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Issued on March 21, 2024.

Victor Wicklund,

Deputy Director, Compliance & Airworthiness Division, Aircraft Certification Service.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM22–2–000]

Compensation for Reactive Power Within the Standard Power Factor Range

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to revise Schedule 2 of its *pro forma* open-access transmission tariff (*pro forma* OATT), section 9.6.3 of its *pro forma* large generator interconnection agreement (LGIA), and section 1.8.2 of its *pro forma* small generator interconnection agreement (SGIA) to prohibit the inclusion in transmission rates of unjust and unreasonable charges related to the provision of reactive power within the standard power factor range by generating facilities. The Commission invites all interested persons to submit comments on the proposed reforms and in response to specific questions.

DATES: Comments are due May 28, 2024. Reply comments are due June 26, 2024.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways. Electronic filing through *https://www.ferc.gov* is preferred.

- *Electronic Filing:* Documents must be filed in acceptable native applications and print-to-PDF, but not in scanned or picture format.
- For those unable to file electronically, comments may be filed by USPS mail or by hand (including courier) delivery.
  - *Mail via U.S. Postal Service Only:* Addressed to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.
  - *Hand (including courier) delivery:* Deliver to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

The Comment Procedures section of this document contains more detailed filing procedures.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

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I. Introduction

1. The Commission is proposing to revise Schedule 2 of its *pro forma* OATT 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[1] from generating facilities. We further propose to remove from the *pro forma* LGIA and *pro forma* SGIA the requirement that a transmission provider pay an interconnection customer for reactive power within the standard power factor range if the transmission provider pays its own or affiliated generators for the same service. Accordingly, transmission providers would be required to pay an interconnection customer for reactive

[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.

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.

2. The Commission's policy on reactive power compensation has evolved since issuing Order No. 888 in 1996.[2] In Order No. 888, the Commission required that reactive supply and voltage control from generating facilities be offered as a discrete ancillary service by transmission providers and, to the extent feasible, charged for on the basis of the amount required. The Commission explained that there are two ways of supplying reactive power and controlling voltage. One is to install facilities as part of the transmission system, the cost of which is part of the cost of basic transmission service. The second is to use generating facilities to supply reactive power and voltage control, which must be unbundled from basic transmission service.

3. With respect to compensation, the Commission stated that the transmission provider's ''rates for ancillary services should be cost-based.'' [3] The Commission expected, however, that transmission customers would be in a position to change the amount of reactive power service they required. The Commission also identified the possibility that reactive power could potentially someday be supplied by ''a competitive market for such service'' if ''technology or industry changes'' made such a market possible.

4. Then, in Order No. 2003, the Commission specifically addressed the circumstances and manner in which a transmission provider must pay for reactive power, inside and outside the standard power factor range (sometimes referred to as the ''deadband'').[4] In Order No. 2003, the Commission adopted a standard agreement for the interconnection of large generating facilities (the *pro forma* LGIA), which included the requirement that interconnection customers maintain a composite power delivery at continuous rated power output at the point of interconnection at a power factor within the range of 0.95 leading to 0.95 lagging [5] when synchronized to the transmission system, unless the transmission provider has established a different power factor range. 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 established power factor range. With respect to reactive power within the established power factor range, the Commission 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.'' [6] But in Order No. 2003–A, the Commission 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.'' [7] This standard is generally referred to as the comparability standard.

5. In sum, ''Order Nos. 2003 and 2003–A establish a reactive power compensation policy that, in the first instance, 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 Commission took this approach because, 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 appropriate power factor required to maintain voltage levels for electric power injected into the transmission system during normal operations.[9] By comparison, reactive power provided outside of the standard power factor range is considered an ancillary service for transmitting power across the transmission system to serve load,[10] and thus, the Commission has required compensation for such service.

6. The Commission has also recognized that there is little to no incremental capital expenditure associated with the equipment necessary for the production of reactive power within the standard power factor range. That is because, for both synchronous and non-synchronous generating facilities,[11] the same equipment is used for the production of real power and reactive power.[12] In

[2] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,705–07 & n.359 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp.* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N. Y.* v. *FERC,* 535 U.S. 1 (2002).

[3] *Id.* at 31,720.

[4] *Standardization of Generator Interconnection Agreements & Procs.,* Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at P 546 (2003), *order on reh'g,* Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), 106 FERC ¶ 61,220, *order on reh'g,* Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g,* Order No. 2003–C, 70 FR 37661 (June 30, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007).

[5] A generating facility's leading reactive power indicates its ability to absorb reactive power and its lagging reactive power indicates its ability to produce reactive power.

[6] Order No. 2003, 104 FERC ¶ 61,103 at P 546 (''We agree that the Interconnection Customer should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation.'').

[7] Order No. 2003–A, 106 FERC ¶ 61,220 at P 416. Section 9.6.3 of the *pro forma* LGIA provided as follows:

Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer.

Similarly, section 1.8.2 of the *pro forma* SGIA provided as follows:

The Transmission Provider is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Small Generating Facility when the Transmission Provider requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in article 1.8.1. In addition, if the Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.

[8] *Bonneville Power Admin.* v. *Puget Sound Energy, Inc.,* 120 FERC ¶ 61,211 (2007) (*BPA*), *order denying reh'g and granting clarification,* 125 FERC ¶ 61,273, at P 18 (2008) (BPA Rehearing Order).

[9] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.,* 182 FERC ¶ 61,033 (*MISO*), *order on reh'g,* 184 FERC ¶ 61,022, at P 23 (2023) (MISO Rehearing Order) (citing *Mich. Elec. Transmission Co.,* 97 FERC ¶ 61,187, at 61,852–53 (2001) (*METC*)).

[10] *Id.*

[11] Synchronous generating facilities (*e.g.,* coal, gas, nuclear resources) produce electricity in sync with the transmission system at the system frequency. Non-synchronous generating facilities (*e.g.,* solar, wind, battery storage resources) produce electricity that is initially not in sync with the transmission system and use inverters to convert their electrical output to synchronize with the transmission system. *See* FERC Staff Report, *Payment for Reactive Power,* Docket No. AD14–7–000, 7 (Apr. 22, 2014), *https://www.ferc.gov/sites/default/files/2020-05/04-11-14-reactive-power.pdf.*

[12] MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 29–30 (citing *S. Co. Servs., Inc.,* 80 FERC ¶ 61,318, at 62,091 (1997) (noting also that the primary function of a generating plant is to produce real power; thus, if costs were allocated based on the ''predominant'' function of the equipment, ''all of the costs of generation would thus be assigned to real power production and there would be no basis for any separate reactive power charge''); *BPA,* 120 FERC ¶ 61,211 at P 21 (finding that the

Continued

addition, the Commission has noted that any purported costs associated with such provision of reactive power can be recovered in other ways—such as through energy or capacity sales.[13]

7. Consistent with Order Nos. 2003 and 2003–A, multiple regional transmission organizations (RTO), independent system operators (ISOs), and non RTO/ISO transmission providers have elected not to compensate generating facilities for the provision of reactive power within the standard power factor range under Schedule 2 of the OATT.[14] Within these regions, there is no evidence that this lack of compensation has led to an insufficient supply of reactive power or that generating facilities in these regions have been unable to recover any costs associated with the production of reactive power. Additionally, the experiences of these regions where reactive power within the standard power factor range is not separately compensated indicate that investors are able to, and in fact do, develop generating facilities that can satisfy the obligations in their interconnection agreements without separate reactive power compensation.

8. Based on our review of the comments submitted in response to the Commission's Notice of Inquiry [15] in the instant docket, as well as the Commission's experience in the years since the issuance of Order No. 2003–A, we preliminarily find that allowing transmission providers to compensate generating facilities, affiliated and unaffiliated, for providing reactive power within the standard power factor range has resulted in unjust and unreasonable transmission rates. This is because generating facilities providing reactive power within the standard power factor range are only meeting their obligations under their interconnection agreements and in accordance with good utility practice, and in doing so, incur no additional costs or *de minimis* costs beyond that which they already incur to provide real power.[16] Accordingly, we propose 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, including those owned by the transmission owner or its affiliates.

9. First, we propose to add the following sentence to the end of Schedule 2 of the *pro forma* OATT: [17] ''However, such rates shall not include compensation to generating facilities for the supply of reactive power within the power factor range specified in its interconnection agreement.'' Second, we propose to remove the following clause from the *pro forma* LGIA: [18] ''provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer.'' Third, we propose to remove the following sentence from the *pro forma* SGIA: [19] ''In addition, if the Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.''

II. Background

A. What is reactive power?

10. Almost all bulk electric power is generated, transported, and consumed in alternating current (AC) networks. Reactive power, which is measured in megavolt-amperes reactive (MVAr),[20] is a critical component of operating an AC electricity system and is required to control system voltage within appropriate ranges for efficient and reliable operation of the transmission system. Reactive power supports the voltages that must be controlled to provide for delivery of real power and for system reliability. Reactive power can be produced or absorbed [21] by generating facilities, power electronic equipment such as flexible AC transmission system devices, transmission lines and equipment, and load. As relevant here, generating facilities must either produce or absorb reactive power for the transmission system to maintain voltage levels required to reliably supply real power from generation to load.

11. The power factor is the ratio of a generating facility's real power to its apparent power.[22] Power factors can range from 1.0 to 0.0, with 1.0 representing only real power and 0.0 representing only reactive power. Most generating facilities have interconnection agreements that specify a standard power factor range within which the generating facility must be able to operate while producing its full real power capacity.

B. How has reactive power been compensated?

12. As noted above, the Commission's policy on reactive power compensation has evolved since issuing Order No. 888, which included provisions regarding reactive power from generating facilities as an ancillary service in Schedule 2 of the *pro forma* OATT.[23] As relevant here, in Order No. 2003, the Commission adopted a standard agreement for the interconnection of large generating facilities (the *pro forma* LGIA). This standard agreement included the requirement that interconnection customers maintain a composite power delivery at continuous rate of power output at the generating facility's point of interconnection at a power factor within the range of 0.95 leading to 0.95 lagging when synchronized to the transmission system, unless the transmission provider has established a different power factor range. Order No. 2003 required that a transmission provider compensate an interconnection customer for reactive power when the transmission provider requests that the interconnection customer operate its generating facility outside the established power factor range. With respect to reactive power within the established power factor range, the Commission 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.'' [24] But, in Order No. 2003–A, the Commission 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.'' [25] Order No. 2003–A also exempted wind generating

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incremental cost of reactive power service within the standard power factor range is minimal); *METC,* 97 FERC at 61,852–53 (''[R]eactive power provided, not as an ancillary service, but rather as a 'no cost' service within reactive design limitations, may therefore, be provided without compensation.'').

[13] *See, e.g.,* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 42; *BPA,* 120 FERC ¶ 61,211 at P 21; *Sw. Power Pool, Inc.,* 119 FERC ¶ 61,199, at P 39 (2007) (stating that IPPs ''are free to negotiate rates that they charge their customers for real power that are sufficient to compensate them for any costs that they may incur in producing reactive power within their deadbands, just as affiliated generators may seek to negotiate rates that they charge their customers that are sufficient to compensate them for the costs of any reactive power that they provide within their deadbands.'').

[14] *MISO,* 182 FERC ¶ 61,033 at P 1.

[15] *Reactive Power Capability Compensation,* 177 FERC ¶ 61,118 (2021) (NOI).

[16] Real power, which accomplishes useful work (*e.g.,* runs motors), is typically measured in megawatts (MW).

[17] *See pro forma* OATT, Schedule 2.

[18] *See pro forma* LGIA, section 9.6.3.

[19] *See pro forma* SGIA, section 1.8.2.

[20] MVAr is the typical unit of measurement for reactive power.

[21] *See supra* n.5.

[22] Apparent power is the total power output of the system (both real and reactive power).

[23] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,705–07 & n.359.

[24] Order No. 2003, 104 FERC ¶ 61,103 at P 546.

[25] Order No. 2003–A, 106 FERC ¶ 61,220 at P 416.

facilities from maintaining the established power factor range.[26]

13. The Commission treats the provision of reactive power within the standard power factor range differently from that outside the standard power factor range. Where reactive power is provided outside of the standard power factor range, it is considered ''an ancillary service for *transmitting power across the grid* to serve load.'' [27] By contrast, where the generating facility is operating within the standard power factor range, ''it is meeting its obligation as a generator to maintain the appropriate power factor in order to maintain voltage levels for energy *entering the grid* during normal operations.'' [28] ''Put differently, reactive support by generating facilities operating within the standard power factor range ensures that when these facilities inject real power—the product that their facilities exist to create and sell—onto the grid under normal conditions, they can do their part to maintain adequate voltages and to not threaten reliability.'' [29]

14. In Order No. 2006,[30] the Commission adopted identical power factor and compensation requirements for small generating facilities (facilities that have a capacity of no more than 20 MW) but exempted small wind generating facilities from the reactive power requirement. Subsequently, in Order No. 827,[31] the Commission eliminated the exemptions for both small and large wind generating facilities, thus requiring those facilities to provide reactive power. As a result, all newly interconnecting non-synchronous generating facilities were required to provide reactive power within the range of 0.95 leading to 0.95 lagging at the high-side [32] of the generator substation transformer as a condition of interconnection. With respect to compensation, the Commission applied the existing policies on compensation for reactive power as articulated in Order Nos. 2003 and 2003–A and reflected in the *pro forma* LGIA and SGIA. The Commission, however, stated that the record did not contain a sufficient basis for determining a method for calculating compensation for non-synchronous generating facilities and therefore stated that any non-synchronous generating facility seeking reactive power compensation would need to propose a method for calculating that compensation as part of its filing.[33]

15. Consistent with Order Nos. 2003 and 2003–A, the Commission has permitted transmission providers to eliminate separate compensation for generating facilities providing reactive power within the standard power factor range.[34] In these cases, the Commission affirmed its determination that the provision of reactive power within the standard power factor range is not compensable except as a matter of comparability. For example, in *BPA,* the Commission granted a complaint filed by Bonneville Power Administration (BPA) arguing that the rate schedules of certain independent power producers (IPP) for reactive power were no longer just and reasonable given BPA's decision to no longer pay its own or affiliated generators.[35] The Commission found that ''Commission policy clearly allows BPA to discontinue paying all its merchants for inside the deadband reactive power service.'' [36] The Commission also found that a transmission provider's decision to end compensation for reactive power within the standard power factor range did not compromise an IPP's ability to recover costs that they may incur in producing reactive power within such range.[37] The Commission stated that such generating facilities ''may be able to recover such costs in other ways—such as through higher power sales rates of their own.'' [38] To the extent that it could be argued that such recovery was not feasible for IPPs, the Commission found that such arguments lacked plausibility ''since the incremental cost of reactive power service within the deadband is minimal.'' [39] The Commission explained that ''[t]he purpose for which generation assets are built (including reactive power capability to maintain voltage levels for generation entering the grid) is to make sales of real power.'' [40]

16. The Commission made similar findings in *MISO,* wherein it accepted an FPA section 205 application by Midcontinent Independent System Operator, Inc. (MISO) transmission owners to end generator compensation for the provision of reactive power within the standard power factor range.[41] In accepting MISO transmission owners' proposal, the Commission reiterated its longstanding policy ''that the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice,'' such that ''MISO transmission owners do not have an obligation to continue to compensate an independent generator for reactive power within the standard power factor range when its own or affiliated generators are no longer being compensated.'' [42] The Commission also rejected any reliance arguments, reasoning in part that the provision of reactive power within the standard power factor range required little or no incremental investment.[43] In addition, the Commission found that generating facilities have other opportunities, beyond Schedule 2, through which they have the opportunity to seek to recover

[26] *Id.* P 34.

[27] *See, e.g., METC,* 97 FERC at 61,852–53 (emphasis added); MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 23–24.

[28] *METC,* 97 FERC at 61,852–53; *see also* MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 23–24; *BPA,* 120 FERC ¶ 61,211 at P 19; *cf. Dynegy Midwest Generation, Inc.,* 125 FERC ¶ 61,280, at P 16 (2008) (''Reactive power is a localized service that is quickly used by transmission system components and cannot be transported over long distances.'').

[29] MISO Rehearing Order, 184 FERC ¶ 61,022 at P 23.

[30] *Standardization of Small Generator Interconnection Agreements & Procs.,* Order No. 2006, 111 FERC ¶ 61,220, *order on reh'g,* Order No. 2006–A, 70 FR 71760 (Nov. 30, 2005), 113 FERC ¶ 61,195 (2005), *order granting clarification,* Order No. 2006–B, 71 FR 42587 (July 27, 2006), 116 FERC ¶ 61,046 (2006).

[31] *Reactive Power Requirements for Non-Synchronous Generation,* Order No. 827, 81 FR 40793 (June 23, 2006), 155 FERC ¶ 61,277, *order on clarification and reh'g,* 157 FERC ¶ 61,003 (2016).

[32] High-side refers to the side of the transformer with higher voltages. Generally, real power must be stepped up through a transformer to transmission-level voltages before being injected into the transmission system.

[33] Order No. 827, 155 FERC ¶ 61,277 at P 52.

[34] *See, e.g., MISO,* 182 FERC ¶ 61,033 at PP 52–53; MISO Rehearing Order, 184 FERC ¶ 61,022 at P 26; *Pub. Serv. Co. of N.M.,* 178 FERC ¶ 61,088, at PP 29–31 (2022) (*PNM*); *Nev. Power Co.,* 179 FERC ¶ 61,103, at PP 20–21 (2022); *BPA,* 120 FERC ¶ 61,211 at P 20; *E.ON U.S. LLC,* 119 FERC ¶ 61,340, at P 15 (2007); *Entergy Servs., Inc.,* 113 FERC ¶ 61,040, at P 38 (2005).

[35] *BPA,* 120 FERC ¶ 61,211 at PP 19–20; BPA Rehearing Order, 125 FERC ¶ 61,273 at PP 10–11.

[36] *BPA,* 120 FERC ¶ 61,211 at P 20.

[37] *Id.* PP 19–22.

[38] *Id.* P 21 (citing *Sw. Power Pool, Inc.,* 119 FERC ¶ 61,199 at P 39).

[39] *Id.*

[40] *Id.*

[41] *MISO,* 182 FERC ¶ 61,033 at P 53 (''Bearing in mind that the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice, MISO [transmission owners] do not have an obligation to continue to compensate an independent generator for reactive power within the standard power factor range when its own or affiliated generators are no longer being compensated.'' (citation omitted)); *see also PNM,* 178 FERC ¶ 61,088 at P 29 (accepting PNM's revisions to eliminate compensation for reactive service under Schedule 2 and rejecting generators' arguments that it is ''just and reasonable for it to be compensated for investments made'' to provide reactive support consistent with interconnection requirements even though PNM elected to no longer pay its own or affiliated generators for such reactive power).

[42] *MISO,* 182 FERC ¶ 61,033 at P 53 (finding ''those protests that challenge these well-established policies to be collateral attacks on these earlier determinations.'').

[43] MISO Rehearing Order, 184 FERC ¶ 61,022 at P 29.

their costs of providing reactive power.[44]

17. Of the six Commission-jurisdictional RTOs/ISOs, only three currently compensate generating facilities for reactive power provided within the standard power factor range. Generating facilities in PJM Interconnection, L.L.C. (PJM) generally use the cost-based AEP Methodology to calculate cost-of-service rates for the production of reactive power.[45] Because the same generation equipment contributes to the production of both real power and reactive power, the AEP Methodology attempts to functionalize each piece of equipment as between its contribution to real power and reactive power. Then, using allocators calculated based on the facility's output, the AEP Methodology allocates the cost of each piece of equipment based on its relative contribution to each function.

18. Generating facilities in ISO New England Inc. (ISO–NE) and New York Independent System Operator, Inc. (NYISO) are compensated for reactive power under flat rate designs that are adjusted for inflation.[46] California Independent System Operator Corporation (CAISO),[47] Southwest Power Pool, Inc. (SPP),[48] and MISO [49] do not pay separately for reactive power within the standard power factor range.

19. Outside the RTOs/ISOs, transmission providers that pay for the provision of reactive power within the standard power factor range generally compensate generating facilities using the AEP Methodology to set reactive power compensation on an individual generating facility basis. Many non-RTO/ISO transmission providers do not pay separately for reactive power provided within the standard power factor range.[50]

C. Notice of Inquiry

20. On November 18, 2021, the Commission issued an NOI [51] in the instant docket seeking comment on various issues regarding reactive power compensation and market design as a result of the significant changes that have taken place in the electric industry in the last two decades, including changes in the generation resource mix and a general shift away from cost-of-service rates for generating facilities selling into Commission-jurisdictional markets. Generally, the Commission sought to ''examine whether the current regime for reactive power capability compensation requires revisions to ensure that payments for reactive power capability accurately reflect the costs associated with reactive power capability.'' [52] Specifically, the Commission sought comment on various constructs used by transmission providers to allow for reactive power cost recovery, including issues related to the application of the AEP Methodology as well as on issues regarding recovery of reactive power costs through existing energy and/or capacity markets.

21. The Commission received 37 initial comments and 10 reply comments in response to the NOI. The commenters to the NOI are listed and group members are identified in Appendix A. Groups representing transmission customers, such as Joint Customers, the Electricity Consumers Resource Council (ELCON), and the National Rural Electric Cooperative Association (NRECA), believe that the AEP Methodology results in unjust and unreasonable rates and recommend that the Commission establish a new rate methodology.[53] In particular, Joint Customers argue that ''reactive capability alone should not be the basis for compensation.'' [54] By contrast, resource developers, power generation industry groups, and commenters who support the increased use of renewable energy argue in favor of retaining and modifying the AEP Methodology to address the issues discussed in the NOI.[55]

22. The Independent Market Monitor for PJM (PJM IMM) contends that cost-of-service compensation for the provision of reactive power within the standard power factor range is an ''atavistic regulatory paradigm'' that predates the introduction of wholesale power markets and, therefore, is unnecessary in light of potential compensation through the PJM markets.[56] ELCON states that it supports the PJM IMM's position and encourages the Commission to rely on ''competitive markets for the procurement of essential grid services such as reactive power—rather than reliance on traditional cost-of-service rates'' in order to ''ensure that electricity consumers pay the lowest price possible for reliable service.'' [57]

23. RTOs/ISOs generally limit their comments to describing the rate designs in their respective regions, but PJM and CAISO did provide some commentary

[44] *Id.* P 41.

[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). In *WPS Westwood,* the Commission recommended that all generating facilities that have actual cost data and support documentation use the AEP Methodology. *See WPS Westwood Generation, LLC,* 101 FERC ¶ 61,290, at P 14 (2002).

[46] NOI, 177 FERC ¶ 61,118 at PP 14–16.

[47] CAISO never provided compensation for reactive power within the standard power factor range. *See Cal. Indep. Sys. Operator Corp.,* 160 FERC ¶ 61,035, at P 7 (2017) (explaining that CAISO considered the possibility of compensating generating facilities for reactive power in its stakeholder process, but decided against it, reasoning that the ability to provide reactive power is part of a generator's fixed costs, which are recovered through power purchase agreements).

[48] *Sw. Power Pool, Inc.,* 119 FERC ¶ 61,199 at P 30.

[49] *MISO,* 182 FERC ¶ 61,033 at PP 52–66; MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 23–55.

[50] *See, e.g.,* 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) (''This service will be provided at no charge until APS has developed a rate that has been filed with the Commission and allowed to be implemented; however, Transmission Customers taking service at transmission voltage levels shall be responsible for maintaining a power factor of ± 95.0%, and Transmission Customers taking service at distribution voltage levels shall maintain a power factor of not less than 90% lagging but in no event leading, unless agreed to by APS.''); 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) (''As of October 1, 2021, the Effective Date of this Schedule 2, the Transmission Provider is not charging for Reactive Supply and Voltage Control from Generation or Other Sources Service from its own resources. As a result, there will be no separate charge for such service.'').

[51] NOI, 177 FERC ¶ 61,118.

[52] *Id.* P 19.

[53] Joint Customers Initial Comments at 8–13; Joint Customers Reply Comments at 2–10, 12–15; ELCON Initial Comments at 5–7, NRECA Initial Comments at 4–5.

[54] Joint Customers Initial Comments at 9.

[55] *See, e.g.,* EDF Renewables, Inc. (EDFR) Initial Comments at 2–4; Edison Electric Institute (EEI) Initial Comments at 5; Indicated Generation Owners Initial Comments at 5–7; Nuclear Energy Institute (NEI) Initial Comments at 4; PJM Power Providers Initial Comments at 2–4; Renewable Generation Companies Initial Comments at 6–7, 11–15; Renewable Generation Companies Reply Comments at 2–5, 10–11; Clean Energy Coalition Initial Comments at 1–5; Electric Power Supply Association (EPSA) Initial Comments at 2–9; Vistra Corp. and Dynegy Marketing and Trade, LLC (collectively, Vistra) Initial Comments at 6–7; Vistra Reply Comments at 6–7; Pine Gate Renewables, LLC (Pine Gate) Initial Comments at 7–8.

[56] PJM IMM Initial Comments at 2; *see also* PJM IMM, Comments, Docket No. AD16–17–000, at 1, 6–10 (filed Aug. 1, 2016) (detailing the PJM IMM's view that reactive power costs can—and should—be recovered through PJM's capacity market instead of under a cost-of-service paradigm); Monitoring Analytics, 2020 State of the Market Report for PJM, 523 (Mar. 11, 2021), *https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml* (describing the PJM IMM's position and recommended improvements)); PJM IMM, Brief on Exceptions, Docket No. ER17–1821–002, at 3–16 (filed June 12, 2019) (discussing the PJM IMM's concerns about what it termed a ''hybrid of market-based rates and cost of service rates''); PJM IMM, Rehearing Request, Docket No. ER17–1821–005, at 3–5 (filed Apr. 30, 2021) (addressing issues regarding the Energy and Ancillary Services Offset (E&AS Offset) and a generator's proposed reactive power rates).

[57] ELCON Initial Comments at 4–5.

on the merits. While PJM does not advocate for a particular solution in this proceeding, PJM highlights several issues with its current reactive power rate scheme.[58] Specifically, PJM asserts that ''enormous'' amounts of time and resources must be expended to file, litigate, and perform testing for each individual generating facility's cost-of-service rate case,[59] which PJM notes often results in a rate product that is ''of exceptionally poor quality for an important ancillary service.'' [60] CAISO states that despite the fact that it does not compensate for reactive power within the standard power factor range, it ''has seen no evidence to this point that resources cannot comply with reactive power dispatch instructions because they have insufficient funds for the equipment to meet the reactive power dispatch.'' [61]

III. Discussion

A. Need for Reform

24. Since Order No. 2003–A, the Commission has permitted transmission providers to compensate resources for providing reactive power within the standard power factor range provided that, to ensure comparability, the transmission provider pays both affiliated and unaffiliated resources. But, as explained in more detail below, providing reactive power within the standard power factor range is a ''no cost'' [62] or *de minimis* cost service in addition to being a resource's obligation under its interconnection agreement and good utility practice. Further, the record indicates that to the extent that generating facilities have any purported costs associated with providing reactive power within the standard power factor range, these costs can be recovered through energy or capacity sales and do not require separate compensation.

25. We thus preliminarily find that where transmission providers require transmission customers to pay for the provision of reactive power within the standard power factor range, transmission rates may be unjust and unreasonable, as they include costs without a sufficient economic basis or justification.

26. The Commission's experience since Order No. 2003–A and the comments submitted into this record demonstrate that where transmission providers provide compensation, the costs to transmission customers have increased substantially without any commensurate increase in benefits. For example, in many regions today, resources are sited without regard to where there is a geographic need for reactive power, which is significant given that (unlike real power) reactive power cannot be efficiently transmitted long distances. Where such resources are compensated for reactive power that is not needed or necessarily deliverable to areas of the transmission system where reactive power may be needed, customers may be paying for a perceived reliability benefit that they are not receiving.

27. Additionally, implementing the Commission-approved AEP Methodology has become increasingly administratively burdensome to transmission providers, transmission customers, other stakeholders, and the Commission due to the resource- and time-intensity involved in determining individualized, cost-of-service reactive power rates for generation facilities through hearing and settlement judge procedures.[63] It also often results in inconsistent rate treatment across facilities.

1. Compensation for Providing Reactive Power Within the Standard Power Factor Range May Be Unjust and Unreasonable

28. We preliminarily find 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.

29. We begin by explaining why providing reactive power within the standard power factor range imposes no cost or *de minimis* cost to producers. Both synchronous and non-synchronous resources provide real and reactive power as joint products,[64] with joint costs.[65] For synchronous generating facilities, ''the same equipment is used to provide real and reactive power.'' [66] Non-synchronous generating facilities use a different physical process to produce reactive power, but ''the most critical element in VAR production, the inverter,'' [67] is also necessary for non-synchronous generating facilities to produce real power that can be injected into AC systems.[68] In other words, for both synchronous and non-synchronous generating facilities, ''[t]here are few if any identifiable costs incurred by generators in order to provide reactive power'' [69] beyond the investments in equipment already necessary to generate and supply real power to the transmission system.[70]

[58] PJM Initial Comments at 1–2.

[59] *Id.* at 2–3, 5–7. PJM notes that ''many other parties beyond the generator are drawn into the proceeding, including PJM, FERC Trial Staff, zonal transmission customers, transmission owners, and/or the Independent Market Monitor for PJM, among others. These parties must in turn expend time and resources of their own in discovery and analysis of the generator's specific cost characteristics and claims, in order to formulate their own position in the proceeding and form a basis for negotiations or litigation.''

[60] PJM Initial Comments at 3.

[61] CAISO Initial Comments at 5–6.

[62] *METC,* 97 FERC at 61,852–53.

[63] Today, most reactive power filings are made by IPPs and concern non-synchronous resources that produce reactive power using different types of equipment than that contemplated by the AEP Methodology. Additionally, almost all filing entities (both synchronous and non-synchronous) have received waivers of the requirement to maintain their accounts under the Uniform System of Accounts (USofA) rules and to file a FERC Form No. 1 when they were granted market-based rate authority.

[64] *See PSC VSMPO-Avisma Corp.* v. *U.S.,* 688 F.3d 751, 756 (Fed. Cir. 2012) (defining ''joint products'' as ''two dissimilar end products that are produced from a single production process.'').

[65] A joint cost is an expenditure that benefits more than one product, and for which it is not possible to separate the contribution to each product. *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 761 n.25 (1968) (''Joint costs 'are incurred when products cannot be separately produced.' '' (citing M. Adelman, The Supply and Price of Natural Gas 25 (1962))); *see also* AccountingTools, *Joint Cost* (Aug. 25, 2023), *https://www.accountingtools.com/articles/joint-cost.*

[66] EEI Initial Comments at 6.

[67] Duke Energy Corporation Initial Comments at 4.

[68] *See also* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 30 (''As to non-synchronous resources, the principal piece of equipment required for non-synchronous resources to produce reactive power is the inverter, which is already necessary to convert the direct current produced by non-synchronous resources to alternating current—*i.e.,* to supply real power that can be injected into alternating current power systems. On rehearing and in earlier protests, no party points to any other equipment costs incurred by non-synchronous generating facilities that are attributable to providing Reactive Service.'' (citations omitted)).

[69] PJM IMM Initial Comments at 4; *see also* MISO Transmission Owners Reply Comments at 7–8.

[70] *See, e.g., BPA,* 120 FERC ¶ 61,211 at P 21 (finding that the incremental cost of reactive power service within the deadband is minimal); *METC,* 97 FERC at 61,852–53 (''[R]eactive power provided, not as an ancillary service, but rather as a ''no cost'' service within reactive design limitations, may therefore, be provided without compensation.''); *Ariz. Pub. Serv. Co.,* 94 FERC ¶ 61,027, at 61,080 (2001) (rejecting generators' arguments for reactive power compensation for operating within standard power factor range because the generators failed to demonstrate that ''such a requirement will limit the real power output of a generating unit and therefore will not result in any lost opportunity costs'' or that operating a generating unit within the proposed

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30. Moreover, because real and reactive power are provided as joint products with joint costs, any allocation of joint fixed costs between real and reactive power could be viewed as inherently arbitrary.[71] When separate reactive power payments were first established, utilities typically provided both generation and transmission as vertically integrated utilities under a cost-of-service regime. In such a construct, the allocation of costs between generation and transmission facilities had little significance because it affected only the allocation of costs between transmission and generation rates. In other words, prior to the advent of IPPs (which operate only generation facilities), market-based rates for energy, and the development of RTOs/ISOs and bilateral markets, the allocation of fixed costs between real and reactive power did not have a major effect on the overall revenues of a combined vertically integrated utility.[72] However, for reactive power cost recovery, the introduction of RTO/ISO markets and bilateral transactions in non-RTO/ISO regions has provided more efficient and transparent means of compensating resources than the cost-of-service model. For example, RTO/ISO markets provide generating facilities with a means to recover the costs they incur to provide various services, such as real power sales, that rely on the same equipment used for reactive power supply.[73] Additionally, generating facilities in non-RTO/ISO regions (*e.g.,* IPP) can compete in bilateral markets to recover their investment, production, and operating costs.

31. We recognize that the production of reactive power within the standard power factor range can result in certain incremental variable costs such as fuel, maintenance, and potentially other costs. That said, the Commission has repeatedly found,[74] and commenters agree, that ''[v]ariable costs of generating reactive power are *de minimis.*'' [75] Indeed, as SPP notes, variable costs ''are generally limited to changes in losses within the generating facility which are part of the overall efficiency of the resource and, as such, are typically captured in the resource offers.'' [76] Similarly, Joint Customers state that, in CAISO, SPP, and other regions that do not separately compensate for reactive power within the standard power factor range, ''perhaps generators are adequately recovering their costs through some other means.'' [77]

32. By contrast, but outside the scope of this rulemaking, the production of reactive power *outside* of the standard power factor range, for which transmission providers are required to provide compensation, may result in increased costs, including opportunity costs to the generating facility.[78] As such, if the transmission provider requires a generating facility to provide reactive power outside of the standard power factor range, the generating facility may have to ''reduce its MW output in order to comply with such an instruction[,]'' which could limit the generating facility's opportunity to receive compensation for real power sales.[79]

33. Lastly, consistent with Order No. 2003 and multiple subsequent Commission orders since then, generating facilities must produce reactive power in order to be allowed to interconnect to the transmission system, and the industry has recognized that regulating voltage among interconnected generating facilities is a necessary component of good utility practice in an interconnected transmission system. For example, CAISO states that ''[t]he rationale for the CAISO's existing approach to reactive power compensation is that the reactive power ranges called for in each 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.'' [80] The Commission, therefore, has required generating facilities to provide reactive power within the standard power factor range under their interconnection agreements and good utility practice.[81]

standard power factor range will ''affect the generation output of a unit'').

[71] *See* PJM IMM Initial Comments at 2 (''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.''); *id.* at 3, 5, 21, 24; *In re Permian Basin Area Rate Cases,* 390 U.S. at 804 (''There is ample support for the Commission's judgment that the apportionment of actual costs between two jointly produced commodities, only one of which is regulated by the Commission, is intrinsically unreliable.''); Richard A. Posner, *Natural Monopoly and Its Regulation,* 21 Stan. L. Rev. 548, 595 (1969) (''[W]here services involve joint or common costs a rational allocation is impossible even in theory. How much of the cost of a telephone handset is assignable to local and how much to interstate telephone service?''); *see also A.A. Poultry Farms, Inc.* v. *Rose Acre Farms, Inc.,* 881 F.2d 1396, 1400 (7th Cir. 1989) (''How does one allocate the cost of activities that have joint products? Agencies engaged in ratemaking struggle with these problems for years, even decades, without producing clear answers.'').

[72] *See N. States Power Co.,* 64 FERC ¶ 61,324, at 63,379 (1993) (''In general, so long as a utility was selling generation and transmission services on a bundled basis (*i.e.,* full requirements service), the functionalization of costs between generation and transmission was not critical. The historical functionalization of costs, or bright line approach, was administratively simple, it had little or no impact on the overall (*i.e.,* bundled) rate for requirements service, and problems involving cross-subsidization between the generation and transmission functions were minimal. However, strict application of the traditional bright line approach may need to be reexamined in light of changes taking place in the electric industry—particularly the increase in transmission-only service.'').

[73] *See, e.g.,* PJM IMM Initial Comments at 2 (''The current process is an inefficient waste of time because it relies on an atavistic regulatory paradigm that is not relevant in the PJM market framework. The AEP Method[ology] was created, before the creation of the PJM markets, by a regulated utility that had regulatory and financial reasons to want to define some generation costs as transmission costs.''); ELCON Initial Comments at 5 (''The AEP Methodology was established as a workable heuristic during a period in which organized markets were in their infancy and nearly all new resources were synchronous.'').

[74] MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 29–31 (finding that providing reactive service requires ''little or no incremental investment'' by both synchronous and non-synchronous resources); *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097, at PP 7, 28 (2015) (finding that non-synchronous generating facilities are comparable to traditional synchronous generating facilities, in that there are for both types of generating facilities very little if any incremental costs incurred to provide reactive power); *Panda Stonewall, LLC,* 176 FERC ¶ 61,072, at P 6 n.9 (2021) (stating that Panda Stonewall's annual revenue requirement of $2,051,894 reflected a heating losses component of $10,018). We note that the heating losses component reflects the incremental cost of providing reactive power.

[75] SPP Initial Comments at 2; *see also* PJM IMM Initial Comments at 4.

[76] SPP Initial Comments at 2–3.

[77] Joint Customers Initial Comments at 9; *see also* PJM IMM Initial Comments at 1–4; CAISO Initial Comments at 3–4; Dominion Initial Comments at 12; *MISO,* 182 FERC ¶ 61,033 at P 58 (''[J]ust as the MISO [transmission owners'] generators may try to recover their lost revenue through higher power sales rates, so too may independent power producers try to recover their lost revenue through their own higher power sales rates.''); *BPA,* 120 FERC ¶ 61,211 at P 21; *Sw. Power Pool, Inc.,* 119 FERC ¶ 61,199 at P 39 (stating that IPPs ''are free to negotiate rates that they charge their customers for real power that are sufficient to compensate them for any costs that they may incur in producing reactive power within their deadbands, just as affiliated generators may seek to negotiate rates that they charge their customers that are sufficient to compensate them for the costs of any reactive power that they provide within their deadbands.'').

[78] *See, e.g.,* SPP Initial Comments at 2 (''SPP's current Schedule 2 rate per MVArh was calculated to represent the cost of reactive power production from recently constructed generators so as to reflect the upper end of such costs. This rate is applied to compensate qualifying generators located throughout the SPP region that provide reactive power support *outside a power factor dead band.*'' (emphasis added) (citations omitted)).

[79] CAISO Initial Comments at 4.

[80] CAISO Initial Comments at 3.

[81] *See, e.g., MISO,* 182 FERC ¶ 61,033 at P 53 (''Bearing in mind that the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice, MISO [transmission owners] do not have an obligation to continue to compensate an independent generator for reactive power within

Thus, the obligation for generating facilities to provide reactive power within the standard power factor range pursuant to their interconnection agreements is separate from any compensation for reactive power. In turn, because providing reactive power within the standard power factor range is already obligated (a no cost or *de minimis* cost service), compensating for providing such reactive power could result in undue compensation to generating facilities [82] at the expense of transmission customers.

2. Adverse Impacts of the Commission's Current Reactive Power Compensation Policy

34. In the years since the issuance of Order No. 2003–A, numerous issues have arisen in regions that provide compensation to generators for the provision of reactive power within the standard power factor range.

35. First, compensation for reactive power within the standard power factor range is not tied to whether there is a particular geographic need for reactive power. As noted above, reactive power cannot be transferred over long distances across the transmission system and, as a result, the reliability benefits of a generating facility's reactive power depend, in part, on its location.[83] But, compensation in a region for reactive power within the standard power factor range does not vary based on location, meaning that some generating facilities are compensated for reactive power that is not needed at the generating facilities' location on the transmission system. As the MISO transmission owners argue, ''[t]he current framework is . . . unjust and unreasonable because resources are being paid for reactive power capability in geographic areas where not all of the available reactive power is necessary. There are service areas with concentrations of generation but very little load, creating an exporting region where load pays for reactive capability that is unneeded.'' [84] Joint Customers add that, with the vastly increased amount of generation and increase in the number of generators seeking reactive compensation, the Commission ''should reconsider whether unbounded payment for reactive power capability is appropriate, or, to the contrary, whether transmission customers are paying for capability for which they do not receive commensurate benefits.'' [85] It appears that under the current framework, generating facilities are eligible to receive cost-based reactive power payments that do not reflect the reliability benefits of the reactive power at each facility's location (*i.e.,* the extent to which the generating facility supports the voltage of the transmission system), and that the reliability benefit may be zero for certain generating facilities.

36. Second, many commenters explain that in regions that allow generating facilities to file individualized cost-of-service reactive power rates, the process for determining those rates has proven to be resource-intensive, time-intensive, and administratively burdensome for ratepayers, transmission providers, and market participants.[86] Moreover, commenters explain that in addition to being burdensome, the resulting black box settlements produce a ''rate product'' that is ''of exceptionally poor quality for an important ancillary service.'' [87]

37. As noted in the NOI, most of the filings at the Commission seeking to establish rates for reactive power compensation are made by generating facilities (both synchronous and non-synchronous) that have received waivers of the Commission's requirement to maintain their accounts under the USofA rules and to file FERC Form No. 1.[88] Due, in part, to the lack

the standard power factor range when its own or affiliated generators are no longer being compensated.'' (citations omitted)); *id.* P 54 (''We find unpersuasive protesters arguments that it is not just and reasonable to eliminate compensation for Reactive Service within the standard power factor range because generators have come to rely on the compensation for Reactive Service in order for the generators to remain financially viable. The Commission has previously rejected such arguments, finding that all newly interconnecting generators are required to provide reactive power within the power factor range of 0.95 leading to 0.95 lagging as a condition of interconnection.'' (citations omitted)); *PNM,* 178 FERC ¶ 61,088 at P 29 (rejecting generator's arguments that it is ''just and reasonable for it to be compensated for investments made'' to provide reactive support consistent with interconnection requirements even though transmission provider elected to no longer pay its own or affiliate generators for such reactive power); *Nev. Power Co.,* 179 FERC ¶ 61,103 at P 22 (finding that the generating companies' argument, ''that it is not just and reasonable to eliminate their compensation for reactive service because they made investments in their generating facilities based on the expectation that they would receive compensation for reactive service,'' unpersuasive because all newly interconnecting generators are required to provide reactive power within the standard power factor range as a condition of interconnection); Order No. 2003, 104 FERC ¶ 61,103 at P 546.

[82] *See Belmont Mun. Light Dep't* v. *FERC,* 38 F.4th 173, 179, 186 (D.C. Cir. 2022) (finding that the Commission's approval of a portion of ISO–NE's Inventoried Energy Program ''was not reasoned decision making'' and ''thwart[ed] the [Commission's] own 'longstanding policy that rate incentives must be prospective and that there must be a connection between the incentive and the conduct meant to be induced' '' because it would compensate market participants for conduct they already engage in as part of standard business operations). Compensating for reactive power that is already required for interconnection purposes could create a ''windfall'' as suggested by the D.C. Circuit in *Belmont. Id.* at 186 (citing *San Diego Gas & Elec. Co.* v. *FERC,* 913 F.3d 127, 137 (D.C. Cir. 2019)). *But see* Order No. 2003–C, 111 FERC ¶ 61,401 at P 42 (finding that because providing reactive power within the established range is an ''important service,'' payment for such service does not constitute a ''windfall.'').

[83] FERC Staff Report, *Payment for Reactive Power,* Docket No. AD14–7–000, 5 (Apr. 22, 2014), *https://www.ferc.gov/sites/default/files/2020-05/04-11-14-reactive-power.pdf.*

[84] MISO Transmission Owners Initial Comments at 7–8; *see also* Joint Customers Initial Comments at 8–9; Alliant Initial Comments at 4; NYISO, *Reliability and Market Considerations for a Grid in Transition,* at 105 (2019), *https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf/61a69b2e-0ca3-f18c-cc39-88a793469d50* (''Moreover, because voltage support needs are local, the NYISO will need voltage support within specific narrow regions, not necessarily at the locations at which resources able to provide reactive power without incurring substantial commitment costs may be located.'').

[85] Joint Customers Initial Comments at 8–9.

[86] *Id.* at 4–5, 12–13 (''[T]he case-by-case approach to reactive capability rates based on the AEP methodology makes it very difficult for proceedings to be resolved in an efficient manner.''); PJM IMM Initial Comments at 2, 4 (noting that ''[a]pplying cost of service rules is costly and burdensome and unnecessary'' and asserting that ''[r]emoving cost of service rules would avoid the significant waste of resources incurred to develop unneeded cost of service rates''); PJM Initial Comments at 10 (''[T]he current construct for reactive power capability compensation in PJM imposes a significant administrative burden on PJM and its resource owners, both in terms of settlements and testing.''); Dominion Initial Comments at 2–3 (noting that settlement proceedings are time consuming and not transparent); *see also* Clean Energy Coalition Reply Comments at 5; ELCON Initial Comments at 6–7; Renewable Generation Reply Comments at 25; EDFR Initial Comments at 4–5; Pine Gate Renewables Initial Comments at 6–7; PJM Power Providers Group Initial Comments at 4–5; American Electric Power Service Corporation Initial Comments at 2–3; EPSA Initial Comments at 2; Nuclear Energy Institute Initial Comments at 6–7; PJM IMM Initial Comments at 2 (''Most reactive proceedings for generators in PJM are resolved in black box settlements that fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that, not surprisingly, produce a wide, unreasonable and discriminatory disparity among the rates per paid per MW-year.'').

[87] PJM Initial Comments at 3; *see also* PJM IMM Initial Comments at 2.

[88] The Commission's accounting and reporting requirements are particularly important to the evaluation and monitoring of cost-based rates. *See, e.g., Alcoa Power Generating Inc.,* 172 FERC ¶ 61,052, at P 29 (2020); *Third-Party Provision of Ancillary Servs.; Acct. & Fin. Reporting for New Elec. Storage Technologies,* Order No. 784, 78 FR 46178 (July 30, 2013), 144 FERC ¶ 61,056 (2013) (accounting and reporting requirements ''support the rate oversight needs of both this Commission and State Commissions'' and are ''important in developing and monitoring rates, making policy decisions, compliance and enforcement initiatives, and informing the Commission and the public about the activities of entities that are subject to these accounting and reporting requirements.''); *Carville Energy LLC,* 104 FERC ¶ 61,252, at 61,833 n.13 (2003) (''For example, non-exempt public utilities keep financial records, required by this

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of availability of this cost-of-service information, many of these filings are set for hearing and settlement judge procedures.[89] Many commenters, including Joint Customers, note that these settlement proceedings ''require a significant expenditure of resources that include legal and technical consultants,'' and while many of the cases settle on a ''black box'' basis, ''significant effort is undertaken by the Joint Customers [and other participants] in order to obtain information necessary to perform an *AEP*-like calculation and develop settlement proposals.'' [90] The PJM IMM notes that, in its experience, ''[m]ost reactive proceedings for generators in PJM are resolved in black box settlements that fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that, not surprisingly, produce a wide, unreasonable and discriminatory disparity among the rates paid per MW-year.'' [91] Joint Customers also note that the time-consuming process for resolving individual reactive service rate proceedings may leave customers without adequate refund protection.[92]

38. Third, the process for testing and verification under the AEP Methodology is unduly burdensome. Under that process, resources must coordinate with the transmission provider to test and verify capability to produce reactive power under certain conditions, which often requires multiple tests over a series of months and that yields inconsistent results across resources. PJM notes that this has caused a ''significant influx of resources that are not [otherwise] required to test under PJM Manual 14–D . . . seeking to test solely for purposes of filing and/or litigating reactive power capability cases.'' [93] PJM notes that ''under the current regulatory structure, rather than PJM spending time and resources testing units based on *PJM's* operational needs as the Transmission Provider, PJM is now often spending time and resources testing units based on the *resource owner's* need to file and litigate its individual cost-of-service rate case.'' [94]

39. Fourth, as discussed above, in regions where resources recover their costs by participating in organized competitive wholesale markets, providing separate compensation for the provision of reactive power within the standard power factor range risks overcompensation and market distortion in ways that did not exist prior to the existence of organized markets.[95] As noted above, the AEP Methodology originated in an era of vertically integrated utilities, when most utilities (including AEP) filed FERC Form No. 1s, used the USofA to classify their costs, and recovered those costs entirely through cost-based rates.[96] It was thus intended to be a cost-of-service allocation method for assigning joint costs between the generation and transmission functions, but, as the PJM IMM argues, ''[t]he false precision of the AEP Method is entirely based on arbitrary assumptions.'' [97] The PJM IMM argues that even proponents of the AEP Methodology do not claim that the methodology's goal is to recover only the specific costs associated with the production of reactive power, which the PJM IMM claims is not possible in most cases. The PJM IMM further argues that the AEP Methodology was not intended to define such costs. The imprecision associated with the AEP Methodology was less problematic when the total amount that a utility recovered was largely unchanged by the allocation of fixed costs between a generation and transmission function. But, as commenters point out, today most generating facilities recover their costs through competitive markets in both RTO/ISO and non-RTO/ISO regions. The AEP Methodology's imprecision therefore becomes more significant because it can lead to arbitrary increases in the utility's total recovery when cost-based reactive power payments are added to any market recoveries.[98] That is especially true when markets fail to account for separate, cost-based reactive power revenues by using standard rate making techniques (*i.e.,* revenue crediting).[99] For example, in PJM, the

Commission, which, among other things, *are designed to aid in the development of the cost-based rates.*'' (emphasis added)).

[89] Indeed, as the Commission has explained, Parts 41, 101, and 141 of its regulations are critical to its statutory obligation under sections 205 and 206 of the FPA to ensure that rates are just, reasonable, and not unduly discriminatory or preferential. *See PSEG Fossil, LLC,* 97 FERC ¶ 61,211, at 61,920–21 (2001) (*PSEG*), *reh'g denied,* 98 FERC ¶ 61,169 (2002). Moreover, the Commission has stated that customers subject to cost-based rates have a right to cost data so that they may evaluate the ongoing reasonableness of their rates. *See also PSEG,* 97 FERC at 61,920–21.

[90] Joint Customers Initial Comments at 5. When the cases do not settle, Joint Customers note that even more resources must be expended to litigate the individual revenue requirement proposal. For example, Joint Customers note that the Panda Stonewall proceeding lasted four years from the effective date of Panda's reactive service rate to the Commission's order establishing the just and reasonable rate. *Id.* (citing *Panda Stonewall, LLC,* Opinion No. 574, 174 FERC ¶ 61,266, *reh'g denied,* 175 FERC ¶ 62,132 (2023)). During this time, Joint Customers note that they and others paid the approximately $6.2 million annual revenue requirement filed by Panda. Joint Customers state that the Commission's Order on Initial Decision established an approximately $2 million annual revenue requirement. Joint Customers note that this difference resulted in ''approximately $17 million in overcollection and delayed refunds due to customers.'' *Id.*

[91] PJM IMM Initial Comments at 2. Many other commenters express concern over the lack of transparency associated with how these rates are calculated. *See, e.g.,* American Electric Power Service Corporation Initial Comments at 2; Renewable Generation Companies Initial Comments at 22–23; ELCON Initial Comments at 6–7; Joint Customers Initial Comments at 6; PJM Initial Comments at 3–4, 11; Nuclear Energy Institute Initial Comments at 6–7; PSE&G Initial Comments at 10.

[92] *See, e.g.,* Joint Customers Initial Comments at 13, 26; *see also id.* at 28–29 (''The 15-month statutory limitation on refunds [in FPA section 206 proceedings] creates an incentive for the applicant to delay the proceeding in order to profit from their delay by running out the clock to enter a period where the applicant continues to collect the rate as filed (likely to later be determined unjust and unreasonable) without any ongoing refund obligation. While the statute provides for further refunds upon a showing of dilatory behavior by the applicant, it would be difficult to demonstrate such dilatory behavior when the delay in resolution is due to settlement proceedings, or the procedural schedule in a litigated proceeding. Therefore, customers are left in the position of either foregoing or prematurely ending settlement discussions in order to try to achieve a litigated outcome within the 15-month refund period.'').

[93] PJM Initial Comments at 6–7.

[94] *Id.* at 7 (emphasis in original); *see also* Vistra Reply Comments at 8 (''The time and resources that PJM must expend to conduct testing for the purposes of supporting individual rate cases is an anathema to the core purpose of the tests, which is system reliability.'').

[95] *See* ELCON Initial Comments at 5; PJM IMM Initial Comments at 22–23.

[96] *See, e.g.,* Joint Customers Reply Comments at 6–7; ELCON Initial Comments at 5.

[97] PJM IMM Initial Comments at 5. As a point of comparison, black start compensation also requires some cost allocation of joint costs, but this is arguably distinct from allocation for reactive power because incremental costs incurred to provide black start service can be separately identified (*e.g.,* unlike most generators, which require power from the transmission system during start-up, black start-capable generators may have small, on-site diesel generation units, or equivalent equipment, to independently support their station power needs and other electricity-using activities during start-up). *See, e.g.,* PJM Interconnection, L.L.C., Intra-PJM Tariffs, OATT Schedule 6A (12.2.0). Payment is not related only to identifiable costs. Such black start resources will also generally have a different interconnection arrangement which allows for black start service. The determination of whether a particular unit is a black start unit is ultimately defined in the applicable tariff and relates to capability rather than the presence of specific equipment.

[98] PJM IMM Initial Comments at 9–10; PJM IMM Reply Comments at 4 (''[T]he AEP Method allocates a portion (X percent) of the cost of the plant to MVAR production and the balance (1 − X percent) to MW production. In a pure cost of service world, the allocators add to 100% and there can be no over recovery, regardless of the value of X. But that is not true when the units operate in a competitive wholesale power market.'').

[99] *See* PJM IMM Reply Comments at 3 (''The Commission has recognized the relevance of the issue associated with a 'resource receiving cost-

capacity market rules currently account for reactive power payments to resources by assuming average reactive power compensation of $2,546 per MW-year.[100] But reactive power revenue requirements in PJM, many of which result from ''black-box'' settlements, range from roughly $1,000 per MW-year to $13,000 per MW-year.[101] As the PJM IMM explains, this wide range of actual compensation, which is both above and below the amount of assumed reactive power compensation in the capacity market rules, can lead to market distortions.[102]

40. The challenges experienced under the Commission's current reactive power compensation policy are exacerbated by the increasing volume of filings for reactive power compensation. Since Order No. 2003–A, and particularly in recent years, the number of reactive power filings has significantly increased.[103] In turn, the amount of reactive power compensation paid to generating facilities by transmission providers and collected from transmission customers has likewise increased.[104] We are concerned that transmission customers may not be receiving a roughly commensurate increase in reliability benefit.[105]

B. Proposed Reform

41. Having preliminarily found that allowing transmission providers to include charges associated with the supply of reactive power within the standard power factor range from generating facilities results in transmission rates that may be unjust and unreasonable, we propose, pursuant to FPA section 206,[106] that 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.

42. Eliminating such charges ensures that transmission customers do not pay transmission rates that include costs without an economic basis or justification. Moreover, eliminating compensation is consistent with the Commission's original statement in Order No. 2003 (as modified in Order No. 2003–A) and in subsequent cases on the non-compensability of providing reactive power within the standard power factor range. Eliminating compensation also addresses the undue discrimination concerns articulated by the Commission in Order No. 2003–A regarding the disparate treatment of affiliated and non-affiliated generating facilities, which led to the Commission's comparability policy. By requiring the same approach to compensation for all generating facilities, which necessarily includes both affiliates and non-affiliates, we address the potential for undue discrimination by the transmission provider by providing that comparability would no longer be a justification for payment. To the extent that there are incremental costs to provide reactive power within a generating facility's standard power factor range, we see no reason why such costs should not be reflected through energy or capacity offers made in organized and bilateral markets.[107]

1. Eliminating Separate Compensation Will Not Affect Reliability

43. We preliminarily find that 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 is just and reasonable because compensation for providing reactive power within the standard power factor range is unnecessary to maintain reliability.[108] Several commenters argue that separate reactive power compensation is necessary to maintain reliability. For example, Vistra, among others, argues that separate compensation for reactive power is necessary because without it, regions seeing increasing shares of non-synchronous generating facilities in their generation mixes may not have sufficient reactive power.[109] We preliminarily disagree with this argument because we preliminarily find that requiring transmission providers to continue paying for reactive power already required by a generating facility's interconnection agreement is not necessary to ensure that generating facilities provide reactive power when required.[110] As explained in *MISO,* new

based rate recovery while concurrently receiving compensation for market-based rate services involves potential double recovery of costs borne by the relevant cost-based ratepayers.' '' (quoting *Utilization of Elec. Storage Res. for Multiple Servs. When Receiving Cost-Based Rate Recovery,* 158 FERC ¶ 61,051, at P 15 (2017)); ELCON Initial Comments at 5 (''[R]ecouping costs through organized markets while separately recouping the same costs through a cost-of-service rate—would result in double recovery, imposing additional and unnecessary costs on consumers.'').

[100] *See PJM Interconnection, L.L.C.,* 182 FERC ¶ 61,073, at P 135 (2023).

[101] PJM IMM Initial Comments at 21–22; *see also* PJM Initial Comments at 4 (''There is a wide range of revenue requirements that may ultimately be agreed to by the parties to a given proceeding, and the willingness of parties to agree or not agree to a particular number may be influenced by factors completely exogenous to the actual cost and service characteristics of the unit (*e.g.*[,] the legal fees associated with continuing the litigation).'').

[102] PJM IMM Initial Comments at 21–22 (''For example, a marginal resource with reactive revenue of $5,000 per MW-year reflected in their net ACR offer would suppress the capacity market clearing price. Conversely, a marginal resource with a reactive revenue of $1,000 per MW-year reflected in their net ACR offer would inflate the capacity market clearing price.'').

[103] *See, e.g.,* Joint Customers Initial Comments at 4–5 (''In PJM's Dominion zone, there has been a significant increase in the number of reactive revenue requirements filings as well as a drastic increase in the proposed revenue requirements for Reactive Service.''); Vistra Initial Comments at 10 (noting the ''sheer volume of reactive power hearing and settlement proceedings in recent years''); PJM IMM Initial Comments at 13 (explaining that as of February 2022, there were ''over two dozen active proceedings'' and that since 2016, there have been ''more than 100'' reactive power proceedings).

[104] For example, as of December 2023, the total RTO-wide reactive power compensation paid to generating facilities in PJM was approximately $384 million. *See* PJM, Reactive Supply and Voltage Control Revenue Requirements 2023, *https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx* (cell D296 in the .xls file for December 2023).

[105] *See also* Joint Customers Initial Comments at 8–9 (citing *Ill. Com. Comm'n* v. *FERC,* 576 F.3d 470, 477 (2009)); Alliant Initial Comments at 5; MISO Transmission Owners Reply Comments at 10; Joint Customer Reply Comments at 5–6.

[106] 16 U.S.C. 824e.

[107] *See, e.g.,* SPP Initial Comments at 2–3 (''Variable costs of generating reactive power are de minimis and are generally limited to changes in losses within the generating facility which are part of the overall efficiency of the resource and, as such, are typically captured in the resource offers submitted to the SPP Integrated Marketplace.''); PJM IMM Initial Comments at 2–3 (''Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and the recognition that capital costs are not distinguishable by function would increase prices in the capacity market. . . . The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.'').

[108] *See* CAISO Initial Comments at 5–6; Joint Customers Reply Comments at 5–6 (''Despite unsubstantiated claims to the contrary, there has been no demonstration that there is any dearth of reactive power sufficient to maintain reliability in regions where reactive compensation is not based on the AEP methodology.''); MISO Initial Comments at 6 (explaining that the ''method of compensation is incidental to reliability'' because generating facilities' obligation to provide reactive power within the standard power factor range ''ensures that reactive power will be provided to support the Transmission System.'').

[109] Vistra Comments at 4 (citing NYISO, *Reliability and Market Considerations for a Grid in Transition,* 25–26, 104–06 (2019), *https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf/61a69b2e-0ca3-f18c-cc39-88a793469d50* and CAISO, *Reactive Power Requirements—Automatic Voltage Regulator Systems,* Docket No. ER17–490–000 (filed Dec. 5, 2016)). *But see* Joint Customers Reply Comments at 6 (urging ''the Commission to maintain a focus on reliability as the basis for compensating for Reactive Service, but also to be wary of attempts by others to use 'reliability' to justify over-compensation for Reactive Service or to preserve outdated methodologies.'').

[110] *See Essential Reliability Servs. & the Evolving Bulk-Power Frequency Response,* Order No. 842, 83

Continued

and existing generating facilities will still be required to provide reactive power within the standard power factor range as a condition of obtaining and maintaining interconnection.[111] Additionally, as CAISO notes, its current approach to not compensate for reactive power provided within the standard power factor range has not resulted in major issues of concern with the level of reactive power.[112]

44. We seek 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.

2. Eliminating Separate Compensation Does Not Preclude Generating Facilities From Recovering Their Costs

45. We preliminarily find that separate compensation for providing reactive power within the standard power factor range is not necessary for resources to be able to recover their costs. Some commenters argue that cost-of-service payment for reactive power is important for obtaining financing. Although the prospect of receiving separate, fixed reactive power payments may be beneficial for developing certain generating facilities, resource developers continue to develop new generating facilities in regions without such payments.[113] Furthermore, the basis for these payments has always been comparability. Therefore, these arguments do not demonstrate why allowing for separate reactive power payments at the transmission provider's discretion is just and reasonable.

46. Instead, in the context of RTO/ISO markets, we preliminarily find that it is both more efficient and less administratively burdensome for generating facilities to recover any identified reactive power costs, to the extent they exist, through energy and capacity sales,[114] since competition between generating facilities may incentivize efficiency.[115] Another benefit of any such market-based compensation in RTOs/ISOs is that any costs of providing reactive power within the standard power factor range would be more transparent to market participants because they would be included in RTO/ISO energy and/or capacity prices as opposed to generating facility-specific out-of-market cost-of-service agreements.

47. The Commission has repeatedly rejected arguments that generating facilities need separate reactive power payments ''since the incremental cost of reactive power service within the deadband is minimal.'' [116] Therefore, consistent with those findings, for IPPs operating in non-RTO regions, we preliminarily find that cessation of payments for reactive power within the standard power factor range set forth in the Commission's *pro forma* LGIA and SGIA does not compromise an IPP's ability to recover costs that it may incur in producing reactive power within such range because generating facilities have the opportunity to recover such costs in other ways, ''such as through higher power sales rates of their own.'' [117]

48. Both experience in CAISO, SPP, MISO and certain non-RTO regions where generating facilities do not receive compensation for the provision of reactive power within the standard power factor range,[118] and the evidence in the record to date supports these findings. Specifically, experience and evidence demonstrate that: (1) eliminating compensation has not led to an insufficient supply of reactive power in those regions; and that (2) generating facilities in these regions have been able to recover any purported costs associated with the production of reactive power. For example, CAISO notes that it ''has seen no evidence to this point that resources cannot comply with reactive power dispatch instructions because they have insufficient funds for the equipment to meet the reactive power dispatch.'' [119] As Leeward Renewable Energy, LLC, and Union of Concerned Scientists (LRE/UCS) notes, ''the lack of separate reactive power compensation in CAISO or SPP means that all costs have to be recovered through the applicable PPA, which also means that those PPA prices are higher, all other variables being equal, than they would otherwise be.'' [120]

FR 639 (Mar. 6, 2018), 162 FERC ¶ 61,128, at P 121, *order on reh'g and clarification,* 164 FERC ¶ 61,135 (2018) (''While the Commission has approved specific compensation for discrete services that require substantial identifiable costs, such as for frequency regulation and operating reserves, the Commission has not required specific compensation for all reliability-related costs. We agree with those commenters who observe that minimal reliability-related costs such as those incurred to provide primary frequency response, are reasonably considered to be part of the general cost of doing business, and are not specifically compensated.'').

[111] *MISO,* 182 FERC ¶ 61,033 at P 55.

[112] CAISO Initial Comments at 5.

[113] For example, as of February 21, 2024, there were 453 total generating facilities in the CAISO interconnection queue, 440 of which were non-synchronous generating facilities. This corresponds to 122,885 MW of capacity, 120,043 MW of which comes from the non-synchronous generating facilities in the queue. *See* CAISO, *Formatted Generator Interconnection Queue Report, https://rimspub.caiso.com/rimsui/logon.do* (last visited Feb. 21, 2024). Similarly, as of February 21, 2024, there were 947 total generating facilities in the SPP interconnection queue, 770 of which were non-synchronous generating facilities. This corresponds to 175,243 MW of capacity, 141,879 MW of which comes from the non-synchronous generating facilities in the queue. *See* SPP, *Generator Interconnection Active Requests, https://opsportal.spp.org/Studies/GIActive* (last visited Feb. 21, 2024).

[114] *See* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 42 (dismissing Vistra's claim that they would be unable to recover any costs attributable to providing reactive service through mechanisms other that Schedule 2, such as in energy offers and capacity offers. The Commission noted that ''[a]s to capacity offers, among the 'going forward' costs that can be recovered are 'mandatory capital expenditures necessary to comply with federal . . . reliability requirements,' which would appear to include any (hypothetical) capital investments and expenditures associated with Reactive Service. As to energy offers, Vistra does not explain the basis for its assertion that the Tariff bars including any incremental costs associated with Reactive Service (*e.g.,* fuel costs, short-term variable operations and maintenance) in such offers.'').

[115] For example, in PJM, capital costs are included in the Net Cost of New Entry (Net CONE) parameter of the Variable Resource Requirement (VRR) curve in the capacity market and the Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR. As a result, if the Commission were to eliminate reactive power compensation within the standard power factor range, the only change that would be required would be to exclude the reactive power revenues from the Net CONE parameter and to exclude any reactive power revenues from the energy and ancillary services offset from the offer caps for resources that provide reactive power. *See* PJM IMM Initial Comments at 21–22, 25.

[116] *BPA,* 120 FERC ¶ 61,211 at P 21 (citing *Sw. Power Pool, Inc.,* 119 FERC ¶ 61,199 at P 39).

[117] *Id.*

[118] *See Cal. Indep. Sys. Operator Corp.,* 160 FERC ¶ 61,035 at P 19. In 2017, the Commission considered the CAISO's approach and found ''a separate payment for the provision of reactive power capability inside the standard power factor range is not required, and we see no reason to require a separate cost recovery mechanism for reactive power capability based on the record here.'' The Commission later affirmed this approach when it was proposed by different transmission providers. *See PNM,* 178 FERC ¶ 61,088 at P 29 (''Consistent with Commission precedent, a transmission provider may decide to eliminate compensation for having the capability of providing reactive service within the standard power factor range.''); *MISO,* 182 FERC ¶ 61,033 at P 55 (''As stated by MISO [transmission owners] and supporting commenters, new and existing generators in MISO will still be required to provide reactive power within the standard power factor range as a condition of obtaining and maintaining an interconnection. MISO [transmission owners] do not propose to change MISO's ability to manually redispatch individual generators for voltage control and generators will continue to be compensated under a separate Tariff mechanism if MISO directs a generation resource to provide reactive power outside of the standard power factor range.'' (citations omitted)); *see also* Order No. 842, 162 FERC ¶ 61,128 at P 120 (explaining that ''there are interconnection requirements for generating facilities in which the recovery of capital costs and operating expenses are not necessarily ensured.'').

[119] CAISO Initial Comments at 5–6.

[120] LRE/UCS Initial Comments at 16.

49. The record from the Notice of Inquiry contains comments arguing that removal of all reactive power compensation under the standard power factor range without a transition period or other similar mechanism has the potential to disrupt business and investment decisions for generating entities in certain markets in the near term.[121] We seek comment 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. We also seek comment 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.

C. Proposed Revisions for Eliminating Compensation for Reactive Power Supply Within the Standard Power Factor Range

50. To effectuate the changes discussed herein, we propose three revisions discussed further below. Our preliminary findings and these proposed revisions are consistent with the Commission's previous initial statements in Order No. 2003 (which was subsequently revised in Order No. 2003–A) and in subsequent cases on the non-compensability of providing reactive power within the standard power factor range. They also address the undue discrimination concerns articulated by the Commission in Order No. 2003–A, which led to the Commission's comparability policy.[122] By requiring the same approach to compensation for all resources, which necessarily includes both affiliates and non-affiliates, there is no potential for undue discrimination by the transmission provider and comparability would no longer be a justification for payment.

1. Revise Schedule 2 of the Pro Forma OATT

51. We propose to revise Schedule 2 of the *pro forma* OATT to add the following sentence at the end of Schedule 2: ''*However, such rates shall not include any charges associated with the compensation to a generating facility for the supply of reactive power within the power factor range specified in its interconnection agreement.*'' This proposed revision would prohibit separate compensation for the provision of reactive power within the standard power factor range specified in an interconnection agreement.

2. Revise Section 9.6.3 of the Pro Forma Large Generator Interconnection Agreement

52. We propose to revise section 9.6.3 of the *pro forma* LGIA to remove the proviso: ''provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer.'' Accordingly, under our proposal here, section 9.6.3 of the *pro forma* LGIA would read as follows: ''Payment for Reactive Power. Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.'' Along with the other proposed revisions, this proposed revision would prohibit a transmission provider from including in its transmission rates any charges associated with the supply of reactive power within the specified power factor range from a generating facility. Accordingly, transmission providers would be required to pay an interconnection customer for reactive power only when the transmission provider requests the interconnection customer to operate its facility outside the power factor range set forth in its interconnection agreement.

3. Revise Section 1.8.2 of the Pro Forma Small Generator Interconnection Agreement

53. We propose to revise section 1.8.2 of the *pro forma* SGIA to remove the following sentence: ''In addition, if the Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.'' Accordingly, under our proposal here, section 1.8.2 of the *pro forma* SGIA would read as follows: ''The Transmission Provider is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Small Generating Facility when the Transmission Provider requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in article 1.8.1.'' Along with the other proposed revisions, this proposed revision would prohibit a transmission provider from including in its transmission rates any charges associated with the supply of reactive power within the specified power factor range from a generating facility. Accordingly, as above, transmission providers would be required to pay an interconnection customer for reactive power only when the transmission provider requests the interconnection customer to operate its facility outside the power factor range set forth in its interconnection agreement.

IV. Proposed Compliance Procedures

54. We propose to require each transmission provider to submit a compliance filing within 60 days of the effective date of the final rule in this proceeding revising its OATT, *pro forma* LGIA, and *pro forma* SGIA, as necessary, to comply with the requirements set forth in any final rule issued in this proceeding. In addition, we propose to allow 90 days from the date of the compliance filing for implementation of the proposed reforms to become effective.

55. To the extent that any transmission provider believes that it already complies with the reforms adopted in any final rule in this proceeding, the transmission provider would be required to demonstrate how it complies in the compliance filing required 60 days after the effective date of any final rule in this proceeding. In reviewing compliance filings, the Commission will apply the ''consistent with or superior to'' standard to deviations from the adopted *pro forma* language proposed by non-RTO/ISO transmission providers. In evaluating compliance filings made by RTOs/ISOs, the Commission will apply the ''consistent with or superior to'' standard to deviations from the adopted *pro forma* Schedule 2 and the ''independent entity variation standard'' to deviations from the *pro forma* LGIA and *pro forma* SGIA.

56. We seek comment on whether the proposed compliance and

[121] *See, e.g.,* EDF Renewables Initial Comments at 11–12 (''Since independent power producers . . . rely on project financing to finance their project development, predictability of the revenue stream is very important to this industry segment.); Joint Customers Reply Comments at 17 (noting that ''resource developers or owners may have made the decision to invest in resources under the Commission's currently approved methods for determining reactive compensation,'' while also cautioning against allowing unjust reactive power rates to ''remain effective indefinitely.''); Duke Energy Comments at 4 (''Developers have . . . obtained financing based on [the AEP] methodology being in place.'').

[122] *See supra* notes 7–9 and associated text.

implementation timeline would allow sufficient time for changes to be implemented in response to a final rule or whether a limited transition period (beyond the 90-day implementation period proposed in this NOPR) may be necessary. Specifically, we seek comment on the following questions:

• Is a transition period necessary? Please provide discussion supporting any opinion.

• What factors, if any, such as potential business or investment impacts, should be considered in determining whether any transition period is appropriate, how any transition period for reactive power compensation may be structured to minimize impacts, and for what duration any transition period should last? Absent a transition period, would the final rule disrupt business and investment decisions or not? If so, what transition mechanisms other than delaying the implementation date of the final rule would minimize such disruptions and be just and reasonable?

• For regions that have an established capacity market, should transmission providers be allowed to make the implementation date of their compliance filing align with the region's capacity market timelines in order to allow costs associated with reactive power production, if any, to be incorporated into capacity market bids? Would a different transition mechanism, if any, be necessary for regions without a capacity market? Would it be unduly discriminatory or preferential to set different implementation dates for the final rule in different markets and regions?

• If the Commission allows existing generation resources that have previously received compensation for reactive power supply to continue to receive compensation for a limited period while prohibiting new generation resources from receiving reactive power compensation, how should it determine eligibility for continued compensation in a manner that is just and reasonable and not unduly discriminatory or preferential?

V. Information Collection Statement

57. The Office of Management and Budget's (OMB) regulations require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

58. This notice of proposed rulemaking proposes to amend the Commission's regulations pursuant to section 206 of the Federal Power Act, to eliminate compensation to generating facilities for the provision of reactive power within the standard power factor range set forth in each generating facility's individual interconnection agreement. To accomplish this, the Commission proposes to require each transmission provider to amend the standard large interconnection agreement and the standard small generator interconnection agreement in its open access transmission tariff to implement the reforms proposed in this NOPR. Such filings should be made under Part 35 of the Commission's regulations. Subsequently, the proposed rule would revise the following currently approved information collections: *FERC 516H (OMB control. No. 1902–0303): Pro Forma Open Access Transmission Tariff, FERC 516 (OMB control No. 1902–0096): Electric Tariff Filings, and FERC 516A (OMB control No. 1902–0203): Standardization of Small Generator Interconnection Agreements and Procedures [SGIA and SGIP].*

59. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act. Comments are solicited on whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

60. Please send comments concerning the collection of information and the associated burden estimates to: Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW, Washington, DC 20503, Attention: Desk Officer for the Federal Energy Regulatory Commission. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov.* Comments submitted to OMB should refer to OMB Control No. 1902–0303, 1902–0096, or 1902–0203.

61. Please submit a copy of your comments on the information collection to the Commission via the eFiling link on the Commission's website at *https://www.ferc.gov.* If you are not able to file comments electronically, please send a copy of your comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426. Comments on the information collection that are sent to FERC should refer to Docket No. RM22–2–000.

62. *Title:* FERC 516H: Pro Forma Open Access Transmission Tariff, FERC 516: Electric Tariff Filings, and FERC 516A: Standardization of Small Generator Interconnection Agreements and Procedures [SGIA and SGIP].

63. *Action:* Proposed revision of the information collection in accordance with RM22–2–000.

64. *OMB Control No.:* 1902–0303, 1902–0096, 1902–0203.

65. *Respondents for This Rulemaking:* Public utility transmission providers, including RTOs/ISOs.

66. *Frequency of Information Collection:* One-time compliance filing.

67. *Necessity of Information:* The proposed rule will require that transmission providers submit to the Commission a one-time compliance filing proposing tariff revisions.

68. *Internal Review:* The Commission has reviewed the changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry in support of the Commission's ensuring just and reasonable rates. The Commission has specific, objective support for the burden estimates associated with the information collection requirements.

69. *Public Reporting Burden:* The Commission's estimate consists of our estimated effort related to updating the proposed revisions to the Pro Forma Open Access Transmission Tariff, and subsequent revisions to the Large Generator Interconnection Agreements and Small Generator Interconnection agreements and the effort related to submitting a one-time compliance filing.

70. The Commission estimates burden [123] and cost [124] as follows:

A. Collection	B. Number of respondents	C. Annual number of responses per respondent	D. Total number of responses (Column B × Column C)	E. Average burden hours & cost per response	F. Total annual hour burdens & total annual cost (Column D × Column E)	G. Cost per respondent (Column F ÷ Column B)
FERC 516H: Pro Forma Open Access Transmission Tariff						
Transmission Providers (one-time compliance filing)	40	1	40	4 hrs.; $400	160 hrs.; $16,000	$400
FERC 516: Electric Tariff Filings						
Transmission Providers (one-time compliance filing)	43	1	43	4 hrs.; $400	172 hrs.; $17,200	400
FERC 516A: Standardization of Small Generator Interconnection Agreements and Procedures						
Transmission Providers (one-time compliance filing)	43	1	43	4 hrs.; $400	172 hrs.; $17,200	400
Totals					504 hrs.; $50,400	

VI. Environmental Analysis

71. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[125] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this NOPR under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classification, and services.[126]

VII. Regulatory Flexibility Act Certification

72. The Regulatory Flexibility Act of 1980 (RFA) [127] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold for what constitutes a small business. Under SBA's size standards,[128] transmission providers under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), have a size threshold of 950 employees (including the entity and its associates).[129]

73. We estimate that there are 43 transmission providers that are affected by the reforms proposed in this NOPR, based on the NERC Active Compliance Registry Matrix as of January 11, 2024.[130] The Commission used a combination of sources to determine the number of employees within each entity using open-source data and information from Dunn & Bradstreet. We estimate that 6 of the 43 transmission providers, approximately 14% (rounded), are small entities.

74. We estimate that one-time costs (in Year 1) associated with the reforms proposed in this NOPR for one transmission provider (as shown in the table above) would be $400. Following Year 1, the Commission estimates no ongoing costs associated with this proposed rule.

75. According to SBA guidance, the determination of significance of impact ''should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors.'' [131] We do not consider the estimated cost of $400 to be a significant economic impact for any of the entities that would be impacted by this NOPR. As a result, we certify that the reforms proposed in this NOPR would not have a significant economic impact on a substantial number of small entities.

VIII. Comment Procedures

76. The Commission invites interested persons to submit comments on the matters and issues proposed in this document to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due May 28, 2024. Also, reply comments are due June 26, 2024. Comments must refer to Docket No. RM22–2–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

77. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website at *https://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word

[123] ''Burden'' is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the estimated burden, refer to 5 CFR 1320.3.

[124] Commission staff estimates that the respondents' skill set (and wages and benefits) for Docket No. RM22–13–000 are comparable to those of Commission employees. Based on the Commission's Fiscal Year 2024 average cost of $207,786/year (for wages plus benefits, for one full-time employee), $100/hour is used.

[125] *Reguls. Implementing the Nat'l Env't Pol'y Act,* Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[126] 18 CFR 380.4(a)(15).

[127] 5 U.S.C. 601–612.

[128] 13 CFR 121.201.

[129] The RFA definition of ''small entity'' refers to the definition provided in the Small Business Act, which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. The Small Business Administrations' regulations at 13 CFR 121.201 define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 500 employees. *See* 5 U.S.C. 601(3) (citing to Section 3 of the Small Business Act, 15 U.S.C. 632).

[130] North American Electric Reliability Corporation, *NCR Active Entities List,* (Jan. 12, 2024), NERC_Compliance_Registry_Matrix_Excel.xlsx.

[131] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act,* 18 (Aug. 2017), *https://cdn.advocacy.sba.gov/wp-content/uploads/2019/06/21110349/How-to-Comply-with-the-RFA.pdf.*

processing software must be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

78. Commenters that are not able to file comments electronically may file an original of their comment by USPS mail or by courier-or other delivery services. For submission sent via USPS only, filings should be mailed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426. Submission of filings other than by USPS should be delivered to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

IX. Document Availability

79. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*https://www.ferc.gov*).

80. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

81. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY 202–502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

By direction of the Commission.

Issued: March 21, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

Note: The following appendix will not appear in the Code of Federal Regulations.

Appendix A: List of Commenters

A. Initial Commenters

- Haley Benson
- Nikhil Bhushan
- Market Monitoring Unit of Southwest Power Pool, Inc.
- Charles T. Gaunt
- Duke Energy Corporation
- Wolverine Power Supply Cooperative, Inc.
- Nuclear Energy Institute
- PJM Interconnection, L.L.C.
- Electricity Consumers Resource Council
- Southwest Power Pool, Inc.
- California Independent System Operator Corporation
- State Agencies [1]
- Electric Power Service Corporation
- Renewable Generation Companies [2]
- Midcontinent Independent System Operator, Inc.
- Clean Energy Coalition [3]
- Pine Gate Renewables, LLC
- Edison Electric Institute
- National Rural Electric Cooperative Association
- New York Independent System Operator, Inc.
- ISO New England Inc.
- MISO Transmission Owners
- PJM Power Providers Group
- Vistra Corp. and Dynegy Marketing and Trade, LLC
- National Hydropower Association
- Alliant Energy Corporate Services, Inc.
- Dominion Energy Services, Inc.
- Los Angeles Department of Water and Power
- Leeward Renewable Energy, LLC, and Union of Concerned Scientists
- EDF Renewables, Inc.
- Ameren Services Company
- Electric Power Supply Association
- Indicated Generation Owners [4]
- Joint Customers [5]
- PSEG
- Independent Market Monitor for PJM
- American Electric Power Service Corporation

B. Reply Commenters

- Renewable Generation Companies
- Electric Power Supply Association
- Clean Energy Coalition
- Vistra Corp. and Dynegy Marketing and Trade, LLC
- EDF Renewables, Inc.
- PSEG
- Ameren Services Company
- Joint Customers
- MISO Transmission Owners
- Independent Market Monitor for PJM

[1] State Agencies consist of the Connecticut Attorney General, the Connecticut Department of Energy and Environmental Protection, the Connecticut Office of Consumer Counsel, the Delaware Attorney General, the Delaware Division of the Public Advocate, the Office of the People's Counsel for the District of Columbia, the Maine Office of the Public Advocate, the Massachusetts Attorney General, the Attorney General of the State of Michigan, the Minnesota Attorney General, the Oregon Attorney General, and the Rhode Island Attorney General.

[2] Renewable Generation Companies consist of D.E. Shaw Renewable Investments, L.L.C., EDF Renewables, Inc., EDP Renewables North America LLC, Enel North America, Inc., Invenergy Renewables LLC, Lightsource Renewable Energy Operations, LLC, NextEra Energy Resources, LLC, Open Road Renewables, LLC, and RWE Renewables Americas, LLC.

[3] Clean Energy Coalition consists of the Solar Energy Industries Association, the American Clean Power Association, Earthjustice, and the Natural Resources Defense Council.

[4] Indicated Generation Owners consists of Ares EIF Management, LLC, Brookfield Renewable Trading and Marketing LP, Cogentrix Energy Power Management, LLC, and Eagle Creek Renewable Energy, LLC.

[5] Joint Customers consist of Old Dominion Electric Cooperative, Northern Virginia Electric Cooperative, Inc., and Dominion Energy Services, Inc.

[FR Doc. 2024–06556 Filed 3–27–24; 8:45 am]

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DEPARTMENT OF LABOR

Occupational Safety and Health Administration

29 CFR Part 1910

[Docket No. OSHA–2007–0073]

RIN 1218–AC91

Emergency Response Standard

AGENCY: Occupational Safety and Health Administration (OSHA), DOL.

ACTION: Notice of proposed rulemaking (NPRM); extension of comment period.

SUMMARY: OSHA is extending the period for submitting comments by 45 days to allow stakeholders interested in the NPRM on Emergency Response additional time to review the NPRM and collect information and data necessary for comment.

DATES: The comment period for the NPRM that was published at 89 FR 7774 on February 5, 2024, is extended. Comments on any aspect of the NPRM must be submitted by June 21, 2024.

ADDRESSES:

Written comments: You may submit comments and attachments, identified by Docket No. OSHA–2007–0073, electronically at *www.regulations.gov,* which is the Federal e-Rulemaking Portal. Follow the online instructions for making electronic submissions. The Federal e-Rulemaking Portal at *www.regulations.gov* is the only way to submit comments on this NPRM.

Instructions: All submissions must include the agency's name and the docket number for this rulemaking (Docket No. OSHA–2007–0073). All comments, including any personal information you provide, are placed in the public docket without change and may be made available online at *www.regulations.gov.* Therefore, OSHA cautions commenters about submitting information they do not want made available to the public or submitting materials that contain personal information (either about themselves or others), such as Social Security Numbers and birthdates.

Docket: To read or download comments or other material in the docket, go to Docket No. OSHA–2007–0073 at *www.regulations.gov.* All comments and submissions are listed in the *www.regulations.gov* index;