UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE INDICATED TRADE ASSOCIATIONS

The Electric Power Supply Association ("EPSA"),[1] The PJM Power Providers Group ("P3"),[2] the New England Power Generators Association, Inc. ("NEPGA"),[3] Independent Power Producers of New York, Inc. ("IPPNY"),[4] and the Coalition of Midwest

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[1] EPSA is the national trade association representing competitive power suppliers in the U.S. EPSA members provide reliable and competitively priced electricity from environmentally responsible facilities using a diverse mix of fuels and technologies. EPSA seeks to bring the benefits of competition to all power customers. This filing represents the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

[2] P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly designed and well-functioning electricity markets in the PJM Interconnection, L.L.C. ("PJM") region. Combined, P3 members own over 83,000 MW of generation assets and produce enough power to supply over 63 million homes in the PJM region covering 13 states and the District of Columbia. For more information on P3, visit www.p3powergroup.com. This filing represents the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue.

[3] NEPGA is the trade association representing competitive power generators in New England. NEPGA's member companies represent over 90 percent of the installed capacity in New England. NEPGA's mission is to support competitive wholesale electricity markets in New England. NEPGA believes that open markets guided by stable public policies are the best means to provide reliable and competitively priced electricity for consumers. A sensible, market-based approach furthers economic development, jobs and balanced environmental policy for the region. NEPGA's member companies are responsible for generating and supplying electric power for sale within the New England bulk power system. This filing represents the position of NEPGA as an organization, but not necessarily that of any particular member.

[4] IPPNY is a not-for-profit trade association representing companies involved in the development of electric generating facilities, the generation, sale, and marketing of electric power, and the development of natural gas facilities in the State of New York. IPPNY member companies produce a majority of New York's electricity, utilizing almost every generation technology available today, such as wind, solar, natural gas, oil, hydro, biomass, energy storage, waste-to-energy, and

Power Producers ("COMPP")[5] (collectively, the "Indicated Trade Associations") hereby respond to the notice of proposed rulemaking issued by the Federal Energy Regulatory Commission ("FERC" or the "Commission") in the above-captioned proceeding.[6]

Recognizing the critical importance of reactive power to the reliability of the transmission system, the Commission has for decades required reactive power to be provided as a separate ancillary service and provided compensation for this service.[7] Nonetheless, the NOPR now proposes to eliminate compensation to generators for providing reactive power within the standard power factor range (commonly referred to as the "deadband"). As explained herein and in the affidavits of Sherman Knight, the President and Chief Commercial Officer of Competitive Power Ventures ("CPV") (the "Knight Affidavit," provided as Attachment A), and Michael Borgatti, Senior Vice President of RTO Services and Regulatory Affairs at Gabel Associates (the "Borgatti Affidavit,"

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nuclear. This filing represents the position of IPPNY as an organization, but not necessarily the views of any particular member with respect to any issue.

5 COMPP is a non-profit trade association where member companies work together on a cooperative basis to maintain and develop independent, transparent, non-discriminatory, robust, and fully competitive wholesale energy, capacity and ancillary service markets within the Midcontinent Independent System Operator, Inc. ("MISO") region. COMPP members strive to create a "level playing field" in the further development and evolution of MISO's market design working within the open stakeholder process where MISO operates as the nation's first FERC approved Regional Transmission Organization managing the reliable supply and transmission of power within a 15-state region ranging from the Gulf of Mexico to the Canadian province of Manitoba. This filing represents the position of COMPP as an organization, but not necessarily the views of any particular member with respect to any issue.

6 *Compensation for Reactive Power Within the Standard Power Factor Range*, 186 FERC ¶ 61,203 (2024) (the "NOPR").

7 *See 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 21,540 (1996) ("Order No. 888") (cross-referenced at 75 FERC ¶ 61,080), *on reh'g*, Order No. 888-A, 62 FR 12,274 (1997) (cross-referenced at 78 FERC ¶ 61,220), *on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *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. New York v. FERC*, 535 U.S. 1 (2002).

provided as Attachment B), the Commission's proposal is based on incorrect assumptions about the nature and costs of the service that generators provide and without full consideration of the ramifications of the proposal, including harm to reliability, the further erosion of revenue sufficiency and investor confidence, and the creation of a new need for transmission providers to rely on more expensive alternatives. Accordingly, the Indicated Trade Associations urge the Commission to set aside the NOPR proposal. In the alternative, in the event that the Commission decides nevertheless to move ahead with this ill-advised proposal, it cannot do so without adopting a comprehensive transition plan that will minimize harm to investors that have developed generation and entered into bilateral arrangements in reliance on the existing compensation policies. Any transition plan must also account for differing regional transmission organization ("RTO") and independent system operator ("ISO") market structures and rules.

I. THE COMMISSION SHOULD NOT IMPLEMENT THE NOPR PROPOSAL

The Indicated Trade Associations urge the Commission to reconsider the preliminary determinations in the NOPR, which, as described herein, are based on a flawed process and misunderstandings of the underlying facts and potential consequences of the proposal, which would harm reliability and be unjust, unreasonable, and unduly discriminatory in violation of the Federal Power Act (the "FPA"). Upon reconsideration, the Commission must set aside the NOPR.

A. The NOPR Proposal is Not Supported by the Record, Which was Developed to Improve, Rather than Eliminate, Reactive Compensation Methodologies

On November 18, 2021, the Commission issued a notice of inquiry in this proceeding[8] that focused on the continued use of the longstanding "AEP Methodology" that has historically been used to "allocat[e] the costs of generator equipment between real power capability and reactive power capability, as well as the related operations and maintenance costs"[9] in the development of reactive power rates. Specifically, the NOI explained:

> Due to the . . . differences in the generation resource mix and divergent reporting requirements between market-based and cost-based sellers since the time when the AEP Methodology was established, the Commission seeks 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.[10]

As a result, the NOI raised questions on the following three topics:

- "Issues with AEP Methodology-based Reactive Power Compensation,"[11] including issues relating to: (1) "Degradation;"[12] (2) "Accounting and Ratemaking Issues related to Non-synchronous Resources";[13] (3) "Evidentiary Support";[14] and (4) "Market-Based Compensation and Potential Overcompensation in PJM [Interconnection, L.L.C. ("PJM")]";[15]

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8 *See Reactive Power Capability Compensation*, 177 FERC ¶ 61,118 (2021) (the "NOI").

9 *Id.* at P 9. The AEP Methodology takes its name from *American Electric Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999) ("*AEP*").

10 NOI, 177 FERC ¶ 61,118 at P 19.

11 *Id.*, Section II.A. *See also id.* at PP 20-28.

12 *Id.*, Section II.A.1.

13 *Id.*, Section II.A.2.

14 *Id.*, Section II.A.3.

15 *Id.*, Section II.A.4.

- "Alternative Methodologies,"[16] which could include "a flat rate methodology"[17] or "replacement cost ratemaking";[18] and,

- "Distribution-connected Resources,"[19] given the Commission's prior finding that "a transmission provider need not provide compensation to resources for reactive power if the resource is not under the control of the control area operator,"[20] and arguments by the Independent Market Monitor for PJM (the "PJM IMM") that such resources "have not established that they provide reactive power capability service to the PJM transmission system . . . ."[21]

Certain of the Indicated Trade Associations and an array of commenters from across the generation spectrum expended considerable time and effort responding to the NOI.[22] For example, EPSA filed lengthy initial and reply comments, including supporting testimony, addressing the questions posed in the NOI on the continued viability of the AEP Methodology and potential alternatives that could be used to fairly compensate resources for providing reactive power while also minimizing the burden on the Commission.[23]

In stark contrast to the NOI's focus on changes and improvements to the methodology used to determine appropriate reactive power compensation, the

16 *Id.*, Section II.B. *See also id.* at PP 29-32.

17 *Id.* at P 30.

18 *Id.* at P 31.

19 *Id.*, Section II.C. *See also id.* at PP 33-36.

20 *Id.* at P 33.

21 *Id.* at P 34.

22 *See* Comments of the Electric Power Supply Association, Docket No. RM22-2-000 (filed Feb. 22, 2022) ("EPSA NOI Comments"); Comments of the PJM Power Providers Group on Reactive Power Capability Compensation, Docket No. RM22-2-000 (filed Feb. 22, 2022); Reply Comments of the Electric Power Supply Association, Docket No. RM22-2-000 (filed Mar. 23, 2022).

23 *See, e.g.*, NOI, 177 FERC ¶ 61,118 at P 2 (stating that market-based rate sellers are not required to maintain their accounts under the Uniform System of Accounts or file FERC Form 1, which has "contributed, at least in part, to many [reactive power compensation] filings being set for hearing and settlement judge procedures").

Commission now proposes in the NOPR to eliminate reactive power compensation within the deadband. But because the questions in the NOI had little relevance to the current NOPR proposal, the NOPR proposal is inadequately supported by the record. Indeed, as discussed in more detail in Section I.B below, the NOPR relies heavily on unsupported assertions, including those made in other proceedings, rather than evidence provided in this proceeding. For example, the NOPR claims that "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."[24] However, no support is cited for this assertion.

As a result of this flawed process, the NOPR fails to identify evidence needed to support the Commission's dramatic turnaround on reactive power compensation. Ignoring the lack of record evidence from responses to the NOI that would support its proposed action, the Commission instead relies on unsupported assertions, including Commission orders in a separate proceeding that are currently pending review before the United States Court of Appeals for the District of Columbia Circuit.[25] Notably, however, the Commission ignores the fact that many of the cited orders stemmed from proceedings under Section 205 of the FPA,[26] while the Commission must proceed under Section 206 of the FPA in order to implement the NOPR proposal.[27] Because "[t]he proponent of a

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[24] NOPR, 186 FERC ¶ 61,203 at P 26.

[25] *See Midcontinent Indep. Sys. Operator, Inc.*, 182 FERC ¶ 61,033 ("*MISO I*"), *on reh'g*, 184 FERC ¶ 61,022 (2023) ("*MISO II*," and together with *MISO I*, the "MISO Orders"), *petition for review pending*, *Capital Power Corp. v. FERC*, Case Nos. 23-1134, *et al.* (D.C. Cir.) (the "D.C. Circuit Proceeding").

[26] 16 U.S.C. § 824d (2018).

[27] *See* NOPR, 186 FERC ¶ 61,203 at P 41.

rate change under section 206 . . . bears 'the burden of proving that the existing rate is *unlawful*,'"[28] "the showing required of FERC to exercise its section 206 authority to change an existing rate is different from anything required for FERC to approve a utility's proposed rate adjustment under section 205."[29] It is therefore not sufficient for the Commission to rely on the MISO Orders and other orders issued under Section 205 to justify the NOPR Proposal.[30]

For these fundamental reasons, the Commission should set aside the NOPR and consider more measured alternatives to address the concerns that were the purported focus of this proceeding – namely, the administrability and continued workability of existing compensations approaches like the AEP Methodology. Commenters including EPSA provided the Commission with ample record evidence to support a new, refocused next step in this proceeding. The Commission should course correct.

B. The NOPR Proposal is Based on Flawed and Unsupported Assumptions

1. The NOPR Erroneously Assumes that there are No or Only Minimal Costs Associated with the Provision of Reactive Power

In the NOPR, the Commission posits that eliminating compensation for reactive power is permissible because generators "are only meeting their obligations under their

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28 *Emera Maine v. FERC*, 854 F.3d 9, 24 (D.C. Cir. 2017) (emphasis and alterations in original) (citations omitted).

29 *Id.* at 25.

30 *See, e.g.*, NOPR, 186 FERC ¶ 61,203 at n.9 (citing MISO Orders and *Michigan Elec. Transmission Co.*, 97 FERC ¶ 61,187, at 61,852-53 (2001) ("*METC*")); *id.* at n.68 (citing *MISO II*); *id.* at n.70 (citing, among other things, *Arizona Pub. Serv. Co.*, 94 FERC ¶ 61,027 at 61,080 (2001) ("*APS*"), which also was a proceeding under Section 205 of the FPA). The NOPR also relies on *Bonneville Power Administration v. Puget Sound Energy, Inc.*, 120 FERC ¶ 61,211 (2007) ("*BPA*"), *on reh'g*, 125 FERC ¶ 61,273 (2008) ("*BPA II*"), which was a proceeding under Section 206 of the FPA, but as discussed below, involved a "finding" by the Commission without cited support. *See BPA*, 120 FERC ¶ 61,211 at P 21.

interconnection agreements and in accordance with good utility practice" and "incur no additional costs or *de minimis* costs beyond that which they already incur to provide real power."[31] The NOPR claims that, "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' beyond the investments in equipment already necessary to generate and supply real power to the transmission system."[32] As noted above, the prior Commission orders cited in the NOPR do not provide evidence on these points. For example, in the *BPA* order, the Commission summarily stated, "the incremental cost of reactive power service within the deadband is minimal," without any citation or record support.[33] On rehearing, one party argued that "only the short-run marginal cost of producing the next increment of reactive power 'can logically be described as minimal' because it excludes capability costs,"[34] but the Commission sidestepped this issue, stating that "the issue of whether or not the cost is minimal is not relevant to whether the independent power producers are entitled to compensation."[35] In *APS*, another order cited in the NOPR, the Commission simply noted that intervenors "have not demonstrated that [the proposed reactive power] requirement will limit the real power output of a generating unit and therefore will not result in any lost opportunity costs."[36]

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31 NOPR, 186 FERC ¶ 61,203 at P 8.

32 *Id.* at P 29 (footnotes omitted).

33 *BPA*, 120 FERC ¶ 61,211 at P 21.

34 *BPA II*, 125 FERC ¶ 61,273 at n.7.

35 *Id.*

36 *APS*, 94 FERC ¶ 61,027 at 61,080 (cited in NOPR, 186 FERC ¶ 61,203 at n.70).

Even assuming that all of the same equipment is used to produce real and reactive power,[37] the NOPR does not explain why it is appropriate to then assume that the cost of such equipment should be allocated ***solely*** to the production of real power such that reactive power would then be deemed to be provided at zero cost. This assumption is at odds with Order No. 888, which expressly found that reactive service from generation facilities must be priced at ***cost***[38] – thereby acknowledging that there are distinguishable costs associated with the provision of reactive power. Similarly, the Commission fails to reconcile the NOPR's insistence that there are no segregable costs associated with the provision of reactive power with its longstanding precedent on the AEP Methodology, which the Commission specifically approved to isolate the costs of providing reactive power. Indeed, the Commission expressly instructed generators to use the AEP Methodology "***to compute the portion of plant investment attributable to reactive power production***,"[39] explaining:

> [T]he production of reactive power, which is measured in Volt-Amperes-reactive (VArs), is necessary to maintain appropriate voltages in order to effect the transmission of electric power throughout the transmission system. *AEP* identified three components of production plant that are directly related to the production of VArs: (1) the generator and its exciter; (2) accessory electric equipment that supports the operation of the generator-exciter; and (3) the remaining total production investment required to provide real power and operate the exciter. Because these production plants produce real and reactive power, *AEP* developed an allocation factor to ***segregate the reactive production function from the***

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37 The NOPR acknowledges that "[n]on-synchronous generating facilities use a different physical process to produce reactive power," but then claims that "'the most critical element in VAR production, the inverter,' is also necessary for non-synchronous generating facilities to produce real power that can be injected into AC systems." NOPR, 186 FERC ¶ 61,203 at P 29 (footnotes omitted).

38 *See* Order No. 888, 61 FR 21,540 at 21,590.

39 *Virginia Elec. & Power Co.*, 114 FERC ¶ 61,318 at P 3 (2006) (emphasis added).

> ***real power production function***. ***The allocation factor is used to determine the amount of investment allocable to reactive power.*** Once the plant investment associated with reactive power production was determined, *AEP* applied an annual carrying charge to these costs to determine an annual revenue requirement.[40]

As Mr. Knight explains, "we could achieve the same real power capability at lower cost if we were not required to provide reactive power."[41] In fact, the cost of equipment to provide reactive power within the deadband, rather than at a power factor of 1.0, is substantial, as "[f]or a 1,000 MW thermal power plant, the cost difference of the larger equipment would easily be in the millions of dollars," while for solar-powered plants, "[i]nverters typically cost something on the order of $135,000 per MW of installed nameplate, and depending upon the VAR capability required, larger or additional inverters could add hundreds of thousands of dollars of incremental costs to be able to operate beyond a power factor of 1.0."[42]

Even aside from capital costs of equipment, there are other costs of producing reactive power within the deadband. This is made clear by capability curves (commonly referred to as "D-curves") for electrical generators, which demonstrate the real power that must be sacrificed to produce reactive power. As an example, Mr. Knight explains that CPV's Fairview facility has a maximum real power capability of 437.6 MW at a power factor of 1.0, but that such capability "drops to approximately 415 MW and 425 MW at power factors of 0.95 lagging and 0.95 leading, respectively."[43] Moreover, this also affects

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40 *Id.* (emphasis added) (footnotes omitted).

41 Knight Affidavit at P 9.

42 *Id.* at P 11.

43 *Id.* at P 13. *See also* Borgatti Affidavit at 8-9.

the amount of capacity that CPV can sell, resulting in forgone capacity revenues of almost $28 million over the expected 20-year life of the project.[44] Accordingly, in addition to the incremental capital costs associated with providing reactive power, the commensurate reduction in real power and capacity means that generators incur higher capital costs on a per unit basis as a result of the requirement to provide reactive power.

In addition, the NOPR downplays other costs associated with the provision of reactive power. For example, in response to the NOI, a commenter explained that non-synchronous resources "require additional investment in power electronics to increase reactive power capability," which not only involves "the capital costs associated [with] the inverter functionality and the increased active power consumption when the resource is in stand-by mode," but also "increased maintenance expenses."[45] Indeed, the NOPR "recognize[s] 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" but then goes on to claim, with no support at all, that these costs are only *de minimis*.[46] The NOPR also completely ignores the fact that the provision of reactive power within the deadband represents a lost opportunity to produce real power, thereby resulting in lost opportunity costs. On this point, the Market Monitoring Unit for Southwest Power Pool, Inc. ("SPP") explained that the Commission was wrong to assume that reactive power costs within the deadband are small because "during the February 2021 extreme weather event, SPP's real-time market prices exceeded $3,000/MWh because of scarcity

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44 *See* Knight Affidavit at P 13. *See also id.* at P 14 (explaining that these estimates are conservative).

45 Comments of Pine Gate Renewables, LLC at 4-6, Docket No. RM22-2-000 (filed Feb. 22, 2022).

46 NOPR, 186 FERC ¶ 61,203 at P 31.

of real-time power" and "[d]uring this or similar scarcity periods, resources that needed to be backed off to provide reactive power could experience significant lost opportunity costs."[47] In addition, lost opportunity costs may not be limited to forgone energy revenues: for renewable resources, having to back down generation in order to produce reactive power would also result in lost renewable electricity production tax credits ("PTCs"), renewable energy certificates ("RECs"), and similar benefits. As Mr. Borgatti explains, these types of costs often are not recoverable under RTO/ISO rules.[48] The Commission cannot ignore these very real and significant costs.

2. The NOPR Erroneously Assumes that Generators May Recover Their Costs Through Other Mechanisms

After first downplaying the costs required for generators to provide reactive power, the NOPR then claims that "any purported costs associated with such provision of reactive power can be recovered in other ways—such as through energy or capacity sales."[49] The Commission makes this assertion with no factual support or explanation of precisely how generators will include reactive power costs in energy or capacity offers. This lack of factual support or explanation is likely because the RTO/ISO market rules approved by the Commission bar generators from seeking to recover their reactive power costs in energy or capacity offers.

First, the Commission has stated that "LMPs and market-clearing prices used in energy and ancillary services markets ideally 'would reflect the true ***marginal*** cost of

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47 Comments of the Market Monitoring Unit of the Southwest Power Pool on Notice of Inquiry at 3, Docket No. RM22-2-000 (filed Jan. 31, 2022).

48 *See* Borgatti Affidavit at 8.

49 NOPR, 186 FERC ¶ 61,203 at P 6 (footnote omitted).

production,'"[50] and therefore required RTOs and ISOs to implement energy offer caps based on generators' verifiable marginal costs.[51] Thus, for example, PJM only permits cost-based offers to reflect start-up costs, variable operating and maintenance ("O&M") costs, no-load costs, labor costs, operating costs, opportunity costs, emission allowances and adders, maintenance adders, and fuel or charging costs.[52] Other RTOs and ISOs impose similar restrictions on cost-based offers.[53] These market mitigation rules preclude sellers from seeking to include the capital costs of the facilities used to produce reactive power in their energy offers.[54]

Even at times when energy offers are not capped, the Commission cannot reasonably conclude that generators will be able to recover their reactive power costs through energy prices. In light of the change in the resource mix noted in the NOPR,[55] commenters responding to the NOI raised concerns regarding cost recovery because

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[50] *Offer Caps in Mkts. Operated by Reg'l Transmission Orgs. and Indep. Sys. Operators*, Order No. 831, 157 FERC ¶ 61,115 at P 7 (2016) (emphasis added) (footnote omitted), *on reh'g*, Order No. 831-A, 161 FERC ¶ 61,156 (2017).

[51] *See, e.g., id.* at P 5 (adopting reforms to "give resources the opportunity to recover their short-run marginal costs").

[52] Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, § 1.1.

[53] *See, e.g.*, ISO New England Inc., Transmission, Markets, and Services Tariff ("ISO-NE Tariff"), § III.1.9.1.1 (imposing cost-based caps on energy offers); *id.*, Appendix A, § III.A.7.5.1 (providing that the ISO New England Inc. ("ISO-NE") Internal Market Monitor shall determine a resource's marginal costs, which consist of incremental energy, no-load, and start-up costs that are based on fuel, emissions allowances, variable O&M, and opportunity costs); New York Independent System Operator, Inc., Market Administration and Control Area Services Tariff ("NYISO MST"), Attachment F, § 21.4.1 (imposing energy offer cap based on a cost-based reference level); *id.*, § 23.3.1.4.1.3 (reference level to reflect marginal cost based on fuel, emissions allowances, variable O&M, and opportunity costs); Midcontinent Independent System Operator, Inc., FERC Electric Tariff, Module D, § 64.1.4 (establishing reference levels for energy offers based on marginal costs).

[54] *See* Borgatti Affidavit at 14-15.

[55] *See* NOPR, 186 FERC ¶ 61,203 at P 20.

renewable resources have no or almost no variable costs. As a result, increasing market penetration by renewable resources can be expected to create downward pressure on energy prices, meaning that "as more [inverter-based resources ("IBRs")] come on line and synchronous resources retire, the Commission will need to support the development of alternative revenue streams that will cover IBRs' fixed costs and provide necessary incentives for developers to invest in the facilities necessary to provide all ancillary services, including reactive power."[56] In addition, Mr. Borgatti explains that including reactive power costs in energy offers would increase a generator's risk of not clearing in the energy market and thereby being denied energy revenues altogether, and that this risk is "particularly acute in jurisdictions where independent power producers compete with vertically integrated utilities whose generators recover costs through state-jurisdictional retail rates."[57]

Capacity markets also do not provide for recovery of reactive power costs. As an initial matter, capacity offers from existing resources are currently limited to avoidable or going forward costs, and therefore do not allow for inclusion of costs that have already been incurred to provide reactive power.[58] In addition, PJM, ISO-NE, and New York Independent System Operator, Inc. ("NYISO") each currently subtract expected energy and ancillary services revenues, which include reactive power revenues, from the Net

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56 Initial Comments of Leeward Renewable Energy, LLC, and Union of Concerned Scientists at 3, Docket No. RM22-2-000 (filed Feb. 22, 2022) ("Leeward/UCS NOI Comments").

57 Borgatti Affidavit at 14-15.

58 *See PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,097 at P 35 ("We agree that, as a general matter, a competitive offer in the capacity market may reasonably reflect only incremental costs that are avoidable if the resource does not receive a capacity commitment." (footnote omitted)). *See also, e.g.*, PJM, Open Access Transmission Tariff ("PJM Tariff"), Attachment DD, § 6.4(a); ISO-NE Tariff, § III.13.1.2.3.2.1.2.

Cost of New Entry ("CONE") used to develop the demand curves for capacity market auctions.[59] As the PJM IMM has stated, this "Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the [demand] curve,"[60] meaning that capacity commitments have been priced assuming that reactive power would be compensated outside the capacity market. PJM and ISO-NE also hold their capacity auctions three years ahead of the delivery or commitment period, meaning that generators already have capacity commitments for the forthcoming years that were based on these Net CONE calculations, and it would be years after any rule changes before reactive power costs could potentially be reflected in delivery year revenues for resources that clear the auction. Critically, even if these rules are changed such that capacity offers and demand curves can reflect reactive power costs in the future, there is no guarantee that a generator will be able to clear any or sufficient capacity in a capacity auction so that it will be able to recover its costs; indeed, certain types of resources may not even participate in the capacity market.[61]

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59 *See* PJM Tariff, Attachment DD, § 5.10(v-1)(A); ISO-NE Tariff, § 1I.2.2 (definition of "Net CONE"); NYISO MST, § 5.14.1.2.2 (describing costs used in ICAP Demand Curve).

60 Comments of the Independent Market Monitor for PJM at 21, Docket No. RM22-2-000 (filed Feb. 25, 2022).

61 *See, e.g.*, PJM Tariff, Attachment DD, § 6.6A(c) (providing a categorical exception from the capacity must-offer obligation for certain types of resources).

C. The NOPR Will Have Substantial Adverse Impacts on Investors and Reliability

1. Investors Have Relied on Reactive Power Compensation in Developing and Acquiring Generation Resources

As Mr. Knight and Mr. Borgatti both explain, reactive power revenues are considered in decisions regarding the development and ongoing operations of generation resources and the NOPR would, if implemented, disrupt those decisions and arrangements made in reliance on existing reactive power compensation policies. In particular, Mr. Knight explains that the financial modeling used for the financing and refinancing of generation facilities includes reactive revenues and that such revenues have the benefit of being stable and thus do not have to be discounted in the modeling in the same way as energy and capacity revenues.[62] Mr. Knight further states that, in his experience, given the narrow margins for competitive generators, relatively small reactive power revenue streams can make the difference between whether a generator is expected to be profitable over its expected life, and whether lenders are willing to finance the project.[63] Accordingly, reactive power revenues can have a significant impact on the decision of whether to go forward with the development of a project or the decision to keep a project in service.[64]

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62 *See* Knight Affidavit at P 15. *See also* Borgatti Affidavit at 4 ("Reactive compensation is a central part of this future revenue stack, particularly in markets like PJM, NYISO, and ISO-NE, which provide fixed annual payments to provide this service.").

63 *See* Knight Affidavit at PP 15-16.

64 *See id.*; Borgatti Affidavit at 4-5. *See also* Joint Protest of Capital Power Corporation, *et al.*, at 15-16, Docket No. ER23-523-000 (filed Dec. 21, 2022) ("Clean Energy Generation Owners have been able to rely on these Commission-approved ranges to demonstrate to lenders and third party financial institutions that there is another revenue stream under Schedule 2 of the MISO Tariff, even if the most conservative, lowest Commission-approved rate in the market is used. This has provided bases to help secure funding to develop, and investment in, generation. Given increased commodity, construction, interconnection and borrowing costs, projects are often on

In addition, as described in the Borgatti Affidavit, investors have installed new and additional facilities to increase their ability to provide reactive power in reliance on reactive power revenues. Under the AEP Methodology, reactive power compensation is based on the power factor of the generator.[65] Similarly, both ISO-NE and NYISO also provide reactive power compensation based on the reactive capability of the generator.[66] Accordingly, Mr. Borgatti states that developers have had an incentive to go beyond the 0.95 leading to 0.95 lagging requirements that are typical in interconnection agreements, and may thus choose to design and develop their generation projects based on their expectations of the revenues they will receive for additional reactive power capability.[67]

Finally, generators may have structured their power purchase agreements ("PPAs") and other bilateral arrangements in reliance on the Commission's existing reactive power compensation policies. For example, an existing PPA could provide for all of the energy and capacity of a generator to be sold to a third party, but have been priced based on assumptions regarding reactive power compensation and other wholesale revenues.[68] PPAs are typically long-term contracts, and it is highly unlikely that any such existing PPAs could now be modified and repriced to provide the generator with additional

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the margin whether they make economic sense to build. Eliminating reactive revenues may stress project economics and lead to less development in MISO.").

65 *See Bishop Hill Energy LLC*, 185 FERC ¶ 61,056 at n.59 (2023) (explaining that, "under the *AEP*-methodology, a small change to a facility's power factor has a significant effect on that facility's revenue requirement for reactive power capability," and providing a hypothetical where "a difference of 0.15 in claimed power factor leads to a nearly fourfold increase in plant investment attributable to the production of reactive power and, therefore, a nearly fourfold difference in the amount of plant investment that the facility can include in its revenue requirement for reactive power capability").

66 *See* ISO-NE Tariff, Schedule 2, § IV.A.12; NYISO MST, § 15.2.2.1.

67 *See* Borgatti Affidavit at 5-6.

68 *See id.* at 7.

compensation if the NOPR proposal is adopted.[69] At the same time, because the generator's energy and capacity has already been committed under the PPA, it would not be able to make up the missing revenues through energy or capacity sales, as the NOPR suggests. Mr. Borgatti also explains that the NOPR proposal would disrupt other types of arrangements and expectations, including with respect to state-led procurement decisions and "behind-the-meter" arrangements.[70] The NOPR proposal would thus significantly upset the financial security of existing generators.

2. Eliminating Reactive Power Compensation Could Adversely Affect Reliability

The NOPR assumes that the elimination of reactive power compensation will have no impact on reliability because of the reactive power obligations imposed under generators' interconnection agreements.[71] This shortsighted view ignores the fact that, in many areas, retirements are outstripping new development due to market conditions.[72] Eliminating a source of stable, expected revenue for generators could exacerbate this problem because, as discussed above, there is no clear alternate market mechanism for generators to recover those costs. In fact, in a report prepared in 2005, Commission Staff presciently observed:

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[69] *See* Motion for Leave to Answer and Answer of Capital Power Corporation, *et al.*, at 12-13, Docket No. ER23-523-000 (filed Jan. 20, 2023).

[70] *See* Borgatti Affidavit at 6-8.

[71] *See, e.g.*, NOPR, 186 FERC ¶ 61,203 at P 43.

[72] *See generally, e.g.*, Robert Walton, *Rising peak demand, 83 GW of planned retirements create blackout risks for most of US: NERC* (Utility Dive, Dec. 14, 2023), https://www.utilitydive.com/news/generator-retirements-threaten-grid-reliability-NERC/702504/; Nicole Jao, *U.S. grids face greater risks as generators retire, demand rises – NERC* (Reuters, Dec. 14, 2023), https://www.reuters.com/business/energy/us-grids-face-greater-risks-generators-retire-demand-rises-nerc-2023-12-14/; PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Feb. 24, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

> Of course, many generators are able to earn revenues from sources other than reactive power - such as from sales of real power. Thus, much generation investment would continue to be made even if generators are not paid for providing reactive power capability. However, failing to pay generators for reactive power could reduce the amount of generation investment, particularly in areas where reactive power capability is very valuable to the system. That is, some efficient generation investment might not be built or might retire early without reactive power payments because revenues from real power sales and other sources, by themselves, would not be sufficient to cover the project's costs and return a profit.[73]

As explained in the Knight and Borgatti Affidavits, eliminating a stable revenue source can be expected to impact the decision to invest in new generation, which is often made on the margins.[74] In addition, because "$1 million in annual reactive power revenue can support approximately $10 million of debt," Mr. Knight explains that "[e]liminating reactive power compensation would result in a reduction in borrowing capacity necessitating higher equity requirements, all of which result in less economically viable projects."[75] Mr. Borgatti further states that changing the rules for reactive power compensation after financing decisions have been made "can result in violations of contractual financing obligations, prevent investors from reaching their required rates of return, and increase the risk of financial distress."[76]

Pointing to comments by the California Independent System Operator Corporation ("CAISO"), the NOPR states that CAISO's "current approach to not compensate for

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73 *See* FERC Staff Report, *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, at 70, Docket No. AD05-1-000 (Feb. 4, 2005) ("AD05-1 Staff Report").

74 *See* Knight Affidavit at P 15; Borgatti Affidavit at 4-6.

75 Knight Affidavit at P 16. *See also* Borgatti Affidavit at 7.

76 Borgatti Affidavit at 4.

reactive power provided within the standard power factor range has not resulted in major issues of concern with the level of reactive power."[77] This claim, however, ignores the fact that California has long relied on long-term contracts to cover the cost of generation, with CAISO itself noting "the importance of long-term contracting as the primary means for investment in any new generation or retrofit of existing generation needed under the current [CAISO] market design," and that "[n]et revenues summed with a capacity payment . . . are well in excess of going-forward fixed costs in all years but fall short of annualized fixed costs in most years . . . ."[78] In fact, given that CAISO and other RTOs/ISOs have had to rely on reliability must-run ("RMR") agreements to maintain generators needed for reactive power,[79] it makes little sense for CAISO or the Commission to conclude that there is no threat to reliability.[80]

In addition, and as explained previously, developers and owners have also installed new or additional facilities to obtain greater compensation under the AEP

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[77] NOPR, 186 FERC ¶ 61,203 at P 43 (footnote omitted).

[78] CAISO, *2022 Annual Report on Market Issues & Performance*, at 15 (July 11, 2023), https://www.caiso.com/documents/2022-annual-report-on-market-issues-and-performance-jul-11-2023.pdf. *See also* Borgatti Affidavit at 10.

[79] *See, e.g., AES Huntington Beach, L.L.C.*, 142 FERC ¶ 61,017 at P 1 (2013) (RMR agreement for generator in California to provide voltage support); *Gilroy Energy Ctr., LLC*, 161 FERC ¶ 61,311 at P 13 (2017) (discussing RMR designation for generator that was required to "reduce local area voltages"); Letter from PJM to Dale Lebsack, President H.A. Wagner LLC, Re: Deactivation Notice for Wagner Generating Units 1, 3, 4 & CT (Jan. 4, 2024) (stating that PJM had "found reliability concerns (wide area voltage drop and thermal violations in several transmission zones)" resulting from proposed deactivation of certain resources), https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/pjm-response-letter-wagner.ashx.

[80] The NOPR also notes that CAISO "'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.'" *Id.* at P 48 (footnote omitted). However, as the NOPR repeatedly points out, generators in CAISO and elsewhere are obligated to have reactive power capability and provide reactive power. The fact that generators have satisfied their obligations in no way demonstrates that they are adequately recovering the costs of providing this service.

Methodology. Indeed, in response to the NOI, various commenters explained that "certain transmission owners with a need have been asking solar generation owners about arranging to provide reactive support at night,"[81] and that non-synchronous resources have made additional investments to allow them to provide reactive power when they are not producing real power, or to increase their reactive power capability.[82] As the AD05-1 Staff Report previously recognized, there will be no incentive for generators to continue to do so if the Commission adopts the NOPR proposal:

> Failing to pay for reactive power supplied by generation resources also could reduce the amount of reactive power capability installed in new generation equipment. Developers may elect not to add reactive capability beyond the minimum requirements if they are not going to receive any additional revenue from doing so.[83]

The fact that the NOPR states that compensation will continue for reactive power provided outside the deadband[84] does not change this because the NOPR indicates that such compensation will only be available when a generator "provide[s] reactive power outside of the standard power factor range,"[85] which would likely not occur with sufficient regularity to cover the capital costs associated with such capability.

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81 Initial Comments of D. E. Shaw Renewable Investments, L.L.C., *et al.*, at 23, Docket No. RM22-2-000 (filed Feb. 22, 2022) ("Renewable Generation Companies NOI Comments"). *See also* Borgatti Affidavit at 6 (explaining that Mr. Borgatti has advised renewable resource investors regarding the "revenue potential from increasing inverter ratings or the number of inverters").

82 *See, e.g.*, Renewable Generation Companies NOI Comments at 23; Leeward/UCS NOI Comments at 12.

83 AD05-1 Staff Report at 70.

84 *See* NOPR, 186 FERC ¶ 61,203 at PP 1, 52.

85 *Id.* at P 32.

D. The NOPR Will Result in Unjust, Unreasonable, and Unduly Discriminatory Rates

1. The NOPR Would Result in Confiscatory Ratemaking

For almost 30 years, the Commission has recognized that reactive power provided from generation facilities must be treated as a separate ancillary service because it is "necessary to the provision of basic transmission service within every control area."[86] Nothing in the NOPR or otherwise suggests that such reactive power service is no longer required for the reliability of the transmission system. Correspondingly, there is no basis for the Commission to deny generators compensation for providing this critical service. In fact, doing so would be contrary to the requirements of the U.S. Constitution and the FPA.

Public utilities have the statutory and constitutional right to compensation for the services they provide, including reactive power. This right is grounded in the Fifth Amendment of the U.S. Constitution's prohibition against takings of private property for public use without just compensation.[87] This constitutional right to just compensation is

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86 Order No. 888, 61 FR 21,540 at 21,587. *See also id.* at 21,581-82 (discussing need for reactive power provided by generators).

87 *See e.g., Smyth v. Ames*, 169 U.S. 466, 546 (1898) ("*Smyth*"). In *Smyth*, the Supreme Court explained the basis for a regulated entity's constitutional entitlement to just compensation:

> [T]he Corporation performing such public services and the people financially interested in its business and affairs have rights that may not be invaded by legislative enactment in disregard of the fundamental guarantees for the protection of property. The corporation may not be required to use its property for the benefit of the public without receiving just compensation for the services rendered it by it.

Id. at 546. As a result of the Fourteenth Amendment, the same principle applies to state regulation of public utilities. *See Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of W. Va.*, 262 U.S. 679, 690 (1923) ("*Bluefield*") ("Rates which are not sufficient to yield a reasonable return on the value of property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.").

coextensive with the FPA's requirement that rates must, at a minimum, provide a reasonable opportunity for the utility to recover of, and on, its investment.[88]

Brushing off the Commission's obligation to ensure just and reasonable compensation for reactive service, the NOPR claims that compensation is not necessary because the Commission has treated the provision of reactive power within the deadband as "'an obligation of good utility practice rather than as a compensable service . . . .'"[89] But "[t]he commission under the guise of regulation may not compel the use and operation of the company's property for public convenience without just compensation."[90] Indeed, even in a case where a public utility's license was conditioned upon granting rights-of-way to third parties, the Court found that "[c]haracterizing the mandatory access provision as a regulatory condition . . . cannot change the fact that it effects a taking by requiring a utility to submit to a permanent, physical occupation of its property."[91] The same principle applies here, and the Commission cannot deprive public utilities of just and reasonable compensation simply by characterizing the provision of reactive power as a condition of interconnection, particularly where it was the Commission that established this condition.

Citing the MISO Orders, the NOPR also claims that no compensation should be provided because a generator "is doing no more than meeting its obligation as a generator . . . to maintain the appropriate power factor required to maintain voltage levels for

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88 *See FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 607 (1944). *See also id.* at 603 (finding that rates must provide "enough revenue not only for operating expenses but also for the capital costs of the business" and be sufficient for the utility to "maintain its credit and to attract capital").

89 NOPR, 186 FERC ¶ 61,203 at P 5.

90 *Banton v. Belt Line Ry. Corp.*, 268 U.S. 413, 420 (1925).

91 *Gulf Power Co. v. U.S.*, 187 F.3d 1324, 1331 (11th Cir. 1999).

electric power injected into the transmission system during normal operations."[92] This statement suggests that generators are being asked to provide reactive power to offset the impact of the power they inject onto the system. But this is simply not correct: Order No. 888 noted that "NERC further distinguishes reactive supply service based on the source of the need for the service: (1) Reactive supply needed to support the voltage of the transmission system and (2) reactive supply needed to correct for the reactive portion of the customer's load at the delivery point."[93] The Commission thus found that "transmission customer actions do not eliminate entirely the need for generator-supplied reactive power," and that "[t]he transmission provider must provide at least some reactive power from generation sources."[94] It is thus clear that generators are being asked to provide reactive power to support load.

2. The NOPR Would Otherwise Result in Unjust, Unreasonable, and Unduly Discriminatory Rates

Even if the Commission were not obligated to compensate generators for reactive power, the NOPR proposal is unjust, unreasonable, and unduly discriminatory in violation of the FPA. As discussed previously, the NOPR poses a threat to reliability by eliminating revenue that is necessary for generation development and continued operations, and that helps incentivize investments in additional reactive capability. The short-sighted elimination of reactive power compensation for generators will make it more likely that transmission providers turn to more costly options, thereby further harming consumers. In fact, the AD05-1 Staff Report specifically contemplated the situation that would result

[92] NOPR, 186 FERC ¶ 61,203 at P 5 (footnote omitted).

[93] Order No. 888, 61 FR 21,540 at 21,581.

[94] *Id.* at 21,582.

from the NOPR, whereby there would be "regulatory mandates on all generators to supply reactive power without further compensation and . . . cost-of-service transmission procurement by the system operator."[95] However, the AD05-1 Staff Report advised against this approach, because:

> Ultimately, under this option, the new generation may be designed with only minimum reactive power capability and will result in a need to over invest in transmission assets even when generation based solutions would be less costly. Further, generation resources that could provide valuable reactive capability to a local area will have no incentive to incorporate this value into its locational investment decision and may choose to locate in a less costly area that has lower reactive need.[96]

Mr. Borgatti similarly explains that it is likely more cost effective to compensate generators for providing reactive power rather than requiring RMR agreements or the installation of new transmission facilities. For example, Mr. Borgatti explains that PJM has determined that it would cost approximately $720 million to install static VAR compensators to replace the reactive capability of generators in Illinois that are retiring. Although PJM found that new generation could decrease those costs, Mr. Borgatti states that "only the transmission solutions would provide investors with a return on their investment in reactive producing equipment under the proposal contemplated in this proceeding,"[97] and "[g]enerators would not receive compensation for providing the identical service even if they are required to bear the cost of investing in comparable reactive support equipment."[98] Accordingly, while generators and transmission equipment can both

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95 AD05-1 Staff Report at 94.

96 *Id.*

97 Borgatti Affidavit at 9.

98 *Id.* at 9-10.

provide reactive power and while "these technologies can 'compete' against each other to produce the most cost-efficient means of meeting the grid's reliability needs," the NOPR proposal "disincentivizes generators from engaging in this competition, effectively creating a preference for higher-cost transmission solutions."[99]

Critically, in addition to showing that the NOPR proposal could lead to inefficient outcomes, Mr. Borgatti's statements also highlight the fact that, in violation of the FPA's prohibitions against undue preferences and discrimination,[100] the approach proposed in the NOPR will mean that only some public utilities are compensated for providing reactive power.[101] Mr. Knight points out that, "[a]s providers of reactive power capability, generation facilities are acting as substitutes for transmission facilities that could provide the same capability," and yet "transmission owners are guaranteed recovery of the full cost of the transmission facilities they install and operate to provide reactive power, while generators are not."[102] Similarly, the AD05-1 Staff Report previously noted that, notwithstanding the Commission's purported comparability standard, there has historically been discriminatory reactive power compensation because:

> a. Transmission-based suppliers of reactive power capability receive compensation, yet many generation-based suppliers are not compensated for reactive power capability that aids in system reliability.
>
> b. Independent generation resources may not always be compensated for providing reactive power support to the grid in areas where other generators affiliated with vertically integrated transmission owners receive

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99 *Id.* at 9.

100 *See* 16 U.S.C. §§ 824d(b), 824e(a) (2018).

101 *See* Borgatti Affidavit at 9-13 (discussing situations where resources will continue to receive reactive power compensation).

102 Knight Affidavit at P 8.

> cost-of-service payments for providing similar service, despite the Commission's policy requiring comparability.[103]

This discrimination will continue and be exacerbated by the NOPR proposal, which would mean that only transmission providers, their affiliates and certain limited others will have guaranteed cost recovery for reactive power costs. By contrast, many generators will not have any compensation for providing the very same service, and will not be able to make up those revenues through other sales given the restrictions on energy and capacity offers discussed in Section I.B.2 above. Moreover, as Mr. Borgatti explains, even if generators are able to include reactive power costs in their offers, they will not be able to effectively compete against similarly situated resources whose costs are covered through other mechanisms, meaning that they will unfairly be competitively disadvantaged.[104]

3. Concerns Raised in the NOPR Do Not Justify the Proposal to Eliminate Reactive Power Compensation

The NOPR suggests that the proposal to eliminate reactive power compensation within the deadband is motivated, in large part, by the Commission's concern that "implementing the Commission-approved AEP Methodology has become increasingly administratively burdensome to transmission providers, transmission customers, other stakeholders, and the Commission . . . ."[105] A substantial portion of the NOPR is thus devoted to discussing the difficulty and burden of determining reactive power rates.[106] However, the fact that determining the appropriate reactive power rate may be

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103 AD05-1 Staff Report at 4.

104 *See* Borgatti Affidavit at 13-15. *Cf. Dynegy Midwest Generation, Inc. v. FERC*, 633 F.3d 1122, 1127-28 (D.C. Cir. 2011).

105 NOPR, 186 FERC ¶ 61,203 at P 27.

106 *See id.* at PP 36-40.

burdensome in no way justifies eliminating the rate altogether or otherwise adopting an unjust, unreasonable, or unduly discriminatory compensation scheme. Indeed, EPSA and others provided suggestions in response to the NOI to simplify the process for applying the AEP Methodology through the use of a template, or by providing generators with the option of using a flat rate.[107]

The NOPR also expresses concern that "resources are sited without regard to where there is a geographic need for reactive power," and that resources may be receiving compensation "for reactive power that is not needed or necessarily deliverable to areas of the transmission system where reactive power may be needed . . . ."[108] If reactive power is not needed, there is no logical reason for generators to waste capital investing in reactive power capability. An alternative approach would thus be for the Commission to modify its interconnection rules going forward so that a generator will not have reactive power obligations unless the transmission provider determines during the interconnection process that there is a need for the generator to provide reactive power, in which case the generator would be entitled to compensation. This approach would avoid the problem of confiscatory ratemaking that would result from the NOPR proposal and also ensure that resources are not wasted on installing reactive power capability that is not needed. But having found it necessary for generators to install reactive power capability, the Commission cannot now claim that the same generators are not entitled to compensation because their reactive power is not needed.

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107 *See, e.g.*, EPSA NOI Comments at 7-9, 12; Renewable Generation Companies NOI Comments at 26-30.

108 *Id.* at P 26. *See also id.* at P 35.

The NOPR proposal is therefore not necessary to address the concerns identified by the Commission.

II. IF THE COMMISSION PROCEEDS WITH THE NOPR PROPOSAL, IT MUST ENSURE THAT IT HAS COMPREHENSIVE AND REGION-SPECIFIC TRANSITION PLANS IN PLACE

As explained above, the Commission should reconsider and set aside its critically flawed NOPR proposal. Instead, the Commission should refocus on the issues raised in the NOI and developed in the record, which would help address the Commission's concerns regarding potential overcompensation and the burden of implementing the AEP Methodology[109] without raising the Constitutional and other concerns discussed above. In the event that the Commission nonetheless decides to go ahead with the NOPR proposal, it must take steps to mitigate the harm and unintended consequences of the NOPR proposal.

First, as described above, investors have made decisions to proceed with generation development in reliance on the existing reactive power compensation policies. Similarly, PPAs and other bilateral arrangements have been negotiated and entered into taking such compensation into account. It would therefore upend expectations and be highly disruptive for the Commission to now eliminate reactive power compensation within the deadband. Accordingly, the Commission should not apply the NOPR proposal to existing resources and resources that are in advanced stages of development, consistent with the type of approach it has taken in the past. For example, in eliminating an exemption from market power mitigation, the Commission found that it was appropriate

[109] *See* NOPR, 186 FERC ¶ 61,203 at PP 26-27.

to "grandfather units for which construction commenced in reliance on the [prior rule]."[110] The Commission should adopt a similar approach here.[111]

Alternatively, if the Commission decides to ignore the reliance interests of existing generators and apply the NOPR proposal to all generators, it must ensure that it adopts comprehensive transition plans that account for the specific market design and rules of each RTO/ISO. In particular, if the Commission decides to eliminate all reactive power compensation within the deadband, it would, at a minimum, also have to direct each RTO/ISO to make a filing identifying modifications to existing market rules to implement the NOPR proposal and to give resources some chance of recovering their costs through energy or capacity sales, as the NOPR suggests. Such filings should also identify the amount of time that is necessary to implement the new rules and ensure that there is no "gap" in time when generators do not even have the opportunity to recover some of their reactive power costs. For example, if generators in PJM are expected to have a chance to recover some reactive power costs through capacity sales as the PJM IMM

[110] *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 at P 61, *on reh'g*, 112 FERC ¶ 61,031 (2005) ("*PJM II*"), *reh'g denied*, 114 FERC ¶ 61,302 (2006). *See also, e.g., Tennessee Gas Pipeline Co.*, 62 FERC ¶ 61,062 at 61,306 (1993) (explaining that, the Commission had decided to "'grandfather'" prior storage arrangements "in light of the fact that . . . historical customers have already made their conversion elections in reliance on access to this storage").

[111] Such an approach would not raise concerns regarding unduly preferential or discriminatory treatment because generators that relied on the current reactive power compensation policies would be differently situated than any generators that were developed after the implementation of the NOPR proposal. *See, e.g., "Complex" Consol. Edison Co. N.Y., Inc. v. FERC*, 165 F.3d 992, 1012 (D.C. Cir. 1999) ("[T]o show undue discrimination, the petitioner must demonstrate that the two classes of customers are similarly situated for purposes of the rate." (citations omitted)); *Transwestern Pipeline Co.*, Opinion No. 238-A, 36 FERC ¶ 61,175 at 61,433 (1986) ("Undue discrimination is in essence an unjustified difference in treatment of similarly situated customers." (citations omitted)), *aff'd sub nom. Transwestern Pipeline Co. v. FERC*, 820 F.2d 733 (5th Cir. 1987). *See also, e.g., PJM II*, 112 FERC ¶ 61,031 at P 74 (explaining that there is no undue discrimination when "[o]nly those units with reasonable reliance are eligible for grandfathered treatment").

suggests,[112] PJM will need to modify its rules regarding the Net CONE calculations that are used in the PJM capacity auctions and also ensure that offer caps are calculated excluding reactive power revenues. Moreover, PJM will hold its Base Residual Auctions ("BRAs") for the 2025/2026 Delivery Year in July 2024, the 2026/2027 Delivery Year in December 2024, and the 2027/2028 Delivery Year in June 2025,[113] meaning that generators will likely have entered into capacity commitments for the next few years before the new rules can be implemented. Implementation of the NOPR proposal therefore cannot occur until the first Delivery Year where the BRA for such year was conducted with the new rules and revised Net CONE calculations in place, at the earliest.[114] Similarly, the implementation of the NOPR proposal in other RTOs/ISOs would depend on the specific auction schedules and enactment of necessary rule changes for those RTOs/ISOs. Notably, however, even assuming that these changes are implemented and capacity payments can cover some reactive power costs, this would not address the fundamental problems that all resources are required to provide reactive power but only resources that clear in the capacity market will receive compensation and that, unlike transmission providers, generators will not receive full cost recovery for providing this valuable capability.

While the NOPR indicates that generators will be compensated for reactive power provided outside the standard power factor range, it does not discuss how such compensation will be determined. In particular, certain transmission owners currently

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112 *See* NOPR, 186 FERC ¶ 61,203 at P 22 n.56.

113 *See* PJM, RPM Auction Schedule, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.

114 *See* Knight Affidavit at P 18.

impose more stringent reactive power requirements for interconnection than the standard power factor range. For example, Consolidated Edison Company of New York, Inc. ("ConEd") requires interconnecting generation resources to "provide reactive power 0.85 lagging to 0.95 leading at all active power outputs down to 0 MW at the Point of Interconnection."[115] While NYISO currently provides reactive power compensation based on "the sum of the lagging and the absolute value of the leading MVAr capacity of the resource,"[116] the NOPR does not address how this will need to be modified to isolate the sunk and ongoing costs of providing reactive power outside the deadband and ensure that generators are properly compensated for such costs. Along the same lines, the Commission should clarify that transmission providers cannot seek to escape their obligations to compensate generators for reactive power outside the standard 0.95 leading to 0.95 lagging range by modifying the reactive power requirements in their interconnection agreements.

Finally, the Commission should also make clear that the NOPR proposal will only be applied prospectively and will not be applied in determining refunds in cases where the Commission has established hearing and/or settlement judge procedures with respect to rates for reactive power. As the Commission is aware, there are currently a large number of ongoing proceedings involving the rates for reactive power for generators in

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115 ConEd, TP-8100-0, *Performance Requirements for Inverter-Based Generation*, at 3 (effective Aug. 2019), https://www.nyiso.com/documents/20142/7834030/TP-8100-0.pdf/71bc598a-ec8e-2f31-f9bd-42a7f2e47729. *See also* ConEd, TP-7100-19, *Transmission Planning Criteria*, at 4 (effective Nov. 2022) ("New generation facilities shall be designed to provide reactive power 0.85 lagging (reactive power into the Con Edison transmission) to 0.95 leading (reactive power into the generator) at the Point of Interconnection." (footnote omitted)), https://www.coned.com/-/media/files/coned/documents/business-partners/transmission-planning/transmission-planning-criteria.pdf.

116 NYISO MST, § 15.2.2.1.

PJM, and in many of these cases, contested settlement agreements are pending before the Commission due to objections by the PJM IMM. It would effectively constitute impermissible retroactive ratemaking for the Commission to impose refunds in those cases based on the NOPR proposal, and the Commission should therefore clarify that the NOPR proposal will not affect previously charged rates in those cases.

III. CONCLUSION

WHEREFORE, for the foregoing reasons, the Indicated Trade Associations respectfully request that the Commission take these comments under consideration in taking any further action on the NOPR.

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Dated: May 28, 2024

ATTACHMENT A
THE KNIGHT AFFIDAVIT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF SHERMAN KNIGHT

1. My name is Sherman Knight. My business address is 8403 Colesville Road, Suite 915, Silver Spring, Maryland, 20910. I am the President and Chief Commercial Officer ("CCO") of Competitive Power Ventures ("CPV").

2. CPV is a leading North American electric power generation development and asset management company headquartered in Silver Spring, Maryland. CPV develops and operates thermal and renewable power projects throughout the United States. CPV has developed, sold, financed, and acquired approximately 14,800 MW of power generation facilities since 1999 and has developed and financed approximately $7.2 billion in energy facilities over the last 10 years.

3. In my capacity as the President and CCO of CPV, I am responsible for commercial strategy, the origination of off-take agreements and hedges for development projects, and overseeing the commodity marketing and trading activities for CPV's managed portfolio. I joined CPV in 2006 and have over 20 years of experience in the energy sector.

4. I am submitting this affidavit in support of the joint comments being submitted by the Electric Power Supply Association ("EPSA"), The PJM Power Providers Group ("P3"), the New England Power Generators Association, Inc. ("NEPGA"), Independent Power Producers of New York, Inc. ("IPPNY") and the Coalition of Midwest Power Producers on the Commission's March 21, 2024, notice of proposed rulemaking in Docket

No. RM22-2-000.[1] CPV is a member of EPSA, P3, NEPGA and IPPNY and supports the joint comments on the notice of proposed rulemaking. The purpose of my affidavit is to discuss the costs associated with providing reactive power, including the costs of providing reactive power within the 0.95 leading to 0.95 lagging deadband, and how reactive power compensation is factored into equity and debt investments in generation infrastructure.

I. Background

5. Through various subsidiaries, CPV owns and operates a number of generation facilities that currently receive compensation for reactive power, including:

- CPV Fairview, an approximately 1,050 MW natural gas-fired, combined-cycle generating facility in Cambria County, Pennsylvania, within the PJM Interconnection, L.L.C. ("PJM") market;
- CPV Maple Hill Solar, an approximately 100 MWac solar-powered generating facility in Portage, Pennsylvania, within the PJM market;
- CPV St. Charles, an approximately 745 MW natural gas-fired, combined-cycle generating facility in Waldorf, Maryland, within the PJM market;
- CPV Three Rivers, an approximately 1,250 MW natural gas-fired, combined-cycle generating facility in Grundy County, Illinois, within the PJM market;
- CPV Woodbridge, an approximately 725 MW natural gas-fired, combined-cycle generating facility in Woodbridge Township, New Jersey, within the PJM market;
- CPV Valley, an approximately 680 MW natural gas-fired generating facility in Wawayanda, New York, within the New York Independent System Operator, Inc. ("NYISO") market; and
- CPV Towantic, an approximately 805 MW natural gas-fired, combined-cycle generating facility in Oxford, Connecticut, within the ISO New England Inc. ("ISO-NE") market.

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[1] *Compensation for Reactive Power Within the Standard Power Factor Range*, Notice of Proposed Rulemaking, 186 FERC ¶ 61,203 (2024) (the "NOPR").

6. For our projects in the PJM market (CPV Fairview, CPV Maple Hill Solar, CPV St. Charles, CPV Three Rivers and CPV Woodbridge), we receive compensation for reactive power based on unit-specific revenue requirements determined in accordance with the Commission's *AEP* methodology and set forth in rate schedules on file with the Commission. For our project in the NYISO market (CPV Valley), we are compensated for reactive power at a uniform rate pursuant to Section 15.2.2.1 of the NYISO's Market Administration and Control Area Services Tariff. For our project in the ISO-NE market (CPV Towantic), we are compensated for reactive power at a uniform rate pursuant to Section IV of Schedule 2 to ISO-NE's Transmission, Markets, and Services Tariff.

7. It is true enough that given current generator interconnection requirements, we have to provide reactive power within the deadband regardless of whether we receive compensation or not. It is also true, however, that the interconnection agreements for facilities listed above were entered into under tariff paradigms that provided we would be compensated for reactive power. In any case, the fact that providing reactive power is required as a condition to interconnect does not mean that there is no cost to providing reactive power.

8. To make matters worse, generation facilities, as the Commission concedes in the NOPR, are not the only equipment capable of providing reactive power. In fact, reactive power can be and is provided by transmission facilities.[2] Indeed, while it might not be the most cost-efficient approach from a system perspective, sufficient reactive power capability could be engineered into the transmission system such that there would be no need for generators to provide reactive power at all. As providers of reactive power capability,

[2] *See* NOPR at P 10.

generation facilities are acting as substitutes for transmission facilities that could provide the same capability. The only technical difference is that generators are able to provide dynamic reactive power, while most transmission facilities only provide static reactive power. The other, non-technical difference is that as a general rule, the transmission owners are guaranteed recovery of the full cost of the transmission facilities they install and operate to provide reactive power, while generators are not.

9. CPV and other generators incur significant costs to provide reactive power. CPV installs equipment it would not require if it were free to build to, and operate at, a unity power factor (*i.e.*, a power factor of 1.00), rather than within the 0.95 leading and 0.95 lagging range required under its interconnection agreements. As FERC Staff has explained: "In designing generating plants, for a given turbine size, the other equipment (the exciter, alternator, voltage regulator, step-up transformer) can be sized larger for greater production of reactive power when at the same real power output."[3] This equipment is sized in MVA, and in order to achieve the required reactive power capability, a developer will need to install equipment with higher MVA ratings than would be required for a turbine of the same MW size if the unit were not required to provide reactive. Put differently, we could achieve the same real power capability at lower cost if we were not required to provide reactive power.

10. The cost-based revenue requirements calculated using the *AEP* methodology represent an established means of identifying the cost of reactive capability, based on the allocated cost

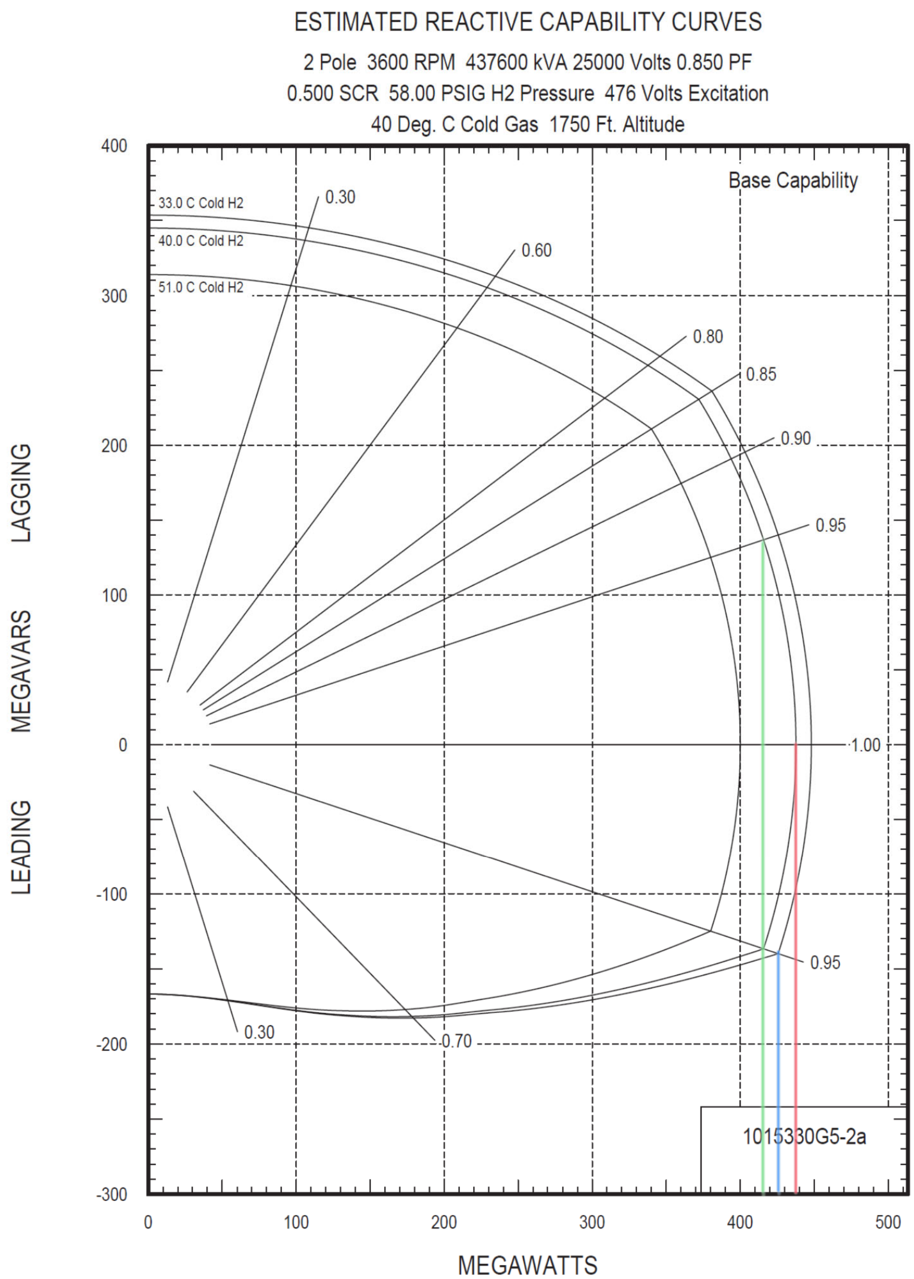
[3] FERC Staff, *Principles for Efficient and Reliability Reactive Power Supply and Compensation* at 133 (Feb. 4, 2005) (the "Staff Report") (Appendix B – An Engineering and Economic Analysis of Real and Reactive Power from Synchronous Generators), https://www.ferc.gov/sites/default/files/2020-04/20050310144430-02-04-05-reactive-power.pdf.

of the equipment used to provide reactive power. As the Commission obviously knows all too well, these costs are significant. In my view, it is entirely reasonable that compensation for reactive power should be determined on a full cost-of-service basis, rather than focusing on supposedly "incremental" costs of providing reactive power, especially when one considers that generators are acting as substitutes for transmission equipment which is compensated on a full cost-of-service basis.

11. Even if it were reasonable to focus solely on incremental costs, however, there is still an incremental cost to the larger (*i.e.*, higher MVA) generators, transformers and other equipment that must be installed to satisfy the requirement to provide reactive power within the deadband, rather than to operate at a power factor of 1.00. For a 1,000 MW thermal power plant, the cost difference of the larger equipment would easily be in the millions of dollars. Similarly, a solar-powered plant can only produce real power and reactive simultaneously by installing larger sized or more inverter capacity or by adding supplemental capacitor banks either of which are necessary to operate beyond the unity power factor. Inverters typically cost something on the order of $135,000 per MW of installed nameplate, and depending upon the VAR capability required, larger or additional inverters could add hundreds of thousands of dollars of incremental costs to be able to operate beyond a power factor of 1.0.

12. Another way to look at the MW/MVAR tradeoff is that the developer could achieve a higher real power capability at the same cost if it were not required to provide reactive power. This tradeoff can be observed, in part, by examining a generator's reactive capability curve or "D-curve" (so called because it is shaped like the letter "D"). A D-curve shows a unit's real power capability to be highest at a power factor of 1.00, when it

is not producing or absorbing VARs, and to decrease in a non-linear way as the leading and lagging power factors are reduced. The D-curve below is for one of the two combustion turbines at the CPV Fairview facility, and its shape is typical of reactive capability curves for units built to the current reactive requirements.



13. As illustrated by this curve, at an ambient temperature of 40 C, the unit has a maximum real power capability of 437.6 MW at a power factor of 1.00. The real power capability

drops to approximately 415 MW and 425 MW at power factors of 0.95 lagging and 0.95 leading, respectively. The requirement to provide reactive capability can reduce MW of capacity we are allowed to sell into the markets. For example, capability testing assumes we can provide reactive power within the deadband, and the test results are generally not adjusted to account for reactive power being provided within this range. In the case of the unit whose D-curve is provided above, that means a potential equivalent loss of up to 22 MW per turbine or 44 MW across the two turbines at CPV Fairview in the amount of capacity we can sell into the market. From a financial perspective, if we use the average of the applicable clearing prices for the last five Base Residual Auctions ("BRAs") ($86.162/MW-day),[4] that translates into foregone capacity revenues of approximately $27.7 million ($86.162/MW-day * 44 MW * 365 days * 20 years) over a 20-year life.

14. Importantly, the D-curve only shows part of the capacity tradeoff, because the shape of the D-curve is a product of the project having been built to provide reactive power – in the case of the CPV Fairview project, having been built to a power factor of 0.85. In the case of the CPV Fairview unit whose D-curve is provided above, that means its configuration was

[4] *See* PJM, *Base Residual Auction Results* at 1 (May 23, 2017) (MAAC clearing price of $86.04/MW-day in BRA for 2020/2021 Delivery Year), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx; PJM, *Base Residual Auction Results* at 1 (May 23, 2018) (RTO clearing price of $140.00/MW-day in BRA for 2021/2022 Delivery Year), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx; PJM, *Base Residual Auction Results* at 1 (Jan. 6, 2022) (MAAC clearing price of $95.79/MW-day in BRA for 2022/2023 Delivery Year), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx; PJM, *Base Residual Auction Results* at 1 (June 21, 2022) (MAAC clearing price of $49.49/MW-day in BRA for 2023/2024 Delivery Year), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.ashx; PJM, *2024/2025 BRA Summary of Auction Results* (May 9, 2024) (MAAC clearing price of $49.49/MW-day in BRA for 2024/2025 Delivery Year), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-results.ashx. CPV Fairview is located in the MAAC Locational Deliverability Area, which separated in the BRAs for the 2020/2021, 2022/2023, 2023/2024 and 2024/2025 Delivery Years (but not for the 2021/2022 Delivery Year).

optimized to minimize the MW/MVAR tradeoff down to a 0.85 power factor. In other words, it was designed to minimize the lost real power capability for operating within a range of 0.85 lagging and 0.85 leading. That can be seen by the way the slope of the curve flattens below 0.85, highlighting the tradeoff between real and reactive power as we lose more MW of real power capability for each additional MVAR of reactive power capability. Importantly, had the unit been designed to operate at a power factor of 1.00 – *i.e.*, if we had not been required to build-in reactive power capability – the curve would have been much flatter between 1.00 and 0.95 (and continuing down to 0.85) than it is in the actual D-curve. In effect, the D-curve would be squeezed so the "D" would be much shorter and wider.

15. For projects in markets with reactive power compensation like PJM, ISO-NE and NYISO, expected reactive compensation is factored into the financial modeling for the financing and refinancing of generation projects. Reactive power compensation is a revenue stream that was, until now, predictable and stable and that did not, therefore, need to be discounted to the same degree as projected revenues from the energy and capacity markets. This financial modeling informs our decisions about whether or not to go forward with planned projects and whether to keep existing projects in service. It also informs lender decisions as to what level of debt they would be willing to provide and at what cost. Because all rational economic decisions are ultimately made on the margin, even a relatively small change in projected revenues can have a material impact on these investment decisions.

16. From a debt financing perspective, a change in projected revenues, especially those that are deemed stable or contracted, can also materially change the amount and cost of debt for a project. Under conventional debt-sizing criteria for these types of projects, changes

in such revenues will have about a 10 to 1 impact on debt capacity. For example, $1 million in annual reactive power revenue can support approximately $10 million of debt. Eliminating reactive power compensation would result in a reduction in borrowing capacity necessitating higher equity requirements, all of which result in less economically viable projects.

17. Elimination of reactive power compensation in markets where generators, like CPV, currently receive such compensation will create a new source of "missing money" that needs to be addressed. There is no mechanism for existing generators, including generators that have cleared forward capacity auctions but not yet come online, to reflect the costs of reactive power capability currently recovered in accordance with generator-specific revenue requirements in PJM and through uniform rates in ISO-NE and NYISO, in offers into the energy, capacity and ancillary services markets administered by PJM, ISO-NE and NYISO. Specifically, as fixed costs, the capital costs of this capability are excluded from offers into energy and ancillary services markets. While new generators may be able to include these capital costs in their capacity offers if separate reactive power compensation is eliminated, existing generators will not be able to do so as the costs are no longer avoidable and will instead be viewed as sunk costs. At the same time, existing generators were not able to include these costs in their offers when they entered the market, because the costs were then expected to be recovered through reactive power-specific payments outside the capacity market.

18. In addition, generators have assumed, and will continue to assume during the pendency of this proceeding, capacity commitments through auctions cleared using demand curves based on net cost-of-new-entry ("CONE") values that assume the reference unit is

receiving cost-based reactive power compensation outside the capacity market. For example, projected reactive power revenues of $2,199/MW-year were included in the projected energy and ancillary services ("E&AS") revenues subtracted from gross CONE to calculate net CONE for purposes of the demand curves used in the PJM capacity auctions for the 2024/2025 year and were likewise included in projected E&AS revenues used to calculate net CONE for the PJM capacity auctions for the 2025/2026 delivery year.[5] The reactive power deduction is slated to increase to $2,546/MW-year in calculating net CONE for the capacity auctions to be conducted for the 2026/2027, 2027/2028, 2028/2029 and 2029/2030 delivery years.[6] Similarly, the demand curves used to clear NYISO's monthly spot market auctions for the 2024/2025 capability year assume reactive revenues for the reference unit of $2,040/MW-year.[7] For at least the duration of capacity commitments undertaken in auctions cleared using demand curves assuming non-zero cost-based reactive revenues, generators should be allowed to continue receiving such revenues. Otherwise, they will have no ability to reflect the costs of providing reactive power in their offers and will at the same time be paid capacity prices artificially suppressed by the false assumption that they are receiving reactive power compensation outside the capacity market.

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19. This concludes my affidavit.

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5 *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073 at PP 135-37 (2023).

6 *See id.*

7 *See* 2021-2025 ICAP Demand Curve Reset Proposal, Transmittal Letter at 32, Docket No. ER21-502-000 (filed Nov. 30, 2020) (describing $2.04/kW-year adder for "likely voltage support service . . . revenues" to energy and ancillary services revenues deducted in the Net CONE calculation), *accepted*, *New York Indep. Sys. Operator, Inc.*, 175 FERC ¶ 61,012 (2021), *rev'd in part not relevant sub. nom Independent Power Producers of N.Y. v. FERC*, No. 21-1166, 2022 WL 3210362 (D.C. Cir. 2022).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT

The undersigned, being duly sworn, states that he has read the foregoing Affidavit of Sherman Knight, knows the contents thereof, and that the same is true as stated, to the best of his knowledge and belief.

Sherman Knight

Subscribed and sworn to before me

this 28th day of May 2024

Notary Public
for the State of Maryland

My Commission expires: December 3, 2027

JOCELYN SCOTT
Notary Public - State of Maryland
Montgomery County
My Commission Expires Dec 3, 2027

ATTACHMENT B
THE BORGATTI AFFIDAVIT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF MICHAEL BORGATTI

Q. Please state your name and business address.

A. My name is Michael Borgatti. My business address is 417 Denison St., Highland Park, New Jersey, 08904.

Q. By whom are you employed, and in what capacity?

A. I am a Senior Vice President with the energy and utility consultancy firm, Gabel Associates. I manage my firm's Wholesale Power and Market Services group, a multi-disciplinary team of professionals advising clients who transact in the U.S. organized wholesale market and non-market areas. Our clients are active in all the FERC-jurisdictional ISOs, RTOs, and ERCOT. I provide advice regarding various subject matter areas, including state and federal electric market design matters, mergers and acquisitions, diligence on wholesale power market transactions, utility ratemaking, operations, generator interconnection, and transmission planning processes. I regularly evaluate revenue opportunities for generators in these markets, including providing ancillary services like reactive power. I have also testified before the Commission in reactive power proceedings, including matters where the *AEP Methodology* was used to calculate fixed capability payments for generating resources in PJM.

Q. What is the purpose of your testimony?

A. My testimony is offered on behalf of the Indicated Trade Associations (the Electric Power Supply Association, The PJM Power Providers Group, the New England Power Generators Association, Inc., Independent Power Producers of New York, Inc., and the Coalition of Midwest Power Producers). It describes the current compensation approaches for suppliers that provide reactive service, the impact that these revenues can have on investment decisions, and the potential effects of the Commission's proposal to eliminate reactive compensation for resources operating within the minimum reactive power range specified in standard Generator Interconnection Agreements ("GIA").

Q. Please provide a summary of your testimony.

A. My testimony explains that electric generators and transmission equipment like synchronous condensers and static VAR compensators provide the same reliability attributes. Both provide voltage support that is necessary to operate the grid reliably. Compensating generators for their ability to provide this service creates parity with regulated transmission utilities, which are eligible to receive a reasonable rate of return on the cost of constructing equipment capable of providing reactive service.

Investors include expected reactive service revenues in their valuations for new and existing generators. They will also consider the value of the revenue potential from different project configurations and incremental capital expenditures to increase reactive power capability beyond the minimum limits in the GIA. This structure incentivizes generators to compete with transmission utilities to provide consumers the same service at equal or lower costs, like the base principles of any well-functioning market. The Commission's proposal to eliminate reactive service revenues within the standard power range undermines investors' revenue expectations and diminishes this incentive at a time when the grid is rapidly changing.

Q. Please provide a general overview of current reactive power compensation mechanisms.

A. There are three approaches to compensation for resources that provide reactive power. The first is conventional cost-of-service ratemaking, allowing the resource owner to earn a reasonable return on their investment in reactive power-producing equipment. This approach is near-universally applied in the context of transmission-owning utility investment in technologies like static VAR compensators that provide voltage support. These utilities receive a regulated rate of return on their assets regardless of how much voltage support these resources provide. Generators in PJM, and until recently MISO, also receive cost-based compensation for power plant equipment that produces reactive power.

The second approach is a stated rate. This stated rate is multiplied by a resource's verified ability to provide reactive power or actual production. This method is implemented by NYISO and ISO-NE, where generators undergo tests to confirm their maximum ability to provide reactive power. The results of these tests are multiplied by a stated rate that ISO-NE and NYISO adjust to reflect the value of this service to the grid. While SPP also utilizes a stated rate for variable reactive supply provided by certain generators when operating outside the standard power factor range, it does not compensate generators for their capability to provide reactive service through wholesale market revenues.

The third approach is providing lost-opportunity cost ("LOC") payments to generators for their reactive power production. Resources dispatched down to provide reactive power are typically compensated based on revenues they would have received by generating real power. Resources that increase their output are paid their incremental production costs or bid to provide energy. PJM, NYISO, ISO-NE, MISO, and CAISO all apply variations of this approach.

Q. Does access to reactive power compensation influence investment decisions?

A. Yes. Quantifying available revenue streams is fundamental to any investor's business case. A generator's value equals the discounted free cash flow investors expect to receive in the future from all available revenue sources. Rational investors should only deploy capital in projects with projected free cash flows likely to meet or exceed their return targets. Reactive compensation is a central part of this future revenue stack, particularly in markets like PJM, NYISO, and ISO-NE, which provide fixed annual payments to provide this service. For example, I am aware of investors in PJM that have financed the development and acquisition of utility-scale energy generation resources and portfolios based, in part, on the expectation that these resources would be eligible for and continue to receive reactive revenues consistent with the current market rules. Changing these market rules after the financing arrangements have been finalized can result in violations of contractual financing obligations, prevent investors from reaching their required rates of return, and increase the risk of financial distress.

Q. In your experience, how has reactive revenue potential influenced investor decisions?

A. I have advised many investors on the reactive power compensation level to include in their asset valuations. Investors in existing resources often seek to understand what factors could cause a current FERC-approved reactive rate to increase or decrease in the future. I have advised many prospective investors to perform due diligence reviews to determine whether a resource's ability to produce reactive power has degraded and requires a change in its electric configuration. Because reactive capability payments in jurisdictions like ISO-NE, NYISO, and PJM are based on the amount of MVARs the generator can produce or consume, unmitigated performance degradation reduces the value of future cash flows. Investors must decide whether to pay the cost to repair the resource or reduce its valuation.

Investors also will evaluate whether a change in ownership will alter an existing reactive service rate. Over the past several years, FERC has adopted a policy of instituting proceedings under Section 206 of the Federal Power Act concerning reactive power rates based on informational filings submitted in conjunction with transfers of generation assets. As a result, in cases where a change in ownership is contemplated, I will evaluate factors that could impact the rate, including available documentation supporting investment in reactive power-producing equipment, changes to the cost of capital inputs like federal income tax rates, and shifts in FERC's policies for factors such as cost recovery for heating losses. This information and proxy values from recent settlements for various resources will inform whether to discount future reactive revenues in the business case.

I have direct experience integrating the recovery of reactive-related costs in investment analyses for independent power producers and investor-owned utilities. Reactive revenue expectations have increased asset valuations and have been a material factor in investment decisions. Several clients have increased their valuations based on an expectation of qualifying to receive reactive revenues, whether through stated rate regimes like those in ISO-NE and NYISO or by filing a specific cost-of-service rate with FERC in PJM. Asset owners have made incremental investments in existing assets partly because reactive revenues would offset some or all the additional costs.

Developers and owners of new resources will also consider the effect of different project configurations on reactive revenue potential. I have advised many developers on how the incremental cost to increase a generator's reactive capability could impact reactive revenue potential. For example, I have advised several combined cycle developers on the revenue potential from expanding the unit's power factor. I have also advised renewable resource investors about the revenue potential from increasing inverter ratings or the number of inverters instead of alternative configurations that manage voltage with capacitors and other technologies. Eliminating reactive compensation undermines these business cases and disincentivizes investors from engaging in similar strategies in the future.

In my experience, reactive compensation can be a factor in state-led resource procurement decisions. For example, jurisdictions like New Jersey and Maryland have aggressive offshore wind procurement goals. These states hold competitive solicitations for Offshore Wind Renewable Energy Certificates ("ORECs") from developers. The winning bidders agree to remit wholesale revenues to ratepayers as credits against the cost of

ORECs. Reactive revenues are a component of the wholesale revenue streams that offset the OREC costs.[1] Eliminating reactive revenues thus effectively increases the cost of ORECs to consumers.

I am also aware of instances where access to reactive revenues was a factor in determining power purchase agreement ("PPA") prices between generators and off-takers. In some cases, generation resource developers and owners were willing to consider negotiating lower PPA prices based on their view of wholesale revenues, including reactive service payments, over a project's estimated useful life. Moreover, lenders size financing based on the generator's total projected revenues, including reactive service, where available. If the Commission were to eliminate or substantially reduce reactive compensation as it contemplates here, other sources of revenues, like PPA prices, must increase to sustain the same level of financing.

Existing resources with executed contracts may be unable to amend pricing during the contract term, which lowers investor returns and could render some projects uneconomic. Projects eligible for reactive compensation secure financing based on projected cash flows, including conservative estimates for reactive service payments. The Commission's proposal to eliminate reactive capability payments has already impacted projects that secured financing expecting to receive these revenues. The lower projected cash flows have impacted debt service coverage ratios, limited efficient use of development capital, and resulted in payments from generators to lenders.

[1] NJBPU Second Solicitation Report. Available at: https://www.nj.gov/bpu/bpu/pdf/boardorders/2021/20210630/Offshore%20Wind%20Solicitation%202%20-%20Levitan%20Evaluation%20Report.PDF.

I have also advised clients on contract pricing for transactions that would cause suppliers with existing rates to become ineligible for reactive revenues in the future. For example, PJM precludes behind-the-meter generators from receiving reactive revenues. I have supported multiple clients in evaluating opportunities to locate a large load behind an existing generator's point of interconnection to the grid. In these cases, loss of revenues must be recovered through a higher price contract with the potential counterparty.

Q. Are you aware of actual or lost opportunity costs that suppliers incur when providing reactive power?

A. Yes. For example, renewable resources are often compensated through a combination of wholesale revenues, PPAs, Renewable Energy Certificates ("RECs"), and production tax credits ("PTCs"). These revenue streams are typically compensated based on the resources' energy production, not ancillary services that could reduce real power output, like providing voltage control. Renewable generators that reduce their actual power output to provide reactive service could forgo certain of these revenues, like RECs and PTCs, which often are not included in ISO and RTO Lost Opportunity Costs ("LOC") calculations.

Similarly, thermal resources also typically reduce their real power production when providing reactive power when operating within the standard power-factor range. Moreover, some utilities have stricter standard power factor requirements than FERC's minimum requirements for grid interconnection. For example, Con Edison requires new generators to provide reactive power at **0.85 lagging** and 0.95 leading.[2] In my experience, generators subject to this requirement could lose real power output when dispatched to provide

[2] *See* Con Edison Transmission Planning Criteria TP-7100-19.

reactive power at the full extent of the lagging range. NYISO's LOC payments offer the only means of recovering the opportunity costs of the reduced output.

Q. What are the potential implications of the Commission's proposal to eliminate reactive compensation for generators?

A. Reactive power is a necessary ancillary service for reliable transmission system operations. The grid is changing rapidly due to various factors, including retirements of aging generation, increasing deployment of inverter-based resources, and accelerating load growth. Generators and transmission equipment can both provide reactive power support. In a practical sense, these technologies can "compete" against each other to produce the most cost-efficient means of meeting the grid's reliability needs. Eliminating reactive compensation disincentivizes generators from engaging in this competition, effectively creating a preference for higher-cost transmission solutions.

For example, PJM, in conjunction with ComEd and NIPSCO, determined that two static VAR compensators were required to replace reactive capability from retiring generation in Illinois at a total cost of about $720 million.[3] PJM also found that siting new generation at the same points as the retiring units would decrease these costs, demonstrating that these technologies are effectively interchangeable.[4] However, only the transmission solutions would provide investors with a return on their investment in reactive producing equipment under the proposal contemplated in this proceeding. Generators

[3] Illinois Generation Retirement Study at p. 4. Available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/2022-pjm-illinois-generation-retirement-study.ashx.

[4] *Id*. at p. 3.

would not receive compensation for providing the identical service even if they are required to bear the cost of investing in comparable reactive support equipment.

Q. Do generators recover the cost of voltage support in regions that do not provide reactive capability payments?

A. Yes. In such regions, compensation for reactive power generally comes from non-market sources. For example, CAISO has explained that the "opportunity to recover capital costs *occurs outside of the CAISO's market* and allows for the recovery of fixed costs associated with the capability of reactive power supply."[5] Indeed, CAISO and state regulatory agencies, chiefly the California Public Utility Commission ("CPUC"), administer the region's resource adequacy construct, which compensates generators for their reliability attributes through bilateral contracts with the state's Load Serving Entities ("LSEs"). "This bilateral contracting construct provides resource developers with the opportunity to structure contractual arrangements in order to provide compensation for the resource's fixed costs associated with [the] generator including the capability to supply reactive power supply."[6] Therefore, it is inaccurate to say that these resources are not compensated for their reactive capability. They are compensated through other means.

The same is true in SPP, where the region's reactive compensation regime is not intended to "provide full revenue requirement recovery for the generating resource's reactive power capability.[7] While it may provide partial compensation for the cost of reactive power

[5] Prepared Statement of Keith Johnson on behalf of the California Independent System Operator Corporation, FERC Docket No. AD16-17 at p. 4 (emphasis supplied).
[6] *Id*. at p. 6.
[7] Reactive Power Capability Compensation, Comments of Southwest Power Pool, Inc., FERC Docket No. RM22-2 at p. 2 (hereafter "Reactive Capability Docket").

capability, it is not structured so as to provide a payment specifically for that purpose."[8] Instead, most generators in SPP recover their fixed costs through vertically integrated utility cost of service rates approved by state regulatory authorities. Like CAISO, the predominant means of compensating generators in SPP for reactive capability occurs outside the region's organized markets.

Conversely, utilities installing reactive support devices like capacitors on the SPP transmission system recover their costs and earn a return on investment through SPP's transmission service rates.[9] SPP does not compensate generators for providing a comparable level of reactive service capability as investments in transmission infrastructure. Eliminating reactive compensation for generators creates an unlevel playing field whereby only vertically integrated utilities, transmission owners, and resources receiving state-mandated bilateral contracts receive compensation for their ability to provide the same service with the same performance obligations as all other resources. As the Independent Market Monitor for SPP has correctly noted, "[r]eactive power has not only costs but more importantly, value to the market and transmission operations."[10] The Commission's policies should provide adequate compensation to all resources that can provide a comparable and valuable reliability service like reactive power.

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[8] *Id*.

[9] *See* SPP OATT Schedules 7, 8, 9, and 11.

[10] Reactive Capability Docket, Comments of the Market Monitoring Unit of the Southwest Power Pool at p. 3.

Q. Are you aware of other scenarios where generation resources would receive compensation for their full reactive capability?

A. Yes. FERC has previously found it just and reasonable to compensate generators for their full reactive capability. For example, the Commission recently approved ISO-NE's proposal to evaluate energy storage resources as a non-wires transmission asset. ISO-NE would use the resource's dynamic reactive capability to address voltage concerns, such as conventional transmission equipment like synchronous condensers.[11] It would also be compensated for this full capability, not just operations outside of a standard power factor range. By contrast, under the Commission's proposal in this proceeding, the same storage resource would not receive compensation for this capability if operating as a generator. MISO and SPP both have constructs similar to ISO-NE where the same logic would apply.[12]

FERC also recently approved MISO's request for a System Support Resource contract to allow the Rush Island coal facility to delay retirement and provide voltage support.[13] The facility will receive a fixed contract payment from MISO for its total energy and reactive capability if it meets specific testing and reliability criteria.[14] Reliability Must Run ("RMR") contracts for the Brandon Shores and H.M. Wagner facilities were recently filed with FERC, both of which PJM requires to remain in operation to provide voltage support until necessary transmission upgrades are complete. Both resources will receive the total value of these

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[11] *ISO New England, Inc.*, 185 FERC ¶ 61,044 (2023).

[12] See, *Midcontinent Indep. Sys. Operator, Inc.*, 172 FERC ¶ 61,132 (2020). *See also*, *Southwest Power Pool, Inc.*, 183 FERC ¶ 61,153 (2022).

[13] *Midcontinent Indep. Sys. Operator, Inc.*, 181 FERC ¶ 61,066 (2022). *See also*, *MISO System Support Resources Agreement with Union Electric Company, d/b/a Ameren Missouri, Regarding Rush Island Units 1& 2*, FERC Docket No. ER22-2691.

contracts regardless of whether the resources provide reactive service beyond the standard power factor range.

Q. Can resources recover their reactive power costs through centralized capacity markets in regions like PJM and ISO-NE?

A. Regions with FERC-jurisdictional centralized capacity and energy markets do not provide an alternative means of compensation for reactive service. As a general matter, FERC's current precedent is that competitive capacity market offers can only reflect "incremental costs that are avoidable if the resource does not receive a capacity commitment."[15]

Competitive capacity sell offers in PJM currently equal a resources' Gross Avoidable Cost Rate ("ACR") minus profits from energy and ancillary service sales.[16] The Gross ACR generally reflects a resource's fixed operating costs, risk of incurring Capacity Performance penalties, and any avoidable incremental capital investment. It excludes the underlying facility's initial construction cost, including any reactive power-producing equipment. Therefore, FERC currently precludes resources in PJM from including capital investment in reactive power-producing equipment in their capacity offers.

ISO-NE uses a similar approach for setting Static Delist Bids in its Forward Capacity Market. Going Forward Costs only include expected costs and incremental capital expenditures that a resource would not incur in a single Capacity Commitment Period.[17]

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[15] *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,097 at P 35 (2024).

[16] PJM also allows resources to request a unit-specific MSOC reflecting the opportunity cost of off-system capacity sales.

[17] ISO-NE Market Rule 1, Sec. III.13.1.2.3.2.1.2.A.

NYISO also defines competitive sell offers from resources in certain Mitigated Capacity Zones in terms of Going Forward Costs that exclude capital investment in production plant equipment.[18] NYISO recently informed the Commission that its current stated-rate reactive service compensation mechanism increases revenues for the best-performing resources, effectively rewarding competitive advantage similar to a well-functioning market. According to NYISO, attempting to compensate reactive power capability "as a component of installed capacity market requirements" eliminates these incentives.[19]

Q. Can generators recover these fixed capability costs through energy markets?

A. No. Energy market offers generally reflect the resource's short-run costs directly related to electricity production. All generators in PJM must submit formulaic cost-based offers to sell energy and documentation supporting inputs like variable operations and maintenance costs, and fuel.[20] Fixed costs cannot be included in these offers. Similarly, regions like MISO, NYISO, and ISO-NE use reference levels that only reflect resources' expected energy production costs and not fixed costs.[21] Generators in each of these jurisdictions and elsewhere could attempt to raise their offers to reflect the cost of reactive power service, but this increases the risk that these generators fail to clear in the energy market. The risk of failing to clear and forgoing energy revenues is particularly acute in jurisdictions where independent power producers compete with vertically integrated

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[18] NYISO Market Services Tariff, Attachment H, Sec. 23.4.5.3.
[19] Reactive Capability Docket, Comments of the New York Independent System Operator, Inc. at p. 7.
[20] PJM Operating Agreement, Schedule 2, Sec. 1.1(a).
[21] See, MISO Business Practice Manual No. 009 Sec. 6.9.1, NYISO Market Services Tariff, Sec. 23.4.2 *et. al.*, ISO-NE Market Rule 1 Appendix A, Sec.III.A.3. *et. al.*

utilities whose generators recover costs through state-jurisdictional retail rates. The U.S. Court of Appeals articulated the challenge nicely:

> Generators that follow the Commission's advice to raise their power sales rates would suffer an increased risk of being undersold by generators from zones where reactive power costs are compensated.[22]

Therefore, energy markets are not appropriate for recovering fixed reactive capability costs.

Q. Does this complete your testimony?

A. Yes.

[22] *Dynegy Midwest Generation, Inc. v. FERC*, 633 F.3d 1122, 1127 (D.C. Cir. 2011).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT

The undersigned, being duly sworn, states that he has read the foregoing Affidavit of Michael Borgatti, knows the contents thereof, and that the same is true as stated, to the best of his knowledge and belief.

Michael Borgatti

Subscribed and sworn to before me

this 28th day of May 2024

Notary Public
for the State of PA

My Commission expires: May 2nd. 2026

Commonwealth of Pennsylvania - Notary Seal
Rafeek T. McEachin, Notary Public
Montgomery County
My commission expires May 2, 2026
Commission number 1321964
Member, Pennsylvania Association of Notaries