**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| Compensation for Reactive Power Within the Standard Power Factor Range | ) ) ) ) | Docket No. RM22-2-000 |

## COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Notice of Proposed Rulemaking issued in this proceeding on March 21, 2024 ("NOPR"),[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits these comments. In the NOPR, the Commission proposed (at P 1) to revise Schedule 2 to the *Pro Forma* Open Access Transmission Tariff ("OATT"), so that "transmission providers would be required to pay an interconnection customer for reactive power only when the transmission provider asks the interconnection customer to operate its facility outside the standard power factor range set forth in its interconnection agreement." The NOPR would align reactive policy for transmission providers like PJM with the policy that has been applied in other organized wholesale markets since as early as the late 1990s.[3] The Commission has repeatedly confirmed that the policy approach included in the NOPR is just and reasonable.[4] The NOPR would extend a just and reasonable, pro competition policy, to all jurisdictional markets and

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1 186 FERC ¶ 61,203.

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

3 *See Pacific Gas & Electric Co.*, 81 FERC ¶ 61,122 (1997) (Order Conditionally Authorizing Limited Operation Of An Independent System Operator And Power Exchange, etc.).

4 *See* NOPR at PP 4–7, 17–19.

public utilities. In order to protect PJM customers from unjust and unreasonable charges for reactive capability that generation owners are already required to provide as a condition to receive interconnection service, and in order to promote reliance on competition and avoid the distorting effects of arbitrary out of market subsidies, a final order based on the NOPR should be issued as soon as possible.

## I. COMMENTS

### A. Cost of Service Compensation for Providing Reactive Power Within the Standard Power Factor Range Is Unjust and Unreasonable.

The NOPR includes (at P 28) a preliminary finding "that providing compensation for the provision of reactive power within the standard power factor range is unjust and unreasonable because the generating facility already provides reactive power within the standard power factor range at no cost or *de minimis* cost, because such compensation may result in undue compensation or other market distortions, and because providing reactive power within the standard power factor range is an obligation of the generating facility as an interconnection customer and consistent with good utility practice."[5]

#### 1. Generation Resources Provide Reactive Power within the Standard Power Factor Range at No Cost or *de Minimis* Cost.

The NOPR identifies (at P 29) a fundamental fact about reactive power capability: "Both synchronous and non-synchronous resources provide real and reactive power as joint products, [footnote omitted] with joint costs [footnote omitted]." The NOPR explains (at P 29) the nuances about reactive capability provided by synchronous resources (e.g. steam, fossil fuels) and asynchronous resources (e.g., solar, wind). The NOPR summarizes (at P 30) the key point: "[B]ecause real and reactive power are provided as joint products with joint

[5] The NOPR states (P 1 n.1): "Operating 'inside the standard power factor range' refers to a generating facility providing reactive power within the power factor range set forth in the generating facility's interconnection agreement when the unit is online and synchronized to the transmission system."

costs, any allocation of joint fixed costs between real and reactive power could be viewed as inherently arbitrary."

The allocation method relied on by all generators filing for reactive rates demonstrates that the allocation is inherently arbitrary. The *AEP* Method was created, before the establishment of the PJM markets, by a regulated utility that had regulatory and financial reasons to want to define some generation costs as transmission costs.[6] At the time, AEP collected both generation and transmission costs under the same cost of service approach. The *AEP* Method was based on three sentences in testimony filed in 1993 that provide no logical, engineering or economic support for allocating a part of generator capital investment to reactive. That testimony was about a subjective decision to reassign costs that were already fully accounted for and not about any asserted costs to provide reactive power that were not recovered elsewhere and not for any asserted additional costs of providing reactive power.[7]

The current process does not actually compensate resources based on their costs of investment in reactive power capability. The allocator typically used by proponents of the *AEP* Method to assign costs to reactive power generation is $(1 - (\text{PowerFactor})^2)$. The power factor has superficial attraction as part of an allocator, but no actual logic has been advanced for using the power factor or $(1 - (\text{PowerFactor})^2)$ as the allocator. No causal link has been asserted or supported between the allocator and actual costs. The power factor does not measure reactive capability. The power factor does not determine a plant's reactive capability. The power factor does not identify costs associated with reactive capability or provide a reasonable basis for allocating those costs to reactive or real power production.

6 The NOPR explains (at 17 n.45): "The AEP Methodology derives its name from Opinion No. 440, where the Commission approved AEP's, a vertically integrated utility, method for calculating the costs of synchronous generation equipment associated with the production of reactive power. *See Am. Elec. Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999), *order on reh'g*, 92 FERC ¶ 61,001 (2000)."

7 See *Fern Solar LLC*, Initial Brief of the Independent Market for PJM, FERC Docket No. ER20-2186, et al. (February 15, 2023) at 24–31.

This is an allocation based on a subjective judgment rather than actual capital costs. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

In PJM and its competitive market design, there is no reason to include complex rules that arbitrarily segregate a portion of a resource's capital costs as related to reactive power and that require recovery of that arbitrary portion through guaranteed revenue requirement payments based on burdensome cost of service rate proceedings.

### 2. Cost of Service Compensation for Reactive Power Distorts Markets and Undermines Competition.

The NOPR would allow PJM to use a market based approach. The interrelated and self sustaining markets in PJM provide the opportunity for all power plants to recover all their costs, including a return on and of capital, including any identifiable reactive costs. There is no reason that part of those capital costs should be paid directly in a nonmarket, guaranteed, riskless revenue stream rather than in the market. This is the case both for energy only resources and for capacity resources. The revenue requirement approach is inconsistent with both the theory and mechanics of PJM markets.

Payments based on the cost of service approach distort market outcomes. The current rules create strong incentives for generators to attempt to maximize the allocation of capital costs to reactive in order to maximize guaranteed, nonmarket revenues. Those nonmarket revenues provide a nonmarket advantage to those generators who receive them. This is a return to using the regulatory process for advantage rather than competing in the market. That advantage is arbitrary, not market based and therefore distortionary.

#### *a. Schedule 2 Rates Vary Significantly without Justification.*

The rates approved in reactive proceedings vary significantly even though they are for the same service. Table 1 demonstrates the wide disparity in payments for reactive capability that result from the current process. Table 1 shows the wide disparity across technology types but does not show the significant disparities within technology types.

**Table 1 Total settled reactive revenue requirements by unit type and fuel type: March 1, 2024**

| Unit Type | Fuel Type | Total Revenue Requirement per Year | MW | Number of Resources | Requirement per MW-year |
|---|---|---|---|---|---|
| CC | Gas | $121,962,724.67 | 50,381.0 | 158 | $2,420.81 |
| CT | Gas | $51,213,720.64 | 28,841.1 | 264 | $1,775.72 |
| CT | Oil | $9,302,004.03 | 3,231.0 | 111 | $2,878.99 |
| Diesel | Gas | $1,380,092.00 | 105.8 | 5 | $13,044.35 |
| Diesel | Oil | $1,175,428.55 | 168.1 | 36 | $6,992.44 |
| Diesel | Other - Gas | $793,998.95 | 115.1 | 13 | $6,898.34 |
| FC | Gas | $45,000.00 | 2.4 | 1 | $18,750.00 |
| Hydro | Water | $16,674,453.62 | 6,235.0 | 53 | $2,674.33 |
| Nuclear | Nuclear | $54,335,315.68 | 32,535.2 | 31 | $1,670.05 |
| Solar | Solar | $5,392,893.89 | 1,429.1 | 18 | $3,773.63 |
| Steam | Coal | $45,628,904.80 | 37,816.4 | 63 | $1,206.59 |
| Steam | Gas | $4,608,575.05 | 4,222.6 | 15 | $1,091.41 |
| Steam | Oil | $2,831,154.15 | 2,852.3 | 9 | $992.59 |
| Steam | Other - Solid | $340,000.00 | 34.0 | 2 | $10,000.00 |
| Steam | Wood | $1,250,000.00 | 153.0 | 3 | $8,169.93 |
| Wind | Wind | $18,171,888.29 | 4,804.3 | 37 | $3,782.42 |
| Total | | $335,106,154.31 | 172,926.4 | 819 | $1,937.85 |

There is no reasonable basis for the disparity in the price to customers for the same service. Reactive is a homogeneous product which should have the same price for all sellers. These results are never explained or supported in the black box offers that are the general rule in reactive cases. This disparity is inconsistent with competitive markets.

Most recent cases settled prior to issuance of the NOPR have settled for costs well in excess of the average cost and well in excess of the ARR offset amount. The issue is growing in significance.

***b. Offset.***

The current approach to reactive compensation distorts and suppresses capacity market prices.

In the capacity market, the parameters that define the demand curve (known as the Variable Resource Requirement or "VRR" curve) are based on the costs of new entry of a reference generating unit, less net revenues from other PJM markets. Net revenues include fixed Schedule 2 revenues (termed the ancillary services offset although it includes only reactive revenue) which is currently set at $2,199 per MW-Year. This value is termed the Offset. The $2,199 per MW-Year value is based on a Market Monitor calculation of the average Schedule 2 payment for reactive done in 2008 and based on reactive rates from prior years. The net cost of new entry (CONE) is suppressed as a result of the reactive revenue offset. Market seller offer caps in the capacity market are also net of net revenues from other PJM markets, including reactive revenues. Market seller offer caps are also suppressed as a result of the reactive revenue offset.

Elimination of the reactive revenue requirement and the reactive revenue offset would increase prices in the capacity market. The VRR curve, or demand curve, would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase.

### 3. Providing Reactive Power within the Standard Power Factor Range Is an Obligation of Resources that Interconnect to the Transmission System and Consistent with Good Utility Practice.

The Commission has a long standing policy that "treats the provision of reactive power inside the [standard power factor range] as an obligation of good utility practice rather than as a compensable service and permits compensation inside the [standard power factor range] only as a function of comparability."[8] The NOPR explains: "where the generating facility is operating within the standard power factor range, it is doing no more than meeting its obligation as a generator, as specified in its interconnection agreement, to maintain the

8 *See* NOPR at P 5, citing *Bonneville Power Admin. v. Puget Sound Energy, Inc.*, 120 FERC ¶ 61,211 (2007), *reh'g denied*, 125 FERC ¶ 61,273 at P 18 (2008).

appropriate power factor required to maintain voltage levels for electric power injected into the transmission system during normal operations."[9]

The NOPR points to CAISO's rationale that the terms of the interconnection agreement "represent a reasonable range of what a generator is expected to provide the CAISO without additional compensation in accordance with good utility practice and as a condition of being part of the CAISO markets and CAISO grid."[10] The NOPR concludes (at P 33): "because providing reactive power within the standard power factor range is already obligated (at no cost or *de minimis* cost service), compensating for providing such reactive power could result in undue compensation to generating facilities[footnote omitted] at the expense of transmission customers." The NOPR supports the statement that such compensation is undue pointing to court cases finding "there must be a connection between the incentive and the conduct meant to be induced … [C]ompensating for reactive power that is already required for interconnection purposes could create a 'windfall.'"[11]

Consistent with the Commission's policies governing interconnection service, the PJM OATT sets forth the conditions to obtain interconnection service.[12] The requirement that generating facilities provide reactive power is stated explicitly:

> For all new Generating Facilities to be interconnected pursuant to the Tariff, other than wind-powered and other non-synchronous generation facilities, the Generation Interconnection Customer shall design its Customer Facility to maintain a composite power delivery at continuous rated power output at a power factor of at least 0.95 leading to 0.90 lagging. For all new wind-powered and

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9 *Id*. at PP 5 & 16, citing *Midcontinent Independent System Operator, Inc.*, 182 FERC ¶ 61,033 (*MISO*), *order on reh'g*, 184 FERC ¶ 61,022 at P 23 (2023), citing *Michigan Electric Transmission Co.*, 97 FERC ¶ 61,187 at 61,852-53 (2001).

10 *Id*. at P 33, citing Comments of the California Independent System Operator Corporation, Docket No. RM22-2-000 (February 22, 2022) at 3.

11 *Id*., citing Belmont Municipal Light Department v. FERC, 38 F.4th 173, 179, 186 (D.C. Cir. 2022).

12 *See* OATT, Attachment O.

> other non-synchronous generation facilities the Generation Interconnection Customer shall design its Customer Facility with the ability to maintain a composite power delivery at a power factor of at least 0.95 leading to 0.95 lagging across the full range of continuous rated power output. … This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two.[13]

The interconnection agreement creates an obligation on generation interconnection customers to supply reactive power at PJM's direction:

> Interconnection Customer agrees, as and when so directed by Transmission Provider or when so directed by the Interconnected Transmission Owner acting on behalf or at the direction of Transmission Provider, to operate the Customer Facility to produce reactive power within the design limitations of the Customer Facility pursuant to voltage schedules, reactive power schedules or power factor schedules established by Transmission Provider or, as appropriate, the Interconnected Transmission Owner.[14]

Reactive power is not the only design obligation that generation interconnection customers assume. Generators are also obligated to provide primary frequency response capability "by installing, maintaining, and operating a functioning governor or equivalent controls…"[15] Primary frequency response capability is required for the reliable operation of the system. The PJM OATT does not, however, provide for an out of market payment for such capability. The provision of primary frequency capability is treated as an obligation assumed by generation interconnection customers for receiving interconnection service.

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13 OATT, Attachment O § 4.7.1.1.1.

14 OATT, Attachment O § 4.7.1.2.

15 OATT, Attachment O § 4.7.2.

The PJM OATT includes a number of other obligations on generation interconnection customers, many of which are important and impose costs, but does so without including any special provisions for out of market compensation.

In PJM's competitive markets, PJM should determine, subject to the Commission's regulation, the design criteria that generation interconnection customers must meet in order to obtain interconnection service. Customers should compete in the markets to meet all of these criteria at the lowest cost.

**B. Administrative Proceedings to Determine Schedule 2 Rates are Wasteful and Undermine the Benefits of Competition.**

Applying cost of service rules is costly, burdensome and unnecessary. Most reactive proceedings for generators in PJM are resolved in black box settlements that require substantial time and resources from all parties, fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that produce a wide, unreasonable and discriminatory disparity among the rates per paid per MW-year for the same service.

The use of the *AEP* Method in Schedule 2 proceedings compounds the inherent wastefulness of Schedule 2 proceedings. The NOPR also recognizes (*id*.) how the information requirements for implementing the *AEP* Method diverts the attention of PJM staff responsible for testing resources for reliability to testing to support the development a record for use in Schedule 2 proceedings.

PJM and PJM's customers would benefit from the elimination of the burdensome process used to implement Schedule 2.

**C. The NOPR Appropriately Extends and Makes Uniform Longstanding Commission Policy.**

The NOPR does not propose a new Commission policy. Rather, it extends and makes uniform policies that have long applied in jurisdictional markets. The sole reason provided for including Schedule 2 payments in the *Pro Forma* OATT is the "comparability standard," meaning "if the Transmission Provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the Interconnection Customer."[16] RTOs like PJM exist in order to establish an independent Transmission Provider that does not itself participate, directly or indirectly, in the market that it operates. An RTO does not have its "own or … affiliated generators." Because the rationale for Schedule 2 to the *Pro Forma* OATT does not apply to PJM, Schedule 2 should never have been carried over into the PJM OATT.

The NOPR observes that CAISO "never provided compensation for reactive power within the standard power factor range."[17] Southwest Power Pool ("SPP") does not provide such compensation.[18] On January 27, 2023, the Commission approved a filing by Midcontinent Independent System Operator, Inc.'s ("MISO") transmission, to remove such compensation from its OATT.[19] The NOPR states "[m]any non-RTO/ISO transmission providers do not pay separately for reactive power provided within the standard power factor range."[20]

In 2003, the Commission confirmed its policy when it issued Order No. 2003. The NOPR states: "Order No. 2003 required that a transmission provider compensate an interconnection customer for the provision of reactive power when the transmission provider requests the interconnection customer to operate its generating facility outside the

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16 *See* NOPR at PP 4 & 45, citing *Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 416 (2004); *Pro Forma* LGIA § 9.6.3.

17 NOPR at P 18, citing *CAISO*, 160 FERC ¶ 61,035, at P 7 (2017).

18 *Id.*, citing *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 30 (2007).

19 *Id.*, citing *MISO*, 182 FERC ¶ 61,033 at PP 52–66 (2023), *reh'g denied*, 184 FERC ¶ 61,022 at PP 23–55 (2023).

20 *Id*. at P 19, citing Arizona Public Service Company, FERC Electric Tariff Vol. No. 2, Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service) (6.0.0); Public Service Company of New Mexico, PNM Open Access Transmission Tariff, Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service) (2.1.0).

established power factor range.[21] The NOPR explained that Order No. 2003 "initially concluded that the interconnection customer should not be compensated for reactive power when operating within the range established in the interconnection agreement because doing so "is only meeting [the generating facility's] obligation," but on rehearing clarified that "if the Transmission Provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the Interconnection Customer." Order No. 2003 also means that PJM should remove Schedule 2 rates. The exception, the comparability standard, does not apply to PJM. The NOPR proposes a rule that would require PJM to take an action in 2024 that PJM should have taken in 2003.

The inclusion of Schedule 2 in PJM was never required by Commission policy, has contradicted Commission policy since 2003, and should be corrected in 2024. The NOPR would require adherence to longstanding logic and policy.

### D. Eliminating Separate Compensation Will Not Adversely Affect Reliability.

The NOPR (at P 44) seeks comment on "the reliability impact of prohibiting transmission providers from including in their transmission rates any charges associated with the supply of reactive power within the standard power factor range from a generating facility in regions where generating facilities currently receive such compensation." There will be no adverse reliability impacts in PJM (or other similarly situated regions) for the same reasons that no there have been no observable impacts in regions that do not compensate generating facilities for the supply of reactive power with the standard power factor range. As in the case of CAISO, SPP and MISO, new and existing generating facilities in PJM are required to provide reactive power within the standard power factor range as a condition of

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21 NOPR at P 4, citing *Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 68 Fed. Reg. 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at P 546 (2003), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15932 (Mar. 26, 2004), 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (Jan. 4, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 70 Fed. Reg. 37661 (June 30, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulated Utilities Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

obtaining and maintaining interconnection service. There is no evidence that expanding the just and reasonable approach to compensation already in place in CAISO, SPP and MISO to PJM will have any adverse impact on reliability in PJM. The salient difference between PJM and CAISO, SPP and MISO, is that PJM customers paid $388,044,837.00 in out of market payments for reactive capability in 2023, and customers in CAISO, SPP and MISO, paid $0.00.[22]

### E. Eliminating Separate Compensation Is Consistent with Competitive Market Design.

Generators will invest in markets when the expected revenues provide for the payment of all costs and a return on and of capital. That is the way competitive markets work. It would be more equitable, more consistent with the PJM competitive market design, and more consistent with appropriate compensation for all generator costs, including reactive, to rely on PJM markets than to continue the outdated mix of regulatory paradigms. The market approach should be used, as it is overwhelmingly more efficient than the current rate case, cost of service approach. Supporters of the cost of service approach have never explained why a nonmarket approach is required in PJM or why it is preferable to a market approach.

The NOPR seeks comment (at P 49) "on whether, and if so how, eliminating separate reactive power compensation within the standard power factor range may affect investment decisions to build, or finish building, generation facilities, and whether, and if so how, the elimination could otherwise affect generators' business decisions in those markets."

There is no evidence that units are built as a result of reactive revenue. There is no evidence that sources of revenue are not fungible and that a decrease in reactive revenues could be not replaced with other sources of revenue. There is no basis for adding new resources to the already very crowded interconnection queue solely based on out of market

22 *See* 2023 State of the Market Report for PJM, Vol. 2 (March 14, 2024) at 611 (Table 10-65).

subsidies from reactive revenues. Such a result would be inconsistent with competitive markets.

The NOPR seeks comment (at P 49) on "on whether and, if so, how the elimination of separate reactive power payments will affect generating facilities' ability to recover their costs in the markets that currently provide reactive power compensation within the standard power factor range."

Generators will invest in markets when the expected revenues provide for the payment of all costs and a return on and of capital. That is the way competitive markets work.

### F. Transmission Providers Should Be Prohibited from Charging Customers for Reactive Power with the Standard Power Factor Range.

The NOPR (at P 41) states "a just and reasonable replacement rate is to prohibit transmission providers from including in their transmission rates any charges associated with the supply of reactive power within the standard power factor range from a generating facility."

In the case of PJM, compliance should mean the elimination of Schedule 2 in conjunction with the elimination the Offset. The sole purpose of Schedule 2 is to provide compensation for reactive capability based on the comparability principle. [23] Because the comparability does not apply and never applied to PJM, Schedule 2 should be removed from the PJM OATT immediately. The Offset should be set to zero immediately and Offset provision should be removed from the tariff. Schedule 2 should be removed at the start of the first RPM Delivery Year with parameters established on the basis of an Offset of zero dollars or no Offset.

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[23] *See* NOPR at P 4, citing *Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 416 (2004); *Pro Forma* LGIA § 9.6.3.

### G. Proposed Transition Period.

There is no legal or equitable reason why Schedule 2 and compensation for reactive capability for reactive power should not be eliminated immediately. There is a direct tradeoff between reduced payments by customers and reduced revenues to generation owners. A faster transition benefits customers and recognizes that customers have been overpaying for reactive for many years. A faster transition reduces revenues to generation owners faster.

The Market Monitor recommends a transition period for PJM with the following components:

- All current approved reactive rates filed pursuant to Schedule 2, to the extent that they exceed the Offset, should be reduced to the level of the Offset that was applicable to the auctions for each RPM Delivery Year.
- All pending reactive filings submitted by eligible resources under Schedule 2 prior to the issuance of the NOPR should only be approved, after review, at a level that does not exceed the level of the Offset that was applicable to the auctions for each RPM Delivery Year.
- Schedule 2 to the PJM OATT should be revised to immediately remove the ability to file for new reactive capability rates.
- The Offset should be reduced to zero dollars, and should be removed from the rules immediately.
- Schedule 2 to the PJM OATT should be eliminated from the OATT in its entirety effective at the start of the first Delivery Year where the Offset included in the capacity market base residual auctions for such Delivery Year is zero dollars.

If PJM eliminates the net revenue offset as a component of the market seller offer caps in the capacity market prior to the end of the proposed transition period:

- The Offset should be reduced to zero dollars, and should be removed from the rules immediately.
- Schedule 2 to the PJM OATT should be eliminated from the OATT in its entirety effective with the change to the market seller offer cap.

Given the schedule for upcoming capacity market auctions in PJM, the timing for the transition will be a direct result of the effective date of a final rule. Given this schedule, there will be a significant lag before the Offset can be removed for an identified delivery year. For example, if the effective date of the final rule were March 1, 2025, the Offset could be eliminated and payments under Schedule 2 eliminated effective June 1, 2027, the start of the delivery year for the base residual auction scheduled to be run in June 2025.

The schedule of future RPM Base Residual Auctions and the start of the applicable Delivery Year is:

| **PJM Base Residual Auction** | **Start of Delivery Year** |
|---|---|
| July 17, 2024 | June 1, 2025 |
| December 4, 2024 | June 1, 2026 |
| June 2025 | June 1, 2027 |
| December 2025 | June 1, 2028 |
| May 2026 | June 1, 2029 |

Adoption of the transition approach proposed by the Market Monitor would minimize potential impacts. The proposed transition is designed to allow those who have a Schedule 2 rate on file or an eligible rate filing pending to receive a rate no greater than the Offset for as long as the Offset affects capacity prices in a delivery year. With the removal of the Offset, markets can be relied upon going forward to provide efficient, just and reasonable, investment incentives.

In PJM, Schedule 2 rates should not have been paid, but to the extent Schedule 2 payments were made, such payments should never have been permitted to exceed the Offset. All Schedule 2 rates should immediately be uniformly capped at the Offset level. It is reasonable to limit eligibility to resources that filed Schedule 2 rates prior to the issuance of the NOPR in this proceeding because owners have had adequate notice of the market flaws and the likelihood of reform and to avoid a rush to file reactive cases prior to the effective date of the final rule.

## II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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