligation (for the 2022/2023 Delivery Year and subsequent Delivery Years) will be determined in the same fashion as prescribed by the Tariff, Attachment DD, section 10A, and for such hour, a net Performance Shortfall shall be determined separately for Capacity Performance Resources and for Base Capacity Resources. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) exceeds the Expected Performance of such resources or Price Responsive Demand, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Base Capacity Resources for such hour. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Base Capacity Resources exceeds the Expected Performance of such resources, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such hour. For the 2020/2021 Delivery Year, the net Performance Shortfall determined for Capacity Performance Resources and Price Responsive Demand shall include the performance of Seasonal Capacity Performance Resources contained in the FRR Capacity Plan.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources or Price Responsive Demand, if any, for each such Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval to establish the additional MW quantities of Capacity Performance Resources, Seasonal Capacity Performance Resources, or Price Responsive Demand that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Capacity Performance Resources in any Delivery Year shall not exceed a MW quantity equal to 0.5 times the MW quantity of the Capacity Performance Resources and Seasonal Capacity Performance Resources that were committed in the FRR Capacity Plan for such Delivery Year and Price Responsive Demand committed such Delivery Year (for the 2022/2023 Delivery Year and subsequent Delivery Years). The FRR Entity's net Performance Shortfall among Base Capacity Resources, if any, for each such Performance Assessment Interval shall be multiplied by a rate of [(0.00139 MWs/Performance Assessment Interval) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)] to establish the additional MW quantities of Capacity Performance Resources or Seasonal Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Base Capacity Resources in any Delivery Year shall not exceed a MW quantity equal to [(0.5 times the MW quantity of the Base Capacity Resources that were committed in the FRR Capacity Plan for such Delivery Year) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)].

An FRR Entity that elects the physical option shall not be eligible for, or subject to, the revenue allocation described in Tariff, Attachment DD, section 10A(g).

SCHEDULE 9

PROCEDURES FOR
ESTABLISHING THE CAPABILITY OF GENERATION CAPACITY RESOURCES

A. Such rules and procedures as may be required to determine and demonstrate the capability of Generation Capacity Resources for the purposes of meeting a Load Serving Entity's obligations under the Agreement shall be developed by the Office of the Interconnection and maintained in the PJM Manuals.

B. The rules and procedures shall recognize the difference in the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow and/or reservoir storage for hydro units, energy storage capability for Energy Storage Resources, energy source variability and intermittency, mechanical limitations, and system operating policies. For this purpose, the basis for determining and demonstrating the capability of a particular generating unit shall be described in RAA, Schedule 9.

C. For Delivery Years through the 2024/2025 Delivery Year

For Unlimited Resources, the capability of the generating unit is based on the level of output that the unit can provide under the site conditions expected to exist at the time of PJM system peak load where such conditions include, but are not limited to, ambient air temperature, humidity, barometric pressure, intake water temperature, and cooling system performance. Generating units with the ability to operate continuously across all hours of an Operating Day without interruption if needed include, but are not limited to, nuclear and fossil-fired steam units, combined cycle units, combustion turbine units, reciprocating engine units, and fuel cell units.

For ELCC Resources, the Office of the Interconnection shall determine the capability of the resource to meet a Load Serving Entity's obligations under the Agreement using an effective load carrying capability analysis, as set forth in RAA, Schedule 9.1, with additional implementation details provided in the PJM Manuals.

D. For the 2025/2026 Delivery Year and Subsequent Delivery Years

The Office of the Interconnection shall determine the capability of Generation Capacity Resources to meet a Load Serving Entity's obligations under the Agreement using an effective load carrying capability analysis, as set forth in RAA, Schedule 9.2, with additional implementation details provided in the PJM Manuals.

SCHEDULE 9.1:

EFFECTIVE LOAD CARRYING CAPABILITY ANALYSIS
FOR DELIVERY YEARS THROUGH THE 2024/2025 DELIVERY YEAR

A. Overview of Effective Load Carrying Capability Analysis

The inputs of the effective load carrying capability analysis include:

-Historical weather and load data;
-Historical output of existing Variable Resources;
-Estimates of putative historical output for planned Variable Resources;
-Forced outage patterns for Unlimited Resources;
-Resource deployment forecast; and
-Modeling parameters for Limited Duration Resources and Combination Resources.

The outputs of the effective load carrying capability analysis include:

-The ELCC Portfolio UCAP, in MW;
-ELCC Class UCAP values, in MW; and
-ELCC Class Rating values, in percent.

B. ELCC Classes

(1) (a) The following are the ELCC Classes for Variable Resources:

- Tracking Solar Class
- Fixed-Tilt Solar Class
- Onshore Wind Class
- Offshore Wind Class
- Landfill Gas Class
- Intermittent Hydropower Class
- Other Variable Resource Class

(b) The following are the types of ELCC Classes for Limited Duration Resources:

- The type of Capacity Storage Resource Classes
- The type of Other Limited Duration Resource Classes

Within those types, the following are the specific ELCC Classes for Limited Duration Resources:

- Capacity Storage Resource Class (4-Hour Duration)
- Capacity Storage Resource Class (6-Hour Duration)
- Capacity Storage Resource Class (8-Hour Duration)
- Capacity Storage Resource Class (10-Hour Duration)
- Other Limited Duration Class (4-Hour Duration)
- Other Limited Duration Class (6-Hour Duration)

- Other Limited Duration Class (8-Hour Duration)
- Other Limited Duration Class (10-Hour Duration)

(c) The following are the ELCC Classes for Combination Resources:

- The types of Hybrid Resource Classes, as further specified below
- Hydropower With Non-Pumped Storage Class
- Complex Hybrid Class
- The types of Other Limited Duration Combination Classes, as further specified below

(2) PJM shall establish Hybrid Resource Classes for all “open-loop” combinations of each Capacity Storage Resource class and each Variable Resource class, as well as all “closed-loop” combinations of each Capacity Storage Resource class and each Variable Resource class. An “open-loop” resource is physically and contractually capable of charging from the grid, while a “closed-loop” resource is not.

(3) PJM shall establish “Other Limited Duration Combination Classes” for all combinations of each Variable Resource Class and each Other Limited Duration Resource Class, and for combinations of an Unlimited Resource with each Other Limited Duration Resource Class.

(4) For a given Delivery Year, ELCC Class Ratings will not be calculated for any ELCC Class to the extent that no member of the class is expected to provide, or offer to provide capacity, in the applicable Delivery Year. PJM will determine the ELCC Class Ratings for an ELCC Class when any one of the following criteria are met:

(a) An Existing Generation Capacity Resource is in such class; or
(b) A Planned Generation Capacity Resource has submitted timely and valid data through the ELCC data submission process and is in such class; or
(c) The resource deployment forecast contains a resource in such class.

(5) (a) For each ELCC Resource, except an ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine the ELCC Class of which such resource is a member by matching the physical characteristics of such resource with the definition of the ELCC Class.

(b) For each ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine, by matching the physical characteristics of such resource with the definition of the ELCC Class, the type of ELCC Class of which such resource is a member; provided however, the Generation Capacity Resource Provider shall choose the specific ELCC Class within the type ELCC Class identified by PJM that corresponds to the chosen characteristic duration.

If the Generation Capacity Resource Provider fails to choose, PJM will choose a specific ELCC Class to assign to such resource. The election of the specific ELCC Class corresponding to the chosen characteristic duration shall be for a term of five consecutive Delivery Years. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in the ELCC Class, based on choosing a different characteristic duration, by submitting to the Office of the Interconnection a written request to switch ELCC Classes and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource shall be considered in the new ELCC Class starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(6) Mixed-technology resources are composed of components with different generation technologies, at least one of which would be an ELCC Resource, behind a single Point of Interconnection. For a mixed-technology resource composed of components that do not have significant interaction, the components are eligible to participate as separate resources. A mixed-technology resource composed of components that have significant interaction must participate as a single Combination Resource (or, if the components would all be Variable Resources, then as a single Variable Resource).

The Generation Capacity Resource Provider of a mixed-technology resource eligible to participate as either a single ELCC Resource or as multiple stand-alone resources shall elect, for a term of five consecutive Delivery Years, whether PJM is to model it as a single ELCC Resource or as multiple stand-alone resources. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in such modelling approach by submitting to the Office of the Interconnection a written request to change the modelling approach and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource(s) intend(s) to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource(s) shall be modelled as requested starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

C. Calculation of ELCC Portfolio UCAP

The effective load carrying capability analysis shall identify a scenario in which the aggregate installed capacity “Y” of a group of Unlimited Resources with no outages yields the same annual loss of load expectation as the one produced by the scenario with all ELCC Resources that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year being analyzed. The ELCC Portfolio UCAP shall be the value “Y”.

D. Allocation from ELCC Portfolio UCAP to ELCC Class UCAP

The ELCC Portfolio UCAP shall be allocated, as specified in the PJM Manuals, to each ELCC Class UCAP according to:

(1) The reliability value of the subject ELCC Class evaluated in the absence of other ELCC Classes, minus

(2) a quantity that is proportional to the product of:

> (a) the difference between the reliability value of the subject ELCC Class when evaluated in the presence of the entire portfolio of ELCC Classes and the reliability value of the subject ELCC Class when evaluated in the absence of the other ELCC Classes, and
>
> (b) the difference between the total reliability value of all the ELCC Classes in the model when evaluated jointly and the sum of the reliability values determined individually for each ELCC Class by evaluating the subject ELCC Class in the absence of other ELCC Classes.

E. Calculation of ELCC Class Rating

(1) The ELCC Class Rating of Variable Resources and Limited Duration Resources shall be the ratio of the applicable ELCC Class UCAP to the aggregate Effective Nameplate Capacity of the modeled ELCC Resources of that ELCC Class that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year being analyzed.

(2) For Combination Resources, there shall be an ELCC Class Rating for each component.

> (i) For a Combination Resource with a Limited Duration Resource component and a Variable Resource component, the Limited Duration Resource component ELCC Class Rating shall be equal to the quotient of (1) the Combination Resource ELCC Class UCAP minus the [product of the Variable Resource ELCC Class Rating and the aggregate Effective Nameplate Capacity of all the Variable Resource components within the subject Combination Resource class] divided by (2) the aggregate equivalent Effective Nameplate Capacity of all the Limited Duration Resource components within the subject Combination Resource class, and the Variable Resource component ELCC Class Rating shall be equal to the ELCC Class Rating for the ELCC Class to which the Variable Resource component would belong if it were not a component of the Combination Resource.
>
> (ii) For a Combination Resource with a Limited Duration Resource component and an Unlimited Resource component, the Limited Duration Resource component ELCC Class Rating shall be equal to the ELCC Class Rating for the ELCC Class to which the Limited Duration Resource component would belong if it were not a component of the Combination Resource, and the Unlimited Resource component would not have an ELCC Class Rating.

(3) For ELCC Resources in the Hydropower with Non-Pumped Storage Class and in the Complex Hybrid Class, no ELCC Class Rating is determined. A resource-specific ELCC rating is determined for each such resource.

F. Calculation of Accredited UCAP and ELCC Resource Performance Adjustment

(1) (a) For Variable Resources and Limited Duration Resources, Accredited UCAP values shall be equal to the product of:

(i) the Effective Nameplate Capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(b) For Combination Resources, Accredited UCAP values shall be equal to the sum of the Accredited UCAP of each component, but not to exceed the Maximum Facility Output of the resource, where:

(i) The value for a Variable Resource component shall be determined in accordance with subsection (a) above.

(ii) The value for a Limited Duration Resource component shall be equal to the product of:

(A) the Effective Nameplate Capacity determined for the Limited Duration Resource component;

(B) [one minus the EFORd for the Limited Duration Resource component]; and

(C) the applicable Limited Duration Resource component ELCC Class Rating as determined in Section E(2)(i).

(iii) The value for an Unlimited Resource component shall be equal to the product of the installed capacity of the Unlimited Resource component and [one minus the EFORd for the Unlimited Resource component].

(iv) The Accredited UCAP for Hydropower With Non-Pumped Storage, and for each member of an ELCC Class whose members are so distinct from one another that a single ELCC Class Rating fails to capture their physical characteristics, shall be based on a resource-specific effective load carrying capability analysis based on the resource's unique parameters.

(2) The ELCC Resource Performance Adjustment shall be calculated according to the following methods, as further detailed in the PJM Manuals:

(a) For a Variable Resource: based on a metric consisting of the average of (1) actual output during the 200 highest coincident peak load hours over the preceding ten years, regardless of the years in which they occur, and (2) actual output during the 200 highest coincident peak putative net load hours over the preceding ten years, regardless of the years in which they occur, where putative net load is actual load minus the putative hourly output of Variable Resources based on the resource mix of the target year. For Planned Resources or resources less than 10 years old, estimated hypothetical historical output will be used to develop this metric. For a given resource or component, the Performance Adjustment shall equal the ratio of such metric to the average (weighted by the Effective Nameplate Capacity) of such metrics for all units in the applicable Variable Resource ELCC Class.

(b) For Limited Duration Resources: based on EFORd.

(c) For Combination Resources with only an Unlimited Resource component and a Limited Duration Resource component: based on EFORd.

(d) For Combination Resources with a Variable Resource component (except for Hydropower With Non-Pumped Storage): (1) based on the direct metered or estimated output of the Variable Resource component, which is then assessed according to the methodology described in subsection (a) above for Variable Resources and in accordance with the PJM Manuals; and (2) based on the EFORd that is applicable to the Limited Duration Resource component.

(e) For Hydropower With Non-Pumped Storage and other Combination Resources that do not fall into the above categories: based on EFORd.

G. Installed Capacity of ELCC Resources

Rules and procedures for technically determining and demonstrating the installed capacity of ELCC Resources shall be developed by the Office of the Interconnection and maintained in the PJM Manuals. The installed capacity of a Limited Duration Resource is based on the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, as described in the PJM Manuals. The installed capacity of a Combination Resource (other than Hydropower With Non-Pumped Storage) is based on the lesser of the Maximum Facility Output or the sum of the equivalent Effective Nameplate Capacity values of the resource’s constituent components considered on a stand-alone basis.

H. Details of the Effective Load Carrying Capability Methodology

The effective load carrying capability analysis shall compare expected hourly load levels (based on historical weather) with the expected hourly output of the expected future resource mix in order to identify the relative resource adequacy value of the portfolio of all ELCC Classes, as well of each individual ELCC Class, compared to a group of Unlimited Resources with no outages. In performing this analysis, the model inputs shall be scaled to meet the annual loss of load expectation of the Office of the Interconnection. The effective load carrying capability analysis shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; and (iii) expected output of Limited Duration Resources and of Combination Resources as described below. These expected quantities are based on actual values for load and actual and putative values for Variable Resource output (standalone or as a component of Combination Resources) after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist. For resources that have not existed each year since June 1, 2012, putative output is an estimate of the hourly output that resource would have produced in a historical hour if that resource had existed in that hour. This putative output estimate is developed based on historical weather data consistent with the particular site conditions for each such resource in accordance with the PJM Manuals.

The effective load carrying capability analysis shall simulate forced outages of Unlimited Resources based on actual historical data, and shall simulate the output of Limited Duration Resources and Combination Resources based on their Office of the Interconnection-validated parameters, including the putative output of the Variable Resource component of Combination Resources, as described above. Forced outages of Limited Duration Resources and Combination Resources shall not be simulated in the effective load carrying capability analysis.

The quantity of deployed resources studied in the analysis shall be based on resource deployment forecasts and, where applicable, on available information based on Sell Offers submitted in RPM Auctions or Fixed Resource Requirement plans for the applicable Delivery Year.

The ELCC Class UCAP and other results of the effective load carrying capability analysis shall be based on the total Effective UCAP of the ELCC Class as a whole.

The ELCC Class UCAP and corresponding ELCC Class Rating values may increase or decrease from year to year as the expected resource mix and load shape change.

Energy Resources are not included in the effective load carrying capability analysis. Generating units that are expected to only offer or otherwise provide a portion of their Accredited UCAP for that Delivery Year are represented in the analysis in proportion to the expected quantity offered or delivered divided by the Accredited UCAP.

I. Methodology to Simulate Output of Certain Resources in the Effective Load Carrying Capability Model

The effective load carrying capability analysis shall simulate the output of Limited Duration Resources and Combination Resources based on their physical parameters, including limited storage capability, and shall simulate the deployment of Demand Resources. The analysis shall simulate output from the subject Limited Duration Resources and Combination Resources in hours in which all output from Unlimited Resources and available output from Variable Resources is insufficient to meet load. The output of the subject Limited Duration Resources and Combination Resources shall be simulated on an hour-by-hour basis in proportion to their Effective Nameplate Capacity without foresight to future hours. The simulated deployment of Demand Resources shall be such that there is adequate Primary Reserves provided by economic resources, if sufficient simulated Demand Resources are available. Primary Reserves shall be assigned to generation resources in order to maximize simulated reliability, provided that assignments to Limited Duration Resources and Combination Resources shall be pro rata according to their Effective Nameplate Capacity. Primary Reserves shall be exhausted prior to identifying a loss of load event in the analysis. Energy Storage Resource charging is during hours with sufficient margin, including between daily peaks if necessary.

J. Administration of Effective Load Carrying Capability Analysis

The Office of the Interconnection shall post final ELCC Class Rating values at least once per year in a report that also includes appropriate details regarding methodology and inputs. The Office of the Interconnection shall post this report and shall communicate ELCC Resource Performance Adjustment values to applicable Generation Capacity Resource Providers no later than five months prior to the start of the target Delivery Year, as described in the PJM Manuals. Starting with the 2023/2024 Delivery Year, Accredited UCAP values for the applicable Delivery Year shall establish the maximum Unforced Capacity that an ELCC Resource can physically provide or offer to provide in the applicable Delivery Year.

The Office of the Interconnection shall also post preliminary ELCC Class Rating values for nine subsequent Delivery Years. For any Delivery Year for which a final ELCC Class Rating has not been posted and a preliminary ELCC Class Rating has been posted, the Accredited UCAP of an ELCC Resource for such Delivery Year shall be based on the most recent preliminary ELCC Class Rating value for that Delivery Year, together with the most recently calculated ELCC Resource Performance Adjustment value for that ELCC Resource. Except to the extent specified above or otherwise specified, the preliminary ELCC Class Rating values for future years are non-binding and are only for indicative purposes. A Generation Capacity Resource Provider can offer or provide capacity from an ELCC Resource that is not subject to a capacity market must offer obligation (as specified in Tariff, Attachment DD, Section 6.6) at a level less than the Accredited UCAP for such resource.

In order to facilitate the effective load carrying capability analysis, the Generation Capacity Resource Provider of each ELCC Resource must submit to the Office of the Interconnection the required information as specified in the PJM Manuals by no later than August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2026/2027 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The required information may include relevant physical parameters, relevant historical data such as weather data and actual or estimated historical energy output, and documentation supporting such parameters and historical data. The relevant physical parameters are those that are incorporated into the effective load carrying capability analysis. The parameters required for Hydropower With Non-Pumped Storage shall include Ordinary Water Storage and any applicable Exigent Water Storage. Submitted parameters must indicate the expected duration for which any submitted physical parameters are valid.

The Office of the Interconnection shall evaluate, validate, and approve the foregoing information in accordance with the process set forth in the PJM Manuals. In evaluating the validity of submitted information, the Office of the Interconnection may assess the consistency of such information with observed conditions. If the Office of the Interconnection observes that the information provided by the Generation Capacity Resource Provider of the ELCC Resource is inconsistent with observed conditions, the Office of the Interconnection will coordinate with the Generation Capacity Resource Provider of the ELCC Resource to understand the information and observed conditions before making a determination regarding the validity of the applicable parameters. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the foregoing information.

After the Office of the Interconnection has completed its evaluation of the foregoing information, the Office of the Interconnection shall notify the Generation Capacity Resource Provider in writing whether the submitted information is considered invalid by no later than September 1 following the submission of the information. The Office of the Interconnection's determination on the validity of the foregoing information shall continue for the applicable Delivery Year and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

In the event that the Office of the Interconnection is unable to validate any of the required information, physical parameters, supporting documentation, or other related information submitted by the Generation Capacity Resource Provider of an ELCC Resource, then the Office of the Interconnection shall calculate Accredited UCAP values for that ELCC Resource based only on the validated information. Such ELCC Resource shall not be permitted to offer or otherwise provide capacity above such Accredited UCAP values until the Office of the Interconnection determines new Accredited UCAP values for such resource.

Generation Capacity Resource Providers of ELCC Resources that are hydropower plants with water storage must provide documentation to support the physical parameters provided for expected load carrying capability analysis modeling, as specified in the PJM Manuals. This documentation must: (a) support the plant's physical capabilities; (b) demonstrate that the parameters do not violate any federal, state, river basin, or other applicable authority operating limitations of the plant; and (c) demonstrate full authorization from FERC, any river basin commissions, and any other applicable authorities to meet those capabilities.

SCHEDULE 9.2:

EFFECTIVE LOAD CARRYING CAPABILITY ANALYSIS FOR THE 2025/2026 DELIVERY YEAR AND SUBSEQUENT DELIVERY YEARS

A. Overview of Effective Load Carrying Capability Analysis

The inputs of the effective load carrying capability analysis shall consider similar data and forecasts as that used in development of the FPR, as described in Schedule 4.C, and will include:

-Historical weather and load data;
-Historical output of existing Variable Resources;
-Estimates of putative historical output for planned Variable Resources;
-Forced outage patterns for Unlimited Resources, including consideration of correlated outage risks;
-Resource deployment forecast; and
-Modeling parameters for Limited Duration Resources, Combination Resources, and Demand Resources.

The outputs of the effective load carrying capability analysis include:

-ELCC Class Rating values, in percent.

B. ELCC Classes

(1) (a) The following are the ELCC Classes for Variable Resources:

- Tracking Solar Class
- Fixed-Tilt Solar Class
- Onshore Wind Class
- Offshore Wind Class
- Intermittent Landfill Gas Class
- Intermittent Hydropower Class
- Other Variable Resource Class

(b) The following are the types of ELCC Classes for Limited Duration Resources:

- The type of Capacity Storage Resource Classes
- The type of Other Limited Duration Resource Classes

Within those types, the following are the specific ELCC Classes for Limited Duration Resources:

- Capacity Storage Resource Class (4-Hour Duration)
- Capacity Storage Resource Class (6-Hour Duration)
- Capacity Storage Resource Class (8-Hour Duration)
- Capacity Storage Resource Class (10-Hour Duration)

- Other Limited Duration Class (4-Hour Duration)
- Other Limited Duration Class (6-Hour Duration)
- Other Limited Duration Class (8-Hour Duration)
- Other Limited Duration Class (10-Hour Duration)

(c) The following are the ELCC Classes for Combination Resources:

- The types of Hybrid Resource Classes, as further specified in subpart (2) below
- Hydropower With Non-Pumped Storage Class
- Complex Hybrid Class
- The types of Other Limited Duration Combination Classes, as further specified in subpart (3).

(d) The following are the ELCC Classes for Unlimited Resources

- Nuclear Class
- Coal Class
- Gas Combined Cycle Class
- Gas Combustion Turbine Class
- Gas Combined Cycle Dual Fuel Class
- Gas Combustion Turbine Dual Fuel Class
- Diesel Utility Class
- Steam Class
- Other Unlimited Resource Class

(e) The following are the ELCC Classes for Demand Resources

- Demand Resource Class

(2) PJM shall establish Hybrid Resource Classes for all "open-loop" combinations of each Capacity Storage Resource class and each Variable Resource class, as well as all "closed-loop" combinations of each Capacity Storage Resource class and each Variable Resource class. An "open-loop" resource is physically and contractually capable of charging from the grid, while a "closed-loop" resource is not.

(3) PJM shall establish "Other Limited Duration Combination Classes" for all combinations of each Variable Resource Class and each Other Limited Duration Resource Class, and for combinations of an Unlimited Resource with each Other Limited Duration Resource Class.

(4) For a given Delivery Year, ELCC Class Ratings will not be calculated for any ELCC Class to the extent that no member of the class is expected to provide, or offer to provide capacity, in the applicable Delivery Year. PJM will determine the ELCC Class Ratings for an ELCC Class when any one of the following criteria are met:

(a) An Existing Generation Capacity Resource is in such class; or
(b) A Planned Generation Capacity Resource has submitted timely and valid data through the ELCC data submission process and is in such class; or
(c) The resource deployment forecast contains a resource in such class.

(5) (a) For each ELCC Resource, except an ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine the ELCC Class of which such resource is a member by matching the physical characteristics of such resource with the definition of the ELCC Class.

(b) For each ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine, by matching the physical characteristics of such resource with the definition of the ELCC Class, the type of ELCC Class of which such resource is a member; provided however, the Generation Capacity Resource Provider shall choose the specific ELCC Class within the type ELCC Class identified by PJM that corresponds to the chosen characteristic duration.

If the Generation Capacity Resource Provider fails to choose, PJM will choose a specific ELCC Class to assign to such resource. The election of the specific ELCC Class corresponding to the chosen characteristic duration shall be for a term of five consecutive Delivery Years. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in the ELCC Class, based on choosing a different characteristic duration, by submitting to the Office of the Interconnection a written request to switch ELCC Classes and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource shall be considered in the new ELCC Class starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(6) Mixed-technology resources are composed of components with different generation technologies, at least one of which would be an ELCC Resource, behind a single Point of Interconnection. For a mixed-technology resource composed of components that do not have significant interaction, the components are eligible to participate as separate resources. A mixed-technology resource composed of components that have significant interaction must participate as a single Combination Resource (or, if the components would all be Variable Resources, then as a single Variable Resource).

The Generation Capacity Resource Provider of a mixed-technology resource eligible to participate as either a single ELCC Resource or as multiple stand-alone resources shall elect, for a term of five consecutive Delivery Years, whether PJM is to model it as a single ELCC Resource or as multiple stand-alone resources. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in such modelling approach by submitting to the Office of the Interconnection a written request to change the modelling approach and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource(s) intend(s) to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource(s) shall be modelled as requested starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

C. Calculation of ELCC Class Rating

ELCC Class Ratings for a Delivery Year are calculated by adding to the forecasted resource portfolio incremental quantities of resources belonging to the subject ELCC Class, depending on the resource type:

(1) The ELCC Class Rating of Variable Resources, Limited Duration Resources, Unlimited Resources (except Other Unlimited Resources), and Demand Resources shall be the ratio of the expected unserved energy improvement resulting from adding an incremental quantity of the subject ELCC Class to the expected unserved energy improvement resulting from adding an incremental quantity of an Unlimited Resource with no outages, where expected unserved energy improvement is calculated relative to the Portfolio EUE for the Delivery Year.

(2) No ELCC Class Rating is determined for Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class, and in any ELCC Class whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics.

D. Calculation of Accredited UCAP and ELCC Resource Performance Adjustment

(1) (a) For Variable Resources and Limited Duration Resources, Accredited UCAP values shall be equal to the lesser of the resource's Capacity Interconnection Right or the product of:

(i) the Effective Nameplate Capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(b) For any resource in an ELCC Class for which no Class Rating has been calculated pursuant to C(2), the Accredited UCAP shall be based on a resource-specific effective load carrying capability analysis based on the resource's unique parameters.

(c) For Unlimited Resources that have an ELCC Class Rating determined pursuant to C(1), Accredited UCAP values shall be equal to the product of:

(i) the installed capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(d) For Demand Resources, Accredited UCAP values shall be equal to the product of:

(i) the Nominated Value of the Demand Resource; and
(ii) the applicable ELCC Class Rating.

(2) The ELCC Resource Performance Adjustment shall be calculated according to the following methods, as further detailed in the PJM Manuals:

(a) For a Variable Resource, a Limited Duration Resource, and an Unlimited Resource: based on a metric consisting of the weighted average expected hourly output of the resource in the ELCC model during hours of loss of load risk where: (i) the weights correspond to the modeled probability of losing load in such hour and (ii) the expected hourly output is based on the resource's modeled output during the same hour on days since June 1st, 2012 identified as having similar weather from an RTO-perspective. For a given resource or component, the Performance Adjustment shall equal the ratio of such metric to the average (weighted by the Effective Nameplate Capacity) of such metrics for all units in the applicable Variable Resource ELCC Class or applicable Unlimited Resource ELCC Class.

In determining the ELCC Resource Performance Adjustment, the actual output of a Variable Resource shall be adjusted to reflect historical curtailments, and output in any hour shall be capped at: (i) the greater of the Variable Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, for hours in the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's assessed deliverability, as defined in the PJM Manuals, for hours in the months of November through April of the Delivery Year. The output of an Unlimited Resource in any hour shall be capped at the greater of the resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year..

E. Calculation of Accredited UCAP Factor

For Generation Capacity Resources, PJM shall determine an Accredited UCAP Factor, which is the ratio of the resource's Accredited UCAP to the resource's installed capacity.

G. Installed Capacity of ELCC Resources

Rules and procedures for technically determining and demonstrating the installed capacity of ELCC Resources shall be developed by the Office of the Interconnection and maintained in the PJM Manuals. The installed capacity of a Limited Duration Resource is based on the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, as described in the PJM Manuals. The installed capacity of a Combination Resource (other than Hydropower With Non-Pumped Storage) is based on the lesser of the Maximum Facility Output or the sum of the equivalent Effective Nameplate Capacity values of the resource's constituent components considered on a stand-alone basis. The installed capacity of an Unlimited Resource and Variable Resource shall be determined in accordance with the PJM Manuals. The installed capacity of Demand Resources, for purposes of the ELCC analysis, is based on the forecasted deployment level in the PJM Load Forecast.

H. Details of the Effective Load Carrying Capability Methodology

The effective load carrying capability analysis shall compare expected hourly load levels (based on historical weather) with the expected hourly output of the expected future resource mix in order to identify the relative marginal resource adequacy value of each individual ELCC Class compared to an Unlimited Resource with no outages. In performing this analysis, the model inputs shall be scaled to meet the annual reliability criteria of the Office of the Interconnection. The effective load carrying capability analysis shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; (iii) expected output of Limited Duration Resources and of Combination Resources as described below; (iv) expected Unlimited Resource output; and (v) expected Demand Resource output. These expected quantities are based on forecasted load and actual and putative values for Variable Resource output (standalone or as a component of Combination Resources) and Unlimited Resource output after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist. For resources that have not existed each year since June 1, 2012, putative output is an estimate of the hourly output that resource would have produced in a historical hour if that resource had existed in that hour. For Variable Resources, this putative output estimate is developed based on historical weather data consistent with the particular site conditions for each such resource in accordance with the PJM Manuals; for Unlimited Resources, the putative output is developed based on actual performance of similar units in accordance with the PJM Manuals.

Variable Resource actual output shall be adjusted in the ELCC analysis to reflect historical curtailments, and output shall be capped in any hour at: (i) the greater of the Variable Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, during the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's assessed deliverability, as defined in the PJM Manuals, during the months of November through April of the Delivery Year. The output of Unlimited Resources shall not exceed the greater of the Unlimited Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

The effective load carrying capability analysis shall simulate performance of Demand Resources, and shall simulate the output of Limited Duration Resources and Combination Resources based on their Office of the Interconnection-validated parameters, including the putative output of the Variable Resource component of Combination Resources, as described above.

The quantity of deployed resources studied in the analysis shall be based on resource deployment forecasts and, where applicable, on available information based on Sell Offers submitted in RPM Auctions or Fixed Resource Requirement plans for the applicable Delivery Year, and, where applicable, information provided to the Office of the Interconnection regarding intent to offer in an RPM Auction, pursuant to the requirements in the Tariff, Attachment DD, section 5.5.

The model inputs, including the set of ELCC Resources that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year, shall be scaled to meet the annual reliability criteria of the Office of the Interconnection. The resulting expected unserved energy constitutes the Portfolio EUE for the Delivery Year. Energy Resources are not included in the effective load carrying capability analysis. Generating units that are expected to only offer or otherwise provide a portion of their Accredited UCAP for that Delivery Year are represented in the analysis in proportion to the expected quantity offered or delivered divided by the Accredited UCAP.

I. Methodology to Simulate Output of Certain Resources in the Effective Load Carrying Capability Model

The effective load carrying capability analysis shall simulate the output of Limited Duration Resources and Combination Resources based on their physical parameters, including limited storage capability, and shall simulate the deployment of Demand Resources. The analysis shall simulate output from the subject Limited Duration Resources, Combination Resources, and Demand Resources in hours in which all output from Unlimited Resources and available output from Variable Resources is insufficient to meet load. The analysis shall first simulate the output of Demand Resources. If the simulated output of Demand Resources is insufficient to meet load, then the output of the subject Limited Duration Resources and Combination Resources shall be simulated on an hour-by-hour basis based on their relative duration, starting from longer duration resources to shorter duration resources. The output of Combination Resources shall be capped in any hour at: (i) the Combination Resource's Capacity Interconnection Rights during the months of June through October and the following May of the Delivery Year, and (ii) the Combination Resource's assessed deliverability, as defined in the PJM Manuals, during the months of November through April of the Delivery Year. Energy Storage Resource charging is during hours with sufficient margin, including between daily peaks if necessary.

J. Administration of Effective Load Carrying Capability Analysis

The Office of the Interconnection shall post final ELCC Class Rating values at least once per year in a report that also includes appropriate details regarding methodology and inputs. The Office of the Interconnection shall post this report and shall communicate ELCC Resource Performance Adjustment values to applicable Generation Capacity Resource Providers no later than five months prior to the start of the target Delivery Year, as described in the PJM Manuals. Accredited UCAP values for the applicable Delivery Year shall establish the maximum Unforced Capacity that an ELCC Resource can physically provide or offer to provide in the applicable Delivery Year.

The Office of the Interconnection shall also post preliminary ELCC Class Rating values for nine subsequent Delivery Years. For any Delivery Year for which a final ELCC Class Rating has not been posted and a preliminary ELCC Class Rating has been posted, the Accredited UCAP of an ELCC Resource for such Delivery Year shall be based on the most recent preliminary ELCC Class Rating value for that Delivery Year, together with the most recently calculated ELCC Resource Performance Adjustment value for that ELCC Resource. Except to the extent specified above or otherwise specified, the preliminary ELCC Class Rating values for future years are non-binding and are only for indicative purposes. A Generation Capacity Resource Provider can offer or provide capacity from an ELCC Resource that is not subject to a capacity market must offer obligation (as specified in Tariff, Attachment DD, Section 6.6) at a level less than the Accredited UCAP for such resource.

In order to facilitate the effective load carrying capability analysis, the Generation Capacity Resource Provider of each ELCC Resource must submit to the Office of the Interconnection the required information as specified in the PJM Manuals by no later than August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Years such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The required information may include relevant physical parameters, relevant historical data such as weather data and actual or estimated historical energy output, and documentation supporting such parameters and historical data. The relevant physical parameters are those that are incorporated into the effective load carrying capability analysis. The parameters required for Hydropower With Non-Pumped Storage shall include Ordinary Water Storage and any applicable Exigent Water Storage. Submitted parameters must indicate the expected duration for which any submitted physical parameters are valid.

The Office of the Interconnection shall evaluate, validate, and approve the foregoing information in accordance with the process set forth in the PJM Manuals. In evaluating the validity of submitted information, the Office of the Interconnection may assess the consistency of such information with observed conditions. If the Office of the Interconnection observes that the information provided by the Generation Capacity Resource Provider of the ELCC Resource is inconsistent with observed conditions, the Office of the Interconnection will coordinate with the Generation Capacity Resource Provider of the ELCC Resource to understand the information and observed conditions before making a determination regarding the validity of the applicable parameters. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the foregoing information.

After the Office of the Interconnection has completed its evaluation of the foregoing information, the Office of the Interconnection shall notify the Generation Capacity Resource Provider in writing whether the submitted information is considered invalid by no later than September 1 following the submission of the information. The Office of the Interconnection’s determination on the validity of the foregoing information shall continue for the applicable Delivery Year and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

In the event that the Office of the Interconnection is unable to validate any of the required information, physical parameters, supporting documentation, or other related information submitted by the Generation Capacity Resource Provider of an ELCC Resource, then the Office of the Interconnection shall calculate Accredited UCAP values for that ELCC Resource based only on the validated information. Such ELCC Resource shall not be permitted to offer or otherwise provide capacity above such Accredited UCAP values until the Office of the Interconnection determines new Accredited UCAP values for such resource.

Generation Capacity Resource Providers of ELCC Resources that are hydropower plants with water storage must provide documentation to support the physical parameters provided for expected load carrying capability analysis modeling, as specified in the PJM Manuals. This documentation must: (a) support the plant’s physical capabilities; (b) demonstrate that the parameters do not violate any federal, state, river basin, or other applicable authority operating limitations of the plant; and (c) demonstrate full authorization from FERC, any river basin commissions, and any other applicable authorities to meet those capabilities.

Attachment C

Affidavit of Adam Keech
on Behalf of
PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER24-___-000**
	)	

AFFIDAVIT OF ADAM KEECH
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

Qualifications

1. My name is Adam Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am the Vice President of Market Design and Economics at PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its capacity market reform filing. In my current role I oversee the design of all of the wholesale markets operated by PJM and the development of large-scale advanced analyses such as those done for carbon pricing and renewable integration. I am also responsible for the applied innovation area that focuses on evaluating, leveraging and supporting the implementation of advanced solutions in the planning, markets and operations areas. I have worked for PJM since 2003 and held senior leadership roles in both the Market Services and System Operations divisions. I earned a Bachelor of Science in electrical engineering from Rutgers University in 2002 and earned a Master of Science in applied statistics from West Chester University in 2013.

Purpose of This Affidavit

2. The purpose of my affidavit is to first explain the importance of the capacity market's role as part of the overall suite of PJM's markets and describe the motivation to seek changes now. As explained in my affidavit and in various other work performed by PJM, the industry is in a period of rapid change. While the foundation of PJM's markets is strong, it is necessary to evaluate their designs in light of the change in the industry to ensure they are configured to continue to provide reliability at low cost to consumers and send efficient price signals for performance, entry and exit. From there I go on further to explain the rationale for specific, necessary, enhancements including a move to marginal accreditation, stronger testing requirements and a collection of changes to the Fixed Resource Requirement option.

Why is the Capacity Market Necessary?

3. The capacity market is necessary because the energy and ancillary services ("E&AS") markets do not consistently produce sufficient revenues to support investment in sufficient resources to maintain the desired level of reliability (one

loss of load event in ten years, on average). This lack of revenues, or "missing money", comes from two primary causes:

a. Limitations on the revenues permitted to be settled in the E&AS due to rules such as offer and price cap levels, and,

b. A desire not to shed load at a frequency greater than one event every ten years, on-average.

4. The purpose of my affidavit is not to argue merits of those rules; however, it is helpful to understand them as key drivers that lead to the "missing money" problem that PJM uses the Reliability Pricing Model (RPM) to address.

5. At its core, capacity is a reserve product. The product itself is generation or load curtailment capability to provide enough supply to, at a minimum, meet the desired level of reliability. The revenues from the sale of the product go directly towards addressing the revenue gap between those produced by the E&AS markets and those necessary to meet the desired level of reliability. PJM uses a uniform clearing price market to procure the capacity product at least cost in the short- and long-term by harnessing the benefit of competition.

6. In the PJM market where approximately 70% of the load is in a state that has restructured its retail electricity market, a functioning capacity market like the RPM is required to procure adequate supply to meet the desired level of reliability in any given Delivery Year. In general, supply resources in restructured states do not receive cost recovery through a state agency and therefore rely on the capacity market and E&AS markets in PJM for the vast majority their revenues. Failure of the capacity market to perform can result in a shortfall supply relative to the amount necessary to maintain desired level of reliability resulting in frequent load-shedding events, or excess capacity whose costs exceed its reasonable incremental impact to reliability. Neither of these outcomes are desirable and therefore careful thought must be put into the various parameters of the capacity market to result in just and reasonable outcomes.

Why Are We Changing the Capacity Market?

7. Since the start of the Resource Adequacy Senior Task Force (RASTF) in late-2021, a primary motivator of PJM's focus on capacity market reforms has been to enhance its resource adequacy risk modeling and accreditation methods. Historically, resource adequacy risk modeling and accreditation methods have relied on assumptions that:

a. Resource adequacy risk is aligned with peak load conditions,

b. Generator outages are independent of each other, and,

c. Average historical performance is a reasonable estimate of future performance during resource adequacy risk periods.

8. For decades, these assumptions have generally held true and have shaped the way the industry thinks about resource adequacy. However, over the last decade, evidence has emerged that these assumptions may no longer be workable and that a fresh look at resource adequacy risk modeling and accreditation is needed to provide for reliability both now and in the future.

9. In the recently released presentation titled, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations", NERC and FERC highlight that Winter Storm Elliott represents the fifth event where, "cold weather-related generation outages jeopardized bulk power system reliability".[1] Two of those five events, the 2014 Polar Vortex and Winter Storm Elliott in 2022, directly impacted PJM. In fact, the 2014 Polar Vortex spurred the implementation of Capacity Performance in 2015, and Winter Storm Elliott introduced a significant number of action items and recommendations,[2] several of which are being addressed in PJM's proposal. The statement by NERC and FERC very succinctly captures the need to reform resource adequacy risk modeling and accreditation as it highlights two issues:

    a. Bulk power system reliability was jeopardized in the winter, not summer. PJM is not a winter-peaking system in terms of load, but in recent years the resource adequacy risk has been empirically observed in the winter. This demonstrates that, at least for PJM, the existing resource adequacy risk modeling assumption of risk aligning with primarily with peak load is incorrect.

    b. The aforementioned resource adequacy risk was driven by generation outages that were correlated with temperature; in this case cold weather. This communicates a few things:

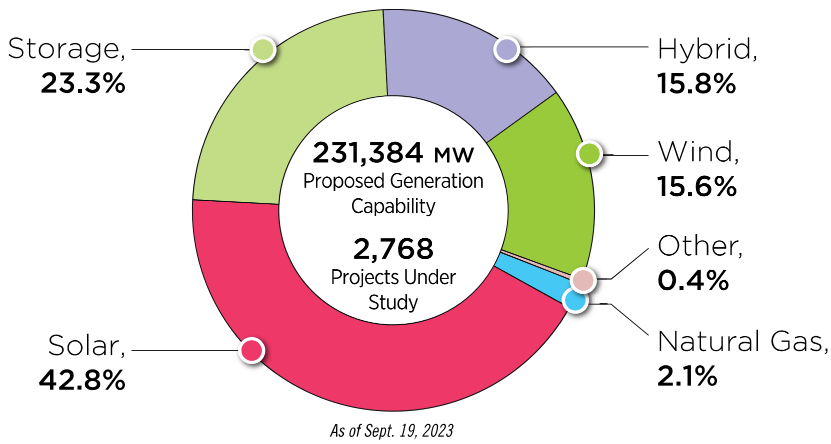
        i. Poor fleet performance, on its own, can create resource adequacy risk. This was the case in the 2014 Polar Vortex and Winter Storm Elliott in 2022. Establishing a model where resource performance can be a driver of reliability risk is essential.

        ii. Generator outages are correlated with temperature. FERC and NERC highlight that this is the fifth instance of this in the last 11 years which demonstrates that these are not anomalous observations.

[1] FERC, NERC, and Regional Entity Joint Staff Inquiry, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations*, Federal Energy Regulatory Commission, 3 (Sept. 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[2] *Winter Storm Elliott: Event Analysis and Recommendation Report*, PJM Interconnection, L.L.C. (July 17, 2023), https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

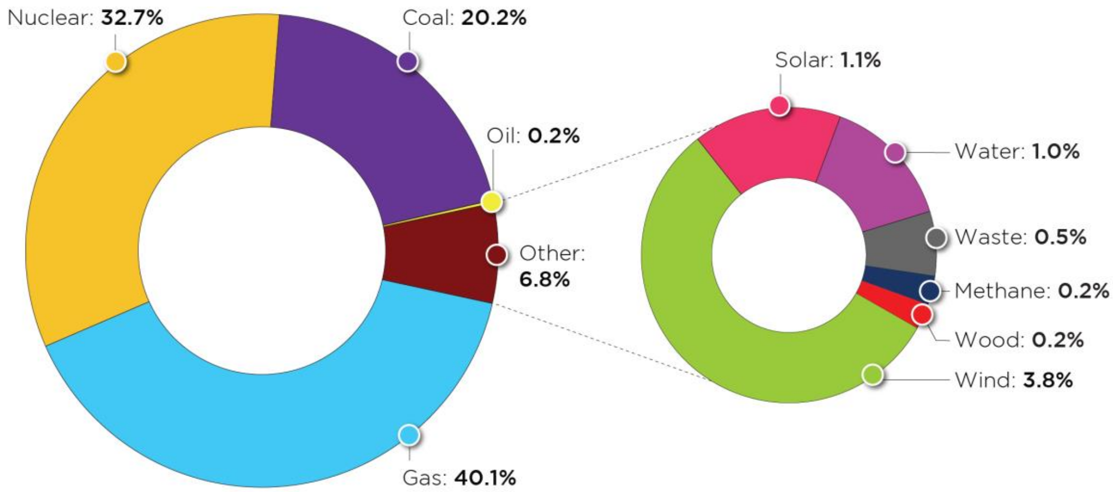
10. Further motivating the need for capacity market reform is the ongoing energy transition. As shown in Figure 1, PJM's current generation interconnection queue is primarily composed of solar, storage, hybrid resources and wind. Today in PJM, the penetration levels of these resource types are relatively low in comparison to the shares that exist in the queue and what is interconnected in other ISO/RTOs. PJM anticipates that the penetration of these resources will increase in the future based on what is in the PJM generation interconnection queue and the continued growth of these resource types in other areas of the country. Because these resources have different operating profiles than those that they stand to replace[3], implementing a method to accurately value the capacity capability of these resources and assess how their performance effects resource adequacy risk is critical to maintaining resource adequacy through the energy transition.



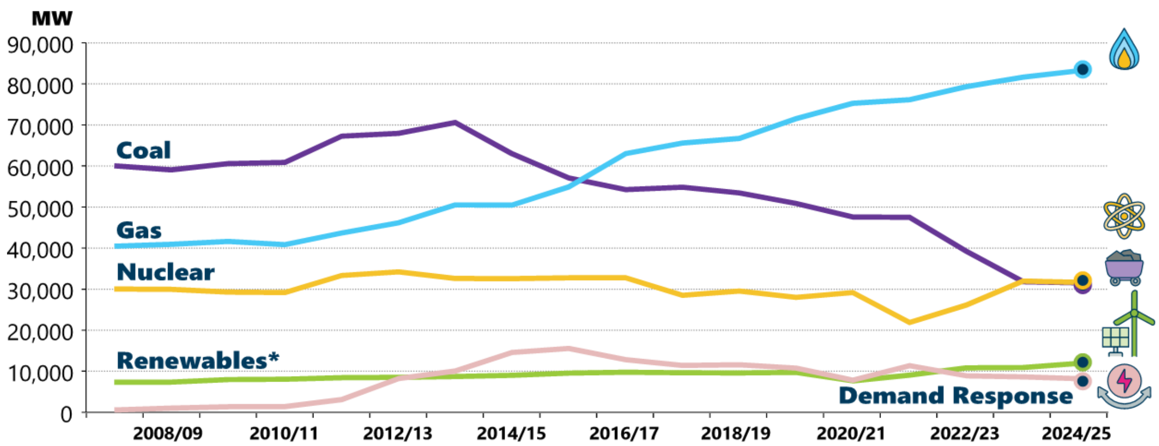
11. Another event that has already substantially impacted the demographics of the PJM generation fleet is the "shale gas revolution" that has occurred over roughly the last decade. This has resulted in the transition to natural gas as the primary fuel for the production of energy in PJM and the primary resource type providing capacity in PJM.

[3] Different operating profiles between solar, wind, storage and hybrid resources include, for solar and wind, correlation between output level and weather conditions that may not align with resource adequacy risk periods and for storage and hybrid resources, energy limitations related to storage capability and weather conditions.

2022 PJM Fuel Mix



Committed Unforced Capacity in PJM



**Renewables include solar, wind, hydro and wood. Note: All values include capacity cleared in RPM BRA or committed in FRR plan*

12. Many of these new gas-fired resources are incredibly flexible and provide much-needed reliability attributes. However, their performance is subject to the rules and restrictions of the interstate natural gas pipeline and production systems which, in terms of resource adequacy risk modeling, represents a common-mode failure that was a factor in their performance during the 2014 Polar Vortex and Winter Storm Elliott that led to resource adequacy risk. In PJM, changes to the resource fleet that have already occurred from the "shale gas revolution" and stand to occur due to the energy transition stand to create a generation fleet whose performance is more dependent on exogenous factors than ever experienced with previous resource mixes. In the case of renewable resources, they are dependent on weather patterns that do not always align with resource adequacy risk conditions. In the case of natural gas-fired resources, upstream limitations on pipeline capacity and production can adversely affect a broad set of resources in the PJM footprint simultaneously. These common-mode failures of supply-side resources are not

accurately represented in the current resource adequacy risk modeling and accreditation approaches and on their own can result in resource adequacy risk.

13. The need to depart from the legacy assumptions of (i) the alignment of resource adequacy risk with peak load conditions, (ii) independence of generator outages, and (iii) using average availability as an estimate of performance during risk periods, has required PJM to significantly enhance its resource adequacy risk modeling and accreditation approach to incorporate hourly granularity and the explicitly modeling of correlated outages as described in detail by Dr. Rocha-Garrido. These changes will more robustly determine periods of resource adequacy risk and more accurately estimate resource performance during those risk periods. In turn, these changes will allow PJM to better accredit the capacity capability of each resource by identifying each resource's relative reliability value to the PJM Region. Further, these changes have downstream impacts on the parameters that apply to the capacity market and the incentives that need to be sent to maintain resource adequacy cost-effectively in the short- and long-term.

Marginal Accreditation

14. Capacity accreditation is the process whereby PJM converts the nameplate capability of a resource to an accredited level of capacity that it may offer to sell in an auction. Under today's rules PJM uses average Effective Load Carrying Capability (ELCC) for intermittent, storage and combination resources, Equivalent Demand Forced Outage Rate (EFORd) for thermal resources (i.e., Unlimited Resources), and nominated capability times the Forecast Pool Requirement (FPR) for Demand Response (DR). Each of these methodologies is based on different performance assumptions for each resource type. For example, using EFORd for thermal resources assumes that the average historical performance of a thermal generator is a good approximation of future performance during risk periods. Using average ELCC for intermittent resources accredits based on the expected alignment of resource performance with risk conditions. For DR, the use of FPR as the sole component to determine accreditation assumes DR are always available during risk conditions and always perform perfectly. Each of these approaches have shortcomings but the shortcomings of each approach are different and affects accreditation of the applicable resource type in a different way.

15. Through this filing, PJM proposes to move to a marginal ELCC approach for all Capacity Resource types except of Energy Efficiency (EE) Resources.[4] Dr. Rocha-Garrido details in his affidavit how the marginal ELCC accreditation approach works. There are several drivers for this change:

    a. PJM seeks to unify its accreditation approach across all resources so there is consistency in the accreditation process.

[4] PJM Forward Market Operations, *PJM Manual 18B: Energy Efficiency Measure & Verification*, PJM Interconnection, L.L.C. (Sept. 21, 2022), https://pjm.com/~/media/documents/manuals/m18b.ashx.

b. The marginal accreditation approach proposed by PJM naturally aligns the level of accredited capacity of resource with its expected performance during risk periods.

c. The marginal accreditation approach proposed by PJM sends investment signals that are consistent with the marginal benefit to reliability (in this proposal Expected Unserved Energy (EUE)) of a specific resource or class. This creates incentives to invest in resources and resource classes that directly benefit resource adequacy needs.

16. A consistent accreditation approach is important in treating the various supply resources in the capacity market and creating a reasonably uniform capacity product across the various resource types. Under the current rules it could be argued that certain resource classes may be advantaged, or disadvantaged, just because of the accreditation approach that is applied to them. The benefit of a single accreditation approach is even more critical because it creates a single, fungible capacity product which could be argued to not be the case under the current rules given the various accreditation methods used. A simple example is that the EFORd approach applied to thermal resources today values average historic performance without focused consideration of performance during risk periods, whereas the use of ELCC for intermittent, storage and combination resources values performance coincident with risk periods. The result is two different products that are not fungible yet are treated as such in the current design. A single accreditation approach for all resources addresses this issue. Using one method to accredit resources results in a common definition of the capacity product across the various resource types and allows for the creation of a single, fungible product.

17. The marginal ELCC approach proposed by PJM calculates the marginal benefit to reliability, measured as a reduction in EUE, resulting from an incremental increase in nameplate capability of that class. Each class-level marginal ELCC is then propagated to individual resources within the class based on each individual resource's actual performance relative to others in the same class. Accrediting in this manner for all resources establishes a uniform capacity product across each resource participating in the market but also has the secondary benefit of aligning the level of accredited capacity for a resource with its expected performance during periods of risk as identified in the resource adequacy risk models explained by Dr. Rocha-Garrido. This is a beneficial change because it more precisely estimates how a resource will perform during identified periods of resource adequacy risk rather than assuming average performance (EFORd) or perfect performance (current accreditation method for DR). Accrediting capacity resources based on expected performance during risk periods is critical to ensuring that the actual resource adequacy needs of the system are being met and that consumers paying for capacity are get the reliability they are paying for.

18. As an example, assume a 100 MW thermal resource is on a forced outage 5% of the time (438 hours per year) such that under the current rules it has 95 MW of accredited capacity. Under the current rules and with respect to accreditation, those

438 hours of forced outage can occur at any time during the year and it will result in the same accredited level of capacity. Whether the 438 hours of forced outages overlap with the riskiest hours in the year or they do not, the accredited value of capacity is the same. This is a major downside of average accreditation methods, that is, consumers pay for performance on average rather than specifically for performance during resource adequacy risk periods for which they purchase capacity. In the case of PJM today, Capacity Performance and the associated Non-Performance Charges and bonus payments send incentives to perform during risk hours, however, those events are infrequent in nature and absent aligning accreditation with expected performance during risk periods, consumers could pay such a resource for capacity, possibly for years in between events when the resource does not actually contribute to reliability consistent with the revenues it is collecting.

19. Marginal ELCC as proposed by PJM sends investment signals that are consistent with the marginal reliability benefit of a resource resulting in strong incentives to invest in resources that directly improve resource adequacy (measured as a reduction in EUE). In general, this occurs because the capacity product itself as defined by using marginal ELCC represents a resource's incremental benefit to reliability. Resources that do not perform well during risk conditions have lower contributions to overall system reliability, will have lower accredited levels and as such will collect less revenues than resources that perform well during risk periods and reduce the system's EUE. Dr. Graf explains this concept further through simulations in his affidavit.

20. Finally, the shift to a marginal accreditation approach is consistent with other ISO/RTOs which either have, or are working towards, similar enhancements. For instance, NYISO filed a marginal accreditation approach with the Commission in 2022 that has been accepted.[5] ISONE is currently working towards implementing a marginal accreditation approach, as is MISO. The movement of other ISO/RTOs towards marginal accreditation and the fact that the Commission has already found this approach to be just and reasonable gives further credence to the method. This approach represents the industry's best-known method to model the various factors that can influence resource performance during risk periods using standard statistical algorithms and results in market outcomes that incentivize investment in resources that benefit resource adequacy at least cost.

Testing

21. PJM is proposing several changes to its testing requirements that will require a demonstration of resource capability in both the summer and winter seasons and improve operational readiness prior to extreme weather events. The purpose of making these changes is to better balance the financial incentives for performance conveyed through Capacity Performance with actual demonstrations of capacity

[5] *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102 (2022).

resource capability prior to the Performance Assessment Intervals where Non-Performance Charges and bonus payments may apply.

22. PJM proposes three key changes:

a. An additional requirement for capacity resources to physically perform a capability test in the winter in addition to the current requirement for summer capability testing, and,

b. A change to the calculation of the MW shortfall used to determine whether a Generation Resource Test Failure Charge applies from the current average method to a daily assessment, and,

c. The creation of a new test called the Generator Operation Test intended to test resource capability and operating parameter accuracy prior to periods of the year where PJM may experience extreme weather conditions.

23. PJM's current Generation Capacity Resource capability testing rules require only a single test to be conducted in the summer and permits the use of ambient temperature adjustments from the summer test result to demonstrate winter capability. At the end of each Delivery Year, the annual average of the installed capacity committed on each resource is compared to the highest installed capacity rating determined for the resource during the relevant summer or winter testing period and any shortfalls are assessed a Generation Resource Rating Test Failure Charge. The Generation Resource Rating Test Failure Charge is equal to the Daily Deficiency Rate multiplied by the MW shortfall where the Daily Deficiency Rate is the higher of the $20/MW-day or 1.2 * Weighted Average Clearing Price that the resource receives for the Delivery Year based on the MW quantities and clearing prices it receives from each auction it cleared in.

24. There are two shortcomings with this approach that PJM seeks to amend with this proceeding. First, empirical observations from Winter Storm Elliott and similar extreme events in other ISO/RTOs, as well as the analysis performed by Dr. Rocha-Garrido to determine the ELCC for capacity resources, clearly demonstrate that generators operate differently in the summer and winter. These observation and analyses indicate that the current method of extrapolating winter capability from summer capability through ambient temperature adjustments is not suitable to determine the true winter capability of a generation resource. The best way to assess both summer and winter capability is by requiring physical demonstrations of this capability in each season. As such, PJM proposes to require seasonal rating tests for each generation capacity resource with the details of those test to be defined in PJM manuals as they are today.

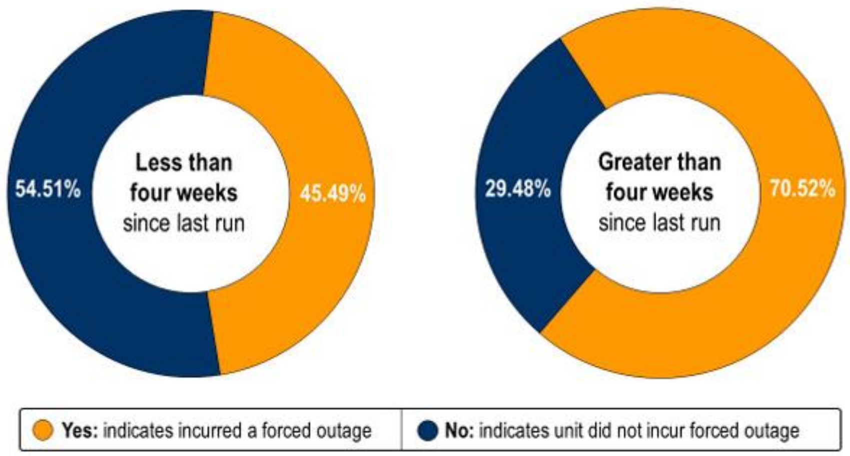
25. The second proposed change to the Generation Capacity Resource capability testing process is with regard to the calculation of the MW shortfall portion of the Generation Resource Test Failure Charge. Currently the Generation Resource Rating Test Failure Charge is calculated at the end of each Delivery Year and

includes MW shortfall calculation based on the *annual average* of the installed capacity committed on each resource minus the highest installed capacity rating determined for the resource during the relevant summer or winter testing period. That MW shortfall is then converted to an unforced capacity basis, and multiplied by the Daily Deficiency Rate. PJM's proposed change is with regard to the calculation of the MW shortfall only. PJM is not proposing to change the Daily Deficiency Rate. Rather, in calculating the MW shortfall, PJM proposes to assess the resource's MW shortfall on the daily installed capacity commitment of the resource instead of the annual average of the installed capacity committed on the resource. The rationale for this change is to more precisely determine whether the installed capacity the resource is committed for each day aligns with its demonstrated capability. The current process of using an annual average is directionally reasonable but can miss scenarios where on any given day a resource's committed installed capacity is higher than its demonstrated seasonal capability but when averaged annually is missed. The objective of this change is to have greater confidence that for every single day of the Delivery Year, each resource has demonstrated the capability to meet its capacity commitment. If it cannot, it will be assessed as deficient and subject to a Generation Resource Rating Test Failure Charge.

26. The third proposed change to Generation Capacity Resource testing is the implementation of a new testing process called Generation Capacity Resource Operational Testing. The purpose of this test is to have greater confidence that Generation Capacity Resources can operate successfully when called based on their submitted operating parameters. The intention of this test is to check that accurate information regarding the operational status and operating parameters of a Generation Capacity Resource are provided to PJM and that the Generation Capacity Resource can successfully demonstrate that through performance. This is particularly important for those Generation Capacity Resources that do operate frequently and may be asked to operate during a resource adequacy risk period after not running for several months.

27. The motivation for such a test comes from analysis done by PJM on generator performance during Winter Storm Elliott. Following that event, PJM analyzed and published the following chart regarding generation resource performance during Winter Storm Elliott. The following chart shows that resources that had run within a month of Winter Storm Elliott experienced a forced outage rate that was 25% percentage points lower than those that had not run as recently. This data supports the conclusion that a generator that has not operated recently and is asked to start in anticipation of or during a capacity emergency is at a higher risk of experiencing a forced outage than one that has operated more recently.

Force Outage Versus Last Run Time



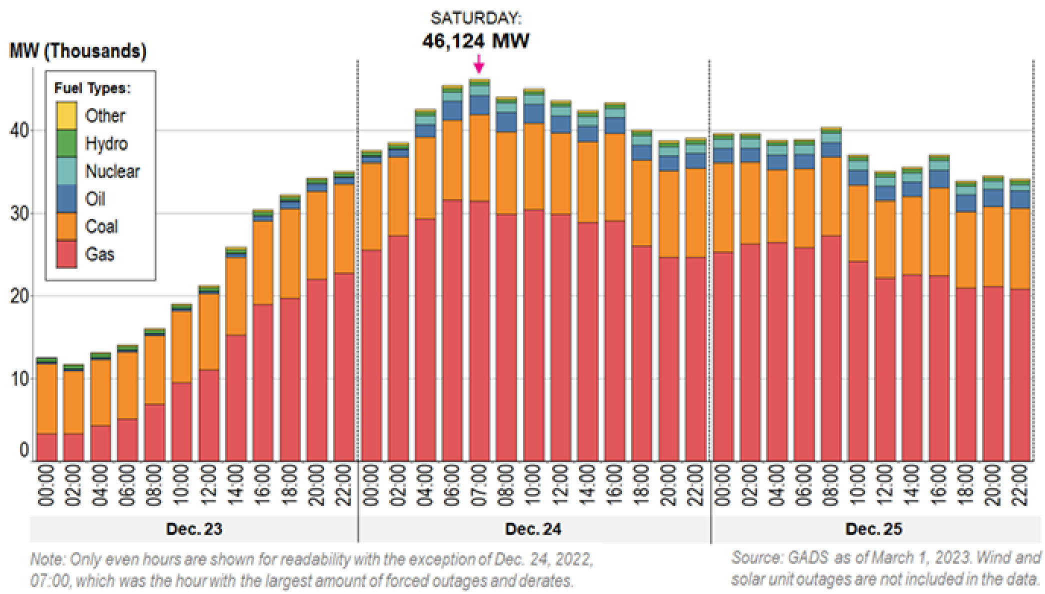
28. Further, during Winter Storm Elliott, PJM experienced a significant number of outages that were mechanical in nature. The following charts show two key points:

    a. On the first chart, approximately 75% of the generator forced outages experienced during Winter Storm Elliott were from generation resources whose fuel was natural gas, and

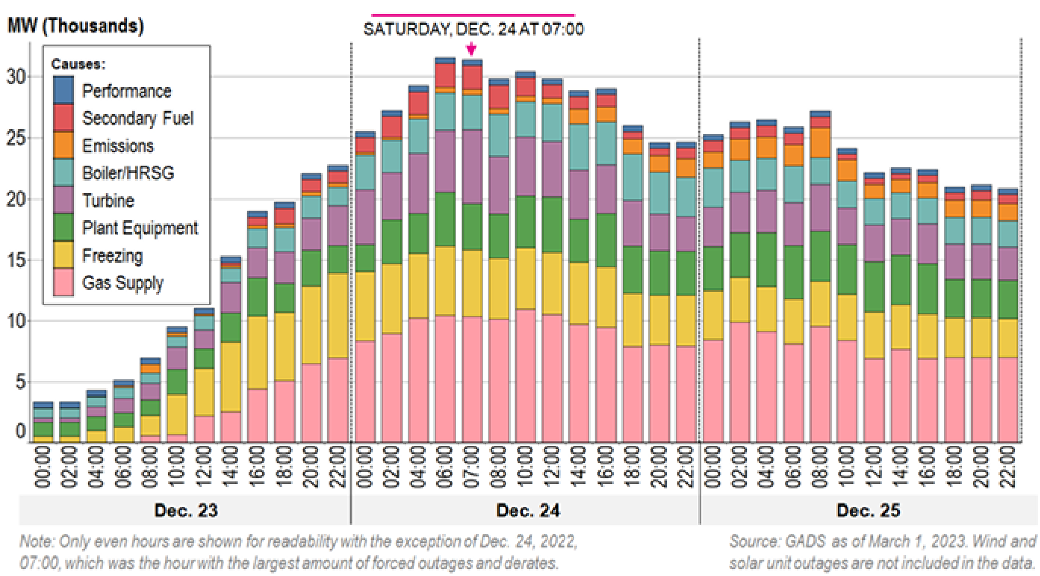
    b. On the second chart, only approximately 25% of those outages to natural gas units were related to "Gas Supply" issues.

29. In short, over 80% of the outages experienced during Winter Storm Elliott were mechanical in nature. PJM interprets this data to show that there is an opportunity to enhance testing and better balance the demonstration of performance through testing with the financial incentives conveyed through Capacity Performance. While it is impossible to test Generation Capacity Resources during Winter Storm Elliott-like or summer peak load conditions, additional operational testing will be beneficial to the early identification and correction of some mechanical issues that can help to bolster fleet performance during actual capacity emergencies.

Winter Storm Elliott Forced Outages by Fuel Type



Causes of Forced Outages to Gas Generators During Winter Storm Elliott



30. As stated previously, the purpose of this test is to confirm that Generation Capacity Resources, especially those that have not operated recently, can do so upon PJM request and according to their operating parameters. The goal is to make sure Generation Capacity Resources can operate and given them an opportunity to demonstrate that rather than to assess penalties. However, should a resource continually fail in Generation Capacity Resource Operational Testing, it demonstrates the Generation Capacity Resource's inability to perform and must eventually result in some level of financial penalty.

31. The framework of the new Generation Capacity Resource Operational Testing process gives PJM the ability to request an operational test up to two times per Generation Capacity Resource, per summer or winter season, not including re-tests. The timing of such tests shall be at the discretion of PJM. This provides PJM an opportunity to test resources during the types of system conditions that, to the degree possible, are representative of those experienced during actual reliability events. A successful test for a Generation Capacity Resource demonstrates the following abilities:

    a. Start within the startup and notification time parameters submitted with the Generation Capacity Resource's applicable energy offer, plus the greater of 10 minutes or 10%, and

    b. Operate for the entirety of the minimum run time consistent with energy market offer.

32. During the testing period, the Generation Capacity Resource will be dispatched and settled the same as any other resource operating in the PJM energy market, including any uplift to allow the resource to recover its operating cost under PJM's existing uplift provisions. If the resource fails its test, regardless of whether that failure is due to a failure to start within the provided time or meet its minimum run time parameters, PJM can issue a re-test at a future time. The retest will be the same as the initial test except that the resource will not be eligible for any uplift payments to recover testing costs, and the retest will not be counted towards the two operational tests allowed per season. If the retest is also failed, regardless of the reason, PJM may issue another re-test at a future time, and continue doing so until the resource successfully passes the test. This allows PJM to continue re-testing resources that fail, without subjecting load to further uplift payments, which improves PJM's visibility of the operational capabilities of resources, and provides an incentive for generation owners to be accurate in the operating parameters submitted to PJM and used for scheduling.

33. Furthermore, for resources that entirely fail to start up and synchronize to the grid during a re-test, a Generation Capacity Resource Operational Test Failure Charge shall apply from the point at which the resource failed the re-test until it can successfully come online and operate. This is appropriate as the resource has demonstrated through multiple failed tests an inability to provide any capacity value during this time. The charge shall be assessed against the full daily committed UCAP MW of the resource and multiplied by the same Daily Deficiency Rate as used in the Generation Resource Rating Test Failure Charge.

34. It is my belief that the Generation Capacity Resource Operational Test will result in better operational performance of the generation fleet during capacity emergencies because it specifically creates an opportunity to test the operating capability of a resource prior to the event itself. This will help to identify any operational issues with a Generation Capacity Resource before an actual emergency condition arises. Furthermore, the operational test provides a check on the reported

availability of Generation Capacity Resources, which can improve the availability and outage metrics that feed into resource accreditation for future Delivery Years. This is particularly true for resources that are reported as available for extended periods of time, but rarely scheduled to operate, as these tests provide a check on that availability and can significantly increase the number of times that the ability of the resource to successfully start up and run when scheduled is tested each year.

Fixed Resource Requirement (FRR) Changes

35. PJM is proposing to make additional changes to the FRR option to create equitable treatment between FRR entities and RPM participants and equivalent standards and methods for resource adequacy risk modeling and accreditation. As such, the changes PJM proposes to the FRR option fall in the categories of:

    a. Resource Adequacy Risk Modeling and Accreditation,

    b. Performance Assessments Including Capacity Performance and Testing,

    c. Deficiency and Insufficiency Charges, or

    d. FRR Transition.

36. A brief summary of the changes in each area and the supporting rationale are provided in the following sections.

Risk Modeling and Accreditation Implementation in the FRR Option

37. PJM proposes to apply its new methods of resource adequacy risk modeling and accreditation to FRR entities. In short, the obligations of FRR entities and the accreditation of resources in the FRR Plans will be determined using the same methods of resource adequacy risk modeling and marginal accreditation as used for loads and suppliers participating in RPM Auctions. PJM's proposed methods for risk modeling and capacity accreditation present a significant enhancement over the existing processes. Uniform standards and calculations for the determination of resource adequacy risks and accredited capacity levels need to be done consistently across the PJM Region so that there are no gaps in how risks are assessed between RPM and FRR and that resource types are not accredited uniquely simply because of the business model they operate in. This portion of the proposal simply transposes the new risk modeling and accreditation proposal onto FRR entities and makes no further changes.

Performance Assessments Including Capacity Performance and Testing in the FRR Option

38. Under today's rules, FRR entities that demonstrate under-performance during a PAI have the option to elect a "physical assessment" in which they are obligated to carry additional capacity rather than the financial assessment that occurs for RPM entities. The "physical" option allows FRR entities with under-performing

resources the option to assign more capacity in the future rather than pay Non-Performance Charges for the under-performance. This form of a penalty, which defers the penalty's effects, can severely mute incentives to perform when the system needs it the most, especially when the FRR entity has excess supply not in its FRR Plan or can readily purchase it on the market at low cost. Removal of the "physical assessment" will expose FRR entities to the same financial incentives for performance as those with RPM commitments and thus create a uniform set of performance incentives across all capacity resources during a PAI.

39. Similar to the proposal for risk modeling and accreditation, PJM plans to apply the aforementioned reforms to Generation Capacity Resource testing and the associated Non-Performance Charges from failed tests to resource's committed in an FRR Plan as well. This change is beneficial as it would maintain uniform standards for testing across all Generation Capacity Resources.

Deficiency and Insufficiency Charge Enhancements

40. To create appropriate incentives for FRR entities to have sufficient megawatts of accredited capacity in place to meet their obligations, PJM proposes to adjust the level of the FRR deficiency and insufficiency charges from the current level of 1.2 * Base Residual Auction ("BRA") Clearing Price and 2 * Gross CONE, respectively, to the price-level corresponding to Point 1 on the Locational Deliverability Area ("LDA") Variable Resource Requirement (VRR) curve where the FRR obligation exists. This change makes equal the penalty to an FRR Entity for either not having adequate capacity in its initial FRR Plan when it is due (insufficiency charge), or, being short of capacity obligation during the Delivery Year (deficiency charge). This level provides sufficiently high incentives for FRR Entities to contract with resources in a timely manner to meet their obligations. Two times gross CONE for the insufficiency charge is higher than any point on the VRR Curve used in the RPM Auctions and may be inappropriately high and punitive. Conversely, for the deficiency charge at 1.2 times the BRA clearing price, low BRA clearing price levels, such as those recently observed (e.g., $34.13/MW-Day for the 2023/2024 Delivery Year) may be low enough that it is less expensive for an FRR Entity to pay the applicable charges instead of procuring sufficient capacity to meet the requirements of its plan. This is a bad outcome from a resource adequacy perspective and therefore needs to be addressed.

41. PJM selected the price-level of Point 1 on the applicable LDA VRR curve because the obligation of an FRR Entity is set based on the FPR which represents the amount of UCAP required to maintain the one-day-in-ten-years Loss of Load Expectation standard. Failure to meet that falls short of the target level of reliability and should correspond to a high penalty rate to incentivize curing the shortfall expeditiously. Additionally, the price associated with Point 1 on the applicable LDA VRR curve also generally corresponds to the maximum price level loads participating the in the BRA would pay if the RPM Auction cleared short of the reliability target. While they are not exact, using the price-level associated with Point 1 on the LDA VRR

curve is a reasonable proxy given that it is already an accepted anchor point on the VRR curves used in the BRA

42. For these reasons, it is reasonable for FRR entities to be subject to a similar economic signal to avoid being short of capacity in their FRR Plans.

FRR Transition

43. In recognition of the relatively longer lead times necessary for capacity planning in FRR regions, the significance of changes proposed in the filing, the relatively short timeframe in which such changes will be implemented, and the unique circumstances that FRR entities are in due to their inability to purchase capacity in an RPM Auction, PJM proposes a transition mechanism for FRR entities containing two elements:

    a. PJM proposes to allow a one-time option for FRR entities who have not yet met the minimum five-year commitment to the FRR election to re-join RPM beginning with the 2025/2026 BRA and carrying through the 2028/2029 BRA. Note that an election to re-join RPM during those years still requires a five-year minimum commitment period as applies under the current rules, meaning that entities will not be free to jump in and out of the market.

    b. For FRR entities remaining in the FRR option, PJM proposes to waive, for a four-year period, the insufficiency charge that applies when an FRR entity is unable to demonstrate at the time the initial FRR plan is due, that they have enough resources to meet their projected obligation. The waiving of this charge for the same period of Delivery Years simply allows FRR entities more time to meet their obligations without the assessment of an insufficiency charge.

44. The overall objective of this transition proposal is ultimately to procure all the resource adequacy needs of the entire PJM Region, either through RPM Auctions or through FRR Plans. FRR Entities concerned about being able to meet their obligation can re-join RPM, which would grant them access to sell their resources in RPM Auctions and purchase capacity from the pool. FRR Entities who remain in the FRR Alternative would be granted more time to procure or build Capacity Resources without being subject to insufficiency charges. This is appropriate given the magnitude of the changes and relatively quick implementation schedule. This is a reasonable transition proposal considering the unique circumstances that FRR entities are in.

45. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	**)**	**Docket No. ER24-___-000**
	)	

I, Adam Keech, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Adam Keech referred to in the foregoing document entitled "Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

/s/ Adam Keech
Adam Keech
Vice President of Market Design and Economics
PJM Interconnection, L.L.C.

Dated: October 13, 2023

Attachment D

Affidavit of Dr. Walter Graf
on Behalf of
PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER24-__-000**
	)	

AFFIDAVIT OF DR. WALTER GRAF
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

I. QUALIFICATIONS

1. My name is Dr. Walter Graf. I am the Chief Economist for PJM Interconnection, L.L.C. ("PJM"). My business address is 2750 Monroe Blvd, Audubon, PA 19403.

2. In my current position my core function is to advise the executive team and staff of the market services division on all economic policy and economic analysis activities related to market operations, design, and long-term evolution, across all PJM markets including the energy, ancillary services, capacity, and financial transmission rights markets. My responsibilities include: providing analysis of operational, economic, and accounting data on the overall performance of the competitive wholesale electricity markets; supporting the development of a strategic direction of PJM's activities in market development and evolution; performing qualitative and quantitative economic analysis of proposed changes to the PJM market rules; and supporting the stakeholder process in related areas.

3. Prior to my current position I was Senior Director, Economics for PJM, before which I was Associate and Senior Associate at The Brattle Group, an economic consulting firm. Among other engagements, I worked for regulators, market operators, and market participants on matters related to resource adequacy in five jurisdictions worldwide. I provided economic expertise, analysis, and recommendations on design decisions involving resource qualification and capacity value rating methodologies; demand curve design; auction format and mechanics; market power mitigation approach, thresholds, and unit-specific reviews; performance obligations and incentives; cost allocation to retailers and consumers; and assessment of cost impacts to customers.

4. I received Bachelors of Science degrees in Economics and in Civil and Environmental Engineering from the University of Michigan in Ann Arbor, MI. I received a Masters of Science degree and a Doctor of Philosophy degree in Agricultural and Resource Economics from the University of California in Berkeley, CA.

II. OVERVIEW AND PURPOSE OF AFFIDAVIT

5. I am submitting this affidavit on behalf of PJM in support of its proposed changes to the Reliability Pricing Model ("RPM"). The substantial changes PJM proposes

are intended to better align the RPM, or “capacity market,” with the twin objectives of reliability and efficiency:

a. **Reliability:** securing adequate resources to meet a target loss of load metric.

b. **Efficiency:** upholding competitive principles and providing transparent price signals for efficient entry and exit of resources. In this context, efficiency means achieving the maximum possible reliability for a given societal cost, or minimizing societal costs for the delivered level of reliability.

6. Fundamentally, the PJM Reliability Pricing Model is an administrative framework, grounded in market principles, which PJM employs to procure a capacity "product" to sustain long-term reliability and efficiency. The capacity product is a reserve-like commitment to be available and perform (that is, provide energy or reserves) when needed by PJM to meet potential future reliability needs. Solidifying this “commitment” into a tangible and transactable product is accomplished through complementary capacity market design elements including:

a. Qualification and Accreditation: Establish eligibility and quantity available for sale.

b. Obligations: Define the responsibilities incumbent upon the seller.

c. Performance Incentives: Define consequences of both adequate and inadequate performance

7. In other words, the capacity product under the PJM framework necessitates a binding commitment to perform as and when required by PJM, especially during periods of stressed system conditions—times when there is a need for resource adequacy or there exists a risk of load shed. This commitment is subject to stipulated penalties for any instances of non-performance and is eligible for bonus credits in cases of over-performance.

8. Furthermore, the committed capacity must exist in a physical form, whether as an existing resource or one that meets the established criteria for a planned resource, and it must be deliverable to load. This commitment is measured and accredited in terms of Unforced Capacity (“UCAP”) megawatts (“MW”), a metric designed to encapsulate a resource’s anticipated performance during periods of load shed risk and to quantify its incremental contribution to system resource adequacy.

9. Moreover, the capacity product is substitutable; one megawatt of UCAP can be interchanged with any other megawatt of UCAP while preserving equivalent resource adequacy, as per established metrics. This interchangeability is maintained even across resource types with varying operational characteristics and limitations.

10. The following sections of this affidavit describe how the proposed changes to RPM serve to better align the market construct with supply-demand fundamentals for the capacity product outlined above to in service of the twin objectives of reliability and efficiency. These changes include:

a. Enhancements to the core analysis used to evaluate reliability risks,

b. A move to marginal accreditation, consistently using the enhanced risk model for all capacity 87resources,[1]

c. Changes to the Capacity Performance construct to incent performance, and

d. Changes to the market power mitigation framework to better align with the principles of competitive markets.

III. RISK MODELING ENHANCEMENTS

11. The core of PJM's proposal is a novel analytical framework for assessing the patterns, drivers, and probabilities of reliability risk. The proposed approach assesses resource adequacy under a broad range of potential system conditions, each representing one potential combination of weather, load and resource availability. This substantially enhances the accuracy of PJM's reliability risk assessment, enabling the identification and integration of incremental risks that inherently exist—present in the "ground truth"—but remained undetected under the status quo risk modeling framework.

12. **Hourly Granularity Analysis:** By leveraging historical data, PJM has created a robust model to estimate loss of load risk, duration and magnitude. PJM's approach examines resource adequacy at an hourly level. This granularity ensures that short-term fluctuations, which might be overlooked in a daily or monthly analysis, are captured. Such fluctuations can be critical, especially during peak demand hours or unexpected system stresses.

13. **Weather Outcomes Impacting Load and Resource Availability:** Weather plays a central role through its impact on both demand and supply. Extreme cold or hot conditions can lead to increased demand, while also impacting the availability or output of certain resources. PJM's proposed approach accounts for a wide spectrum of historically observed weather outcomes.

14. **Common-Mode Failure Analysis:** Beyond weather-related impacts, PJM proposes to adopt an innovative, non-parametric approach to also capture the impact of other (sometimes unobserved) drivers of common-mode failures. These are scenarios where multiple resources might become unavailable due to a shared vulnerability. By re-sampling from historical outage patterns, PJM's analysis can identify the extent to which these shared vulnerabilities have historically impacted class- and fleet-wide forced outages, and further identify the extent to which such outages have historically (and may in the future) drive elevated system risk.

15. As further discussed in the Affidavit of Dr. Rocha-Garrido, the result is a reliability risk model that better captures the likelihood, severity, and patterns of risk, including that of extreme event risk from correlated factors.[2] The proposed risk modeling framework aligns well with emerging best practices, and the overall

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[1] Excluding Energy Efficiency Resources, as discussed further in section IV.

[2] Affidavit of Dr. Patricio Rocha-Garrido on Behalf of PJM Interconnection, L.L.C.,Docket No. ER24-___-000 (Oct. 13, 2023).

approach was well received by stakeholders in the PJM stakeholder process. Nearly every package sponsor put forward packages that rely on the PJM framework for enhanced risk modeling.

IV. MARGINAL ACCREDITATION USING ENHANCED RISK MODEL FOR ALL CAPACITY RESOURCES

16. Capacity accreditation quantifies the amount of capacity product a resource may offer into the capacity market. As discussed above, the capacity market and product continue to focus on resource adequacy and procurement of sufficient resources to satisfy the loss-of-load criterion. As such, capacity accreditation serves to capture a resource's contribution to resource adequacy, or expected ability to perform during times of system risk. Accreditation allows for a single, substitutable market product (i.e., accredited capacity. UCAP, or Accredited UCAP) to be used across resources with disparate operating characteristics, where one MW of the qualified product can be exchanged for any other MW of qualified product on the margin while maintaining equivalent resource adequacy outcomes

17. The main goal of PJM's proposed accreditation reforms is to improve accreditation to capture additional risk drivers and more accurately and equitably determine resources' relative contributions to resource adequacy.

18. These reforms occur against the backdrop of an evolving resource adequacy paradigm. Historically, the focus was primarily on planning for the (summer) peak given concentration of risk at that time. With the implementation of effective load carrying capability ("ELCC") for certain resources, PJM started down a path of fully recognizing resources differential contributions to reliability over time and across scenarios. Under the new paradigm, the focus is on identifying the least-cost, efficient portfolio of resources that—in aggregate—is expected to provide resource and energy adequacy in every hour of the year, across all potentially anticipatable scenarios, up to the target reliability metric.

19. PJM proposes two fundamental changes to capacity accreditation:

    a. **Modeling:** Incorporate enhanced risk modeling to directly assess resources relative contributions to resource adequacy, accounting for supply-side availability risks for all resource types.

    b. **Metric.** Accredit each resource "on the margin" to reflect its expected incremental contribution to system reliability during periods of risk.

IV.A ACCREDITATION MODELING ENHANCEMENTS

20. Under the status quo, there is no consistent application of a single accreditation methodology to all resource types. Thermal resources are accredited by de-rating the installed capacity ("ICAP") rating of the resource by a measure of the forced outage rate; intermittent and storage resources are accredited using a probabilistic model that does not directly use weather data, does not capture temperature- or other weather-dependent outage patterns, and does not capture "common mode" or other correlated outage drivers. And other resources are accredited using yet

other metrics designed to approximate their resource adequacy contribution, albeit approximations that were developed under a different understanding of the system's reliability risk drivers than we have today.

21. PJM proposes to directly leverage the enhanced analytical framework for risk assessment to consistently accredit all resources to reflect their assessed relative resource adequacy value. Capturing correlated outage drivers is crucially important for accurately assessing resource accreditation because system risk is higher when more resources are on outage, and by definition average resource performance is lower when more resources are on outage. If correlated outage drivers of any type increase the level of coincident resource outages and, consequently, of system risk, then any resource whose outages are correlated with those of other resources contributes less to preserving system reliability *during the reliability events that are likely to occur.*

   a. **For thermal resources:** The proposed approach reflects the impact of temperature-dependent forced outages and de-rates, other non-temperature related correlated outages observed historically, and planned and maintenance outages (which are assumed to be distributed throughout the year so as to avoid periods of risk insofar as possible).

   b. **For Demand Resources:** The approach accounts for the coincidence between periods of risk and availability limitations, as well as the variable load reduction available from the demand response as system load varies over the year while resources' firm service levels remain constant.

   c. **For Intermittent Resources and storage:** While these resource types are today accredited using an ELCC model, the enhanced accreditation methodology proposed will reflect different patterns of risks, changing risk weighting, and interactions between these resources and all other resources now modeled comprehensively.

22. PJM proposes to exclude Energy Efficiency Resources from the enhanced modeling and continue to assess their value, as under status quo, based on post-installation and measurement and verification reporting, which estimate the impact of energy efficiency measures on peak loads. Because the impact of energy efficiency is largely already included in the PJM load forecast models, it would be inappropriate to include such resources against the system risk and accreditation analysis, which would require further reducing forecasted hourly loads. Doing so would double-count the impact of energy efficiency, impact modeled system risk patterns in a counterfactual manner, change PJM's assessment of risk patterns, and distort the assessed capacity value of all other modeled resources.

IV.B MARGINAL ACCREDITATION

23. Marginal accreditation is a metric that reflects, for a given system, **the expected incremental reliability contribution** of each resource. Marginal reliability values can be extracted from the probabilistic risk analysis of a resource's contribution to avoiding load shed in the model. The reliability contribution of a resource is most naturally observed as a change in the reliability metric when the resource is added;

using the EUE metric, it is the change in system EUE caused by adding the resource. This EUE-denominated contribution can be translated to MW by comparing the EUE impact of the resource in question to the EUE impact of a hypothetical "perfect" resource. A resource that reduces EUE by X times as much as the level of reduction in EUE from 1 MW of perfect always-available capacity thus receives a translated value of X MW of accredited value.

24. The principle of marginal-value compensation is fundamental to the design of efficient wholesale markets. This principle underlies all key market products, including energy (locational marginal prices) and reserves. The core design of the capacity market supply-demand clearing mechanism also embodies marginal pricing, where the price allocated to all cleared capacity resources in a specific transmission-constrained area equals the marginal value of the last MW of capacity cleared in that area. Marginal accreditation aligns coherently with the established marginal pricing approach prevalent in the capacity market and indeed all PJM wholesale markets. As described by Potomac Economics, "[i]n competitive markets, the debate between total/average value and marginal value never arises because competitive markets always value products at their marginal value."[3]

25. Beyond aligning with the principles underlying all wholesale markets in PJM, accrediting capacity to reflect its expected incremental impact on has substantial benefits over alternatives. I briefly describe these here, and provide numerical examples in an appendix to my affidavit.

26. **Encourages cost-effective investment and retirement of resources.** Adopting a marginal approach to capacity accreditation fosters an environment where resource owners are incentivized to make economically rational decisions. Specifically, it drives investment into resources that offer the greatest reliability per dollar and steers away from resources that are more costly for the incremental reliability they provide. Moreover, it signals the retirement of less efficient resources whose energy, ancillary services, capacity, and other market and non-market value is less than their operational, maintenance, and amortized costs of necessary investments. As a result, resources that remain on the grid are those that best balance cost and reliability.

27. **Aligns the accredited value with expected performance during high-risk hours in operations**, which is necessarily on the margin. In operational terms, the most valuable resources are those that are available during times of highest stress or demand on the system – typically during high-risk hours. Marginal accreditation ensures that the capacity value assigned to resources directly corresponds with their expected performance during these critical periods. This approach recognizes and appropriately compensates resources for their true value during periods of expected operational risk.

28. **Yields a reliability-neutral exchange rate** and allows for a substitutable product definition where accredited capacity can be exchanged on the margin with no

[3] Comments of Potomac Economics, Docket No. ER22-772-000, at 13 (Feb. 11, 2022).

expected change in reliability. Marginal accreditation establishes a framework where capacity resources are interchangeable or substitutable as they offer equivalent reliability contributions per accredited unit of capacity. This means that when one unit of accredited capacity is exchanged for another on the margin, the overall reliability of the system remains unchanged. This enhances reliability by mitigating the reliability impact of imperfect forecasting of the resource mix, as small changes from the assumed mix yield nearly equivalent reliability at the same total accredited MW level.

29. **Naturally reflects interactions between resource types in accreditation values.** A marginal accreditation approach inherently accounts for interactions across traditional thermal, renewable, storage, and other resources. When accrediting capacity, this method does not view each resource class in isolation but considers their value in the context of the broader system, leading to more accurate and representative accreditation values. A marginal accreditation approach recognizes how the demographics of the fleet influence overall system risk and how that impacts the accreditation of each resource.

30. **Captures synergies and diminishing reliability value among resources** without a need to allocate diversity benefits to classes. As the mix of resources on the grid changes, certain combinations of resources can lead to synergistic reliability benefits. Conversely, as the penetration of a particular resource type increases, its incremental reliability value might diminish. Marginal accreditation naturally captures these dynamics, ensuring that capacity values remain representative of each resource's actual contribution. This eliminates the need for arbitrary allocation of diversity benefits to specific resource classes, simplifying the accreditation process and increasing the level of objectivity and fairness in treatment across resource types.

31. Potomac Economics, the NYISO Market Monitoring Unit, summarized the benefits as follows in the FERC proceeding regarding marginal accreditation in NYISO:

> A marginal approach will pay resources based on their expected availability at times when reliability is most threatened. Marginal capacity values will naturally change over time as the resource mix and needs of the system change. This will appropriately align capacity payments with the incremental reliability impact that an investment or retirement decision would have on the system. Marginal capacity payments provide signals to invest in the most efficient mix of clean energy resources, build or maintain additional resources that are needed for reliability, and retire the surplus generators that provide the least reliability benefit.[4]

[4] Motion to Intervene and Comments of Potomac Economics, Docket No. ER22-772-000, at 3 (Jan. 26, 2022).

IV.C ANALYSIS OF BENEFITS OF ENHANCED RISK MODELING AND ACCREDITATION

32. I conducted simulation analysis to compare potential clearing results under the status quo Base Residual Auction design with those under the proposed capacity market with risk modeling and accreditation enhancements. The analysis analytically demonstrates, for one potential set of market conditions, as recently observed, the reliability and efficiency benefits expected from the PJM proposal on risk modeling and accreditation. I briefly summarize the framework and results of this analysis here, and provide additional details regarding the modeling framework and assumptions in an appendix to this affidavit.

33. From the most recent Base Residual Auction, conducted for the 2024/2025 delivery year, I used offers, load forecasts, and an assumed resource mix (for risk modeling). For the status quo case, I removed LDA internal capacity and Capacity Emergency Transfer Limit constraints and re-cleared the auction to yield an "unconstrained" RTO price. This maximized comparability with other cases given that not all LDA requirement levels had yet been assessed at the time of analysis. I incorporated updated resource accreditation consistent with the changes proposed, and translated offers to maintain the same total cost in dollars that were actually observed for each 2024/25 offer or offer segment. For example, suppose an 8 MW UCAP resource offered at $50/MW-day, reflecting costs of $400/day; if under the proposed changes the resource is now accredited at 5 MW UCAP, I updated the offer to $80/MW-day corresponding to the same $400/day total resource cost. I also updated the reliability requirement and Variable Resource Requirement ("VRR") curve, and re-cleared the auction.

34. For context, the 2024/2025 Base Residual Auction actual clearing quantity was 139,810 UCAP MW at a price of $28.92/MW-day. In this analysis under the "unconstrained" (no LDA constraint) status quo base case, the cleared quantity was 139,145 UCAP MW at $43.33/MW-day. This corresponds to a 15 percent reserve margin (that is, UCAP MW cleared relative to 50/50 summer peak load), which under the status quo risk modeling was believed to correspond to roughly a 1 in 100 LOLE and 75 MWh EUE. However, when I assess the cleared results from that status quo base case using the enhanced risk analysis as proposed, it reveals substantially lower reliability: roughly 1 in 40 LOLE and 350 MWh EUE (that is, over four times as much expected unserved energy as previously believed).

35. I then reran the 2024/2025 Base Residual Auction using the proposed enhancements to risk modeling and accreditation. The impact is such that the auction results clear a different set of resources and improve reliability to 1 in 50 LOLE and 260 MWh EUE, a 25 percent improvement in EUE relative to the status quo case. This outcome is the result of the combined effect of several moving pieces. Some resources have higher accreditation under the enhanced modeling than under status quo; these offer more UCAP megawatts at lower prices. Others (most) receive lower accreditation than before, and offer less UCAP megawatts at higher prices. Even before considering changes to the reliability requirement and VRR curve, these two effects in combination yield beneficial swapping of cleared and uncleared resources on the margin, yielding a more reliable cleared resource

mix. In addition, changes in the forecast pool requirement (driven by changes in risk modeling) and in Net CONE (driven by changes in the accreditation of the reference technology) shift the VRR curve upwards and to the left. This causes the market to be relatively less tight than without the demand adjustment, though in combination with the aggregate reductions in accreditation, there is an overall tighter supply-demand balance than under the status quo.

36. Total costs to consumers increase modestly from $2.2 billion in the status quo case to $2.4 billion in the enhanced design case. Further, the total supply cost (that is, total offered cost of cleared resources, equivalent to production costs in the energy market) actually *falls*, from $330 million to $310 million. These results suggest that the risk modeling and accreditation enhancements allow for more efficient clearing outcomes, improving reliability (25% decrease in EUE) at moderate customer costs (10% increase) and slight savings (5% decrease) in overall system-wide costs of supply by enabling PJM to identify and procure the low-hanging fruit of reliability beyond the margin. I believe this is a reasonable representation of the potential benefits of the proposed approach under relatively over-supplied capacity market conditions such as those that persisted in PJM in the early 2020s.

37. To investigate the potential impacts of the proposed changes under relatively tighter system conditions, I compared the outcomes under status quo to those under the PJM proposal under alternative, synthetic, assumptions of the supply/demand balance. In particular, I adjusted supply offers from the 2024/25 auction by scaling all UCAP quantities offered at a zero price by 90%, thereby contracting the supply curve. This yielded RTO clearing prices of $86.13/MW-day under the status quo case and $114.17/MW-day under the alternative case. I assessed the reliability outcomes and found that the cleared resources under the status quo case were expected to yield substantially worse reliability outcomes of 940 MWh EUE compared to 400 MWh EUE under the enhanced design case. In other words, the proposed design reduced unserved energy by nearly 60 percent when under tighter supply/demand conditions. Customer costs increased less than 20 percent, from $4.3 billion in the status quo case to $5.1 billion in the enhanced design case, while the total supply cost of cleared resources again fell slightly, from $500 million to $490 million. These results are consistent with those of other similar scenarios I tested (with different assumptions regarding the contraction of the supply curve) and indicate that the proposed design enhancements could substantially improve efficiency in clearing outcomes when the system is tight.

38. The analysis described above is indicative of the impact the proposed changes are expected to have on auction results under a range of system conditions, but it captures only a portion of the expected benefits of the proposal. This is because the analysis thus far has focused only on comparing outcomes for a single auction and a single delivery year, holding offered costs constant. This illustrates what may be termed the "short-run" benefits of the proposed changes. In the "longer-run," the proposal will also induce changes in exit, entry, and other investment behavior consistent with market participants maximizing profits under a different market regime. These effects, not captured here, will change participant offer behavior and levels, because the competitive offer level in one year depends on discounted future revenues, which are different under different accreditation levels

and auction outcomes. These "longer-run" changes would tend to magnify the reliability and efficiency benefits expected in the short term that are demonstrated in the indicative analysis above.

V. CAPACITY PERFORMANCE CONSTRUCT

39. PJM continues to believe in the importance of in-year, operational, event-based performance assessments to incentivize performance of committed capacity resources and re-allocate capacity revenues from relatively poor performing resources to relatively high performing resources, as the Capacity Performance construct does today. The proposed changes to the performance assessment framework aim to refine, not violently disturb, the Capacity Performance construct.

40. Before discussing those changes, it is valuable to place the Capacity Performance construct in the context of the overall RPM performance assessment and testing framework designed to help ensure delivery of the capacity that has been committed through forward auctions.

    a. **Generator Seasonal Rating Tests**. Assesses resources' ability to operate at committed ICAP in both summer and winter seasons. Relative to the status quo, PJM proposes to require physical demonstration of capability in each season, and remove excusals for inability to test to committed ICAP in each season. As today, a daily commitment deficiency penalty would be assessed for resources that have insufficient UCAP. The Daily Deficiency Rate set at the applicable clearing price ($/MW-day) for the resource plus the greater of $20/MW-day and 20% of clearing price.

    b. **Generator Operational Testing.** Allows PJM-initiated testing of generators' availability status to better ensure they are capable of operating if and when needed for reliability, up to twice in each season (summer and winter), excluding re-tests following a failed test.

    c. **Capacity Performance Assessment Intervals.** Enhanced assessment of performance during times of highest system reliability risk.

41. Returning to the Capacity Performance construct, there exists a tension across three natural design criteria for performance assessments, requiring compromise across them: (a) the value of sufficiently strong incentives, (b) the value of assessments focused on hours of risk, and (c) the value of limiting risk of atypical under-performance.

42. The primary components of the Capacity Performance framework include the elements below. The design enhancements PJM proposes to these elements aim to strike a different balance across those competing design criteria.

    a. Definition of a Performance Assessment Interval ("PAI"),

    b. Non-Performance Charge and bonus rate,

    c. Stop-loss, i.e., maximum penalty for an under-performing resource,

    d. Assessed resources, i.e., resources that are eligible for penalty and bonus,

e. Balancing Ratio, i.e., the threshold between penalty and bonus, and

f. Rules regarding performance excusals.

V.A DEFINITION OF A PAI

43. A PAI occurs when certain system conditions are met. PJM recently filed and the Commission accepted a change to remove certain existing triggers (e.g., deployment of pre-emergency Demand Resource) and more narrowly focus on a set of triggers that reflect times of greater reliability risk. PJM does not propose further changes on this element.

44. Focusing the timing of assessments on hours of highest reliability risk aligns the financial risks with the periods for which we procure capacity—during system stress events. This alignment ensures consistent incentives for real-time performance and fosters prudent investments, maintenance, and preparations to mitigate risk and enhance performance. Further, this timing aligns with the fundamental definition of capacity in the PJM design, which is focused on hours of operational risk. Any divergence in the value of real-time capacity product from hours of risk would misalign incentives, creating a disparity between resources' accredited value, which is aligned with performance during hours of risk in our marginal accreditation concept, and the different incentive introduced by the performance assessment.

45. For example, consider a 100 MW ICAP resource accredited at 10 MW UCAP due to high correlation of its outages with other resources' outages and elevated risk. Such accreditation enables the resource to receive compensation commensurate with their expected contribution to resource adequacy, equivalent to 10 MW of perfect, always available capacity. Suppose the resource is expected to perform substantially better during performance assessment intervals under an alternative, broader definition of Performance Assessment Interval triggers, such that its average availability and performance during the broader definition equals 20 MW. Even though the additional performance during non-emergency assessed intervals does not improve system resource adequacy, the resource would expect to receive Capacity Performance bonus revenues for performing above committed UCAP. This re-distribution of capacity revenues works against and partially reverses the benefits of the proposed accreditation changes and harms incentives to invest in enhancing performance during the system conditions most strongly associated with loss of load risk.

V.B NON-PERFORMANCE CHARGE AND BONUS RATE

46. The Non-Performance Charge rate is the \$/MWh rate paid by resources that underperform and allocated to resources that over-perform. Currently the Non-Performance Charge rate is proportional to the Net Cost of New Entry (Net CONE) and is today (in the 2023/2024 Delivery Year) approximately equal to \$3,350/MWh; PJM does not propose to change the rate. This retains the relatively high penalty rate for resources that fail to perform during the hours of greatest reliability risk. As discussed above, this provides strong incentives in both the

forward time frame (e.g., for investment decision) and in the operational time frame (e.g., for fuel purchase and other operational decisions).

47. The bonus rate calculation is determined by the ratio of the total amount of charges collected by under-performers divided by the total MWh of over-performance. PJM has proposed and most package sponsors adopted a small modification to better equalize the penalty and bonus rates, such that an MWh of under- or over-performance is more nearly equally valued during PAIs (further discussed below in section V.E).

V.C NON-PERFORMANCE CHARGE STOP-LOSS

48. The stop-loss is the maximum amount of Non-Performance Charges, in dollars, that a resource can accrue in a given Delivery Year. This provision is in place to ensure that Non-Performance Charges to a Capacity Resource are bounded. Currently the stop-loss is set based incurring Non-Performance Charges up to a level of 1.5*Net CONE*Committed Capacity*365 (1.5x Net CONE in shorthand). PJM proposes to reduce the stop-loss to 1.5 x applicable Base Residual Auction clearing price. For clarity, the stop-loss applies to the total gross Non-Performance Charges incurred by individual resources and would not imply any RTO-wide limitation on the number of PAIs.

49. The primary driver of this change was to reduce the tail-end risk of the most extreme Non-Performance Charges that could harm the investability of the PJM markets. An assessment and incentive structure with a high Non-Performance Charge rate and a high stop-loss places substantial idiosyncratic risk on Capacity Market Sellers. Given the relatively low number of PAIs, the Law of Large Numbers does not guarantee that any given resource's average observed performance matches their long-term average or capability. Thus, a resource with high underlying, natural, "expected" performance may nevertheless face substantial penalties. This risk, borne by Capacity Market Sellers, imposes real societal costs, and reasonably would be expected to be reflected in sellers' offers; ultimately, the cost of the risk may be borne partially or substantially by consumers. In other words, the potential, however unlikely, for a Capacity Market Seller to lose multiple years of capacity revenues for non-performance in a single event may deter future investments in PJM's markets, ultimately undermining the competition that the capacity market needs to meet the twin objectives of reliability and efficiency.

50. Reducing the stop-loss should not have a significant impact on the overall incentives provided by the Capacity Performance construct, for two reasons. First, the changes to the accreditation methodology substantially improve the alignment between resources' accredited levels and the level of expected performance during PAIs. Enhancements in the resource testing framework further mitigates the risk of systematic underperformance. Thus, risk that a resource is systematically over-accredited is substantially mitigated. This increases the probability that resources will perform at or near expectation during capacity emergencies reduces the likelihood of exceeding the stop-loss.

51. Second, the recently approved change in the PAI definition and triggers in Summer 2023 has focused PAIs on only the most extreme circumstances such that under the prior and current definition, the new definition is likely to produce less PAI. As an example of the impact of this change, PJM has conducted an analysis of the potential and likely future impact of the recent PAI trigger changes during Winter Storm Elliott. Between the 23rd and 24th of December, 2022, there were a total of 277 five-minute intervals (23 hours) that met the definition of a PAI under the previous PAI definition, which prevailed at that time. Only 73 intervals (6 hours) of the Winter Storm Elliott events would have been PAIs under PJM's current RAA/Tariff rules.

52. Even during Winter Storm Elliott no resource met the stop-loss, nor would have met the stop-loss under the proposed rules given the applicable BRA price. Thus, this change would likely have little impact on the operational or investment incentives associated with a future potential event of the magnitude of Winter Storm Elliott.

V.D ASSESSED RESOURCES

53. Under current rules, any resource or transaction that out-performs its committed level during a PAI is eligible for a bonus credit. This can include energy-only resources, partially committed capacity resources, and import transactions from neighboring regions. PJM proposes to instead limit the pool of resources that are assessed during PAIs to only committed capacity, such that resources must meet the capacity qualification criteria and accept the obligations associated with a commitment to be eligible to receive any capacity revenues, including capacity PAI bonus revenues.

54. Under this proposal, resources would be eligible to receive bonus payments for performing up to committed ICAP if such performance exceeds the level of performance expected of them, given the balancing ratio (discussed in a later sub-section below). Non-committed capacity resources, non-capacity resources, and imports not associated with committed pseudo-tied external resource would not be eligible for bonus.

55. This change further clarifies the differences between the capacity product and the energy product. As described at the start of this affidavit, the capacity product is a *commitment* to perform, around which PJM can plan for the reliable operation of the system. The capacity product requires that the resource's output be assessed as deliverable to load, and that such deliverability is supported by Capacity Interconnection Rights. The capacity product implies a commitment to compliance with a number of testing requirements to ensure that the resource is ready and capable of performance when needed by PJM, to the extent it is possible to do so under the conditions that occur in the delivery year. And the capacity product carries with it an obligation to offer into the wholesale energy and ancillary services markets. None of these requirements apply to energy-only resources, and only some apply to non-committed capacity resources.

56. In short: a resource that has not sold the capacity product, has not taken on a capacity obligation, and has not met all requirements associated with that is not

providing the capacity product by simply providing energy during a performance assessment interval. Under the revised capacity performance framework and other capacity product definition changes, capacity performance is no longer intended to be a replacement or substitute for sufficiently robust energy & ancillary services prices. It is not clear why the incentives for performance for non-capacity resources must or should come from the capacity market. In fact, these incentives are much more naturally found in the energy & ancillary services markets.

57. Ultimately the status quo capacity performance framework effectuates a re-distribution of capacity revenues, including to resources that would never qualify to participate in the PJM capacity market. Non-capacity resources can, in expectation, earn capacity revenues even though they would never qualify to offer the capacity product or receive a capacity commitment. This also applies to resources that could qualify but chose not to participate, as well as to resources that did participate in the capacity market but *through their offer level indicated an unwillingness to accept a capacity obligation at the prevailing price.* The proposed change seeks to provide a more consistent definition to the capacity product, and the compensation for that product, by limiting *capacity* revenues to just those resources that meet the qualification criteria to be capacity and have been committed as capacity in the market.

58. Furthermore, relative to the status quo, this proposal reduces the capacity revenues transferred to non-committed and non-capacity resources during PAIs, making it relatively more attractive to accept a capacity commitment and the corresponding obligations. Because there is no expectation of bonus revenue for uncommitted capacity, there is no foregone bonus revenue when a resource takes on a commitment. In other words, the opportunity cost associated with bonus payments associated with Capacity Performance for selling capacity is eliminated under the proposed design. This will incent resources to more readily offer capacity in the forward auctions and provide the forward, planning value that committed capacity resources bring to the system and that uncommitted resources may not. This also recognizes the difference in value provided by a committed capacity resource that takes on testing obligations and energy must offer obligations compared to an energy-only resource that does not have these additional requirements.

59. There are a few additional impacts that naturally result from the proposed change in assessed resources during PAIs that are worth noting. First, the incentive to perform for non-committed capacity and energy-only resources, as well as energy-only imports, is directionally lower during PAIs when they are not eligible to receive a portion of capacity revenues during PAIs. Nonetheless, this proposed change to limit the pool of capacity compensation to committed capacity resources is reasonable for the reasons provided above, and the appropriate market price for those resources providing energy or ancillary services at the time of a PAI, but that have not been cleared or committed as capacity, is the relevant prices in the energy and ancillary services markets, with which the incentive provided by high energy prices during triggered PAIs (i.e. reserve shortages) is not negligible.

60. In addition, the proposed change renders Demand Resource and Price Responsive Demand ineligible for bonus payments, as the Expected Performance of those

resource types during PAIs is set at the committed ICAP level of the resources, which implicitly limits the performance considered in the assessment to no more than the amount that's expected to perform. Notwithstanding, the netting of performance across underlying customers, registrations, and resources that are dispatched during a PAI is still allowed, such that the "over-performance" of any dispatched Demand Resource can still be used to offset the under-performance on another resource in the CSP's account during a PAI. This appears to be a reasonable and non-discriminatory outcome. There are two ways that Demand Resource (or any resource) could be eligible for a bonus payment under the status quo Capacity Performance design: (1) performance of uncommitted capacity, and (2) performance of committed capacity at committed level when the balancing ratio is below unity.

61. Regarding the first point, bonus compensation for performance of uncommitted capacity is being eliminated for all resources. A Demand Resource only commits to reducing load to the Firm Service Level ("FSL") and is accredited for the value of this reduction. Any reduction below FSL would be uncommitted capacity as the underlying load did not accept a capacity commitment for such additional curtailment.

62. Regarding the second point, under the status quo, Demand Resources and Price Responsive Demand are already ineligible for bonus compensation for performance above balancing ratio. "Expected Performance," or the level against which performance is assessed for the purposes of PAI settlements, is set at ICAP (rather than UCAP * Balancing Ratio) and PJM does not propose to change this. The rationale for this design choice is that the commitment that Demand Resources take on is to reduce load to the FSL, not, like Generation Capacity Resources, to provide output up to a certain level. The expected resource adequacy value of such reduction to FSL is assessed in the accreditation and risk analysis, where the load available to curtail is modeled as scaling proportionally with the level of system load. The balancing ratio falling below one during a Performance Assessment Interval corresponds to an event when system load was below the total amount of capacity procured. Because Demand Resource load is modeled as scaling proportionally with system load, the load underlying the Demand Resource would be expected to naturally fall below such load's peak load contribution during the event. When such a resource curtails load to FSL, the amount of curtailment value actually provided is not equal to UCAP but rather is expected to equal UCAP times the balancing ratio. Thus, because the Demand Resource is providing value exactly equal to that which was assumed during accreditation, there is no over-performance to compensate.

63. Energy Efficiency Resources are also ineligible for bonus compensation under the proposed design. This element is a straightforward application of the proposed design. As there is no way to conduct in-year assessments of the value that Energy Efficiency Resources provided during performance events, there does not appear to be any basis to compensate for over-performance.

V.E BALANCING RATIO

64. The Balancing Ratio is used in determining the level of expected performance from committed generation during PAIs. It is intended to capture the amount of generation needed from committed resources to meet the system load during a PAI. For example, if system load during a PAI is at 120 GW and the total amount of committed generation on the system is 160 GW, the Balancing Ratio for the PAI would be set at 75%.

65. PJM proposes straightforward modifications to the Balancing Ratio formula to reflect the proposed changes to assessed resources and to adjust for excused MW, better balancing the penalty rate and bonus rate during PAIs.

    a. Balancing Ratio Numerator = Total Committed Generation Capacity Resource's Actual Performance (capped at the committed ICAP of each resource). No Net Energy Imports or Demand Resource/Price Responsive Demand Bonus MW.

    b. Balancing Ratio Denominator = Total Generation Committed UCAP (reduced for committed MW that are excused from the assessment)

66. These changes serve to reduce the potential differences between the Non-Performance Charge rate and bonus rate. Under the status quo calculation of the Balancing Ratio, a significant disparity can be introduced because the Balancing Ratio is invariant to the amount of excused resources. For example, suppose the Balancing Ratio was calculated under the status quo design. If one-quarter of the resources with Actual Performance below Expected Performance were excused, the total penalties collected would be reduced by roughly one-quarter. This reduces the available bonus pool to be distributed across resources with Actual Performance above Expected Performance. Thus, the bonus rate would be reduced by roughly one-quarter.

67. The proposed change has at least two benefits. First, improving the symmetry between Bonus and Penalty rates better aligns the marginal incentives of committed capacity resources that over-perform compared to those that under-perform during a PAI. Second, it better allows market participants with over-performing resources to use the bonus revenues collected for such over-performance to net against non-performance charges on a MW-for-MW basis.

V.F RULES REGARDING PERFORMANCE EXCUSALS.

68. The current rules regarding when a resource with a capacity commitment may be excused from performance during a PAI lack clarity on certain specific operational circumstances. The changes PJM proposes are primarily clarifying changes regarding the limited cases in which offline resources are excused. Recent experience administering the Non-Performance Charges following Winter Storm Elliott confirmed earlier concerns regarding the urgent need for clarification.

69. The tariff language describing excusals is now clear that offline resources shall not be excused except when on planned or maintenance outages previously approved by PJM and when given direct manual dispatch instructions to turn or remain

offline. Online resources, if underperforming, may only be excused for partial planned and maintenance outages previously approved and reductions in output due to transmission system limitations communicated via manual dispatch instructions or security-constrained economic dispatch ("SCED").[5]

V.G ADDITIONAL CAPACITY PERFORMANCE REFORMS

70. PJM proposes two additional Capacity Performance-related changes which I discuss in this section: first, to remove the option for Fixed Resource Requirement ("FRR") Entities to elect a physical penalty assessment and instead apply the same financial assessment to all committed capacity; and second, to enable more granular transactions of the PAI obligations associated with committed UCAP.

71. Under the status quo Capacity Performance design, FRR Entities are provided the choice of either a physical or financial penalty assessment in the event of non-performance of resources in their portfolio. The physical penalty assessment requires non-performing entities to provide additional, "physical" capacity in the following delivery year as compensation for their non-performance. However, maintaining two distinct penalty mechanisms could lead to inequities in treatment for differently situated market participants and may ultimately under-incentivize performance during PAIs by FRR Entities. PJM is thus proposing to move to a singular, financial penalty assessment for all market participants. This approach:

   a. **Reduces inequities in treatment.** Different penalty mechanisms can lead to disparities in how similarly situated market participants are treated. For instance, two entities with similar under-performance could face substantially different consequences, one more severe than the other, simply based on their choice of penalty mechanism. This can result in perceived or actual unfairness, undermining trust in the market's ability to effectuate equitable outcomes.

   b. **Ensures strong and consistent incentives for performance during PAIs.** The financial incentives associated with PAIs are set at high levels to reflect the genuinely high potential costs of non-performance during periods of heightened risk. When an FRR Entity that has elected the physical penalty underperforms, its subsequent commitment to bring additional capacity in the following delivery year does not adequately compensate the system or other PJM participants for the risk caused by this under-performance. This is fundamentally because capacity is not interchangeable or fungible across different Delivery Years. More specifically, having an excess of committed capacity in one Delivery Year, when the amount of reliability risk is uncertain, likely does not provide the same level of system reliability as what was compromised by falling short by an equivalent quantity during an actual operational risk event. As such, the emphasis on the importance of

[5] For clarity, online units are excused if LMP-desired (that is, the level of output that would be economic based on a resource's dispatched schedule, absent ramp constraints) falls below the expected performance level.

an FRR Entity fulfilling its capacity commitments during these crucial operational events within the specified Delivery Year cannot be understated. The penalties and incentives must be sufficiently robust to ensure that the committed capacity is available when it's most needed.

72. PJM proposes to introduce a new mechanism that allows Capacity Market Sellers to exchange the PAI obligation associated with committed UCAP at up to interval-level granularity. The primary motivation for this proposed mechanism is to enable Capacity Market Sellers to more effectively manage Capacity Performance risk and to provide for greater opportunity for the financial PAI obligation to be backed by a physical hedge.

73. By allowing for more granular transfers of the PAI obligations associated with committed UCAP, Capacity Market Sellers are granted increased flexibility to adjust their positions and manage their exposure to Capacity Performance risk in response to both unexpected and expected events. Capacity Market Sellers can mitigate their exposure to Capacity Performance risk by reacting promptly to unforeseen changes in their expected availability, such as when they face a higher probability of forced outages, and transacting the PAI obligation with a different market participant who is available and able to essentially offer insurance against under-performance during potential PAIs.

74. The ability to transfer PAI obligations on a granular basis also provides Capacity Market Sellers with a broader array of opportunities to hedge their positions. In the existing framework, there often exists a mismatch between static UCAP-based financial obligations and a resource's expected physical availability. This discrepancy is particularly acute for intermittent resources with diurnal patterns but also applies to resources whose probability of availability may vary in more complex ways depending on weather patterns and other system conditions. With the proposed changes, Capacity Market Sellers can more closely match their financial obligations with the expected availability of their physical resources. This alignment both reduces individual participants' Capacity Performance risk and also helps to ensure that there is a physical backing for financial commitments, enhancing the system's reliability and robustness. Having a physical hedge means that the system can count on actual energy or capacity being available when required, reducing the risk of shortages or reliability issue. Furthermore, this alignment means that Capacity Market Sellers may be able to reduce their total exposure to uncertainty in Capacity Performance bonus revenues and Non-Performance Charges, thus reducing their overall Capacity Performance Quantitative Risk ("CPQR").

75. The following table summarizes the key elements of the proposed PAI obligation transfer.

Design Element	Existing Transfers and Replacements	Proposed PAI Obligation Transfer
Product	Committed UCAP	PAI Obligations of Committed UCAP
Maximum Obligation	Owned UCAP	Lesser of owned ICAP and CIRs
Locational Constraints	Recognizes LDA constraints	Status quo rules on replacements
PAI Impact	Adjusts committed MW in PAI shortfall calculation for all intervals in day	Adjusts committed MW in PAI shortfall calculation for applicable intervals
Other Impacts	Impacts other obligations (e.g. energy market must offer, testing requirements)	No impact beyond PAIs
Indemnification	Seller indemnifies PJM if buyer can't pay	Seller indemnifies PJM if buyer can't pay

VI. MARKET POWER MITIGATION AND MARKET SELLER OFFER CAP

76. The fundamental objective of market power mitigation in the capacity market is to return the capacity market to outcomes that would prevail in a competitive market: one with prices reflecting marginal value and the marginal economic costs of competitive market participants. Accomplishing this objective requires mitigation of uncompetitive offers to competitive levels. For each Capacity Resource offered into the capacity market, the competitive offer level is the expected profit-maximizing offer for a competitive Capacity Market Seller—that is, one that does not have the incentive and ability to affect market prices through their offer quantities and/or levels. Ultimately, the competitive offer level is the price below which the costs of accepting a capacity obligation exceed the benefits (net profits) from doing so, and below which a competitive seller would prefer not to clear.

77. Economic theory reveals that a competitive Capacity Market Seller's profit-maximizing offer is equal to their economic costs of offering the resource into the capacity market, accepting the capacity commitment, and complying with all relevant obligations of a Capacity Resource. Thus, the competitive offer level must necessarily reflect all economic costs of the resource. Those economic costs include all costs that a competitive Capacity Market Seller would consider when making an offer.

78. Economic costs for a competitive seller are *going-forward net avoidable costs*:

a. *going-forward*: costs that have not yet been incurred; costs that are not sunk;

b. *net*: costs net of revenues that are enabled by choosing to experience the costs; and

c. *avoidable*: costs that can be avoided if not supplying the good/service.

79. Thus, the relevant costs that a competitive Capacity Market Seller would wish to represent in a capacity offer are any and all costs that have not yet been incurred and could be avoided by not selling capacity, net of any revenues that are enabled by the Capacity Market Seller choosing to incur the costs and sell capacity.

80. There are two scenarios under which these relevant costs would substantially differ. The first scenario is that of a Capacity Market Seller who receives insufficient revenues from the energy and ancillary services markets (the "E&AS Offset") alone to justify the continued profitable operation of a resource. Such a Capacity Market Seller would rationally plan to retire or mothball their resource if they receive insufficient capacity market revenues to support continued operation. A competitive offer for such a Capacity Resource would reflect the full economic costs of selling capacity: the total gross going-forward avoidable costs of continuing to operate the resource rather than retiring or mothballing, net of the energy and ancillary services revenues that are enabled by the choice to continue operating the resource.

81. The second scenario is that of a Capacity Market Seller who does receive sufficient revenue from the energy and ancillary services markets to justify continued profitable operation of the resource, without additional capacity revenues. Such a resource is profitable and not at risk of mothball or retirement. However, a competitive Capacity Market Seller, given the choice, would not willingly accept a capacity obligation at any arbitrarily low price. Rather, they would choose to offer the capacity from such a resource according to the same economic framework outlined above: the offer would reflect economic costs, equal to going-forward net avoidable costs—only those costs that could and would be avoided by not selling capacity. Of the components currently included in the PJM Avoidable Cost Rate (ACR"), CPQR is clearly avoidable if not committed for capacity; all or parts of other ACR components may also be avoidable in certain circumstances (for example, a resource that incurs costs to arrange firm fuel that they would not incur absent a capacity obligation).

82. Thus, a Capacity Market Seller who plans to continue operating a profitable Capacity Resource regardless of their single-year revenues in the capacity market has economic costs at least as high as CPQR; it follows that the natural, profit-maximizing offer for such a Capacity Market Sellers and such a resource is at least as high as CPQR.

83. The PJM proposed changes to the Market Seller Offer Cap calculation follow this logic. Under the proposed design, Capacity Market Sellers would be enabled to reflect avoidable costs and foregone relative to those they would face given the unit's operating state if not cleared in the capacity market:

a. **Mothball/Retirement:** MSOC = Net ACR = Gross ACR – E&AS Offset, where avoidable costs in Gross ACR are determined relative to those incurred if the unit were to not operate for the year and mothball or retire, as applicable;

b. **Continue Operating:** MSOC = Gross ACR, where avoidable costs in Gross ACR only include the incremental costs of taking on a capacity obligation relative to continuing to operate and participating solely in E&AS markets (e.g., CPQR).

84. As an example of the issue with the current mitigation levels, consider a Capacity Market Seller with a gross avoidable cost rate of $50/MW-day, of which $10/MW-day is the CPQR component. Suppose this resource has a net E&AS offset of $60/MW-day. Under the status quo mitigation framework, the seller would be required to offer the capacity for this resource at $0/MW-day. However, the seller would prefer to not clear the capacity market unless they expect to receive more than $10/MW-day, offsetting the costs they *actually face* by selling capacity. In a competitive market, this seller would not offer less than $10/MW-day. Under the PJM proposal, the example seller would be able to offer the resource at their economic going-forward net avoidable costs, which are equal to the CPQR of $10/MW-day.

85. Certain objections raised to this proposal were raised during the stakeholder process. One such claim is that a resource expecting to receive excess profit in the E&AS market, sufficient to offset fixed and variable costs of continuing operation as a capacity resource, in fact do have net avoidable costs of zero. Such objections are not grounded in the economics of competitive markets. As described above, the purpose of the market power mitigation framework is to return the market to competitive outcomes. If the capacity market were a competitive market, no market power mitigation would be needed. In such a market a Capacity Market Seller facing non-zero CPQR or other going-forward avoidable costs would not offer to sell capacity below the level of those costs.

86. The capacity must-offer obligation imposed by the market power mitigation construct is *not* a must-clear or must-sell obligation. It is an obligation to offer as a competitive market participant would. Such a competitive participant would avoid CPQR by not selling capacity. Therefore, a competitive Capacity Market Seller should not be willing to accept a capacity obligation (and associated risk) for free, because they take on additional costs when selling capacity, compared to a baseline assumption of continuing operation without selling capacity. This is true even if the resource expects net profits in the E&AS market sufficient to offset their fixed and variable costs.

87. In summary: to accomplish the fundamental objective of market power mitigation—returning capacity market outcomes to those that would prevail in a competitive market—capacity offers cannot be mitigated below those levels equal to the natural, profit-maximizing offers of competitive Capacity Market Sellers. Such over-mitigation yields uneconomic outcomes. In order to avoid uneconomic over-mitigation, the Market Seller Offer Cap must reflect and allow all demonstrable net going-forward avoidable costs of selling capacity.

88. Indeed, this proposed approach is consistent with the formulation of bids in the ISO-NE Forward Capacity Market, where static delist bids (parallel to PJM capacity offers) are allowed above the dynamic delist bid threshold at the level of net going-forward costs, which are a function of going-forward costs minus energy and ancillary service market infra-marginal rent.

89. As described in ISO New England Inc. ("ISO-NE") training materials, going-forward costs are those "[c]osts reduced or avoided by not having a capacity supply obligation" and explicitly are "incremental costs" and "may be different if a resource is active versus inactive in energy markets."[6] In particular, if a "[p]articipant has negative outlook on market conditions during capacity commitment period," then the "[g]oing-forward cost (GFC) estimate includes all costs avoided from not participating in capacity, and energy and ancillary service markets" and "[i]nfra-marginal rents (IMR) are deducted from GFC estimate to account for portion of total avoided costs otherwise recovered through energy and ancillary service markets."[7] Alternatively, if a "[p]articipant has positive outlook of market conditions during CCP" then the "[g]oing-forward cost (GFC) estimate includes all costs avoided if resource were not participating in capacity market only" and "[c]osts incurred due to decision to remain in energy and ancillary service markets are excluded; infra-marginal rent (IMR) is set to zero."[8] The ISO-NE tariff further elaborates:

> GFC = annual going forward costs, in dollars. These are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period.

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[6] Ryan Hoskin, *FCM Delisting: Participant Training Webinar*, ISO New England, 23 (Feb. 9, 2023), https://www.iso-ne.com/static-assets/documents/2023/02/20230209-fcm-delisting.pdf ("FCM Delisting Webinar").

[7] FCM Delisting Webinar at 25.

[8] FCM Delisting Webinar at 26.

IMR = expected annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all submitted cost data representing the cumulative expected cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00.[9]

90. Further, the ISO-NE approach allows for the inclusion of "risk premium" costs, including costs stemming from exposure to Pay-for-Performance charges. These costs would not be offset by infra-marginal rents when a resource plans to continue operating in the energy and ancillary services markets, as the value of the infra-marginal rent used in the determination of net going-forward costs is $0.00. The full delist bid formulation is provided in the ISO-NE training materials as follows:[10]

$$NGFC = \frac{[GFC - IMR] \times InfIndex + RP + CPP}{(CQ_{summer}, kW) \times (12, months)}$$

Where:

- **NGFC** is *net going-forward costs*
- **GFC** is *going-forward cost* including opportunity cost
- **IMR** is *infra-marginal rent*
- **InfIndex** is four-year expected inflation rate as published by the Cleveland Federal Reserve Bank
- **RP** is *risk premium*
- **CPP** is expected *capacity performance payments*
- **CQ_{summer}** is summer *qualified capacity*

91. In short, the proposed PJM approach is entirely consistent with ISO-NE's approved methodology today.

VI.A STANDARD CPQR APPROACH

92. PJM proposes to introduce a standard approach to estimate resource-specific CPQR based on assessment of resource-specific Capacity Performance risk given

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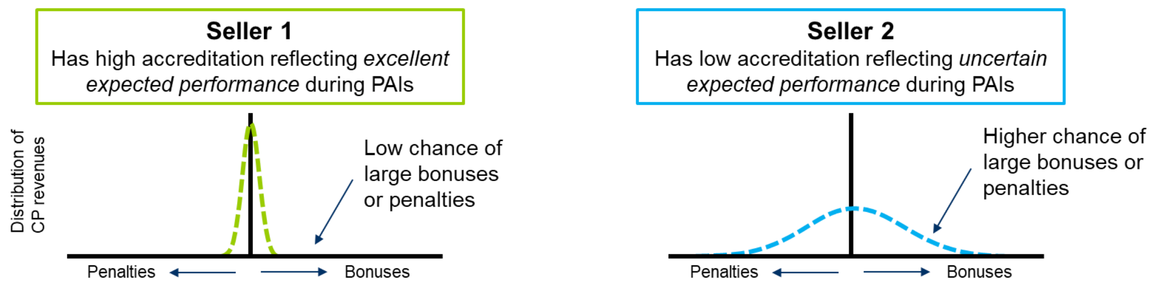
[9] ISO New England Inc. Transmission, Markets and Services Tariff, section III.13.1.2.3.2.1.2.A.

[10] FCM Delisting Webinar at 22.

historical performance. Such an approach would provide an acceptable starting point for CPQR that PJM will accept as reflective of the expected costs of a competitive participant to mitigate and manage the risks associated with a Capacity Performance obligation. It helps to improve transparency regarding the CPQR calculation for all market participants, including suppliers as well as load interests with cost concerns. In the remainder of this section I describe and provide rationale for the proposed approach.

93. CPQR is generally intended to reflect both expected net penalties and the cost of risk incurred by a risk-averse Market Participant from facing an uncertain distribution of delivery-year penalties and bonus revenues. Competitive Capacity Market Sellers naturally evaluate the capacity price at which they would be willing to accept capacity performance penalty risk. Suppose both of the following sellers envision a distribution of penalties and bonuses that on average cancel out such that the *expected value* of Capacity Performance bonus plus penalties is zero.



94. In this example, although there is no net bonus or penalty *on average,* neither seller should be willing to take on the risk for free nor could mitigate the risk for free. Both sellers would express a cost of accepting the risk in their offers, even if positive outcomes exactly offset negative outcomes *in expectation.* Seller 2 has a higher cost of risk (and cost of mitigating risk) and wishes to express higher offer price.

95. To implement the standard CPQR approach and reflect such differences across resources, PJM proposes an approach that is broadly consistent with the PJM Independent Market Monitor's simulation-based approach which reflects weather experienced during historical PAIs and condition probabilities (based on weather) for estimating the number of PAIs and unit outage probability.[11] In PJM's proposal, for each resource PJM would conduct a probabilistic analysis of unit-specific performance under a range of system conditions, using the same enhanced analytical framework used to study reliability risks and assess resource accreditation. This analysis would yield a distribution of performance during simulated PAIs, as well as other parameters (Balancing Ratio, etc.) necessary to assess the distribution of potential net Non-Performance Charges and bonuses.

[11] Joe Bowring & Siva Josyula, *CPQR Simulation Example*, PJM Interconnection, L.L.C. (June 10, 2022), https://www.pjm.com/-/media/committees-groups/task-forces/rastf/2022/20220613/item-03---cpqr-methodology-and-examples---imm.ashx ("CPQR Simulation").

96. The competitive cost of mitigating this quantified risk would then be assessed using a straightforward "value at risk" analysis. The standard CPQR would be calculated as the product of the extreme *value* at risk and the percentage *cost* of this risk:

Standard CPQR = Risk Cost × Extreme Value

97. In choosing a standard methodology for estimating CPQR, or the cost of managing the risk of Non-Performance Charges, there is not a singularly acceptable way to assess and value financial risk. The analytical approach selected by PJM for the standard CPQR methodology builds on one commonly used measure, the value at risk ("VaR"). This analytical approach estimates, using historical data or simulation-based analysis, the distribution of potential financial outcomes over a period of time, and then considers the potential exposure to financial losses at a pre-defined percentile level of that distribution. With respect to CPQR, PJM is proposing to use a probabilistic model, consistent with the one used for resource accreditation, to assess the distribution of potential annual net Non-Performance Charges that a resource may face in the Delivery Year, and then from that distribution, take the maximum exposure to Non-Performance Charges at a pre-defined confidence interval typically used in this VaR analysis, the 95th percentile. That risk exposure, which is generally intended to reflect an extreme value on the tail of the distribution, is then multiplied by an estimated cost of managing the risk to determine the CPQR value.

98. The probabilistic model used in the reliability risk analysis and accreditation of resources, or ELCC model, provides a robust and reasonable approach to assess the distribution of potential net Non-Performance Charges a resource may face in the Delivery Year as it already integrates many of the relevant factors that impact the calculation of net Non-Performance Charges. These factors include performance of the resource, which is simulated in the accreditation model under a broad range of system conditions and weather scenarios, the number and timing of modeled PAIs, which can be simulated in the model when the available supply falls below the load and reserve requirement in an hour, representing a reserve shortage and trigger for a PAI, as well as the parameters that feed into the Balancing Ratio and expected performance of resources to determine shortfall or bonus MW during the simulated PAIs. The other key factors that influence the calculation of net Non-Performance Charges that a resource may face in the Delivery Year are either known values, such as the Non-Performance Charge rate, or are values that will be estimated outside of the model and used as inputs to the probabilistic analysis, such as the annual stop-loss for the resource.

99. This approach is widely regarded as a prudent and methodologically sound practice within this context. Indeed, the ISO-NE internal market monitor "agrees that an industry-standard [VaR] approach is an acceptable framework for participants to manage and measure risk in the context of the Pay-for-Performance] capacity market" and further describes that "[VaR] and similar measures are widely used by financial institutions and businesses to measure risk

and determine whether action is needed to bring risks within acceptable corporate risk tolerances."[12]

100. Establishing the threshold at the 95th percentile is commonly accepted as a reasonable measure of a typical extreme value that is placed at risk (with some small probability) when facing the distribution of potential outcomes. This is consistent with application of the VaR methodology by the ISO-NE internal market monitor when designing a framework for "measuring and valuing risk that addresses resource-level specific risk factors under the Pay-for-Performance construct:"[13] "[t]he IMM applied the VAR approach by calculating the estimated loss at the 95th percentile of possible Capacity Scarcity Condition hours (H). In other words, the IMM set a one-in-twenty maximum acceptable net loss. However, rather than pricing the exposure dollar-for-dollar, the IMM placed a cost of risk for negative income at the chosen exposure level."[14] Furthermore, the 95th percentile was also used as an example of a reasonable choice of extreme value in the similar framework proposed by PJM Independent Market Monitor.[15]

101. The ultimate cost of mitigating or managing the Capacity Performance risk depends on the cost of reducing or hedging the maximum loss a participant is likely to incur once in 20 years (the 95th percentile loss identified above), that is, the cost of pursuing risk-management transactions including "entering financial hedges, acquiring insurance, or diversifying the participant's portfolio of risk assets."[16] The proposed VaR analysis uses an estimated cost of managing the extreme value risk reflecting a typical after-tax weighted average cost of capital ("ATWACC"). The ATWACC represents how much a company pays for capital, adjusted for taxes. It takes into account the cost of debt (interest rate), the cost of equity (expected equity returns), the company's debt-to-equity ratio, and the tax shield from interest payments on debt. It can also be thought of as representing the opportunity cost of capital for a firm, and is the minimum return that a company needs to generate on its investments to satisfy its investors (debt holders and equity holders).

102. Investors put their money in various assets with the expectation of a return. But all investments come with some level of risk. The riskier an investment is perceived to be, the higher the return investors will demand to compensate for that risk. This is known as the risk-return tradeoff. This impacts a company's cost of capital as follows:

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[12] Informational Filing for Qualification in the Forward Capacity Market by ISO New England Inc., Docket No. ER15-328-000, Attachment B (Internal Market Monitor Review of De-list Bids for the Ninth Forward Capacity Auction: A Methodology Document), at 12 (Nov. 4, 2014) ("Internal Review").

[13] Internal Review at P 13.

[14] Internal Review at P 14.

[15] CPQR Simulation at 21.

[16] Internal Review at P 12.

a. The **cost of equity** is determined by the perceived riskiness of the company's equity shares. If investors perceive the company to be risky, they demand a higher return on equity, which in turn raises the WACC.

b. If the company is considered a credit risk (meaning there's a higher chance it might default on its debt), lenders will demand a higher interest rate, raising the **cost of debt** and thus the WACC.

c. If a company is heavily financed by more expensive equity (compared to cheaper debt), its **capital structure** leads to a higher WACC.

103. PJM today estimates a reasonable market default ATWACC for the purposes of estimating costs of the reference technology (for Net CONE) and the avoidable project investment recovery rate ("APIR") as a component of net avoidable cost rates ("net ACR"). While certainly not the only measure of the potential costs of the risk-mitigation transactions to lower the one-in-twenty risk exposure, the ATWACC represents one reasonable, conservative estimate of those potential costs. The cost of risk and other assumptions would be periodically reviewed to maintain alignment with potentially changing market fundamentals.

104. As an illustration of this calculation, consider a Capacity Market Seller with a resource that PJM assesses would face a \$150/MW-day penalty risk as the 95th percentile of the unit-specific penalty/bonus distribution assessed as described above. If the ATWACC representing the cost of risk is equal to 10%, PJM's assessment of the resource-specific CPQR would be \$15/MW-day.

105. Note that this approach, in combination with the stop-loss, provides an upper limit on the standard estimate of CPQR across all resources. In particular, the proposed stop-loss caps any participants' exposure at 1.5 times the Base Residual Auction clearing price; by definition this "extreme value" must be at or above the 95th percentile of the distribution of potential net penalties described above. Thus, the standard CPQR assessment can be no higher than the expected Base Residual Auction clearing price multiplied by the cost of risk. For a cost of risk of 10%, as in the example directly above, the CPQR can be no higher than ten percent of the expected auction clearing price. Thus, this approach conservatively limits the potential CPQR costs that Capacity Market Sellers can express in capacity sell offers without providing substantial evidence to support and justify the need to offer at higher levels.

VI.B FORWARD-LOOKING ESTIMATE OF NET ENERGY & ANCILLARY SERVICES REVENUE

106. Through this filing, PJM is also proposing to adopt a forward-looking approach to determine the net energy and ancillary service revenues ("Net EAS"), in the context of the Market Seller Offer Cap and the Minimum Offer Price Rule, that a resource can reasonably be expected to earn in PJM participating in the energy and ancillary service markets. To that end, PJM proposes to replace the existing tariff provisions as they relate to the Net EAS calculation in the Market Seller Offer Cap and the Minimum Offer Price Rule ("MOPR"), which currently calculate Net EAS revenues based on a historical rolling average. Instead, PJM proposes to utilize a

forward looking Net EAS methodology that will instead use forward-looking electricity and fuel data.[17] This approach effectively adopts the same one that the Commission previously approved.[18]

107. As part of this proposal, PJM will also employ the same Projected EAS Dispatch model for the determination of energy and ancillary services revenues for dispatchable resources that the Commission recently approved as part of PJM's 2022 Quadrennial Review.[19] In addition, all generation resource types will continue to be credited with revenues for providing reactive service.

108. A forward-looking approach necessarily relies on forward-looking data, and PJM's approach is grounded in forward energy and fuel prices at liquid trading points for the subject Delivery Year. Because buyers and sellers reflect anticipated changes in market design when transacting on a forward basis, the EAS Offset should reflect forward expectations. That is, as a liquid forward energy market should reflect market design changes in forward prices, the EAS Offset will also account for such market design changes.

109. The proposed approach forecasts EAS revenues using a Projected EAS Dispatch Model, as explained in detail below, to strengthen the connection between liquid forward market prices and expected resource revenues. This change affects only the EAS Offset determination for dispatchable resources, e.g., natural gas-fired combustion turbine ("CT"), natural gas-fired combined cycle ("CC"), coal-fired steam turbines, and storage resources; PJM will use an assumed output model, also utilizing forward energy and fuel prices, as applicable, for nuclear, wind, and solar, when developing the forward EAS Offset as described below.[20] The Projected EAS Dispatch model is more consistent with commercial expectations of the revenue a resource can reasonably expect to earn in PJM's energy and ancillary services markets. As a result, the offers in the capacity market will better reflect the costs that a resource actually needs to recover through the capacity market.

110. PJM accordingly proposes a common forward-looking EAS Offset estimating method, with three main components, that is adaptable to each of these existing Tariff applications of the EAS Offset:

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[17] Given that PJM is proposing to implement the forward-looking EAS Offset commencing with the Base Residual Auction for the 2025/2026 Delivery Year so as to appropriately harmonize, the Tariff revisions included in this filing make clear that the existing historical EAS Offset approach will remain in place for the Incremental Auctions for the 2024/2025 Delivery Year and the forward-looking EAS Offset will apply for the 2025/2026 Delivery Year and subsequent Delivery Years. The revisions updating the determination of the Market Seller Offer Cap to a forward-looking approach also make clear that the new approach will apply for the 2025/2026 Delivery Year and subsequent Delivery Years. *See* proposed Tariff, Attachment DD, section 6.8(d-1).

[18] *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 (2020), *order on reh'g*, 174 FERC ¶ 61,180 (2021).

[19] *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073 (2023).

[20] PJM typically does not dispatch such resource types and they generally do not ramp up or down their energy production in response to energy prices.

- Using publicly available energy and fuel price data from liquid forward markets for the same timeframe as the Delivery Year at issue, applying locational adjustments and hourly (for energy) and daily (for fuel) price shaping using commercially reasonable and customary methods;
- Running resource revenue models with the forward-based energy and fuel prices, and key resource characteristics and parameters, as inputs, using two basic model types:
    - A Projected EAS Dispatch Model for dispatchable resources; or
    - An assumed output model, for non-dispatchable resources, applied to the forward energy prices referenced above; and
- Estimating market-based ancillary service revenues using ancillary services prices in co-optimized dispatch models, plus cost-based reactive service revenues.

111. PJM proposes to adapt and apply that general method to estimate:

- The EAS Offsets for resource-type default MOPR Offer Floor Prices, using resource-type-appropriate fuel and assumed output or Projected EAS Dispatch models;
- EAS Offset determination methodologies for resource-specific exceptions to the MOPR Floor Offer Prices, with certain defined flexibility, and certain defined limitations; and
- EAS Offset determination methodologies for resource-specific Market Seller Offer Price Caps.

1. Description and justification of main components of the overall forward EAS Offset estimating method.

a. <u>PJM's proposed changes base EAS Offset estimates for a Delivery Year on the energy and fuel prices in liquid futures markets for the time frame of that Delivery Year.</u>

112. The Brattle/S&L experts "recommend that PJM adopt the principles and methods we would use when supporting a client in an investment or contract decision for a similar timeframe," including "rely[ing] on market prices to the extent they are observable."[21] The Brattle/S&L experts accordingly "recommend using forward prices for electric energy and natural gas applicable to PJM market participants"

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[21] Compliance Filing of PJM Interconnection, L.L.C., Docket No. EL19-58-003, Attachment C (Affidavit of Samuel A. Newell, James A. Read, Jr., and Sang H. Gang on behalf of PJM Interconnection, L.L.C.) ¶ 11 (Sept. 30, 2022) ("Brattle Aff."). As noted in the Brattle Aff., Dr. Samuel A. Newell "has frequently used forward markets as part of asset valuation assignments to support investment decisions by market participants," *id.* ¶ 2, while Mr. James A. Read Jr. "has worked with many companies on valuation and risk management assignments, including the development of forward price curves and the modeling and estimation of price volatility." *Id.* ¶ 3.

which "reflect expectations of market conditions at corresponding delivery dates and thus should incorporate assessments of the many factors that determine prices at delivery, including such factors as market design changes and additions and retirements of generation and transmission capacity."[22]

113. Several important design parameters flow from these principles. First, the forward prices used in the energy and ancillary services revenue estimates are best taken from liquid futures markets. When markets are liquid (i.e., there are substantial numbers of both buyers and sellers), settlement prices will better reflect Market Participants' expectations about future conditions. Such markets also post their settlement prices publicly, and mark to market daily, allowing current and prospective Market Participants to see the market's current collective judgment on expected future conditions and to react to those prices based on their own expectations of future conditions, and their knowledge of their own plans, transactions, and operations. Consistent with this important condition, the Brattle/S&L experts carefully assess market liquidity, and propose reliance on particular market hubs and products that trade with sufficient liquidity.

114. Second, futures market products, locations, and time periods do not automatically supply every assumption needed for every EAS Offset estimate required by the Tariff. Other forward markets can help fill some of those gaps, such as PJM's long-term Financial Transmission Rights ("FTR") auctions, which usefully reveal market expectations about future locational (congestion-based) price differences. For other aspects of the analysis, patterns established in historic data are reasonably used to adapt the output of futures markets to meet the need for particular inputs to the EAS Offset estimate.

115. Third, because "[t]he price of natural gas . . . is one of the principal drivers of electric energy prices," and "forward electricity prices on any given date will reflect forward natural gas prices on that same date," the forward EAS estimating methodology should be "sensitive to the alignment of forward price observation dates and forward contract delivery dates for power, natural gas, and other fuel commodities," and thereby "avoid systematic errors in forecasts of [EAS] margins."[23]

116. As explained in the following subsections, PJM's proposed use of energy and fuel prices in the EAS Offset estimating methodology takes account of these principles.

i. Forward electric energy prices

117. The proposed forward EAS Offset methodology will rely on futures markets prices. As explained by the Brattle/S&L experts, the established futures markets are well-suited to this purpose because:

- they are "marked to market and resettled on a daily basis;"

[22] Brattle Aff. ¶ 11.

[23] Brattle Aff. ¶ 49.

- they "determine a settlement price for each contract on each business day;" and
- "the sponsoring exchange makes its futures settlement prices public."[24]

118. The futures markets also trade multiple electric energy and natural gas products for delivery at multiple times and multiple locations in the PJM Region, and thus provide abundant, current, public data on forward prices needed for a forward EAS estimate.

119. However, not all of those products, locations, and delivery periods exhibit the liquidity desired for a reliable forward EAS estimate. The Brattle/S&L experts therefore assessed liquidity for multiple alternatives, and identified those with sufficient liquidity to use as a source of forward prices. In financial markets "liquidity" refers to how efficiently and easily trades can occur. Liquidity can and will change over time. For example, although the PJM Western Hub remains one of the most liquid trading hubs in the nation, activity at other trading hubs is evolving. Therefore, rather than locking in a fixed set of trading hubs or requiring the Commission to adjudicate in future proceedings the liquidity of individual trading hubs on a hub by hub basis, PJM is not proposing to embed in the Tariff, at least at this time, the specific products and hubs that the consultants identified in this analysis. Rather, PJM proposes to reflect in the Tariff that the particular hubs used for the EAS Offset will be specified in the PJM Manuals.

120. The Brattle/S&L experts use "open interest" as a gauge of futures market liquidity. Open interest in a futures market trading contract (i.e., a particular product for delivery at a particular place and time) "reflects the cumulative number of contracts that have been opened but not yet closed out or offset."[25] The Brattle/S&L experts explain that "the greater the open interest, the greater the amount of trading in the contract and thus the better the information revelation of market prices, other things being equal."[26] Moreover, "greater open interest and contract trade volumes reduce the chances that market prices can be manipulated successfully."[27]

121. For their liquidity analysis, the Brattle/S&L experts considered the open interest "at each of the trading hubs and transmission zones in PJM that are reported by [Intercontinental Exchange, Inc. ("ICE")]."[28] To measure open interest, they considered all products in the same product family (i.e., day-ahead peak, day-ahead off peak, real-time peak, and real-time off peak) because "the settlement

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[24] Brattle Aff. ¶ 46.

[25] Brattle Aff. ¶ 47. To be clear, there is a futures contract with a buyer and seller; the interest is "open" only because it has not yet gone to delivery or been liquidated.

[26] Brattle Aff. ¶ 48.

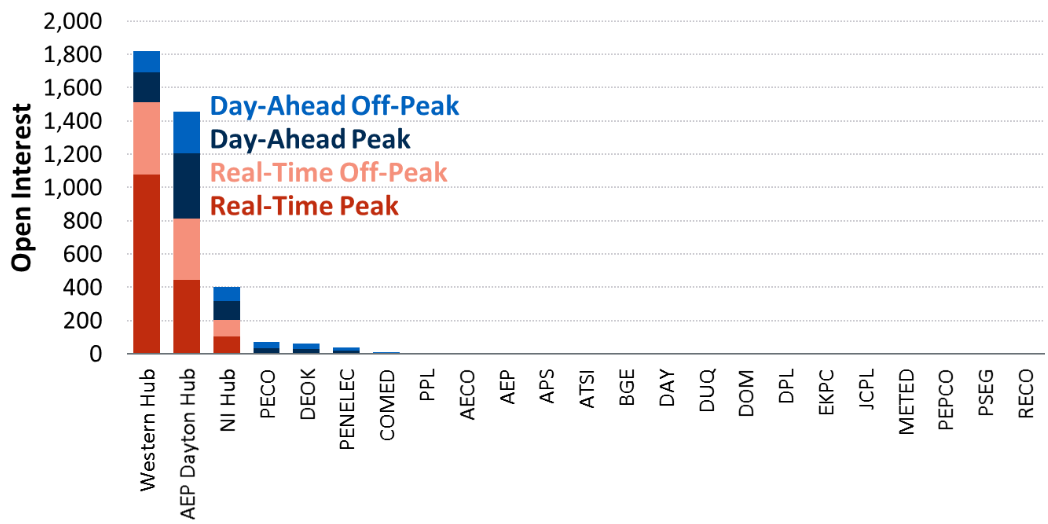
[27] Brattle Aff. ¶ 48.

[28] Brattle Aff. ¶ 50. They also checked open interest on electricity contracts traded on New York Mercantile Exchange platforms, but found it was more limited than open interest on the ICE. *Id.*

prices for day-ahead and real-time contracts for long-term futures . . . are nearly identical," and "the aggregate level of activity [for the related products reasonably] inform[s] the level of liquidity."[29] For both the forward price and liquidity analyses Brattle conducted in 2020, Brattle reviewed prices for 2024, reflecting that PJM typically will undertake its pre-auction energy and ancillary services revenue estimating analyses roughly four years before the relevant Delivery Year.[30]

122. The results of their liquidity analysis are shown in Figure 1 below, which is reproduced from the Brattle Affidavit.

Figure 1: Open Interest for PJM Futures Products at Trading Hubs and Zones for Calendar Year 2024



123. As can be seen, open interest for these PJM energy products in 2024 was substantial for the three traded PJM Region hubs, but minimal to non-existent for the 20 traded PJM Region zones. Looking beyond 2024 to additional years, the Brattle/S&L experts also note that open interest at the PJM Zones "is . . . inconsistent from year to year."[31] Based on these facts, in their affidavit, they recommended using electric energy futures settlement prices at PJM Western Hub, AEP-Dayton Hub, and Northern Illinois Hub ("NI Hub") for the forward EAS estimates.[32]

[29] Brattle Aff. ¶ 50.

[30] Brattle Aff. ¶ 51.

[31] Brattle Aff. ¶ 51.

[32] Brattle Aff. ¶ 14.

124. PJM's proposed approach, per the Brattle/S&L experts' recommendation,[33] averages the settlement prices reported for the 30 most recent trading days. This approach "balances the benefit of the most recent market information with potential vulnerability to market manipulation from indexing to a single day."[34]

125. PJM also proposes to use the day-ahead product's future prices. As the Brattle/S&L experts explain, the day-ahead and real-time futures prices "are nearly equivalent, such that relying on either will have little to no impact on the estimated E&AS net revenues."[35] PJM adopts their recommendation to use the day-ahead product prices. Moreover, the monthly prices from the day-ahead futures can be used to develop both hourly day-ahead prices and hourly real-time prices, relying on the distinct patterns of day-ahead and real-time hourly price shapes in the recent historic record, as discussed below.

126. In sum, the end result of this step of the analysis is forward day-ahead energy prices for each of the three PJM hubs, and for each month, on-peak period, and off-peak period in the Delivery Year.

ii. Determination of zonal prices

127. As noted above, there is little trading of day-ahead or real-time energy futures for delivery to individual PJM Zones in 2024, and the little trading observed is inconsistent from year-to-year. The Brattle/S&L experts correctly observe that "[t]he limited liquidity of zonal futures makes them more vulnerable to manipulation, which could cause large distortions in the capacity market parameters and outcomes."[36] While the zonal futures prices themselves should therefore be avoided in the analysis, fairly high correlations in historic prices between each hub and specific Zones enable ready mapping of Zones to hubs.

128. Specifically, the Brattle/S&L experts "analyzed the correlation of historical prices between the three electricity hubs and the 20 PJM zones, using monthly average peak and off-peak data," and found that "for each zone, the hub with highest price correlation is that which is geographically closest," and this correlation persisted for both peak and off-peak prices.[37] The resulting hub-Zone mapping is shown in the Brattle Affidavit.[38]

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[33] Brattle Aff. ¶ 16. Note that the daily interval here refers to settlement price updating. The underlying product is monthly (e.g., delivering energy at the specified location every day for the month of July 2024).

[34] Brattle Aff. ¶ 16. To implement the recommended 30-day averaging, PJM plans to retrieve, 180 days before the start of each Base Residual Auction, forward pricing data for each month of the future Delivery Year, and will use the daily settlement data from the 30 trading days prior to that date. This will provide PJM with time to calculate the EAS Offsets for the reference resources prior to having to post the preliminary default MOPR Floor Offer Prices at 150 days prior to the auction.

[35] Brattle Aff. ¶ 16; *see* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(2).

[36] Brattle Aff. ¶ 51.

[37] Brattle Aff. ¶ 53.

[38] Brattle Aff. ¶ 53.

129. This mapping does not mean that PJM proposes simply to adopt for each Zone the price in the hub to which it is mapped. Rather, this mapping defines the appropriate sources and sinks for determining locational basis differentials between each Zone and its mapped hub. Adding these differentials to the mapped hub price determines the corresponding Zone price.

130. PJM proposes to use forward market information (i.e., long-term FTR auction results), along with historic data on marginal losses, to calculate forward monthly peak and off-peak prices for each Zone. This is not a novel approach. As the Brattle/S&L experts explain, their "standard practice" for estimating future congestion differentials a few years out "is to use differences in congestion prices between each zone and the hub, from the latest long-term [FTR] auction."[39]

131. The longest-term FTRs traded in PJM's auctions are three years forward.[40] Even allowing for the fact that the latest long-term FTR auction results available at the time of PJM's EAS Offset calculations will be for the Delivery Year prior to that for which the Base Residual Auction is being run, "[t]he long-term FTRs are a reasonable indicator of the market's view of future congestion applicable in the [D]elivery [Y]ear and will reflect shifting patterns much more quickly than, for example, relying on historical congestion differentials from four to six years before the [D]elivery [Y]ear."[41]

132. As the Brattle/S&L experts explain, PJM's "long-term FTR auctions are centralized, multilateral, and locational-based markets, producing nodal clearing prices . . . . determined by bids from many market participants for source-sink pairs across the PJM system;" and have been found competitive, with ownership unconcentrated.[42] The consultants also "analyzed how well historical long-term FTR prices align with realized congestion in the day-ahead market between the trading hubs and zones during the same delivery years."[43] Although "[l]ong-term FTRs of course do not accurately predict the realized congestion in the delivery year due to the uncertainty of the market conditions . . . FTR prices do incorporate trends . . . [and therefore] [u]sing FTR prices to forecast basis differentials incorporates such shifts sooner than using trailing historical prices to forecast [basis differentials]."[44]

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[39] Brattle Aff. ¶ 17.

[40] *See* Tariff, Attachment K – Appendix, section 7.1A.1; Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 1, section 7.1A.1.

[41] Brattle Aff. ¶ 17. Although the Market Monitor has claimed that FTRs systematically understate congestion, their analysis ultimately shows only that it is hard to predict congestion occurring several years hence. By contrast, the Brattle/S&L experts explain that the specific Hub-to-zone FTRs relevant here do not appear systematically mis-priced based on the available evidence. *Id.* ¶¶ 54-56.

[42] Brattle Aff. ¶ 54.

[43] Brattle Aff. ¶ 55.

[44] Brattle Aff. ¶ 55 (citing example of regional price shifts from Marcellus shale gas production).

133. In addition to the congestion differences, Zonal prices also need to incorporate the marginal losses expected between the hub and its mapped Zones. This adjustment is reasonably performed using historical zonal day-ahead loss prices (scaled by the relationship between the forward price at the hub and the historic day-ahead Locational Marginal Pricing ("LMP") for the hub. Such use of historic loss data "[is] sufficient because losses tend to be relatively small and more stable over time, and there is no forward-looking, market-based source for directly estimating future losses."[45]

134. The end result of this step of the analysis is forward day-ahead energy prices for each of the 20 PJM Zones, and for each month, on-peak period, and off-peak period in the Delivery Year.

iii. Forward natural gas prices

135. Fuel costs are a critical input to the energy and ancillary services revenue estimates as they are the principal cost incurred by most resources to obtain energy revenues. For the forward EAS Offset methodology, PJM proposes to use fuel futures market prices in a manner similar to the proposed methodology's use of electric energy futures market prices. This discussion focuses on natural gas prices, since the Reference Resource assumed for setting the VRR Curve is natural gas- fired. The approach for other fuels is adjusted as necessary, as discussed later.

136. As with energy futures prices, there are multiple futures markets for natural gas deliveries to PJM Region locations, but the liquidity of those markets varied for the 2024 time period used to match the energy futures prices. As with electric energy futures, open interest is also reported for these natural gas futures trading hubs, which enables a reasonable assessment of liquidity. As explained in their affidavit, the Brattle/S&L experts found six gas hubs with sufficient liquidity (i.e., Chicago, Transco Zone 6 (non-NY), Dominion South, Michcon, TETCO M3, and Columbia-Appalachia TCO),[46] based on the open interest results summarized in their Figure 4.[47]

137. The PJM Region is also served by three other natural gas hubs, (i.e., Transco Zone 6 (NY), TGP LA 500 Leg, Transco Zone 5 Delivered) but their 2024 futures markets were not sufficiently liquid to rely on their settlement prices. However, based on historical price correlations, each of these hubs can be mapped to one of

[45] Brattle Aff. ¶ 18. Specifically, PJM will calculate the added loss differential as the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of the forward monthly average on-peak or off-peak day-ahead LMP at such hub to the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period.

[46] Brattle Aff. ¶¶ 29, 66.

[47] Brattle Aff. ¶ 66.

the six hubs that is sufficiently liquid in the 2024 futures market.[48] Once mapped, forward prices for these less-liquid hubs can be derived "by scaling the forward price of the mapped hub by the average ratio of monthly prices at the illiquid hub and the mapped [liquid] hub over the most recent three years."[49] This reliance on historic data is reasonable. The three hubs are only illiquid *in the futures market*; the locations were actively traded in the historic period, permitting reasonable assessment of the relationship between prices at these hubs and prices at the hub to which they are mapped.

138. PJM proposes to use a simple average of natural gas settlement prices for the most recent 30 trading days, for the same reasons noted above for the forward energy prices.[50] Finally, PJM will assign prices from the nine natural gas futures trading hubs to the 20 PJM Zones using the hub-zone mapping previously developed and recorded in PJM Manual 18.

iv. Shaping futures market monthly prices to the hourly and daily prices needed to make resource revenue estimates

139. The steps above produce monthly forward prices for electric energy and natural gas. Estimating resource revenues, however, requires prices on a shorter timescale, to capture the changing operating and economic conditions that drive resource dispatch, output, and revenues. Energy prices by hour, and natural gas prices by day, provide reasonable granularity for purposes of the estimate given this matches the timescale of the day-ahead energy and gas markets. Historic data can help fill this gap.

140. For this purpose, one could shape monthly prices to hourly prices based on historic multi-year relationships, and then run the dispatch model using those prices. Different years will exhibit different pricing patterns; simply averaging price variations across multiple years will mute the in-year volatility that significantly affects resource revenues. That approach also would not sufficiently respect the strong relationship between electric energy prices and fuel prices. Trying to match, for example, a multi-year average pattern of gas prices to a multi-year average pattern of energy prices could ignore that a strong natural gas price trend produced a strong energy price trend. A synthetic year that tries to encompass multi-year pricing pattern variations thus may be *too* synthetic, and therefore less realistic. As the Brattle/S&L experts explain, "[h]istorical price patterns provide the best information for the hourly shapes of day-ahead and real-time prices,"

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[48] Brattle Aff. ¶ 66 & Table 6. PJM has memorialized this mapping in Manual 18. *See* Capacity Market & Demand Response Operations, *PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C. (July 26, 2023), http://www.pjm.com/-/media/documents/manuals/m18.ashx.

[49] Brattle Aff. ¶ 30. Note that this use of historic prices to estimate monthly natural gas prices at illiquid hubs differs from the three simulations, discussed below, that each use one of three recent years of hourly price shaping data.

[50] Brattle Aff. ¶ 16. Specifically, PJM will retrieve the forward gas price data 180 days before the relevant Base Residual Auction, and use data from the 30 preceding trading days at that time.

which warrants "using the price patterns from each of the three most recent years to capture random variation in price shapes from year to year."[51]

141. For this reason, PJM's proposed approach is more sophisticated, using historic pricing patterns from each of the three most recent years to produce three years of shaped hourly energy forward prices and shaped daily natural gas forward prices, and *then* running the revenue model separately for *each* of those years. Under this approach, the revenues resulting from those three years are averaged to produce an annual EAS estimate that reasonably encompasses varying patterns in hourly energy or daily natural gas prices. PJM will produce hourly energy prices for each Zone, for each applicable generation bus,[52] and for the PJM Region.[53]

142. Specifically, PJM proposes to:

- Separately consider hourly electric energy prices and daily gas prices from each of the three most recent years, for three separate analyses;
- For each monthly on-peak period and off-peak period within a given historic year, develop an hourly energy price shape by dividing each individual hour's Day-ahead or Real-time LMP by the average Day-ahead or Real-time LMP across all hours in the given period;
- Apply that shape to the corresponding monthly on-peak period or off-peak period day-ahead price developed from the energy futures markets in the steps described above, to produce hourly energy prices for each hour in those periods, and thus for each hour of the year;
- Develop daily natural gas price shapes in the same way, deriving in-period daily price patterns for each month of the historic year, and applying those patterns to the corresponding monthly prices developed from the natural gas futures markets;
- Use the shaped forward hourly energy prices and shaped forward daily natural gas prices developed using shapes from each historic year;
- Calculate net EAS revenues for each of those years using the appropriate model for the resource under consideration; and
- Average the resulting three years of revenues to produce a single-year estimate.

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[51] Brattle Aff. ¶ 19.

[52] PJM will also determine prices to each applicable generation bus for use in determining resource-specific EAS Offsets by applying basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone.

[53] To determine the PJM Region forward energy prices, PJM will take the load-weighted average of the monthly on-peak and off-peak Zonal LMPs, developed using the historical average load for each on-peak and off-peak period. Then, PJM will shape those monthly values to forward hourly LMPs using the same shaping process for zonal forward hourly LMPs, but use historical LMPs "for the PJM Region pricing point," i.e., (Pricing Node ID 1: PJM-RTO). *Id.*

b. PJM is adding market-derived ancillary services revenues to the EAS Offset.

143. In addition to considering forward price data for energy and fuel, PJM is proposing to account for revenues from market-based ancillary service products in the EAS Offset, except for Regulation. The current EAS Offset approach omits such ancillary services, and instead only considers the cost-based revenues from providing reactive service as the representative of the estimated ancillary services revenues. Accordingly, PJM is proposing to continue to provide credit for reactive services *and* start to account for revenues from other market-based ancillary services in the EAS Offset.

144. To do so, PJM will use a new dispatch model (i.e., the Projected EAS Dispatch discussed in the next section) that co-optimizes energy and reserves, similar to PJM's Day-ahead and Real-time Energy Markets. However, as Brattle explains, there are no observable forward markets for such ancillary services, so PJM must rely on historical market prices for ancillary services.[54] Thus, for Synchronized and Non-synchronized Reserves, PJM will employ historical prices for these reserves in the Projected EAS Dispatch, where they will interact with the Forward Hourly LMPs, and commitment and dispatch projections for the resource will be made accordingly. PJM will use the historic real-time Synchronized and Non-Synchronized Reserve prices for simulated real-time reserve dispatch as a proxy for the unavailable historical day-ahead prices in the simulated day-ahead reserve dispatch. In other words, under PJM's new dispatch approach, it will determine revenues associated with Synchronized and Non-Synchronized Reserve on both day-ahead and real-time bases.

145. For Secondary Reserve, at this time, PJM is proposing to set the clearing price for Secondary Reserves to \$0.00/MWh for both the day-ahead and real-time dispatch simulations. This is grounded in the fact that PJM's simulations have shown very low prices for Secondary Reserve (\$0.00/MWh once rounded to the nearest penny),[55] and Brattle's conclusion that even without setting the price at \$0.00/MWh, the product would not materially affect resources' net EAS revenues.[56] Accordingly, PJM's approach for Secondary Reserves is reasonable.

146. As PJM, Brattle and S&L worked on putting together a process to estimate forward ancillary services prices, the primary method discussed was one similar to that used for Regulation (explained further below)—to scale historic reserve market clearing prices by the ratio of the forward energy prices to the historic energy prices. While in the long-term, such an approach may be suitable, this could result

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[54] Brattle Aff. ¶ 22.

[55] *See* Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket No. EL19-58-000, at 105 (Sept. 29, 2019) (citing *id.*, Attachment D (Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C.) ¶ 42, Table 4).

[56] Brattle Aff. ¶ 62.

in scaling *down* reserve market clearing prices in some cases.[57] As a result, and in an effort to not introduce arbitrary bias into the new approach, PJM proposed to use unscaled, historic ancillary services market clearing prices for the initial implementation.

147. This approach for determining market-based ancillary services revenues is necessarily limited to only dispatchable resources. Thus, only CT, CC, coal, and storage resource types will, by default, be credited with revenues for Synchronized Reserve, Non-synchronized Reserve, and Regulation, as these resource types are inherently capable of reliably ramping up or down their energy production when called upon to deploy. All resource types will continue to get credit for providing reactive services.

148. Consistent with PJM's existing Tariff, sellers of resources that rely heavily on ancillary services for annual revenues may seek to use an alternate approach through a resource-specific determination. Indeed, any Capacity Market Sellers that would like a different ancillary revenues estimate for its resource's EAS Offset than one determined using the process outlined above and detailed in the Brattle Affidavit can seek a resource-specific exception and establish the resource's Market Seller Offer Cap through that process.[58] For example, and subject to the strictures of the resource-specific exception process,[59] if a seller of a wind, solar, nuclear, or demand response resource would like to reflect revenues from the dispatched ancillary services in the EAS Offset for its resource, then the seller will need to demonstrate that its resource can earn (or has earned) revenues providing these reserve products.

149. In addition, as discussed below, under the resource-specific exception process, sellers may propose to use different forward prices for ancillary services, but such prices must be from a publicly available source or be otherwise readily available (like through a subscription service) and demonstrated to be more appropriate for use on a resource-specific basis than the methodology set forth herein and in the Tariff.

c. Replacing the Peak-Hour Dispatch model with the Projected EAS Dispatch model that simulates dispatch for all hours in a day with the objective of optimizing the resource's dispatch in response to input prices.

150. Once the forward energy and fuel prices, and the ancillary services prices, have been developed, PJM will input those, along with the applicable resource's operating parameters, into a dispatch model to determine an estimate of the resource's expected energy and ancillary services revenues for the future Delivery Year. Brattle/S&L observes that "this is best done with an optimization model that, like PJM's actual market, puts each resource to its highest value use,

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[57] *See* Brattle Aff. at Table 2.

[58] *See* proposed Tariff, Attachment DD, sections 5.14(h-2)(3)(A) & (B)(ii).

[59] *See* proposed Tariff, Attachment DD, sections 5.14(h-2)(3).

recognizing each resource's capabilities, costs, and operating constraints."[60] However, PJM's new dispatch model will only apply to dispatchable resources, e.g., CT, CC, coal, and storage, while PJM will continue to use an assumed output model for nuclear, wind, and solar, as PJM typically does not dispatch such resource types and they generally do not ramp up or down their energy production in response to energy prices.

151. Accordingly, as part of the updated EAS Offset approach, PJM is proposing to switch from using the Peak-Hour Dispatch market simulation to a "Projected EAS Dispatch" simulation. The Projected EAS Dispatch approach, like the existing Peak-Hour Dispatch, takes the input prices as given and treats each generator as a price-taker, assuming that the reference resource will run when the estimated forward LMP exceeds the cost of operating the resource, without consideration of supply/demand balancing. However, the Projected EAS Dispatch approach will simulate whether the reference resource will run in any hour of the day and for any "contiguous period(s)," in which the resource would generate at a profit, whereas the Peak-Hour Dispatch only simulates whether the reference resource may be dispatched into the day-ahead and real-time energy market in four independent, four-hour blocks (between hour ending 8:00 and hour ending 23:00) each day. Further, the Peak-Hour Dispatch model does not account for ancillary service commitment and dispatch, unlike the Projected EAS Dispatch approach, which co-optimizes a resource's commitment and dispatch between the energy and ancillary service markets. Thus, Projected EAS Dispatch better simulates actual market outcomes and is more consistent with the resource's commercial expectations. As Brattle explains, PJM will employ "an industry-standard simulation model" that allows for "the same approach we often use in commercial applications."[61] To effectuate this change, PJM is utilizing the defined "Projected EAS Dispatch" for calculating future EAS Offsets.

152. To implement the Projected EAS Dispatch, PJM will employ a simulation software that offers a broad range of capabilities for modeling and optimization of energy systems.[62] Because the purpose of the exercise is to determine a resource's expected revenues, PJM will set the software's objective function to optimize the energy and ancillary services commitment and dispatch of the generator in order to maximize the resource's value (as measured by net profit) based on the input energy and ancillary service and fuel prices discussed above, subject to the constraints of the generator parameters.[63] To do so, the model will compare an energy offer, composed of the resource's marginal costs and other costs associated with generating energy, and including the cost for a complete start and shutdown cycle.

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[60] Brattle Aff. ¶ 37.

[61] *See* Brattle Aff. ¶

[62] Brattle Aff. ¶ 37.

[63] *See* Tariff, Definitions O-P-Q (defining Projected EAS Dispatch).

153. The Projected EAS Dispatch will simulate commitment and dispatch for both the day-ahead and real-time energy and ancillary service markets. Similar to the sequencing of the day-ahead and real-time markets, the model will first run a day-ahead commitment and dispatch against the input forward day-ahead energy and ancillary service prices. A real-time commitment and dispatch against forward real-time energy and ancillary service prices is then run where the model assumes the resource runs in real-time for the periods in which it was committed day-ahead, but adjusts the dispatch for such hours based on the forward real-time LMPs and ancillary service prices. The resource may also be committed and dispatched for additional hours beyond those for which it was committed day-ahead. The gross revenues from such dispatch are then calculated assuming all day-ahead committed MWh are paid the forward day-ahead energy or ancillary service market clearing prices, as appropriate, and that any deviations between the real-time dispatch and the day-ahead dispatch are settled at the forward real-time energy or ancillary service market clearing prices, as appropriate. The settlement includes make-whole payments such that total gross revenues cover resource's real-time costs.

154. Thus, the Projected EAS Dispatch will forecast revenues from the resource based on the optimal commitment and dispatch of the resource per the objectives of the PJM energy and ancillary service markets, thus approximating actual resource behavior and reasonable commercial expectations.[64] To determine the "net" revenues that will comprise the EAS Offset, PJM subtracts the costs to generatethe energy MWh for the hourly intervals in which the resource is dispatched in the real-time model (i.e., incremental energy costs, plus startup and shutdown costs).

155. To further approximate actual resource operations and commercial expectations, PJM will adjust the net revenues yielded by the model to linearly scale down the revenues to account for the resource's expected and unplanned outages. PJM will also assume maintenance outages. For example, PJM will assume CT and CC resources take a two-week maintenance outage during the shoulder month of October, when such resources often take scheduled outages.

156. The resulting simulated generation pattern and the corresponding revenues net of operating costs for each day of the Delivery Year yield the projected energy revenue portion of the EAS Offset for each reference resource. PJM performs this simulation with energy, ancillary services, and fuel prices shaped by historical data from each of the three full preceding calendar years, and then takes the average of the revenues yielded by the three simulations as the EAS Offset value for the resource.

[64] To the extent the simulation produces the scenario in which the unit cannot recover its real-time generation cost for the day (e.g., real-time LMPs that are lower than the day-ahead LMPs on which the resource was committed), the model credits the resource with an "uplift" (or make-whole) payment equivalent to the difference between the real-time generation cost and the revenue from energy an ancillary services. As such uplift payments occur in the same manner in PJM's energy markets today, the Projected EAS Dispatch model is simply and reasonably approximating PJM's energy markets.

157. The methodology for calculating the net energy revenue offset is the same methodology approved previously by the Commission.[65] While the methodology is the same, the underlying values have had updates. This is expected as there is more recent and relevant data available now compared to when the original filing was made.

158. The net energy revenue offset is estimated for each resource class type in each Zone using the average of the annual net energy revenues from the three most recent calendar years preceding the Base Residual Auction where the annual net revenues are calculated using the zonal locational marginal pricing ("LMP") from the relevant zone as described below. Ancillary service revenues are assumed to be the average of the previous three years of posted data from the Market Monitor's Annual State of the Market Report[66] for each resource type except for the combined cycle for which the ancillary service revenue is assumed to be the currently prescribed value for the Reference Resource combined cycle in section 5.10(a)(v)(A) of the Tariff, Attachment DD. Section 5.14(h-2) of the Tariff, Attachment DD provides the following methodologies for calculating EAS values for new resources subject to MOPR:

- For nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant for the 2025/2026 Delivery Year[67], or starting with the 2026/2027 Delivery Year and subsequent Delivery Years, $7.99/MWh for a single unit plant or $7.74/MWh for a multi-unit plant[68]] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus reactive services revenue of $2,251/MW-year[69];

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[65] *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073 (2023); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 (2020).

[66] *State of the Market Report for PJM – Volume 2: Detailed Analysis*, Monitoring Analytics, LLC, Table 7-3 (Mar. 9, 2023), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-vol2.pdf.

[67] *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, The Brattle Group and Sargent & Lundy, 7-10 (Mar. 17, 2020), https://www.brattle.com/wp-content/uploads/2021/05/19714_gross_avoidable_cost_rates_for_existing_generation_and_net_cost_of_new_entry_for_new_energy_efficiency.pdf ("2020 Brattle Report").

[68] *Gross Avoidable Cost Rates Existing Generation*, The Brattle Group and Sargent & Lundy, 16-19 (Jan. 9, 2023), https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230223/20230223-item-02---4-brattle-gross-avoidable-costs-for-existing-generation-report.ashx ("2023 Brattle Report").

[69] *Id*.

- For coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh[70] and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh[71] for the 2025/2026 Delivery Year, or starting with the 2026/2027 Delivery Year and subsequent Delivery Years, $10.92/MWh[72]) using day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $2,217/MW-year[73];

- For the 2025/2026 Delivery Year, for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a single General Electric Frame 7HA turbine with evaporating cooling, Selective Catalytic Reduction technology, with dual Fuel capability, with the heat rate assumed for the combustion turbine resource shall be 9,134 BTU/kWh, the variable operations and maintenance expenses for such resources, inclusive of Maintenance Adder costs, shall be $6.93/MWh, plus ancillary services revenue of $2,199/MW-year.[74] Starting with the 2026/2027 Delivery Year and subsequent Delivery Years, for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a single General Electric Frame 7HA.02 turbine with evaporating cooling, Selective Catalytic Reduction technology, with the heat rate assumed for the combustion turbine resource shall be 9,189 BTU/kWh[75], the variable operations and maintenance expenses for such resources, inclusive of Maintenance Adder costs, shall be $1.19/MWh[76], plus ancillary services revenue of $3,565/MW-year;[77]

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[70] *See Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, U.S. Energy Information Administration, Table 2-1 (Feb. 2020), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf ("EIA Study").

[71] *See* 2020 Brattle Report at 10-13.

[72] *See* 2023 Brattle Report at 19-24.

[73] *Id*.

[74] These values align with the Reference Resource combustion turbine specifications at described in Tariff, Attachment DD, section 5.10.

[75] *See PJM CONE 2026/2027 Report*, The Brattle Group, v (Apr. 21, 2022) https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx ("2022 CONE Report").

[76] 2022 CONE Report at 63. The variable O&M costs for the CONE Areas are: $1.19/MWh (EMAAC); $1.18/MWh (SWMAAC); $1.15/MWh (Rest of RTO); and $1.22/MWh (WMAAC).

[77] *Id*.

- For combined cycle resource type, for the 2025/2026 Delivery Year, the net energy and ancillary services revenue estimate for each Zone shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year. Starting with the 2026/2027 Delivery Year and subsequent Delivery Years, for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combined cycle;

- For solar PV resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $6,791/MW-year.[78] Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

- For onshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24 hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $4,027/MW-year;[79]

- For offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $4,027/MW-year;[80] and

[78] *Id*.

[79] *Id*.

[80] *Id*.

- For Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,903/MW-year.[81]

VII. CONTINUED EVOLUTION OF THE PJM CAPACITY MARKET

159. The long-term integrity and sustainability of the PJM capacity market relies on its ability to represent the supply and demand dynamics it was structured to address. Over time, certain foundational assumptions may no longer hold due to cumulative changes in supply and demand fundamentals since the initial development of the market. No market – or administrative construct attempting to uphold competitive market principles – is final or unalterable. PJM has the responsibility to continually refine its markets to align with the evolving realities of the power system and maintain a coherent and relevant market structure. It is PJM's role and indeed imperative to continually evolve the wholesale markets, including the Reliability Pricing Model, in such a way to best reflect the most salient "ground truth" elements of the power system and translate into a workable and hopefully understandable market construct. This continuous adaptation is essential to sustain market relevance and integrity in a constantly changing environment.

160. Thus, there are a number of elements that PJM anticipates will continue to evolve in the pursuit of "more perfect" markets, including, at least: seasonal or other more granular capacity market design; evolution in understanding of distribution of potential delivery-year weather patterns and related enhancements to risk assessments; and accreditation enhancements to more accurately value the expected contribution to reliability of different resources.

161. PJM plans to continue to evaluate potential approaches to enhance and improve our understanding of the distribution of potential delivery-year weather outcomes in the presence of climate change. As the global community becomes more cognizant of the impacts of climate change, the importance of adapting our wholesale markets in response to these evolving conditions becomes paramount. PJM recognizes the potential value of integrating historical weather assessments with forward-looking climate change adjustments to produce a more accurate and robust understanding of potential delivery-year weather outcomes. Such assessments are no longer just about analyzing past trends but must also incorporate projections that consider the increasing volatility and unpredictability brought about by global warming.

162. The ongoing and projected shifts in weather patterns, characterized by more frequent extreme events and seasonally skewed temperature variations, compel a

[81] *Id*. The $3,903/MW-year is the average of all technologies reactive service revenue, since there is no Capacity Storage Resource value calculated.

re-evaluation of how the power system is anticipated to respond. This not only has implications for resource availability and demand but also affects the grid's resilience in the face of these changing conditions. By proactively integrating climate science into its risk assessments, PJM can ensure that its markets are prepared to address the challenges of the future and not just those of the past.

163. While there did not appear to be sufficient scientific consensus regarding a path forward in the short term, recognizing the potential for climate change to further alter traditional risk paradigms, PJM is committed to investing in research and collaboration with climate experts and with staff at other ISOs/RTOs and FERC to explore and develop alternative modeling techniques. The aim is to better anticipate, understand, and mitigate the effects of climate change on the reliability and efficiency of the power system.

164. Another crucial aspect of PJM's capacity market evolution will center on the refinement of accreditation modeling. The power system is increasingly characterized by uncertainty, underscoring the need for models that accurately capture the real-world complexities and limitations of resources. While the approach PJM has developed for this filing is a substantial step forward, a remaining challenge lies at the intersection of imperfect information about future system conditions and the inherent operational constraints of resources.

165. For instance, certain resources have prolonged start-up times or specific forward notification requirements. These operating parameters can impact how they respond to operator direction or market signals and, consequently, their contribution to system reliability. Models that do not factor in these operational limitations may over-estimate such resources' contribution to resource adequacy, and, in turn, relatively under-estimate the capacity contribution of more flexible resources. The difficulty of incorporating and implementing reasonable assumptions regarding operators' imperfect information about future conditions – be it changing weather patterns, sudden spikes in demand, or unexpected outages – further compounds the challenge.

166. PJM recognizes these complexities and is invested in the continued evolution of its accreditation modeling. The goal is to bridge the gap between theoretical modeling and real-world operational realities, ensuring that each resource's accreditation reflects its potential contributions and limitations. This will require a multi-faceted approach, integrating detailed operational data, stakeholder feedback, and advanced modeling techniques to continually evolve towards a more accurate, responsive and adaptive accreditation framework.

167. As this modeling continues to evolve, it will become instrumental in guiding investment decisions, operational strategies, and other market responses. By ensuring that the accreditation model accurately reflects the realities of power system operations, PJM aims to foster a market environment that is both efficient and resilient, ready to meet the demands of a dynamic and uncertain future.

168. This concludes my affidavit.

APPENDIX TO AFFIDAVIT:
NUMERICAL EXAMPLES OF BENEFITS OF MARGINAL ACCREDITATION

Encourages cost-effective investment and retirement of resources

Illustrative Example

- Suppose Resource X and Y have average and marginal ELCC values as shown in the table below.
  - 1 nameplate MW of Resource X adds the equivalent reliability value of 0.2 MW of perfect capacity.
  - 1 nameplate MW of Resource Y adds the equivalent reliability value of 0.8 MW of perfect capacity.
- Investment in Resource Y is 4x more effective in reducing load shed risk (per nameplate MW).
- Investment in Resource Y is 3x more costly (per nameplate MW).

Net Impact: Resource Y provides the more cost-effective solution with cost per added reliability value (reduction in load shed risk) being 75% that of Resource X – aligned with compensation and incentives under marginal approach.

Marginal clears the most cost-effective solution, while average clears the cheaper $/MW UCAP solution but pays more $ per reliability improvement.

			AVERAGE APPROACH			MARGINAL APPROACH		
Resource	Nameplate MW	Cost ($/MW-Day, Nameplate)	ELCC %	UCAP MW	Cost ($/UCAP)	ELCC %	UCAP MW	Cost ($/UCAP)
Resource X	100	$50	40%	40 MW	$125	20%	20 MW	$250
Resource Y	25	$150	80%	20 MW	$187.50	80%	20 MW	$187.50

Aligns the accredited value with expected performance during high-risk hours in operations (which is necessarily on the margin)

Illustrative Example (solely intended to show the concept and not represent future outcomes)

- Assume a resource mix and level of solar penetration that has resulted in expected hours of load shed risk shifting entirely into the evening hours after the sun has set.
- The marginal ELCC of solar in this scenario will be zero (next MW of nameplate solar provides no reduction in load shed risk given all risk occurring outside of solar performance hours).
- Suppose average ELCC of solar is 10% in this scenario, such that every MW nameplate of solar is accredited 0.1 MW of capacity value or UCAP.
- Marginal accredited value (and compensation) is consistent with expected performance of solar resources during the high-risk hours for that year and given portfolio.
- Average accredited value is above the expected performance level of solar during the high-risk hours.

This systematic misalignment results in expected net penalties for solar resources.

		AVERAGE APPROACH		MARGINAL APPROACH	
Resource	Nameplate	ELCC %	UCAP MW	ELCC %	UCAP MW
Solar X	1	10%	0.1 MW	0%	-

Allows for a substitutable product definition where accredited capacity/UCAP can be exchanged on the margin with no expected change in reliability

Illustrative Example: Assume the reliability metric used in accreditation is Expected Unserved Energy (EUE) in MWh.

- Suppose perfect capacity provides an incremental reliability improvement (reduction in EUE) of 20 MWh.
  i.e., 1 MW nameplate of perfect capacity has a marginal reliability impact of 20 MWh EUE.
- Suppose Resource X has an average ELCC of 40% and marginal ELCC of 20%.
  The incremental reliability value is 20% that of perfect capacity (reduction in EUE of 4 MWh per nameplate MW).
- Suppose Resource Y has an average and marginal ELCC of 80%.
  The incremental reliability value is 80% that of perfect capacity (reduction in EUE of 16 MWh per nameplate MW).

- Under average, exchanging 1-for-1 UCAP MW between Resources X and Y can impact reliability.
  - Resource X: 2 nameplate MW = 0.8 MW UCAP; Incremental reliability impact = 2x (4 MWh EUE) = 8 MWh EUE
  - Resource Y: 1 nameplate MW = 0.8 MW UCAP; Incremental reliability impact = 16 MWh EUE
  - Exchange of UCAP results in different changes to reliability
- Under marginal, exchanging 1-for-1 UCAP MW between Resources result in same reliability.
  - Resource X: 4 nameplate MW = 0.8 MW UCAP; Incremental reliability impact = 4x (4 MWh EUE) = 16 MWh EUE
  - Resource Y: 1 nameplate MW = 0.8 MW UCAP; Incremental reliability impact = 16 MWh EUE
  - Exchange of UCAP results in equivalent impact on reliability

Benefits of having a 1-for-1 exchange rate for UCAP MW:
- Improves fungibility of the product
- Provides the same compensation to individual resources that provide the same improvement to system reliability

		AVERAGE APPROACH		MARGINAL APPROACH	
Resource	Nameplate	ELCC %	UCAP MW	ELCC %	UCAP MW
Resource X	2	40%	0.8 MW	20%	0.4 MW
Resource Y	1	80%	0.8 MW	80%	0.8 MW

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER24-__-000**
	)	
	)	

VERIFICATION

I, Dr. Walter Graf, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Walter Graf referred to in the foregoing document entitled "Affidavit of Dr. Walter Graf on Behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

/s/ Walter Graf
Walter Graf
Chief Economist
PJM Interconnection, L.L.C.

Dated: October 13, 2023

Attachment E

Affidavit of Dr. Patricio Rocha-Garrido
on Behalf of
PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER24-___-000**
	)	

AFFIDAVIT OF DR. PATRICIO ROCHA-GARRIDO
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Dr. Patricio Rocha-Garrido. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am a Senior Lead Engineer in Resource Adequacy Planning in the System Planning division of PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its Federal Power Act, section 205 proposal in this proceeding.

2. Specifically, in this affidavit, I provide support for PJM's proposal to modify the Risk Analysis and Accreditation models.

Qualifications

3. I joined PJM in 2011. As a Senior Lead Engineer with the Resource Adequacy Planning department, I am responsible for performing long-term resource adequacy studies involving loss-of-load probability calculations whose results serve as inputs into PJM's Reliability Pricing Model ("RPM") as well as PJM's Regional Transmission Expansion Plan. In 2020, I was actively involved in the establishment of an Effective Load Carrying Capability ("ELCC") construct for resource accreditation purposes at PJM. I have also collaborated with PJM's planning and operations groups on projects related to long-term load forecasting, short-term solar forecasting, and net-interchange schedule forecasting models. Prior to joining PJM, as a graduate student/research assistant, I performed research and wrote articles on topics pertinent to restructured electricity markets, namely generation capacity expansion and financial transmission rights.

4. I hold a Bachelor of Science degree in Industrial Engineering from the University of La Frontera-Chile, and a Masters and Ph.D. degree in Industrial Engineering from the University of South Florida.

Analytical Methodology and Dispatch.

Overview

5. In 2021, PJM implemented an ELCC methodology to calculate the Accredited Unforced Capacity ("UCAP") value of Variable Resources, Limited Duration Resources, and Combination Resources, resources that PJM deemed, at the time, to be more likely to be responsible for system risk events due to correlated

unavailability. This Accredited UCAP value is used by Market Participants to develop the quantity component in their sell offers for PJM's capacity market, the RPM. At its most basic, the model employed to calculate the ELCC of resources can be described as an hourly loss of load probability model, whose objective is to quantify the reliability contribution of resources during hours of system risk when the system is meeting the target reliability criteria.

6. As a logical step after implementing an hourly ELCC methodology for accreditation purposes, PJM recognized the need to transition to an hourly framework for other resource adequacy studies namely, the Reserve Requirement Study ("RRS") and the Capacity Emergency Transfer Objective ("CETO") studies. The RRS determines the Installed Reserve Margin ("IRM") and Forecast Pool Requirement ("FPR") which are used by PJM to determine the amount of capacity needed to meet the loss of load expectation ("LOLE") reliability criteria of 1-day-in-10-years. The FPR is employed to determine the regional transmission organization ("RTO")-wide Reliability Requirement, i.e., the quantity of megawatts (or "MW"), designated in UCAP, targeted to be procured for the RTO in each RPM Auction. The CETO studies are performed for each Locational Deliverability Area ("LDA") and have a twofold purpose: (i) to determine the CETO for an LDA, where the CETO can be described as the amount of megawatt imports required by that LDA to meet reliability targets; and (ii) to determine the Reliability Requirement for that LDA. As I will explain further later in this affidavit, the PJM proposal includes transitioning to an hourly framework for the RRS and the CETO studies.

7. Between 2021 and today, PJM completed two annual ELCC studies as well as several forward-looking studies that used ELCC as the accreditation method for Variable Resources, Limited Duration Resources, and Combination Resources.[1] The results from those studies coupled with the resource performance observed during Winter Storm Elliott made clear to PJM that the ELCC methodology needed to undergo two main changes.

Two Changes to PJM's Current ELCC Approach: (1) Switch to Marginal Approach; and (2) Application of ELCC Approach to Unlimited and Demand Resources

8. The first change is switching from an "average" ELCC framework to a "marginal" ELCC framework. The diminishing average ELCC values calculated for some

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[1] *See Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM Interconnection, L.L.C. (Feb. 24, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx; *Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid*, PJM Interconnection, L.L.C. (May 17, 2022), https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220517-energy-transition-in-pjm-emerging-characteristics-of-a-decarbonizing-grid-white-paper-final.ashx; *Energy Transition in PJM: Frameworks in Analysis*, PJM Interconnection, L.L.C. (Dec. 15, 2021), https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx; *Reliability in PJM: Today and Tomorrow*, PJM Interconnection, L.L.C. (Mar. 11, 2021).

classes as the forecasted penetration of the resources in those classes increases[2] and the ongoing and forecasted changes to the resource mix provide the impetus for the switch to a marginal ELCC approach.

9. For instance, under the average ELCC approach, if the system has a significant amount of winter risk caused by a high deployment level of resources with poor winter-performance (i.e., resources with low winter output or high correlated outages during winter), adding more such resources to the system will result in a diminishing average ELCC Class Rating for the class that includes such resources. The diminishing average ELCC Class Rating will be reflective of the output of that ELCC Class of resources in: (i) hours of system risk identified after adding the last resource in the poor winter-performance class to the expected system portfolio (i.e., winter hours as described in the setup of the example); and *also* in (ii) hours of system risk identified before adding the first resource in the poor winter performance class to the expected system portfolio (i.e., hours that are likely to be different, even from a different season, from the winter hours described in the setup of the example). In contrast, ELCC Class Ratings calculated with a marginal ELCC approach will be reflective exclusively of the output of the resources in hours of system risk identified after adding the last resource in the poor winter-performance class to the expected system portfolio. As a result, the marginal ELCC approach will better identify which resource types will provide more reliability benefit, relative to additional MW increment from another resource class, and thus which resource type in which sellers should invest, *given the expected resource mix in the system*. In other words, the marginal ELCC approach provides a more accurate comparison between the reliability benefit of resources, and the corresponding accreditation that resources should receive, given the expected resource mix in the system.

10. The second change is to apply the ELCC approach to determine the UCAP value of Unlimited Resources and Demand Resources using the ELCC methodology. As made evident during Winter Storm Elliott (and during the January 2014 Polar Vortex), the amount of correlated outages (in the case of Unlimited Resources) and the impact of a limited performance window (in the case of Demand Resources) can be substantial drivers of supply-side risk that must be reflected in the accreditation of resources. Currently, these drivers are not reflected in the accreditation of those resources, but will be captured using PJM's proposed marginal ELCC approach.

11. The need to switch from an average ELCC framework to a marginal ELCC framework can be illustrated by the following example. If the average ELCC-determined Accredited UCAP of Y megawatts nameplate of an ELCC Class is X megawatts UCAP and the average ELCC of Y + y megawatts nameplate of an

[2] *See December 2022 Effective Load Carrying Capability (ELCC) Report*, PJM Interconnection, L.L.C. (Jan. 6, 2023), https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx; *December 2021 Effective Load Carrying Capability (ELCC) Report*, PJM Interconnection, L.L.C. (Dec. 31, 2021), https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2021.ashx.

ELCC Class is also X megawatts UCAP, then under an average ELCC framework the accreditation rating that Y + y megawatts nameplate of such class will receive is X / (Y + y) percent, which is a diminishing average ELCC class value compared to the accreditation rating equal to X / Y that the class receives prior to adding y megawatts nameplate. In contrast, under a marginal ELCC framework, the accreditation of those same Y + y megawatts will be based on the change in UCAP megawatts associated with the incremental addition of y megawatts nameplate, which in this example is zero. In the event that a resource from the subject ELCC Class is competing against a resource from another ELCC Class that does not have diminishing reliability value to be the marginal market clearing resource, it is clear that, for efficiency purposes, the market clearing algorithm should select the resource from the class that does not have diminishing reliability value. Using the marginal ELCC accredited value (i.e., zero percent in the above example) for the resource of the subject ELCC Class ensures that the efficient outcome occurs.

12. In addition, the above example illustrates that the marginal ELCC framework provides better investment incentives: the marginal accreditation result (i.e., zero) makes clear that the system does not benefit from additional investments in resources from that ELCC class. Conversely, the average accreditation in the above example (X / (Y + y) percent) may still signal to the market the need for more investment in resources from that ELCC class.

13. Employing marginal ELCC approach to determine the UCAP accreditation calculation for Unlimited Resources and Demand Resources is also necessary. In my 2021 affidavit supporting adoption of PJM's current average ELCC approach, which is used for accrediting the capacity capability of intermittent and storage resources, I stated that using ELCC for Unlimited Resources would not be appropriate "due to the fact that the large majority of unplanned outages experienced by these resources are random, which means that the chance of having a large amount of these resources on an outage simultaneously is small."[3] However, recent events have demonstrated that my understanding is no longer correct, and ELCC provides an appropriate accreditation approach for determining UCAP of Unlimited Resources. Indeed, the performance of a large number of Unlimited Resources during Winter Storm Elliott belies my prior understanding. The correlated outages of Unlimited Resources during Winter Storm Elliott can be thought of as akin to the outages experienced by Variable Resources because of their non-random nature and their established patterns, two reasons that I used to argue in favor of applying ELCC for Variable Resources in my 2021 affidavit.[4]

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[3] Updated Effective Load Carrying Capability Construct of PJM Interconnection, L.L.C., Docket No. ER21-2043-000, Attachment C, Affidavit of Dr. Patricio Rocha-Garrido on Behalf of PJM Interconnection, L.L.C. ¶ 6 (June 1, 2021).

[4] *Id.* ¶ 15.

14. Further, PJM currently accredits Unlimited Resources based on their respective equivalent demand forced outage rate ("EFORd").[5] However, the emergence of further evidence that some Unlimited Resources experience correlated, non-random outages and outage patterns and the switch to accrediting Unlimited Resources using the ELCC model undermines the usefulness of EFORd in PJM's capacity market. That is, the logic underlying use of EFORd as the main accreditation metric assumes that unplanned outages experienced by the Unlimited Resources are random and thus each resource's forced outage pattern is independent from other resources' forced outage patterns, and we now know this to not be the case (in the case that an Unlimited Resource experiences random forced outages only, the accreditation such resource will receive with PJM's proposed marginal ELCC approach will be consistent with the EFORd of such resource).

15. Regarding Demand Resources, Winter Storm Elliott triggered high loads during hours outside of the Demand Resources' performance window. In other words, there was high unavailability of Demand Resources in hours outside of the Demand Resources' performance window (specifically during over night and early morning hours). The consequences of this common unavailability are akin to the consequences of duration limitations of Limited Duration Resources, which is the main reason I used to argue in favor of using ELCC for Limited Duration Resources in my 2021 affidavit.

Implementation of Marginal ELCC Approach

16. Developing an adequate methodology to determine the Accredited UCAP value of resources via ELCC analysis requires estimating the expected performance of resources during expected system reliability events. To achieve this, it is necessary to simulate the PJM system based on: (i) a given portfolio of resources and its associated total installed capacity (or "ICAP"); (ii) probabilistic load scenarios; (iii) probabilistic resource performance scenarios; and (iv) a target reliability criteria (currently, a LOLE of 1-day-in-10-years). In other words, the ELCC calculations are performed using a probabilistic model informed by load scenarios and resource performance scenarios that identifies the amount of installed capacity required to serve load while meeting the target reliability criteria.

17. The RRS is designed to determine the amount of installed capacity reserves, i.e., the IRM, and the corresponding amount of UCAP (determined using the FPR) required to meet expected energy demand and procuring sufficient reserves to meet the 1-day-in-10-years target reliability criteria by analyzing load and resource performance scenarios. Furthermore, the IRM and FPR calculations rely on the same set of inputs used for the ELCC analysis. Clearly, there is significant overlap between the RRS model and the ELCC model. Currently, a full overlap between the ELCC and the RRS model is being precluded by the fact that only a subset of

[5] *See* Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA"), Schedules 5 and 9.

all Capacity Resources are evaluated and accredited through the ELCC analysis and thus included in the ELCC model (i.e., Variable Resources, Combination Resources and Limited Duration Resources). Under PJM's proposal, all Capacity Resources (except for Energy Efficiency Resources) will be accredited through the ELCC model. As a result, the ELCC and RRS models will fully overlap, and the same model that accredits the capacity capability of almost all Capacity Resources also will determine the IRM.

18. Furthermore, the FPR is currently calculated as the product of "*one plus IRM*" and "*one minus pool wide average EFORd,*" where "*one minus pool wide average EFORd*" provides a means to convert the IRM quantity, denominated in installed capacity, to UCAP.[6] However, the combination of: the declining relevance of EFORd, the proposed application of ELCC model to accredit the vast majority of Capacity Resources, and the proposal to use the same model for resource accreditation (i.e., ELCC) and for performing the RRS, means that this approach for determining FPR will no longer be appropriate.

19. Through the proposed changes to the RAA implementing PJM's proposal, PJM will calculate the FPR based on the output of the ELCC model, as the accreditation ratings of almost all Capacity Resources (i.e., the equivalent to the *one minus pool wide average EFORd* concept) are calculated with the ELCC model. Therefore, the FPR logically is the product of one plus IRM and the newly defined pool-wide average Accredited UCAP Factor, where pool-wide average Accredited UCAP Factor assumes the role of *one minus pool wide average EFORd* in the current formula. And, it is defined as the total Accredited UCAP in the ELCC model divided by the sum of all the installed capacity in the ELCC model. Since PJM is proposing to perform all RRS calculations (i.e., FPR and IRM) with the ELCC model, from this point in my affidavit I refer to the ELCC model as the ELCC/RRS model.

20. The proposed ELCC/RRS model includes several improvements that better capture and reflect the range of uncertainties faced by the PJM system relative to the current average ELCC model that PJM implemented in 2021 and the current RRS model:

    a. The weather history employed to derive load scenarios in the proposed ELCC/RRS model includes data starting on June 1, 1993 (i.e., the beginning of delivery year 1993/1994) whereas the current ELCC model includes weather history starting on June 1, 2012 and the current RRS model includes weather history from a period no longer than fifteen years. Expanding the weather history in the ELCC/RRS model allows PJM to examine a wider range of load scenarios (as weather is the most significant driver of load in the PJM system) and to simulate the expected performance of resources under those scenarios (particularly for those resources whose performance is weather-dependent). PJM recognizes that climate change is affecting weather but, when analyzing PJM-region temperature data starting June 1, 1993, no clear consistent trend is

[6] *See* RAA, Schedule 4.1.

observed in the period 1993-2022, and therefore, PJM is not at this time considering an adjustment for climate change. However, as PJM adds each Delivery Year's weather data, PJM will continue to analyze the data for any observable trends and adjust for such trends, as applicable;

b. The forced outage modeling of Unlimited Resources in the proposed ELCC/RRS model would be based on RTO-aggregate historical outage data that captures historical patterns of correlated (and uncorrelated) outages of such resources as a function of weather, whereas the current ELCC model and the current RRS model assume that outages of Unlimited Resources are correlated only during the winter peak week of each year regardless of the weather being simulated during the winter peak week. (For the rest of the weeks in the year, the current ELCC model and the current RRS model assume that outages of Unlimited Resources are independent.) For example, the proposed approach would allow PJM to capture the large volume of forced outages observed during January 7, 2014 (Polar Vortex event of 2014) and Winter Storm Elliott as well as the better performance observed during a similarly cold event, February 20, 2015 by assuming that such RTO-wide outage levels would be repeated under similar weather conditions in the future, with a certain probability level;

c. The forced outage modeling of Unlimited Resources in the proposed ELCC/RRS model would include resource performance data back to June 1, 2012, with data from each passing Delivery Year added to the model. In contrast, the current ELCC model and the current RRS model include resource performance data only from the previous five years. Expanding the historical period employed to derive resource performance scenarios for use in the ELCC/RRS model would allow PJM to include resource performance data during weather events that do not occur very frequently but that nonetheless have a non-negligible probability of occurring;

d. The historical correlation (or lack thereof) between forced outages of Unlimited Resources and the unavailability of Variable Resources is reflected in the proposed ELCC/RRS model whereas in the current ELCC model it is only partially reflected (for a given hourly weather pattern only one scenario of Variable Resource unavailability was modeled while there were multiple patterns of Unlimited Resources forced outages modeled) and in the current RRS model it was not reflected at all (the current RRS model does not include Variable Resources). Similar to the above improvement, modeling historical correlations between resource types provides a more accurate indicator as to the expected performance of the overall resource portfolio under diverse weather scenarios; and

e. Using hourly modeling in the RRS, and in turn in the determination of the FPR for use in determining the Reliability Requirement to derive the RPM demand curves. This improvement only applies to the RRS which is currently performed by only analyzing the peak hour of each day. This will enable the RRS to capture both load variability and resource performance variations over the full 8760-hour period.

21. In addition to the adoption of a marginal ELCC approach, the expansion of the ELCC model to now evaluate Unlimited Resources and Demand Resources, the alignment of the ELCC and RRS models, and the above ELCC/RRS risk modeling improvements, the PJM proposal also includes reflecting the impact of a set of supply-side risks associated with Unlimited Resources namely, ambient derates, maintenance outages, planned outages, and correlated forced outages, in the accreditation of such resources. Currently, the impact of these supply-side risks is reflected on the demand-side, where they increase the FPR used to calculate the Reliability Requirement in RPM. This proposed change aligns the accreditation paradigm for Unlimited Resources with that currently used for Variable Resources, Limited Duration Resources and Combination Resources. The paradigm simply establishes that supply-side risks should be reflected in the accreditation of resources.

22. Another key element in the PJM proposal is to adopt expected unserved energy ("EUE") as the resource adequacy metric in the resource accreditation process as well as in the resource adequacy analysis at the LDA level in CETO studies. EUE and LOLE, the current resource adequacy metric, are both employed to assess resource adequacy. EUE measures the expected megawatt-hours of load that a system cannot meet due to resource adequacy insufficiency, while LOLE measures the number of days that are expected to have some level of resource adequacy insufficiency, regardless of the duration and magnitude of the loss of load event s. Clearly, by providing information about the magnitude of loss of load events, EUE provides a more useful characterization of the events for resource adequacy planning purposes than LOLE. Setting aside the limited software and computational capability available decades ago when LOLE was introduced as the most common resource adequacy metric, the resource mix in the system decades ago was more homogeneous than the current and expected future resource mix, which resulted in more homogenous loss of load events. Under homogeneous loss of load events (e.g., similar duration, similar depth), the choice between LOLE and EUE was not important. However, as the resource mix changes, the expected future resource mix is likely to have a significant impact on the nature of the loss of load events (at the RTO level and more so, because of their smaller size, at the LDA levels). The expected changes to the resource mix (e.g., renewable resources replace traditional resource types) will make the loss of load events more heterogeneous; for example, there likely will be (i) shorter loss of load events in the summer evening in a summer peaking LDA due to reduction of solar output in an LDA with high solar penetration; (ii) longer but shallower loss of load events in the summer afternoon in a summer peaking LDA due to load patterns in an LDA with no solar penetration; and (iii) extended and deeper loss of load events in the winter due to no solar output and high thermal correlated forced outages in a winter peaking LDA with high penetration of solar and gas units. Therefore, the resource mix changes compel a prudent operator to use a resource adequacy metric that can

provide information at a more granular level about expected loss of load events. As a result, PJM is proposing to use EUE as the resource adequacy metric:

a. In the accreditation process, by measuring the reliability improvement that ELCC Classes provide to the system in terms of EUE. The accreditation process is performed at the PJM-wide level. The loss of load events can exhibit heterogeneity at the PJM-wide level as illustrated by events that may occur in the summer season and those that may occur in the winter season. The summer events tend to be shorter and shallow (less megawatt-hours impacted) while the winter events tend to be longer and deeper (more megawatt-hours impacted). Analyzing the contribution to reliability that ELCC Classes provide in terms of EUE in these heterogeneous events is more meaningful than using LOLE, given that LOLE would treat each type of event equally.

b. In the CETO studies for LDAs, by replacing the current LOLE-based criteria (1-day-in-25-years) with an EUE-based comparable criteria. At the LDA level, given the heterogeneity of load profiles (e.g., summer peaking vs. winter peaking LDAs), resource mix (e.g., LDAs with high penetration of renewables of a certain type vs. LDAs with low penetration of renewables vs. LDAs with high penetration of renewables of a different type) and the resulting loss of load risk profiles, setting the CETO studies criteria to an EUE-based value provides a higher degree of comparability between the targeted reliability of LDAs relative to the comparability provided by an LOLE-based criteria.

More details about the use of EUE for the above purposes is provided later in my affidavit.

23. To be clear, at this time, PJM is not proposing to change the LOLE criteria of 1-day-in-10-years for the RTO-wide IRM and FPR calculations. However, PJM will calculate and publish the RTO-wide EUE value associated with the LOLE criteria of 1-day-in-10-years.

ELCC and RRS Inputs

24. Similar to the original ELCC methodology filed in 2021, PJM's proposed ELCC/RRS methodology models the performance of resource portfolios under a range of future system conditions on an hourly basis. The primary inputs to determine the range of future system conditions are Load Uncertainty and Resource Performance Uncertainty. The resulting range of future system conditions can be designated as ELCC/RRS Scenarios. Each one of the ELCC/RRS Scenarios is annual and has a probability of occurrence associated with it. Therefore, the ELCC/RRS methodology is probabilistic in nature.

25. Modeling Load Uncertainty in the ELCC/RRS methodology entails deriving multiple 8,760 Hourly Load Scenarios to cover a range of load conditions. PJM is proposing to use the hourly load scenarios produced as part of the PJM Load Forecast using weather data starting on June 1, 1993, as the basis for the Hourly

Load Scenarios in the ELCC/RRS model. These hourly load scenarios include the impact of forecasted behind-the-meter solar deployment levels. To illustrate how the PJM Load Forecast produces hourly load scenarios, consider the following example. If the future year being studied with the ELCC/RRS model is X, then zonal weather data from the 1993/1994 Delivery Year (i.e., June 1, 1993 through May 31, 1994) is used to produce an hourly load scenario for the RTO for delivery year X assuming that the delivery year X starts the same day of the week as the 1993/1994 Delivery Year did. In addition to this hourly load scenario, the PJM Load Forecast derives additional hourly load scenarios under the assumption that the weather experienced on a certain day can also occur within a range of -6 days to +6 days (12 additional load scenarios). PJM does this for each Delivery Year from 1993/1994 through 2022/2023. By using this "weather rotation" scheme, PJM can analyze weather patterns that in the historical record occurred during a weekend (where peak loads tend to be lower than weekdays) but that also have a chance of occurring during a weekday. As an example of the total Hourly Load Scenarios that the PJM proposal considers, at the CIFP stakeholder process, PJM included 30 x 13 = 390 hourly load scenarios (30 is the total number of weather delivery years, from 1993/1994 through 2022/2023; 13 is the number of weather rotations performed). Given the significant number of hourly load scenarios considered, each weather scenario is assumed to have the same probability of occurrence.

26. An additional variability component is considered to derive the Hourly Load Scenarios in the ELCC/RRS model. The PJM Load Forecast shows an error of approximately one percent when comparing fitted with actual values of historical high peak loads. To account for this error, in the ELCC/RRS model, the daily loads of each day are adjusted randomly by sampling from a normal distribution with mean zero and standard deviation equal to approximately 1.2%. In this manner, the updated ELCC/RRS will be able to capture this additional uncertainty component not reflected in the Hourly Load Scenarios discussed above.

27. Modeling Resource Performance Uncertainty in the ELCC methodology entails deriving the hourly output of each resource in each Hourly Load Scenario. The procedure to derive the hourly output differs by resource category and/or resource class.

   a. <u>Unlimited Resources and Variable Resources</u>. As mentioned earlier, the correlation of Unlimited Resources forced outages and Variable Resources unavailability (or to put it differently, the correlation of their output levels) will be captured in the updated ELCC/RRS model as a function of weather. This is achieved by setting a "label" for each historical day in the simulation based on the observed minimum hourly RTO-wide temperature[7] if the day is a winter day and the observed maximum hourly RTO-wide temperature if the day is a

[7] PJM is effectively using the Temperature Humidity Index (THI) instead of simply temperature. *See* Resource Adequacy Planning, *PJM Manual 19: Load Forecasting and Analysis*, PJM Interconnection, L.L.C., section 3 (defining THI) (Dec. 31, 2023), https://www.pjm.com/~/media/documents/manuals/m19.ashx.

summer day.[8] The labels are effectively temperature values. These labels are then grouped using binning methods (e.g., the Freedman Diaconis Estimator method[9]) employed in the development of histograms. The objective of the binning procedure is to identify days in the historical record (since June 1, 1993) where PJM experienced similar RTO-wide temperatures. The bins derived after applying this binning procedure are the "load bins." Since PJM is proposing to use historical performance data starting on June 1, 2012, in the ELCC/RRS model, removing the dates prior to June 1, 2012, from the load bins produces the "resource performance bins." The resource performance bins are used to derive 100 different Resource Performance Patterns of Unlimited Resources and Variable Resources to be used in the ELCC/RRS model, as illustrated by the following example:

i. Assume that the ELCC/RRS model is simulating day D, which occurred prior to June 1, 2012. During day D, PJM experienced a very cold RTO-wide minimum temperature. Therefore, day D is included in the *load bin* where other four similarly cold days are placed. As a result, that load bin includes days D, E, F, G, and H. Further assume that day E also occurred prior to June 1, 2012. The *resource performance bin* associated with these cold days therefore includes only F, G, and H. To derive the performance of Unlimited Resources and Variable Resources in the ELCC/RRS model during day D, PJM samples 100 times from the corresponding resource performance bin (referred to below as the "sample-from-bins" approach) that includes resource performance data observed (or putative) in historical days F, G, and H for all Unlimited and Variable Resources included in the expected resource portfolio. Roughly, the sampling will result in one third of the scenarios simulated for day D using resource performance data from each of the three days in the resource performance bin. The resource performance data will be used as recorded for resources that were in-service at the time the historical observation was recorded; for resources that were not in service at the time the historical observation was recorded, class average availability rates will be used as putative values for each hour.

For Unlimited Resources, additional types of outages and/or derates are reflected in the ELCC/RRS model as follows:

A. Ambient derates: ambient derates refer to reductions in resource output due to ambient conditions. The PJM proposal considers using

[8] Winter is considered as the period from November of a calendar year to April of the next calendar year. Summer is considered as the period from June to October of a calendar year plus May of the next calendar year.

[9] The primary method used by PJM to perform the binning is Freedman–Diaconis (*see Freedman–Diaconis Rule*, Wikipedia, https://en.wikipedia.org/wiki/Freedman%E2%80%93Diaconis_rule (last visited Oct 12, 2023).). However, if bins contain very few observations, the bins are merged to include a larger amount of observations.

historical data on ambient derates recorded in eDART[10] starting on June 1, 2012. The ELCC/RRS model will derive ambient derate patterns following the same "sample-from-bins" approach described above for forced outages of Unlimited Resources and unavailability of Variable Resources, while also capturing the historical correlation between the ambient derates and the forced outages of Unlimited Resources and unavailability of Variable Resources; and

B. Planned Outages and Maintenance Outages: planned and maintenance outages are different from forced outages due to the fact that these outages can, for the most part, be scheduled and also recalled.[11] Accordingly, the PJM proposal considers scheduling the large majority of these outages using a heuristic that seeks to levelize reserves throughout the year in each load scenario. The outcome of such heuristic is that most of the planned outages and maintenance outages will be scheduled during periods of lower loads. However, a portion of the planned outages will be intentionally scheduled to take place during high risk periods. This assumption is rooted on historical planned and maintenance outages that have taken place during periods of high loads since June 1, 2012 (e.g., July 17, 2012, and July 18, 2013 in summer; January 7, 2014, and February 20, 2015 in winter). The requirement of planned and maintenance outage for each individual Unlimited Resource will be calculated in units of megawatts-week per year based on historical data starting on June 1, 2012.

For Variable Resources, PJM will reflect ambient derates, planned outages and maintenance outages in the historical unavailability data used in the sample-from-bins approach so no differentiated treatment is needed.

b. Variable Resources – Intermittent Hydropower. For intermittent hydropower resources, PJM proposes to simply use the historical availability observations (for units that existed at the time the historical observation was recorded starting on June 1, 2012) and class average availability values (for units that did not exist at the time the historical observation was recorded) instead of the "sample-from-bins" approach described above for other Variable Resources. This is because river streamflow patterns tend to be annual (i.e., wet years vs. dry years) and the *sample-from-bins* methodology described for other Variable Resources may result in using performance patterns for consecutive days in the ELCC/RRS simulation that may come from days in different years.

c. Limited Duration Resources, Combination Resources and Demand Resources. The performance of Limited Duration Resources, Combination Resources, and

[10] eDART (Dispatcher Application and Reporting Tool) allows generation and transmission owners to submit generation and transmission outage requests.

[11] *See* Operating Agreement, Schedule 1, sections 1.9.2(b) and 1.9.3(b); Tariff, Attachment K-Appendix, sections 1.9.2(b) and 1.9.3(b).

Demand Resources in the ELCC/RRS model will be based on an hourly-simulated dispatch that depends on other system conditions (load, other resources' performance) for that same hour. Forced outages as well as other outages of Limited Duration Resources and Combination Resources will be reflected in the ELCC/RRS model. Due to software limitations and other complexities, PJM is not proposing to simulate an economic dispatch in the ELCC model. Instead, PJM is proposing a simulated dispatch that is governed by the following principles:

i. *Less available resources are dispatched after the more available resources to maximize the system reliability benefit.* This principle recognizes that during a day likely to experience an extended RTO-wide emergency event, if during a certain hour early on in the emergency event PJM has to choose between serving load with a more available resource (e.g., Demand Resource available for more than 10 hours) and serving load with a less available resource (e.g., a four-hour Limited Duration resource), PJM will dispatch the more available resource first. This ensures that during the final hours of the emergency event (but still within the availability window of the Demand Resources), PJM will have at its disposal the megawatts from the more available resource *plus* the megawatts from the less available resources. This outcome (having the megawatts available from both, more available and less available resources later in the day) is significantly less likely to occur if PJM chooses to serve load first with the less available resource rather than with the more available resource. It is my understanding that PJM Operations would adhere to this principle under the circumstances described above.

ii. *Recognizing variability of resources within some ELCC Classes*. There are some classes of Limited Duration Resources and Combination Resources whose members (i.e., the individual units) exhibit heterogeneity in the parameters impacting their potential dispatch. Such classes, therefore, do not lend themselves to be modeled, for simulated dispatch purposes, in an aggregate fashion. An example of such a class is Hydropower with Non-Pumped Storage. The members of this class, for instance, show a wide range of values for the parameter that describes how quickly they can replenish their storage component (this parameter is a function of hourly streamflow data and storage size).

d. In addition to *dispatching* resources, PJM is proposing a simulated dispatch algorithm that includes simulating the charging or charging-equivalent process whereby Limited Duration Resources and Combination Resources replenish their storage components. The procedure to derive the simulated dispatch for Limited Duration Resources and Combination Resources applied to each hour in each ELCC Scenario is the following:

i. Calculate the *Margin Threshold* as total available resources prior to dispatching Limited Duration Resources, Combination Resources, and Demand Resources minus load.

ii. If the *Margin Threshold* is greater than zero, charging for resources that require charging can proceed. However, the charging can only occur to the extent that the additional load in the system does not cause the *Margin Threshold* to be less than zero. PJM is proposing to recognize in the ELCC/RRS model differences between classes within the Limited Duration Resources and Combination Resources category regarding the charging or charging-equivalent process. This entails using hourly streamflow data to replenish the storage component of resources within the Hydropower with Non-Pumped Storage class, charging the storage component in closed-loop solar-storage resources only to the extent that the solar component can support that charging, and reflecting charging constraints on standalone storage resources and storage components in open-loop solar-storage resources.[12]

iii. If the *Margin Threshold* is less than zero, Demand Resources are dispatched. The margin after dispatching Demand Resources is known as the *Margin Threshold post DR.*

iv. If the *Margin Threshold post Demand Resource* is less than zero, Limited Duration and Combination Resources are dispatched in an availability-based order (from most-available to less-available). For example, the dispatch order that PJM currently includes in the ELCC/RRS model is shown below:

1. 10-hour Storage
2. 8-hour Storage
3. 6-hour Storage
4. Hydropower with Non-Pumped Storage
5. Solar-Storage (4-hour) Hybrids Open-Loop
6. Solar-Storage (4-hour) Hybrids Closed-Loop
7. 4-hour Storage

v. For ELCC Classes that require specific modeling of the individual units in the Simulated Dispatch (e.g., Hydropower with Non-Pumped Storage), the load assignment that each individual unit in the class receives will be based on the ICAP of the unit.

[12] Closed-loop solar-storage resources refer to resources configured such that the storage component cannot charge from the grid, only from the solar component. Open-loop solar-storage resources, on the other hand, are configured such that the storage component can charge from the grid.

The hourly output described above for the individual resources in each different ELCC Class is capped, depending on the season, at the resource's Capacity Interconnection Right value or assessed winter deliverability, as applicable for each resource type.[13]

28. A further clarification regarding the dispatch of Demand Resources in the ELCC/RRS model is required. If the simulated hour falls outside of the seasonal performance windows established for Demand Resources,[14] the amount of Demand Resources dispatched in the hour is assumed to be zero. If the simulated hour falls within the seasonal performance windows established for Demand Resources, then the amount of Demand Resources available to be dispatched in the hour is estimated based on the fact that most of the Demand Resources in PJM are categorized as Firm Service Level ("FSL"). In simple terms, FSL means that Demand Resources, when dispatched, must reduce their megawatt consumption to a specified firm level, which is reflective of 50/50 (median) peak load conditions, regardless of their megawatt consumption at the time of the dispatch. For example, if all Demand Resources are dispatched to perform in hours H1 and H2, the total megawatts observed by PJM dispatchers at H1 and H2 may be different, even if there is 100% compliance from the Demand Resources in both hours. To capture this feature in the ELCC model, the amount of Demand Resources available to perform during an hour that falls within the seasonal performance windows established for Demand Resources is calculated as Nominated Demand Resource Value (a constant value for an entire delivery year) times F, where F is defined as the ratio of simulated hourly load (in MW) to 50/50 peak load (in MW).

29. The inputs described above are not technically *input* into the ELCC model. In fact, some of these "inputs" are actually calculated by the ELCC software itself prior to performing the loss-of-load metric and ELCC calculations. However, they can be classified as inputs in the sense that they are the drivers of such calculations.

Loss of Load Expectation ("LOLE"), Expected Unserved Energy ("EUE") and ELCC Class Rating Calculations

30. The number of ELCC/RRS Scenarios that PJM is proposing to include in the ELCC/RRS model is a function of the number of Hourly Load Scenarios and Resource Performance Patterns. As indicated above, the number of Hourly Load Scenarios depends on the number of weather delivery years and weather rotations while the number of Resource Performance Patterns analyzed for each Hourly Load Scenario is one hundred. Therefore, the total quantity of ELCC/RRS Scenarios is determined by the product of weather delivery years *times* weather rotations *times*

[13] *See* proposed RAA, Schedule 9.2.

[14] The seasonal performance windows for Demand Resources are 10:00 AM to 10:00 PM Eastern Prevailing Time for June-October and the following May and 6:00 AM to 9:00 PM Eastern Prevailing Time for November-April. *See* Capacity Market & Demand Response Operations, *PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C., section 4 (July 26, 2023), https://www.pjm.com/~/media/documents/manuals/m18.ashx.

one hundred. The probability of each of the ELCC/RRS Scenarios is assumed to be equal and therefore determined by one divided by the quantity of ELCC/RRS Scenarios. As an example of the total ELCC/RRS Scenarios that the PJM proposal considers, at the CIFP stakeholder process, PJM included 30 weather delivery years and 13 weather rotations, which results in 13 x 30 x 100 = 39,000 ELCC/RRS Scenarios. The probability of each of the ELCC/RRS Scenarios was 1/39,000.[15]

31. As I noted above, the ELCC/RRS methodology proposed by PJM will continue to use the well-known resource adequacy LOLE criterion of 1-day-in-10-years (translated as 0.1 days per year when applied to a single year). PJM is also proposing to calculate the EUE associated with an LOLE of 0.1 days per year for purposes of resource accreditation and zonal resource adequacy calculations.

32. In the ELCC/RRS model, a loss of load occurs when the hourly load is greater than the hourly output of all the resources considered available in the simulation. The PJM proposal considers calculating LOLE as follows:

    a. For each modeled scenario, count the number of days in a year that include at least one hour of loss of load;

    b. Multiply the quantities from the previous step by the corresponding probability associated with each modeled scenario (these probabilities were discussed above); and

    c. Sum all the quantities calculated in the previous step. The result is the LOLE of the simulated system.

33. Similarly, the PJM proposal considers calculating EUE in the ELCC/RRS model as follows:

    a. For each modeled scenario, count the number of megawatt-hours of unserved energy in a year;

    b. Multiply the quantities from the previous step by the corresponding probability associated with each modeled scenario; and

    c. Sum all the quantities calculated in the previous step.

The result of the foregoing steps is the EUE of the simulated system.

34. PJM is proposing to iteratively adjust the load scenarios until the LOLE criterion of 0.1 days per year is achieved. This iterative process is required due to the fact that PJM uses a forecasted resource portfolio which includes all units that are likely to offer into a given RPM Auction. This forecasted resource portfolio may fall long

[15] CIFP - Resource Adequacy, *Capacity Market Reform: PJM Proposal*, PJM Interconnection, L.L.C. (July 27, 2023), https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230727/20230727-item-02a---cifp---pjm-proposal-update---july-27.ashx.

or short in meeting the LOLE criterion. Hence, the need for the iterative process adjusting load described above. The annual peak load of the iteration that meets the LOLE criterion is designated the "Solved Load." At this point, the EUE associated with the LOLE criterion is calculated. This EUE value is designated the "Portfolio EUE."

35. Once the ELCC/RRS model has found the Solved Load that meets the LOLE criterion, the ELCC Class Rating of the modeled ELCC Classes is calculated as follows:

a. Add an incremental quantity (e.g., 100 MW ICAP) of an Unlimited Resource with no outages to the forecasted resource portfolio. This resource serves as a proxy for a "perfect" resource. Calculate the resulting EUE of the system and the EUE improvement relative to the Portfolio EUE (i.e., Portfolio EUE minus new EUE value). The magnitude of the improvement is designated the *EUE Perfect Resource Improvement*.

b. For each ELCC Class, setting separate runs of the ELCC/RRS model, add an incremental quantity (e.g., 100 MW ICAP/Nameplate) to the forecasted resource portfolio. Calculate the resulting EUE of the system and the EUE improvement relative to the Portfolio EUE (i.e., Portfolio EUE minus new EUE value). The magnitude of the improvement is designated the *EUE Class Improvement.*

c. Calculate the ratio of the EUE Class Improvement to the EUE Perfect Resource Improvement. The result constitutes the ELCC Class Rating.

36. The ELCC Class Rating is multiplied by the forecasted total ICAP/Nameplate of the corresponding ELCC Class to determine the ELCC Class UCAP. Given that there is heterogeneity in the performance of resources within a class, PJM proposes to continue calculating a Performance Adjustment value[16] that is intended to differentiate good performers from poor performers within the class so that the final Accredited UCAP[17] value that an individual resource receives reflects this performance difference relative to other members of the ELCC Class.

Forecast Pool Requirement ("FPR")

37. After completing the previously described step that iteratively adjusts the load scenarios in the ELCC/RRS model until the LOLE criteria of 0.1 days per year is achieved, PJM will calculate the IRM by using the following formula:

IRM = [(Total installed capacity in the ELCC model / Solved Load) – 1] – Capacity Benefit of Ties.

[16] *See* RAA, Schedule 9.1, section F(2); proposed RAA, Schedule 9.2, section D(2).

[17] *See* RAA, Schedule 9.1, section F(1); proposed RAA, Schedule 9.2, section D(1).

where the Capacity Benefit of Ties ("CBOT") is an exogenous quantity stated as percent of forecasted peak load, representing the amount of emergency non-committed capacity assistance that PJM assumes can be provided by neighboring Control Areas, as limited by the Capacity Benefit Margin.

The IRM represents the amount of installed capacity (expressed as a percentage) committed to provide capacity in excess of the peak load that the system requires to serve such peak load (and the associated load uncertainty), while meeting an LOLE criteria of 0.1 days per year.

38. Subsequently, after calculating the Accredited UCAP values for all the resources included in the ELCC/RRS model, PJM will then calculate the pool-wide average Accredited UCAP Factor, where pool-wide average Accredited UCAP Factor assumes the role of one minus pool-wide average EFORd in the current FPR formula[18] as follows:

> pool-wide average Accredited UCAP Factor = total Accredited UCAP in the ELCC model / total installed capacity in the ELCC model.

Pool-wide average Accredited UCAP is an appropriate replacement for one minus pool-wide average EFORd. Given that pool-wide average EFORd generally represents the forced outage rate of the vast majority of resources in PJM, pool-wide average Accredited UCAP Factor should provide a comparable ratio of UCAP to installed capacity, allowing PJM's existing calculations.

39. Finally, the FPR can be calculated in an analogous way to the current calculation by using the two parameters described above:

> FPR = (1 + IRM) x pool-wide average Accredited UCAP Factor.

Basically, the role of the pool-wide average Accredited UCAP Factor in the FPR formula is to convert the IRM, which is expressed in terms of installed capacity, to UCAP, and the pool-wide average Accredited UCAP Factor provides the relevant conversion ratio.

40. The calculation of the Reliability Requirement for an RPM auction can then be based on the product of the FPR value and the annual forecasted peak load for a future delivery year.

Further Comments on the Capacity Emergency Transfer Objective (CETO) calculation

41. PJM's proposal also includes changes to the resource adequacy analysis performed for LDAs namely, the calculation of the CETO for an LDA and the Reliability

[18] Current FPR formula, FPR = (1 + IRM/100) x (1 – Pool Wide Average EFORd/100). *See* RAA, Schedule 4.1.

Requirement for an LDA. The changes are aligned with the ELCC/RRS modeling changes discussed previously. First, PJM is proposing to use the ELCC/RRS model structure to calculate the CETO and Reliability Requirement for an LDA. This entails deriving Hourly Load Scenarios and Resource Performance Patterns specific to each LDA using the same methodology outlined above for the RTO. Second, PJM is proposing to replace the current 1-day-in-25-years LOLE criteria used for the calculation of both, CETO and Reliability Requirement for an LDA, with a comparable EUE-based criteria: 40% *times* Portfolio EUE *times* Annual Energy Normalizing Factor, where the Annual Energy Normalizing Factor is defined as the LDAs' forecasted Annual Net Energy divided by the RTO's forecasted Annual Net Energy (these forecasted annual net energy values are published in the PJM Load Forecast Report).

42. The proposed EUE-based criteria for an LDA seeks to maintain the principle that the transmission/imports risk of an LDA should be small enough relative to the RTO resource adequacy risk so that the total risk that an LDA could face under a worse reserve case scenario (i.e., the sum of the LDA's transmission/import risk criteria and the RTO's resource adequacy risk criteria) is not large. This is the reason behind using the 40% value in the formula for the EUE-based criteria for the LDA, which corresponds to the ratio of the current LOLE criteria for an LDA (1-in-25, or 0.04 days/year) and the current LOLE criteria for the RTO (1-in-10, or 0.1 days/year). In other words, the current and proposed transmission/imports risk criteria for an LDA is 40% of the current and proposed RTO's resource adequacy criteria. In addition, the proposed EUE-based criteria for an LDA is established relative to the EUE calculated for the RTO (i.e., the Portfolio EUE) but adjusted by the Annual Energy Normalizing Factor to account for the fact that LDAs are portions of the RTO and as such, LDA loads and total energy are significantly less than the RTO load and total energy.

Illustrative Results

43. As detailed in Dr. Graf's affidavit, PJM conducted a simulation analysis for the 2024/2025 Base Residual Auction at the RTO level (i.e., to determine an "unconstrained" RTO price). The inputs to the simulation were derived based on the ELCC/RRS model described above.

44. PJM derived Hourly Load Scenarios and Resource Performance Patterns using the modeled resource portfolio for Delivery Year 2024/2025. The load scenarios were adjusted (i.e., scaled, without altering the relationship between the hourly loads in the scenarios) until the 1-day-in-10-years annual LOLE criteria was met. The Portfolio EUE calculated for the RTO at the 1-day-in-years LOLE criteria was 1,135 MWh/year.

45. Analysis of the Portfolio EUE value revealed that approximately 64% of the EUE was observed in the winter period while the remaining 36% was observed during the summer period. A similar analysis of the LOLE metric showed that around 65% of the LOLE was observed during the summer period while the remaining 35% of

the LOLE was observed during the winter period. Relative to results produced historically with the current ELCC and RRS models, which show negligible risk in the winter period as measured with the LOLE metric, the proposed ELCC/RRS model results show significantly more risk in the winter, as a result of the proposed model's enhancements concerning capturing correlated outages more accurately. In addition, the calculation of the EUE value that corresponds to the 1-day-in-10-years annual LOLE criteria, further reveals the different nature of the simulated loss of load events in each season: given that the majority of the EUE is in winter and the majority of the LOLE is in summer, one can infer that expected summer loss-of-load events are more common but less impactful from a magnitude standpoint than those expected to occur in winter when the PJM system has reserve levels consistent with the 1-day-in-10-years LOLE criteria.

46. Further analysis of the simulated hourly loss of load events in the ELCC/RRS model reveals that the annual EUE is distributed in accordance with the monthly and daily patterns shown in the heatmap in Figure 1. The sum of the percentages in the heatmap is 100 % (representing the annual EUE). From the heatmap, it is clear that the EUE in the summer is concentrated in month 7 (i.e., July) and to a much lesser extent in month 8 (i.e., August) during the late afternoon/early evening (i.e., hours beginning 17, 18, 19) whereas the EUE in the winter is concentrated in month 1 (i.e., January) and to a lesser extent in month 2 (i.e., February) and significantly more distributed from a daily perspective (i.e., multiple hours in the morning and multiple hours in the evening show a non-negligible share of EUE). These results are consistent with PJM Operations' recent experience during system emergency events.

47. Under the annual construct that PJM is proposing, this more accurate quantification of seasonal and hourly risk illustrated by the heatmap in Figure 1 provides a means to improve:

a. the accuracy of the accreditation that resources receive (e.g., a resource that performs well in summer and poor in winter will receive an annual accreditation that is reflective of this disparate seasonal performance and *also* of the distribution of seasonal risk in the model, 64% of the EUE in winter and 36% of the EUE in summer using the numbers above), and

b. the accuracy of the total amount of annually accredited capacity that the system requires to meet reliability standards. Because of the better accuracy in the accreditation of resources mentioned above, the annual reliability requirement calculated for the system, expressed in megawatts of accredited UCAP, will be representative of the seasonal and hourly risk patterns expected for the system.

In contrast, the current resource adequacy model understates winter risk, and therefore does not provide accurate accreditation values and an accurate reliability requirement value.

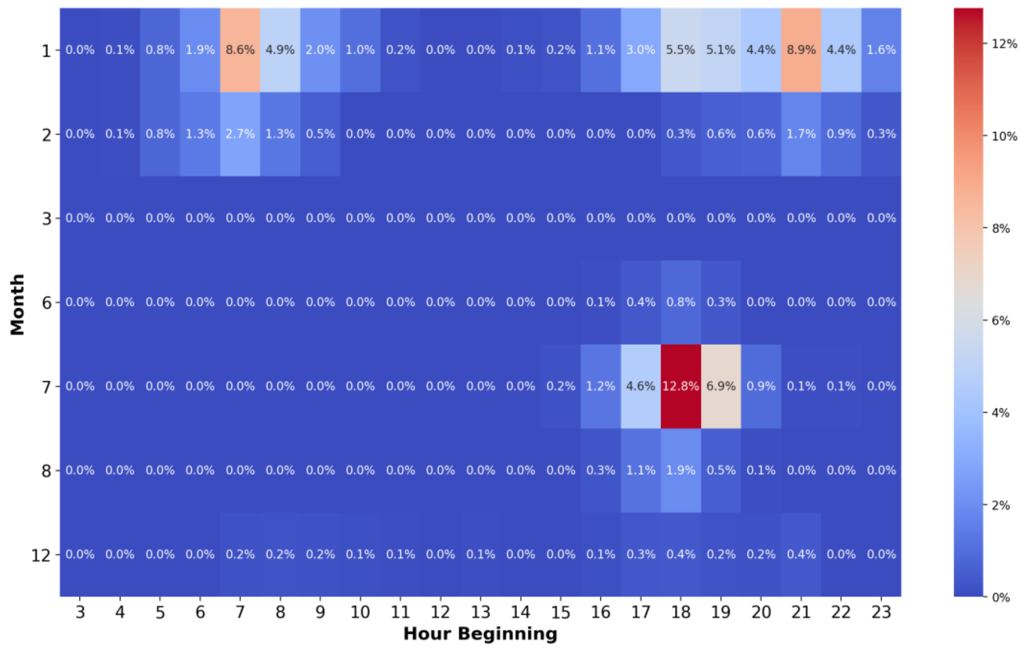

Figure 1: Share of EUE by Month and Hour

48. The procedure whereby an incremental quantity (e.g., 100 MW ICAP/Nameplate) of each ELCC Resource Class is added to the modeled resource portfolio, and the resulting EUE Class Improvement is compared to the EUE Perfect Resource Improvement yielded the following ELCC Class Ratings for 2024/2025:

ELCC Class	**2024/25 ELCC Class Rating**
Onshore Wind	27%
Offshore Wind	51%
Solar Fixed Panel	12%
Solar Tracking Panel	20%
4-hr Storage	67%
6-hr Storage	73%
8-hr Storage	79%
10-hr Storage	84%
Solar Hybrid Open Loop *	37%
Solar Hybrid Closed Loop *	37%

Hydro Intermittent	42%
Landfill Gas Intermittent	54%
Hydro with Non-Pumped Storage *	90%
Nuclear	96%
Coal	85%
Gas CC	84%
Gas CT	77%
Demand Resources	87%

* ELCC Class Ratings are not calculated for this ELCC Class but values are shown in this table for illustrative purposes.

49. The total installed capacity in the model was 194,017 MW and the Solved Load that the modeled resource portfolio for 2024/2025 can serve while meeting the 1-day-in-10-years LOLE criteria was 164,452 MW. Therefore, the IRM is 194,017 MW divided by 164,452 MW minus one, which is equal to 0.1798 or 17.98%.

50. PJM used the ELCC Class Ratings for 2024/2025 to calculate the pool-wide average Accredited UCAP Factor, which, as described above, is calculated as the total Accredited UCAP in the ELCC/RRS model divided by the total installed capacity in the ELCC/RRS mode. The total Accredited UCAP was 159,971 MW while the total installed capacity was 194,017 MW. This results in an Accredited UCAP Factor equal to 0.8245 or 82.45%.

51. The FPR was derived using the IRM and the Accredited UCAP Factor in accordance with the formula presented above.

$$FPR = (1 + 17.98\%) \times (82.45\%) = 0.9727$$

52. The above values were calculated assuming a CBOT equal to zero. To facilitate the comparison with historically calculated IRM and FPR values, the above IRM can be reduced by 1.5%, which corresponds to an average CBOT values in a set of historical studies. This produces an IRM equal to 16.48%. Recalculating the FPR using the CBOT-adjusted IRM value produces a CBOT-adjusted FPR equal to 0.9604.

53. The resulting CBOT-adjusted FPR value, 0.9604, is lower than historical FPR values (i.e., around 1.09) as a result of the implementation of marginal accreditation and the previously discussed shift of some Unlimited Resources' supply-side risks from the FPR to the accreditation of those resources. The former factor is the major driver in the reduction of the FPR as there are several ELCC Classes in the PJM

system that exhibit diminishing reliability value as the deployment level of resources in those classes increases and the future resource portfolio changes. This diminishing reliability value results in Accredited UCAP values that are lower under a marginal accreditation approach compared to the status quo accreditation approach. On the other hand, the CBOT-adjusted IRM value, 16.48%, is similar to historical IRM values (around 15% or 16%).

54. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER24-___-000**
	)	

VERIFICATION OF DR. PATRICIO ROCHA-GARRIDO

I, Dr. Patricio Rocha-Garrido, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Dr. Patricio Rocha-Garrido referred to in the foregoing document entitled "Affidavit of Dr. Patricio Rocha-Garrido on Behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

/s/ Patricio Rocha-Garrido
Patricio Rocha-Garrido
Senior Lead Engineer
PJM Interconnection, L.L.C.

Dated: October 13, 2023