UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER19-1486-000**
PJM Interconnection, L.L.C.	**)**	**Docket No. EL19-58-000**
		(Not consolidated)

SUPPORTING COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION

In accordance with the notices of filing issued by the Federal Energy Regulatory Commission (the "Commission") on March 29, 2019 and April 1, 2019,[1] the Electric Power Supply Association ("EPSA")[2] hereby comments in support of the March 29, 2019 filings of PJM Interconnection, L.L.C. ("PJM") in the above-captioned proceedings.[3] The ER19-1486 and EL19-58 Filings propose revisions to the PJM Open Access Transmission Tariff (the "Tariff") and the Amended and Restated Operating Agreement of PJM (the "Operating

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1 *See* Combined Notice of Filings #2, Docket Nos. EG19-87-000, *et al.* (Mar. 29, 2019) (unreported); *PJM Interconnection, L.L.C.*, Notice of Filing, Docket No. EL19-58-000 (Apr. 1, 2019) (unreported).

2 Launched over 20 years ago, EPSA is the national trade association representing leading independent power producers and marketers. EPSA members provide reliable and competitively priced electricity from environmentally responsible facilities using a diverse mix of fuels and technologies. Power supplied on a competitive basis collectively accounts for 40 percent of the U.S. installed generating capacity. EPSA seeks to bring the benefits of competition to all power customers. This pleading represents the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue. EPSA has separately moved to intervene in each of these proceedings. *See* (doc-less) Motion to Intervene of the Electric Power Supply Association, Docket No. ER19-1486-000 (filed Apr. 1, 2019); (doc-less) Motion to Intervene of the Electric Power Supply Association, Docket No. EL19-58-000 (filed Apr. 1, 2019).

3 *See* Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket No. ER19-1486-000 (filed Mar. 29, 2019) (the "ER19-1486 Filing"); Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket No. EL19-58-000 (filed Mar. 29, 2019) (the "EL19-58 Filing" and, together with the ER19-1486 Filing, the "March 29 Filings").

Agreement"),[4] respectively, that will, as discussed herein and in the Affidavit of Paul M. Sotkiewicz, Ph.D. provided in Attachment A hereto (the "Sotkiewicz Affidavit"), substantially improve price formation in the PJM-administered reserve markets. As discussed herein and in the March 29 Filings, the existing rules for those markets are inconsistent with the Commission's guidance on price formation and are unjust and unreasonable. The Commission should, therefore, adopt the just and reasonable changes to those rules proposed in the March 29 Filings.

I. BACKGROUND

In the ER19-1486 and EL19-58 Filings, PJM proposes substantively identical revisions to the Tariff and the Operating Agreement pursuant to Sections 205 and 206 of the Federal Power Act (the "FPA"),[5] respectively. With supporting testimony from William W. Hogan and Susan L. Pope (the "Hogan/Pope Affidavit"),[6] Adam Keech (the "Keech Affidavit"),[7] Christopher Pilong (the "Pilong Affidavit")[8] and Patricio Rocha Garrido,[9] PJM

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[4] Capitalized terms not otherwise defined herein have the meaning set forth in the Tariff and the Operating Agreement or, if not defined therein, in the March 29 Filings.

[5] 16 U.S.C. §§ 824d, 824e (2018).

[6] *See* ER19-1486 Filing, Attachment C, Affidavit of Drs. William W. Hogan and Susan L. Pope on Behalf of PJM Interconnection, L.L.C.; EL19-58 Filing, Attachment C, Affidavit of Drs. William W. Hogan and Susan L. Pope on Behalf of PJM Interconnection, L.L.C. *See also* Hogan/Pope Affidavit, Exhibit 1, William W. Hogan & Susan L. Pope, *PJM Reserve Markets: Operating Reserve Demand Curve Enhancements* (Mar. 21, 2019) (the "ORDC Report").

[7] *See* ER19-1486 Filing, Attachment D, Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C.; EL19-58 Filing, Attachment D, Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C.

[8] *See* ER19-1486 Filing, Attachment E, Affidavit of Christopher Pilong on Behalf of PJM Interconnection, L.L.C.; EL19-58 Filing, Attachment E, Affidavit of Christopher Pilong on Behalf of PJM Interconnection, L.L.C.

[9] *See* ER19-1486 Filing, Attachment F, Affidavit of Dr. Patricio Rocha Garrido on Behalf of PJM Interconnection, L.L.C.; EL19-58 Filing, Attachment F, Affidavit of Dr. Patricio Rocha Garrido on Behalf of PJM Interconnection, L.L.C.

demonstrates how critical flaws render the existing reserves market rules set forth in the Tariff and the Operating Agreement unjust and unreasonable and unduly discriminatory and how its proposed revisions to those rules are just and reasonable and not unduly discriminatory.

PJM explains that the revisions proposed in the March 29 Filings are targeted at three flaws in the design of PJM's reserve market that fail to "support efficient market outcomes" or to "provide the support for reliable operations":[10]

- A Synchronized Reserve product that is separated into two products – Tier 1 and Tier 2 – with disparate rules around commitment, compensation, and performance penalties;
- An Operating Reserve Demand Curve ("ORDC") which fails to incentivize reserve performance due to the inadequate level of the penalty factor and the shape of the curve; and
- The misalignment of reserve products between the day-ahead and real-time markets, which does not adequately procure forward reserves and leads to inefficient commitment and pricing outcomes.[11]

As a result of these flaws, PJM states, its current reserve markets "lead to unjust and unreasonable rates that are unduly discriminatory and preferential."[12] PJM emphasizes that its concerns reflect "facts specific to the PJM Region and design flaws specific to the PJM reserve market rules . . . ."[13]

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10 ER19-1486 Filing, Transmittal Letter at 3. *See also* EL19-58 Filing, Transmittal Letter at 3 (same).

11 ER19-1486 Filing, Transmittal Letter at 3-4. *See also* EL19-58 Filing, Transmittal Letter at 3 (same).

12 ER19-1486 Filing, Transmittal Letter at 3. *See also* EL19-58 Filing, Transmittal Letter at 3 (same).

13 ER19-1486 Filing, Transmittal Letter at 5. *See also* EL19-58 Filing, Transmittal Letter at 5 (same).

In the March 29 Filings, PJM proposes revisions to the Tariff and the Operating Agreement to address these three design flaws. First, it proposes to consolidate the Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve products into a single "Synchronized Reserve" product.[14] Second, PJM proposes to revise the current ORDC by:

> o raising the Reserve Penalty Factor to $2,000/MWh, to recognize that sellers could have legitimate opportunity costs up to that level during shortage conditions from foregoing energy market sales (or load reductions) in order to commit as reserves;
>
> o changing the ORDC curve shape based on a systematic, probabilistic quantification of the same categories of load and supply uncertainties that PJM operators are currently trying to address when they bias dispatch schedules or take other out-of-market actions to guard against PJM falling short of its [Minimum Reserve Requirements ("MRRs")] . . . .[15]

Third, PJM proposes to align the day-ahead and real-time reserve markets.[16] PJM demonstrates in the March 29 Filings that the proposed revisions will address the flaws in its existing reserves market design and improve price formation in the reserves markets.

II. COMMENTS

For the reasons set forth below and in the Sotkiewicz Affidavit, EPSA strongly supports the March 29 Filings and urges the Commission to grant the relief requested

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[14] *See* ER19-1486 Filing, Transmittal Letter at 9; EL19-58 Filing, Transmittal Letter at 9.

[15] ER19-1486 Filing, Transmittal Letter at 9. *See also* EL19-58 Filing, Transmittal Letter at 9 (same).

[16] *See* ER19-1486 Filing, Transmittal Letter at 9; EL19-58 Filing, Transmittal Letter at 9.

therein by December 15, 2019, as PJM requests.[17] The Commission has consistently emphasized that:

> the goals of price formation are to: (1) maximize market surplus for consumer[s] and suppliers; (2) provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; (3) provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and, (4) ensure that all suppliers have an opportunity to recover their costs.[18]

The existing reserve market rules frustrate these goals and are otherwise unjust and unreasonable. PJM's proposed revisions to those rules, on the other hand, would advance these goals and are otherwise just and reasonable.

A. The Existing Reserve Market Rules are Unjust and Unreasonable and Unduly Discriminatory

1. The Two-Tier Synchronized Reserve Construct Is Unjust and Unreasonable and Unduly Discriminatory

PJM's existing two-tier synchronized reserve construct is inherently unjust and unreasonable and unduly discriminatory. This construct, which is "unique to the PJM

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[17] *See* ER19-1486 Filing, Transmittal Letter at 2; EL19-58 Filing, Transmittal Letter at 1.

[18] *Settlement Intervals & Shortage Pricing in Mkts. Operated by Regional Transmission Orgs. & Indep. Sys. Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 5 (2016) ("Order No. 825") (footnote omitted). *See also Uplift Cost Allocation & Transparency in Mkts. Operated by Regional Transmission Orgs. & Indep. Sys. Operators*, Order No. 844, 163 FERC ¶ 61,041 at P 6 (2018) ("Order No. 844") (same); *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,295 at n.20 (2017) (same); *Price Formation in Energy & Ancillary Servs. Mkts. Operated by Regional Transmission Orgs. & Indep. Sys. Operators*, Notice Inviting Post-Technical Workshop Comments, Post-Technical Conference Questions for Comment at 1, Docket No. AD14-14-000 (Jan. 16, 2015) (unreported) (same).

Region,"[19] is unjust and unreasonable as to both suppliers and consumers. From the supplier side, suppliers are expected to provide Tier 1 Synchronized Reserve service "essentially at no charge,"[20] with the result that "Synchronized Reserves are not appropriately valued in PJM's market today."[21] Over and above the serious long-term harm to consumers from price suppression in the reserves market, however, there is the more immediate and obvious problem that Tier 1 Synchronized Reserve suppliers face "no consequences for a failure to respond."[22] Not surprisingly, the result has been a response rate that "is unacceptably low,"[23] thereby threatening reliability in the region to the detriment of consumers.

The existing two-tier construct is inconsistent with a number of the Commission's price formation principles. It manifestly fails to "provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability."[24] Suppliers of Tier 1 Synchronized Reserve are offered no meaningful carrot for following instructions, making efficient

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[19] ER19-1486 Filing, Transmittal Letter at 5-6. *See also* EL19-58 Filing, Transmittal Letter at 5 (same).

[20] ER19-1486 Filing, Transmittal Letter at 5. *See also* EL19-58 Filing, Transmittal Letter at 5 (same).

[21] ER19-1486 Filing, Transmittal Letter at 20. *See also* EL19-58 Filing, Transmittal Letter at 20 (same).

[22] ER19-1486 Filing, Transmittal Letter at 5. *See also* EL19-58 Filing, Transmittal Letter at 5 (same).

[23] ER19-1486 Filing, Transmittal Letter at 18. *See also* EL19-58 Filing, Transmittal Letter at 18 (same); Pilong Affidavit, ¶ 26 ("[I]n spite of our efforts to improve the response rate of Tier 1 resources, PJM continues to see poor response rates from Tier 1 estimated generators . . . ."); Sotkiewicz Affidavit, ¶ 27 ("Given the lack of any kind of performance obligation or penalties for failing to provide energy in the case of a contingency event, and only a $50/MWh pricing incentive, it should not be shocking that the response performance of Tier 1 [Synchronized Reserve] resources has only been 60 percent in 2017 and 63 percent in 2018." (footnote omitted)).

[24] Order No. 825, 155 FERC ¶ 61,276 at P 5.

investments, or maintaining reliability, and face no stick for failing to do so.[25] At the same time, suppressed prices for Tier 2 Synchronized Reserve mute the incentives for suppliers of that product to engage in the desired behaviors.[26] Similarly, the current structure provides no price transparency that would enable market participants to see the costs of reliably serving load.[27] To the contrary, as PJM observes, the poor response rate of Tier 1 Synchronized Reserves forces PJM system operators to employ out-of-market actions that "are fundamentally at odds with the objectives of market price transparency, and [that] can have a price suppressive effect on reserve prices . . . ."[28]

Undue discrimination is likewise inherent in this two-tier construct. Indeed, this scheme is, as Dr. Sotkiewicz explains, "discriminatory on its face."[29] While Tier 2 Synchronized Reserve prices are suppressed by the two-tier scheme and other flaws in the existing market design, suppliers will at least be paid "a non-zero clearing price" under

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[25] Dr. Sotkiewicz describes the "free option" that the existing rules give Tier 1 Synchronized Suppliers as follows:

> They can respond to a contingency event if they choose, and earn the applicable [Locational Marginal Price ("LMP")] in the energy market plus an additional $50/MWh for any additional energy they provide to PJM, or they can choose not to respond, still get paid the higher LMP due to the contingency event, and face no penalty.

Sotkiewicz Affidavit, ¶ 28. He states that this "free option . . . runs counter to the reliability needs of the system." *Id.*

[26] *See* Sotkiewicz Affidavit, ¶ 30 (explaining how the over-commitment of Tier 1 Synchronized Reserves "will paradoxically lead to lower [synchronized reserve] market prices even though the 'true demand' for [synchronized reserve] from operators is greater than that being shown by the market and should result in higher prices for Tier 2 [Synchronized R]eserves").

[27] *See* Order No. 825, 155 FERC ¶ 61,276 at P 5.

[28] ER19-1486 Filing, Transmittal Letter at 23 (footnote omitted). *See also* EL19-58 Filing, Transmittal Letter at 22 (same); Pilong Affidavit, ¶ 26 ("Given the historically poor response rates of Tier 1 resources, PJM dispatchers must take the action necessary to ensure they have sufficient reserves to maintain reliability and respond to a large generator loss.").

[29] Sotkiewicz Affidavit, ¶ 24 (footnote omitted).

certain circumstances while Tier 1 Synchronized Reserve is essentially deemed to be "free."[30] Tier 1 Synchronized Reserve suppliers are paid nothing even though they "are providing the exact same product . . . ."[31] This is a textbook example of precisely the sort of undue discrimination that is forbidden under the FPA.[32]

2. The Existing ORDC Is Unjust and Unreasonable

PJM's existing ORDC "largely does not address the uncertainties around load, wind and solar forecasts, and unanticipated plant outages that PJM dispatchers currently attempt to address through scheduling bias or other out-of-market actions."[33] As such, the existing ORDC is unjust and unreasonable, because it fails to provide correct incentives or price transparency.[34] Indeed, as PJM observes, the practical effect of the flawed ORDC and the reliance on out-of-market actions it necessitates is the backdoor institution of exactly the sort of "pay-as-bid" pricing scheme[35] that the Commission has

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30 ER19-1486 Filing, Transmittal Letter at 16. *See also* EL19-58 Filing, Transmittal Letter at 16 (same).

31 ER19-1486 Filing, Transmittal Letter at 16. *See also* EL19-58 Filing, Transmittal Letter at 16 (same); Keech Affidavit, ¶ 6 ("When Tier 1 reserves respond during an event, they are compensated differently than Tier 2 for providing the same service. This difference in compensation is discriminatory . . . ."); Sotkiewicz Affidavit, ¶ 24 (explaining that Tier 1 Synchronized Reserve Resources are counted towards the synchronized reserve requirement but "are not compensated for providing reserves at all under the mistaken idea that they are 'running for energy anyway' and given their ramp rates, could respond to any contingency event").

32 *See, e.g., Sebring Utils. Comm'n v. FERC*, 591 F.2d 1003, 1009 n.24 (5th Cir. 1979) (explaining that the "essence" of the statutory prohibition against undue discrimination "is that those who are similarly entitled must be treated equally"); *Transwestern Pipeline Co.*, 36 FERC ¶ 61,175 at 61,433 (1986) ("Undue discrimination is in essence an unjustified difference in treatment of similarly situated customers." (citation omitted)).

33 ER19-1486 Filing, Transmittal Letter at 7. *See also* EL19-58 Filing, Transmittal Letter at 7 (same).

34 *See* Order No. 825, 155 FERC ¶ 61,276 at P 5.

35 *See* ER19-1486 Filing, Transmittal Letter at 50; EL19-58 Filing, Transmittal Letter at 49.

consistently rejected.[36] More broadly, Dr. Sotkiewicz explains that the current construct "makes it practically impossible for price formation to be consistent with reliability needs as operators are taking actions that do not transparently appear to all market participants."[37]

Particularly where biasing is concerned, the status quo is not only troubling from a market design perspective but also raises serious filed rate doctrine concerns and conflicts with the spirit, if not the letter, of Section 205(c) of the FPA.[38] Under the filed rate doctrine, a public utility, such as PJM, is bound by the terms of its rate schedules and tariffs on file with the Commission and is prohibited from imposing un-filed rates.[39] In relevant part, Section 205(c) requires the public filing of "schedules showing all rates for any . . . sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges . . . ."[40] Recognizing the enormous and overwhelming breadth of what might be required to be filed if this statutory command were "taken literally,"[41] the Commission employs a "rule of reason,"[42] under

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36 *See*, *e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,060 at P 41 (2008), *on reh'g*, 127 FERC ¶ 61,054 (2009), *on reh'g*, 137 FERC ¶ 61,213 (2011); *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 109 ("*PJM*"), *on reh'g*, 121 FERC ¶ 61,173 (2007); *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005), *on reh'g*, 115 FERC ¶ 61,133 (2006); *Southwest Power Pool, Inc.*, 112 FERC ¶ 61,303 at P 23, *on reh'g*, 113 FERC ¶ 61,115 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,196 at P 32, *on reh'g*, 103 FERC ¶ 61,210 (2003).

37 Sotkiewicz Affidavit, ¶ 22.

38 16 U.S.C. § 824d(c) (2018).

39 *See*, *e.g.*, *Arkansas La. Gas Co. v. Hall*, 453 U.S. 571, 577-78 (1981); *Montana-Dakota Utils. Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251 (1951).

40 16 U.S.C. § 824d(c) (2018).

41 *Town of Easton v. Delmarva Power & Light Co.*, 24 FERC ¶ 61,251 at 61,531, *on reh'g*, 25 FERC ¶ 61,407 (1983).

42 *Id.*

which rates and rate practices must be filed if "they significantly affect rates and services."[43] PJM's March 29 Filings leave little room for doubt that its operators' biasing practices significantly affect rates.[44]

To be clear, EPSA does not question the necessity of the system operators' actions. Given the overarching importance of maintaining reliability, EPSA agrees with Mr. Pilong that "[u]nder the status quo, [PJM's] practice of biasing and committing generation outside of the market cannot change."[45] While EPSA shares the concerns that inform past calls by the Independent Market Monitor for PJM to require that PJM "document [its] biasing practices,"[46] it does not see such an approach as a practical option. Indeed, it may very well be that, under the rule of reason, documentation and filing of these practices is not legally required on the grounds that they are not "realistically *susceptible* of specification,"[47] inasmuch as such biasing varies from operator to operator

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43 *PacifiCorp*, 127 FERC ¶ 61,144 at P 11 (2009). *See also*, *e.g.*, *Energy Storage Ass'n v. PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,296 at P 105 (2018) (requiring that the inclusion in the PJM Tariff of certain "information [that] significantly affects the rates, terms, and conditions of Regulation service in PJM and is reasonably susceptible to specification"); *ANP Funding I, LLC v. ISO New England Inc.*, 110 FERC ¶ 61,040 at P 23 (2005) (requiring the filing of revisions to operating procedures that "significantly affect rates and services" in that they "could affect compensation that generators receive" under the applicable market rules).

44 *See* Pilong Affidavit, ¶ 17 (stating that biasing "can result in price suppression and uplift"); ORDC Report at 3 (explaining that operator interventions "impact[] settlements across the energy and reserves markets, because when interventions occur they can deploy more reserves than are necessary to resolve a shortage (e.g., by activation of a block of demand response), which can suppress energy and reserve prices and increase uplift costs"); Keech Affidavit, ¶¶ 50-54 (discussing the price-distorting impacts of biasing).

45 Pilong Affidavit, ¶ 19.

46 Comments of the Independent Market Monitor for PJM at 8, Docket No. ER17-775-000 (filed Feb. 1, 2017).

47 *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985).

based on his or her "training, experience and judgement."[48] And, as a practical matter, it is hard to see how these practices could be specified in a meaningful way. But all that only underscores that the status quo is unworkable and unsustainable and must be changed, not only in the interest of improving price formation but also to reduce, if not eliminate, reliance on unfiled and essentially "un-file-able" rate practices[49] while maintaining reliability.[50] Regardless of whether such reliance can be squared with the letter of the filed rate doctrine and Section 205(c), it runs directly contrary to the spirit of these requirements, which are meant to promote the "predictability of rates."[51]

3. The Failure to Align Day-Ahead and Real-Time Reserves Procurement Is Unjust and Unreasonable

PJM currently procures 10-minute reserves in the real-time market, but not in the day-ahead market, and 30-minute reserves in the day-ahead market, but not in the real-time market. This asymmetry between the day-ahead and real-time reserves markets is unjust and unreasonable. As a market design matter, it is inconsistent with a "general objective," described by Drs. Hogan and Pope, of "maintain[ing] consistency between the

48 Pilong Affidavit, ¶ 9. *See also* Sotkiewicz Affidavit, ¶ 16 (explaining that "the nature and level of the true demand [for reserves] is unknown to all but the operators on duty").

49 *See* ER19-1486 Filing, Transmittal Letter at 56 (explaining that an approach that "captur[es] real-time market uncertainties . . . would go a long way toward systematically reducing the need for PJM operators to take actions based on their notions of real-time market uncertainties"); EL19-58 Filing, Transmittal Letter at 55 (same).

50 *See* Pilong Affidavit, ¶ 19 ("Limiting the generation dispatcher's ability to account for forecast uncertainty through biasing . . . and/or taking out-of-market actions, without developing a market mechanism to ensure the availability of sufficient reserves, would lead to operating unreliably. That is not acceptable.").

51 *See West Deptford Energy, LLC v. FERC,* 766 F.3d 10, 12 (D.C. Cir. 2014). *See also*, *e.g.*, *Public Utils. Comm'n of Cal. v. FERC*, 988 F.2d 154, 164 (D.C. Cir. 1993) ("Predictability is an underlying purpose of . . . the filed rate doctrine . . . .").

real-time design and the day-ahead design,"[52] and with the approach taken by other regional transmission organizations ("RTOs") and independent system operators ("ISOs"), nearly all of which procure reserves on a day-ahead basis and all of which align their forward and day-ahead reserves markets.[53] Dr. Sotkiewicz explains that this time consistency objective cannot be met when, as is the case under the current PJM market rules, "the structure of the [day-ahead market] in which energy and reserve markets are defined differently from the energy and reserve markets that are defined and cleared in the [real-time market]."[54]

In practice, the lack of alignment between the day-ahead and real-time reserves markets produces "modeling discrepancies [that] create inefficiencies in operations and market outcomes, including prices and congestion, as well as opportunities for gaming-type behavior."[55] For example, Dr. Sotkiewicz states that, "[g]iven model differences that lead to price differences even under the same supply-demand conditions, financial players can arbitrage the simple model differences, especially in the most extreme cases, when reliability is at its most vulnerable."[56] Moreover, PJM is failing "to procure 10-minute reserves at the lowest cost because, by looking only at resources available to provide reserves in real-time, PJM ignores longer-lead time resources that may have been

52 ORDC Report at 26. *See also PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,139 at P 98 (noting that it is "desirable . . . [to] more closely align the outcome of the day-ahead and real-time market"), *on reh'g*, 164 FERC ¶ 61,170 (2018).

53 *See* ER19-1486 Filing, Transmittal Letter at 40; EL19-58 Filing, Transmittal Letter at 39.

54 Sotkiewicz Affidavit, ¶ 19.

55 ER19-1486 Filing, Transmittal Letter at 14. *See also* EL19-58 Filing, Transmittal Letter at 14 (same).

56 Sotkiewicz Affidavit, ¶ 44. *See also id.*, ¶ 50 (describing "inefficient arbitrage" opportunities for Up-to Congestion transactions as a result of the mismatch).

available and more cost-effective but needed to be lined up day-ahead."[57] At the same time, "by not maintaining a 30-minute reserve product in real-time, the market fails to recognize any value that product may have in maintaining real-time operations."[58]

B. PJM's Proposed Revisions to the Reserve Market Rules are Just and Reasonable

As the March 29 Filings and Dr. Sotkiewicz demonstrate, PJM's proposals reflect good market design and will substantially improve price formation in PJM's reserves market. Accordingly, the modifications set forth in the March 29 Filings are just and reasonable under Section 205 of the FPA and should be approved as replacements for existing unjust and unreasonable rules.

1. PJM's Single Synchronized Reserve Product is Just and Reasonable

PJM's proposal to consolidate the Tier 1 and Tier 2 Synchronized Reserve products into a single Synchronized Reserve product is necessary to address the problems discussed in Section II.A.1 above, and is otherwise just and reasonable and not unduly discriminatory. As indicated in the March 29 Filings, this consolidation would bring PJM into line with the approach taken by other RTOs and ISO.[59] While the Commission can and does allow for regional differences, it has likewise made clear that this does not mean that "principles underlying market design in one region are not applicable to

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57 ER19-1486 Filing, Transmittal Letter at 40-41. *See also* EL19-58 Filing, Transmittal Letter at 40 (same).

58 ER19-1486 Filing, Transmittal Letter at 41. *See also* EL19-58 Filing, Transmittal Letter at 40 (same).

59 *See* ER19-1486 Filing, Transmittal Letter at 48; EL19-58 Filing, Transmittal Letter at 47.

another . . . ."[60] Where, as here, other RTOs and ISOs have uniformly recognized the market design benefits of a single synchronized reserve product, the Commission is entirely justified in relying on that fact in considering PJM's proposal, rather than leaving PJM, "in isolation, [to] continue to deviate from this standardized concept that has worked well in other markets."[61]

The creation of a single Synchronized Reserve product will address the undue discrimination baked into the existing two-tiered system by eliminating the unjustified difference in treatment of suppliers providing "the exact same product . . . ."[62] Equally importantly, eliminating that undue discrimination and creating a single Synchronized Reserve product similar to the existing Tier 2 Synchronized Reserve product will help ensure that reliability is maintained through appropriate prices.

The Commission has consistently emphasized the importance of prices that properly reflect the reliability and operational needs of the system.[63] PJM's experience with separate Tier 1 and Tier 2 Synchronized Reserve products demonstrates the need for a consolidated product with meaningful performance incentives to accomplish this goal. As Mr. Pilong explains, the Tier 1 Synchronized Reserve product is inherently

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60 *Consolidated Edison Co. of N.Y., Inc. v. New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,139 at P 47 ("*Con Edison*"), *on reh'g*, 152 FERC ¶ 61,110 (2015).

61 ER19-1486 Filing, Transmittal Letter at 48. *See also* EL19-58 Filing, Transmittal Letter at 47 (same).

62 ER19-1486 Filing, Transmittal Letter at 16. *See also* EL19-58 Filing, Transmittal Letter at 16 (same).

63 *See, e.g.,* Order No. 825, 155 FERC ¶ 61,276 at P 3 (recognizing that prices should reflect "system conditions and potential reliability costs, as well as the value of both internal and external market resources responding to a dispatch signal"); *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,058 at P 1 (2019) (finding that PJM's fast-start pricing practices are not just and reasonable because they "do not allow prices to reflect the marginal cost of serving load").

unreliable because "[i]t is only an estimate of what response a unit is technically capable of, but not a guarantee that it will achieve it."[64] This product thus only provides an indication of "capability," rather than any suggestion regarding the "expected response of the generator."[65] This shortcoming of the Tier 1 Synchronized Reserve product, in turn, means that the amount of Tier 2 Synchronized Reserves required is understated, and PJM's dispatchers must take manual action to ensure that adequate reserves are procured.[66]

The upshot is that PJM's current two-tiered system makes it difficult for PJM itself and market participants to determine the need for, and value of, reserves. Adopting a single Synchronized Reserve product addresses this issue and provides a clearer indication of the system's needs through price. In this respect, the proposed rules governing the Synchronized Reserve product will provide greater certainty to PJM's dispatchers that resources will actually respond when needed by applying penalties to all committed resources that fail to provide their assigned reserves. This, in turn, will reduce the need for out-of-market actions by PJM's dispatchers,[67] and allow the market to better reflect the amount of needed reserves. As Dr. Sotkiewicz explains:

> This single and uniform treatment of resources providing [synchronized reserve] will help give operators better information on reserve capability throughout the operating day, and over time limit the uncertainty of generator performance and response to ensure the most cost-effective set of resources are providing [synchronized reserve] and

64 Pilong Affidavit, ¶ 24.

65 *Id.*

66 *See* Pilong Affidavit, ¶ 27.

67 *Cf.* Order No. 844, 163 FERC ¶ 61,041 at P 99 (explaining that RTOs/ISOs should report on operator-initiated commitments because such commitments make the market "inherently less transparent," and "can affect energy and ancillary service prices and can result in uplift").

> avoiding the need to commit additional reserves outside the market based on expected performance during contingency events. And in this way the price of [synchronized reserve] will be consistent with the reliability needs of the system.[68]

The single Synchronized Reserve product thereby improves transparency and provides the price signals to incentivize investment when necessary, thereby improving market efficiency.

2. The Proposed ORDC is Properly Structured to Reflect the Cost of Needed Reserves

As discussed in greater detail in the March 29 Filings and the Sotkiewicz Affidavit, PJM's proposed modifications to the ORDC are just and reasonable. These modifications will improve efficiency by reflecting the incremental value of reserves in the market and reducing reliance on biasing and out-of-market actions by PJM's operators.

As Drs. Hogan and Pope explain, the modified ORDC proposed in the March 29 Filings will appropriately allow "the value of incremental reserves [to] vary with the probability of loss of load during actual operation" while remaining "anchored around PJM-specific assumptions about the actions that will be taken as the level of reserves declines below the MRR."[69] Similarly, Dr. Sotkiewicz finds that the proposed ORDC is properly designed to procure the amount of reserves needed to avoid operator interventions and send appropriate price signals regarding the value of such reserves.[70] He explains that increasing the Reserve Penalty Factor is essential to ensuring ORDC may reflect the full

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68 Sotkiewicz Affidavit, ¶ 35.

69 ORDC Report at 17.

70 *See* Sotkiewicz Affidavit, ¶ 77.

costs of the marginal resource.[71] As the Commission has recognized, those costs would reasonably include the opportunity costs that resources incur from committing to provide reserves rather than energy.[72] Given that the Reserve Penalty Factor is currently only $850/MWh, while prices in PJM's energy market may reach $2,000/MWh, this "forc[es] any action at a cost above the [existing] penalty factor to be taken out-of-market and not reflected in prices."[73] It is therefore eminently reasonable and, indeed, essential to align the Reserve Penalty Factor with the energy offer cap in order to "allow the PJM Region to ensure that the value of resource flexibility is better reflected in clearing prices."[74]

As the March 29 Filings acknowledge, PJM's existing ORDC fails to address forecasting uncertainties, forcing PJM's dispatchers to compensate "through scheduling bias or other out-of-market actions."[75] As Dr. Sotkiewicz observes, the fact that PJM's

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[71] *See id.*, ¶ 80.

[72] *See, e.g., Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831-A, 161 FERC ¶ 61,156 at P 38 (2017) (stating that "opportunity costs are legitimate short-run marginal costs that should be considered part of a cost-based incremental energy offer"); *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157 at P 185 (2017) (stating that "an appropriate competitive offer includes all of the marginal and opportunity costs a resource faces to participate in the capacity market"), *on reh'g*, 162 FERC ¶ 61,047 (2018); *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064 at P 99 (2011) ("Paying to all cleared frequency regulation resources a uniform price that includes opportunity costs will ensure that all appropriate costs are considered and will send an efficient price signal to current and potential market participants."), *on reh'g*, Order No. 755-A, 138 FERC ¶ 61,123 (2012); *id.* at P 102 ("Regarding cross-product opportunity costs, which reflect the foregone opportunity to participate in the energy or ancillary services markets, the Commission finds that it is appropriate for the RTOs and ISOs to calculate this and include it in each resource's offer to supply frequency regulation capacity, for use when determining the market clearing price and which resources clear.").

[73] ER19-1486 Filing, Transmittal Letter at 26. *See also* EL19-58 Filing, Transmittal Letter at 25 (same).

[74] ER19-1486 Filing, Transmittal Letter at 11. *See also* EL19-58 Filing, Transmittal Letter at 11 (same).

[75] ER19-1468 Filing, Transmittal Letter at 7. *See also* EL19-58 Filing, Transmittal Letter at 7 (same).

dispatchers have chosen to commit reserves above the MRRs shows that there is a value to such reserves.[76] Nonetheless, the existing ORDC is essentially vertical, meaning that the market fails to reflect the value that PJM, as the system operator, places on the incremental reserves above the MRR.[77] This is the same problem that PJM and other RTOs/ISOs previously faced in the capacity markets, and, there, the Commission consistently found sloped demand curves to be the best solution.[78] In the capacity market setting, the Commission has also identified other "benefits from the use of a sloped demand curve, such as by reducing price volatility and financing costs."[79] The

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76 *See* Sotkiewicz Affidavit, ¶ 62.

77 *See id.*, ¶¶ 59-61.

78 *See, e.g., PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 76 (2006) (stating that "a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve"); *PJM*, 119 FERC ¶ 61,318 at P 94 (stating that "a sloping demand curve would provide a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve"); *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 at P 35 (accepting sloped demand curve because it "rests on a more rational economic basis than the current demand curve, as it more realistically reflects the economic value of capacity reserves. As the likelihood of inadequate capacity decreases with increased reserves, the value of additional reserve capacity decreases. The proposed downward sloping demand curve reflects the decreasing but still positive value of additional reserves (while the existing vertical demand curve does not) and is a substantial improvement over the existing demand curve."), *on reh'g*, 105 FERC ¶ 61,108 (2003), *aff'd sub nom. Electricity Consumers Res. Council v. FERC*, 407 F.3d 1232 (D.C. Cir. 2005); *ISO New England Inc.*, 158 FERC ¶ 61,138 at P 29 (2017) (explaining that sloped demand curves "were designed to reflect more accurately the locational marginal reliability impact of capacity"), *aff'd sub nom. NextEra Energy Res., LLC v. FERC*, 898 F.3d 14 (D.C. Cir. 2018).

79 *PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,052 at P 66 (2014), *on reh'g*, 155 FERC ¶ 61,062 (2016). *See also, e.g.*, *PJM*, 119 FERC ¶ 61,318 at P 102 (finding that "capacity prices under a sloping demand curve would change gradually, in contrast to the drastically changing prices that buyers must pay for varying amounts of capacity under the current capacity construct. In other words, no matter what slope a supply curve has, any movement of the supply curve will create a larger change in price with a vertical as compared to a downward sloping demand curve").

Commission has, in fact, gone so far as to order one RTO/ISO to replace its vertical demand curves with sloped demand curves pursuant to Section 206 of the FPA.[80]

The proposed ORDC modifications are particularly critical in light of recent market developments. In 2017, PJM issued a report finding that, "[a]s penetration of variable energy resources increases, additional load following capability is required from other resources in order to reliably offset rapid changes in output from renewable resources."[81] As Renewable Portfolio Standard ("RPS") programs continue to expand and proliferate in the PJM region,[82] it becomes ever more important for PJM to procure reserves that will "help manage the variable output of intermittent resources."[83] The current market rules fails to support such procurement, because a reserve shortage only occurs when reserves fall below the minimum requirement, meaning that most reserve shortages can only be expected to be transitory. By contrast, the modified ORDC will demonstrate PJM's willingness to pay for reserves over and above the minimum requirement and provide more sustained price signals that properly value reserves.

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80 *ISO New England Inc.*, 153 FERC ¶ 61,338 at P 11 (2015).

81 PJM, *PJM's Evolving Resource Mix and System Reliability* at 19 (Mar. 30, 2017), https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx. *See also* ER19-1486 Filing, Transmittal Letter at 6 ("PJM's inability to know accurately at any given time the amount of reserves expected to respond will continue to challenge PJM as the system operator and only grow as a problem as the system incorporates increasing levels of variable resources."); EL19-58 Filing, Transmittal Letter at 5 (same).

82 *See, e.g., Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 at P 103 (2018) (discussing RPS programs in the PJM region), *reh'g pending*; ER19-1486 Filing, Transmittal Letter at 8 (same); EL19-58 Filing, Transmittal Letter at 7-8 (same).

83 ER19-1486 Filing, Transmittal Letter at 8. *See also* EL19-58 Filing, Transmittal Letter at 8 (same).

PJM properly declined to propose any out-of-cycle adjustment to the Variable Resource Requirement ("VRR") curves in the March 29 Filings. During the stakeholder process, certain parties argued that the proposed ORDC modifications necessitated such an adjustment on the theory that higher prices expected to result from these modifications ought to be reflected through the use of a higher energy and ancillary services ("EAS") offset in calculating the Net Cost of New Entry.[84] As an initial matter, EPSA notes that the Commission has rejected past requests for out-of-cycle adjustments to capacity demand curves.[85] In so doing, the Commission has found that adjustments of this sort cannot be made without considering "all cost and revenue components" of the demand curves[86] and that a comprehensive out-of-cycle review "would promote confusion and uncertainty rather than stability in the market with uncertain future benefits."[87] Even where EAS revenues alone are concerned, Dr. Sotkiewicz observes, offers into RPM Auctions reflect "any number of expectations about expected net energy and ancillary services revenues,"[88] and it has always been understood that actual EAS revenues may differ "from the forward expectation for a multitude of reasons."[89]

Even more fundamentally, calls to revisit the EAS offset ignore the fact that this offset is, by design, backward-, not forward-, looking[90] and that any increase in energy or

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84 *See* Sotkiewicz Affidavit, ¶ 86.

85 *See Independent Power Producers of N.Y., Inc. v. New York Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,311 (2008).

86 *Id.* at P 33.

87 *Id.* at P 35.

88 Sotkiewicz Affidavit, ¶ 87.

89 *Id.*

90 *See* Tariff, Attachment DD, § 5.10(a)(i)-(iii).

ancillary services revenues that results from the proposed ORDC modifications will naturally be accounted for in future EAS offsets. As PJM explains, "[t]his is precisely the manner in which the EAS Revenue Offset is designed to work . . . ."[91] Although a challenge to the backward-looking nature of the EAS offset would be well beyond the scope of these proceedings, in which PJM has proposed no changes to its capacity market rules, it is worth noting that, in an order issued just last month, the Commission found that "PJM's election to continue using historic data to calculate the EAS Offset is a reasonable method by which to account for the EAS revenues earned by generators."[92] Requiring a forward-looking, out-of-cycle adjustment to the backward-looking EAS offset used to set the VRR curves would establish a dangerous precedent and would invite requests for similar adjustments in the future based on market rules changes and other unforeseen developments, including, for example, increased penetration of zero-marginal cost resources.

3. It is Just and Reasonable to Align PJM's Day-Ahead and Real-Time Products

In order to align the products in its day-ahead and real-time markets, PJM proposes to add a 10-minute reserve product to the day-ahead market, and a 30-minute reserve product to the real-time market, with the result that PJM will procure one 30-minute reserve product (Secondary Reserve) and two 10-minute reserve products (Synchronized and Non-Synchronized Reserve) in both markets. As Dr. Sotkiewicz

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91 ER19-1486 Filing, Transmittal Letter at 71. *See also* EL19-58 Filing at 70 (same).

92 *See PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029 at P 119 (2019) (also noting that "the existing historic EAS Offset calculation methodology, which PJM does not propose to change, has previously been accepted as just and reasonable" (citation omitted)).

states, this proposal is consistent with sound market design, which requires the two markets to have the same structure in order to allow prices to rise appropriately in anticipation of possible reserve shortages or uncertain operating conditions.[93]

As PJM concedes, "[e]very other ISO/RTO has a methodology to procure the reserve products needed in real-time in advance of the operating day except PJM."[94] Here again, the Commission's willingness to accommodate regional differences does not justify, much less mandate, that PJM retain a uniquely flawed approach.[95] There are certainly no PJM-specific circumstances that make it acceptable for PJM consumers to pay more than they should for 10-minute reserves. Yet, that is exactly what the existing PJM market rules ensure, because, by failing to procure such reserves on a day-ahead basis, the current construct "ignores longer-lead time resources that may have been available and more cost-effective but needed to be lined up day-ahead."[96] Accordingly, "the real-time reserve commitment almost certainly will not result in the lowest cost solution, relative to a day-ahead procurement."[97] By contrast, as explained in the Sotkiewicz Affidavit, aligning the day-ahead and real-time reserves markets will allow shortage conditions to be signaled in the day-ahead markets.[98] Allowing PJM to procure

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93 *See* Sotkiewicz Affidavit, ¶ 53.

94 ER19-1486 Filing, Transmittal Letter at 40. *See also* EL19-58 Filing, Transmittal Letter at 39 (same).

95 *Con Edison*, 150 FERC ¶ 61,139 at P 47.

96 ER19-1486 Filing, Transmittal Letter at 41. *See also* EL19-58 Filing, Transmittal Letter at 40 (same).

97 ER19-1486 Filing, Transmittal Letter at 41. *See also* EL19-58 Filing, Transmittal Letter at 40 (same).

98 *See* Sotkiewicz Affidavit, ¶ 53. *See also* ER19-1486 Filing, Transmittal Letter at 75 ("Adding the 10-minute reserve products to the day-ahead market will foster more efficient price formation in the day-ahead markets because it will consistently and transparently reflect the real-

the same product in both markets, using the same ORDCs in both markets, will also ensure that PJM will be able to use its joint co-optimization algorithm more efficiently to achieve the least-cost solution.

Aligning the products in the day-ahead and real-time markets also addresses operational and modeling issues identified in the March 29 Filings. As PJM explains, the current mismatch in products raises questions regarding the value of 30-minute reserves,[99] and regarding the amount of 30-minute reserves that can be converted to 10-minute reserves.[100] This mismatch may also create modeling issues,[101] and can cause transmission constraints to differ between day-ahead and real-time, which would affect congestion pricing.[102] Dr. Sotkiewicz explains that aligning the products in the two markets is, therefore, necessary to ensure that prices correctly reflect system conditions, rather than having prices diverge due solely to modeling differences.[103]

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time need for reserves during the day-ahead commitment and pricing processes."); EL19-58 Filing, Transmittal Letter at 74 (same).

99 *See* ER19-1486 Filing, Transmittal Letter at 41-44; EL19-58 Filing, Transmittal Letter at 40-43.

100 *See* ER19-1486 Filing, Transmittal Letter at 42-44; EL19-58 Filing, Transmittal Letter at 41-43.

101 *See* ER19-1486 Filing, Transmittal Letter at 43-44; EL19-58 Filing, Transmittal Letter at 42-43.

102 *See* Sotkiewicz Affidavit, ¶¶ 48-49. *See also* ER19-1486 Filing, Transmittal Letter at 42; EL19-58 Filing, Transmittal Letter at 41.

103 *See* Sotkiewicz Affidavit, ¶ 52.

III. CONCLUSION

WHEREFORE, for the reasons set forth herein, EPSA respectfully requests that the Commission grant the relief requested in the March 29 Filings and approve the proposed reforms effective June 1, 2020.

Respectfully submitted,

ELECTRIC POWER SUPPLY ASSOCIATION

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Electric Power Supply Association

Dated: May 15, 2019

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Dated at Washington DC, this 15th day of May, 2019.

/s/ Stephanie S. Lim
Stephanie S. Lim

Attachment A

The Sotkiewicz Affidavit

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER19-1486-000**
PJM Interconnection, L.L.C.	**)**	**Docket No. EL19-58-000**
		(Not consolidated)

AFFIDAVIT OF PAUL M. SOTKIEWICZ, PH.D.

I. QUALIFICATIONS

1. My name is Dr. Paul M. Sotkiewicz. I am the President and Founder of E-Cubed Policy Associates, LLC ("E-Cubed") and formerly served as the Chief Economist in the Market Service Division of PJM Interconnection, L.L.C. ("PJM"). I have been asked by the Electric Power Supply Association ("EPSA") to submit this affidavit in support of its comments supporting the adoption of PJM's Enhanced Price Formation in Reserve Markets filings in Docket No. EL19-58-000 and Docket No. ER19-1486-000.

2. Prior to founding E-Cubed, I worked as a contractor and directly for PJM Interconnection, L.L.C. ("PJM") in Audubon, Pennsylvania from February 2008 until October 2016. In my time at PJM I first served as a Senior Economist until March 2010 and subsequently as the Chief Economist in the Market Service Division until June 2015. From July 2015 until October 2016, I worked as a contractor for PJM under the Title of Senior Economic Policy Advisor. Prior to joining PJM, I served as the Director of Energy Studies at the Public Utility Research Center ("PURC"), University of Florida from August 2000 until February 2008 and I was an Economist at the Federal Energy

Regulatory Commission ("FERC") from September 1998 until August 2000. I have a B.A. in History and Economics from the University of Florida (1991), and an M.A. (1995) and Ph.D. (2003) in Economics from the University of Minnesota.

3. I have 20 years of experience on matters at the intersection of utility regulatory policy, power system economics, and environmental economics. In my current role, I advise private- and public-sector clients on a range of economic issues related to electricity market design and performance, power generation economics, utility regulatory policy, and the economic impacts of state and federal environmental policies. At PJM I provided expert analysis, advice, and support for PJM initiatives related to market design changes in, and performance of, PJM's energy, ancillary service, and capacity markets.

While the Director of Energy Studies at PURC, I provided executive education and expert advice to regulatory staff and utility professionals from around the world in matters such as electric power regulation, market design, incentive regulation, and cost-of-service rate cases and rate design.

As an economist at FERC, I worked on market design issues and filings related to the newly formed ISO/RTO markets concentrating primarily on the New York ISO and the California ISO markets. The entirety of my experience and work history can be found in my CV attached as Exhibit 1.

A. Specific Experience with Respect to the Implementation of Reserve Shortage Pricing in PJM under Order 719

4. During my tenure at PJM, I led the PJM economic and markets team working through the stakeholder process to implement the Commission's Order 719 that required PJM and the other ISOs/RTOs to implement reserve shortage pricing. I provided two supporting affidavits associated with PJM's filing to gain Commission approval of PJM's initial

reserve shortage pricing framework in Docket No. ER09-1063-004.[1] I have a familiarity and knowledge of how PJM has implemented operating reserve demand curves ("ORDC") into its energy market mechanisms that can provide additional insight as to the just and reasonable changes that PJM has filed and why the current reserve market structure currently in place is unjust, unreasonable, and unduly discriminatory.

II. PRICES AND INCENTIVES MUST BE CONSISTENT WITH THE OPERATIONAL AND RELIABILITY NEEDS OF THE SYSTEM

5. At the most fundamental level, ***price in wholesale power markets is the control signal that provides information about system conditions.*** Just as importantly, *prices provide incentives for both supply resources and the demand-side of the market to take actions in response to those prices signals to ensure reliable operations are maintained*. From an economic perspective, prices result from maximizing market surplus (minimizing costs) and should reflect the marginal cost (or marginal benefit if demand sets the price) of providing one more MW of energy, capacity, or reserves to the system.

6. At the same time, for prices to be truly market clearing in an economic sense, the prices and associated dispatch or consumption awards in wholesale power markets must be individually rational. From the perspective of a supplier, individual rationality means that at the market clearing price, the supplier would not want to change its energy dispatch or reserve commitments because doing so would lead to lower profits. From a consumer perspective, individual rationality means consuming more, or less, at the clearing price will not provide as much net benefit from consumption. In short, individual rationality

[1] PJM Interconnection, LLC, ER09-1063-004 (Compliance Filing), June 18, 2010. Affidavit of Paul M. Sotkiewicz, Ph.D. ("Sotkiewicz 2010 Shortage Pricing Affidavit") and PJM Interconnection, LLC, ER09-1063-004 Answer to Comments and Motion for Leave to Answer and Answer to Protests, August 23, 2010. Affidavit of Paul M. Sotkiewicz, Ph.D. ("Sotkiewicz 2010 Shortage Pricing Reply Affidavit").

of prices and associated production and consumption quantities results in no market participant wanting to change its market quantity position at the market clearing prices. *It is the individual rationality of market clearing prices and quantities that are essential to maintaining reliability in wholesale power markets* since prices are the signal that directs market participants to take actions not only in their economic interest, but also serves the interests of maintaining reliability in system operations or resource adequacy.

7. The ***"prime directive"*** is that prices must be consistent with the operational or reliability needs of the system, and hence are also individually rational when combined with dispatch and reserve assignments for suppliers or consumption decisions for loads. This is the basic tenet behind Locational Marginal Pricing ("LMP"). When there are price differentials on the system due to transmission limits, supply and load on the downstream side of congestion face higher prices which are a signal to ramp up more expensive generation that is locally available while load is receiving a signal to reduce consumption to relieve stress on the transmission system while also maintaining energy balance. Upstream of congestion, generators and loads are receiving a price signal for generation to reduce output or for load to increase consumption to alleviate the transmission constraint while maintaining energy balance.

8. The interaction between energy prices and reserve prices is no different. If generation resources are needed to provide more reserves, it may be the case the only set of resources that can be drawn upon are those already providing energy, but must be backed down from running at full output to provide reserves while other more expensive generation is brought on-line to maintain energy balance. In this case the energy price increases due to more expensive generation being brought on-line to allow reserves to be maintained.

Reserve prices will also need to increase to reflect the opportunity cost of the generator being backed down to provide reserves. In this way the prices are consistent with energy and reserve requirements and this is the basic rationale behind co-optimizing energy and reserves to arrive at prices that are consistent with operational and reliability needs.

9. ORDCs, when properly defined, ensure that market prices are consistent with the reliability and operational needs of the system. ORDCs price the anticipated reliability needs of the PJM system in real-time operations. When incorporated in the Day-ahead Energy Market as proposed by PJM,[2] energy and reserve prices determined through the interaction with the ORDC signals to market participants, with sufficient advance notice, that economically beneficial actions can be taken to ensure reliability in real-time. In the Real-time energy market, ORDCs are reflecting actual system conditions and immediate reliability needs of the system to further incentivize economically beneficial actions that are consistent with reliability needs.

A. Demand for Energy or Reserves Must be Well-Defined and Transparent and Reflect the Marginal Benefit to Consumption/Commitment

10. Price formation that reflects the ***"prime directive"*** of prices being consistent with operational and reliability needs cannot take place without an explicitly well-defined supply, and, even more importantly, a well-defined demand. In wholesale power markets, well-defined supply comes from submitted costs and operational parameters. Demand for energy is explicitly defined in the Day-ahead energy market, and it is the load that must be balanced against generation in real-time operation. In the Day-ahead Energy Market, demand has the ability to be price sensitive and ability to express its marginal

[2] PJM filing at 73-74.

benefit or willingness to pay for energy at different consumption levels. At any point in time in real-time operation, demand is effectively treated as a constraint that must be satisfied, or in effect, unresponsive to price within an interval, but can respond to price in subsequent intervals though the level of price responsiveness is not necessarily transparent to operators.

11. Currently in PJM, the demand for real-time reserves is at best weakly defined in the Day-ahead Market with the current Day-Ahead Scheduling Reserve Product. In real-time, PJM commits and dispatches resources to provide Regulation and Frequency Response ("Regulation"), Synchronized Reserve ("SR"), and Non-Synchronized Reserve ("NSR"). SR are resources that are on-line and synchronized to the system and can respond to a contingency within 10 minutes. NSR can be provided by resources that are offline, but can start up and respond within 10 minutes. Secondary reserve are provided by resources which can respond within 30 minutes, but require more than 10 minutes to respond. On-line or off-line resources can satisfy the secondary reserve requirement.

12. Currently, there are markets for SR and NSR to meet PJM's Primary Reserve (total 10-minute reserve requirement), but no market at all for secondary reserves. These markets currently only exist in the Real-time Market and not in the Day-ahead Market. The demand for SR and NSR is a function of the largest generation contingency and can change from dispatch interval to dispatch interval.[3] Commitment of total operating reserve which includes all reserve that can respond within 30 minutes is 5.29 percent of

[3] PJM Interconnection, LLC, *PJM Manual 13: Emergency Operations*, Revision: 69, April 1, 2019, Section 2.2 at 18. SR commitments are equal to the single largest contingency. Primary Reserve commitments (SR + NSR) are 150 percent of the largest contingency.

forecast peak load.[4] But in any interval, the demand for SR and NSR are taken as simple constraint that must be satisfied, or as a perfectly inelastic demand for the reserve requirements. The demands for SR and NSR are not responsive to price, nor do these demands show a value of reserves beyond the requirement. For example, suppose the SR requirement is 1000 MW. The last or 1000th MW has value at the marginal cost of providing it. The 1001th MW of reserve has a value of zero.

B. Supply Quantities Must be Well-Defined from the Perspective of the Supplier and the Market and System Operators for Price Formation to Follow the "*Prime Directive*"

13. For the typical product in PJM's organized markets, it may seem obvious that the supply quantities are well-defined by the prices and quantities offered. In the context of PJM's reserve markets, this is not so obvious. For example, the quantity of SR should be based on the ramp rates submitted by generation resources and operators should have the ability to count on that quantity to be available and delivered. For on-line resources that are not running at their maximums, the existing rules falsely assume that these generators will respond to a contingency event despite not being paid to provide reserves in the current market paradigm or facing penalties for failing to do so. PJM Operators do not have the luxury of making such an assumption and must account for the fact that, as discussed below,[5] there is no strong incentive to respond to such events and that PJM markets and systems do not provide adequate opportunities to update ramping capabilities as operating conditions change. From the perspective of PJM Operators, realized response differing from submitted ramp rates indicates there is a mismeasurement of available

[4] *Id*. at 18-19. Total reserves that can respond within 30 minutes is equal to 5.29 percent of the peak load forecast to account for load forecast error (2.18%) and generator forced outage rates (FOR) (3.11%).

[5] These are known as Tier 1 SR and is discussed below.

reserves which leads to PJM Operators committing additional resources out-of-market to account for the measurement error.

14. As discussed by PJM in its filing and below, resources considered to be Tier 1 for providing SR have little incentive to respond to contingency because there is no direct compensation for being in reserve, nor are there currently any penalties for non-performance. This lack of penalties and compensation are leading to the perceived mismeasurement problem from a PJM Operator perspective.[6] Yet, as has been the case in PJM, resources being counted on for providing SR, often are not providing all the reserves PJM Operators expect when a contingency event occurs. This creates uncertainty in the minds of operators about how much supply or reserve is actually available to operators when they will need it most.[7]

15. From the perspective of operators, this uncertainty regarding the capability of resources to provide reserves, may require them to over-commit resource in an attempt to get the needed reserves to operate the system reliably. From a market perspective, this looks like an over-supply of reserves (relative to the defined demand) leading to artificially low or zero reserve prices. Furthermore, if such extra reserves are committed, it can also lead to artificially low energy prices as resources are backed down to make room for extra capacity brought on-line to provide the additional reserves operators believe they need.

16. Or thinking of this in another way, the demand for reserves that operators actually require, based on system conditions and uncertainty they perceive regarding the actual level of capable supply, is actually much higher than is reflected under the current market

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[6] PJM filing at 5-6.

[7] Pilong Affidavit PP 24-26.

rules, and are thus committing supply to meet the "true demand". But the nature and level of the true demand is unknown to all but the operators on duty, and price formation is not related at all to the "true demand" that is currently undefined in the current market paradigm.

C. Prices of Energy and Reserves Need to be "Time Consistent" Across the Commitment and Operational Horizons in the Day-ahead and Real-time Markets

17. Time consistency of prices means that the prices in one time-horizon, day-ahead for instance, are indicative of the expected prices in in a subsequent time-horizon; for example, real-time operations in the same hour as the day-ahead horizon. If the expected conditions found in the Day-Ahead Energy Market ("DAM") are realized in the Real-time Energy Market ("RTM"), the pricing and quantity outcomes should be identical.

18. It should also be the case that prices and quantities at different points in time in the RTM should be identical with identical realizations of load and generator availability.

19. Wholesale power markets do not meet the time consistency of prices when the structure of the DAM in which energy and reserve markets are defined differently from the energy and reserve markets that are defined and cleared in the RTM.

20. Time consistency of prices cannot be maintained when operators intervene and commit additional resources outside the market paradigm in anticipation of conditions that may not actually materialize between one real-time period and another real-time period.

D. PJM's Current Reserve Market Structures Fail to Meet Any of the Above Criteria Rendering Them Unjust, Unreasonable, and Unduly Discriminatory and Do Not Achieve Reliability at Least-Cost Through Markets.

21. Given the ability for PJM operators to commit resources outside of the market in anticipation of short-term load forecast errors in real-time operations or anticipated

generator outages or capabilities,[8] there currently is no well-defined market demand for reserves that matches operational needs. Furthermore, the ability to commit resources outside the market also creates a situation whereby there may be no time consistency in prices in the RTM.

22. The current set of incentives for performing to expected ramp rate capabilities leads to uncertainty in the amount of supply that is actually available casting doubt in the minds of operators, who erring on the side of caution, will commit additional supply to ensure there are sufficient resources available in real-time operation.[9] This uncertainty in supply makes it practically impossible for price formation to be consistent with reliability needs as operators are taking actions that do not transparently appear to all market participants.

23. PJM's reserve markets are not time consistent in any sense with DASR markets in the DAM not mirroring the markets for regulation and frequency response, SR, and NSR in the RTM. The RTM also has no formal market for 30-minute reserves, though commitments are being made for 30-minute reserves (also known as operating reserves)[10] and these commitments do not transparently interact with the energy price or other reserve price formation in the RTM. Furthermore, the ability for operators to commit additional resources outside the market further impedes time consistency.

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[8] Pilong Affidavit P 8.

[9] Pilong Affidavit P 10.

[10] PJM Manual 13 at 18.

III. IT IS JUST AND REASONABLE TO CONSOLIDATE SYNCHRONIZED RESERVES INTO A SINGLE MARKET

A. Separate Market Treatment for Tier 1 and Tier 2 Synchronized Reserves are Unjust, Unreasonable and Unduly Discriminatory

24. As PJM explains, the current manner in which PJM commits and compensates resources for providing Synchronized Reserve ("SR") is discriminatory on its face.[11] First, Tier 1 resources, defined as resources dispatched for energy but not fully loaded are counted toward providing SR. Yet, these resources are not compensated for providing reserves at all under the mistaken idea that they are "running for energy anyway" and given their ramp rates, could respond to any contingency event and ramp up to provide more energy when needed. To provide an incentive to ramp up, they are paid an extra $50/MWh to provide extra energy during an event, but do not face penalties for non-performance.

25. Tier 2 resources providing SR are resources that are committed through a market algorithm to provide any additional SR that are not being "provided for free" by Tier 1 resources so PJM can meet its SR target to cover the largest contingency on the system. Tier 2 resources are paid a market clearing price for SR and are obligated to respond to a contingency event or face penalties for non-performance. Additionally, Tier 2 resources are only paid the applicable LMP during contingency events.

26. It is easy to see that similarly situated resources, providing the same service, in this case SR, to respond to the loss of a large generator as an operating contingency face extremely different compensation treatment. From a market perspective alone, given this disparate treatment, the current Tier 1 and Tier 2 construct in PJM for providing SR is highly discriminatory and thus cannot be just and reasonable.

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[11] PJM filing at 15-16.

B. Separate Market Treatment for Tier 1 and Tier 2 Synchronized Reserves Lead to Operational Outcomes that Erode Reliability and thus are Unjust, Unreasonable and Unduly Discriminatory

27. Given the lack of any kind of performance obligation or penalties for failing to provide energy in the case of a contingency event, and only a $50/MWh pricing incentive, it should not be shocking that the response performance of Tier 1 resources has only been 60 percent in 2017 and 63 percent in 2018.[12] From an economic perspective this makes sense. Despite the PJM operators depending on Tier 1 resources to maintain reliable operations, those resources face no consequences for non-performance.

28. In effect, Tier 1 resources are presented with what can be considered a "free option". They can respond to a contingency event if they choose, and earn the applicable LMP in the energy market plus an additional $50/MWh for any additional energy they provide to PJM, or they can choose not to respond, still get paid the higher LMP due to the contingency event, and face no penalty. This free option for Tier 1 resources, which is not available to Tier 2 resources, runs counter to the reliability needs of the system. Such a mechanism from a reliability perspective cannot be just and reasonable.

29. Furthermore, as PJM has pointed out, the "true" availability of Tier 1 resources available to PJM operators is not really known given that ramp rates of such resources may not match their low Tier 1 response rates. From an operator's perspective, it is always easier to "bias" the market toward procurement of additional Tier 2 resources or simply commit additional Tier 2 resources to ensure contingency events can be met with sufficient reserves.[13]

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[12] PJM Filing at 19, Figures 3 and 4 citing to the Independent Market Monitor ("IMM") for PJM 2017 State of the Market Report and 2018 State of the Market Report.

[13] Pilong Affidavit at PP 8-11.

30. The uncertainty of "true" available SR will lead to an out-of-market "over-commitment" of reserves and will paradoxically lead to lower SR market prices even though the "true demand" for SR from operators is greater than that being shown by the market and should result in higher prices for Tier 2 reserves. In this sense, the inherently unjust, unreasonable and unduly discriminatory reliability outcomes of the current Tier 1 and Tier 2 SR construct also leads to market results that do not signal reliability needs.

31. The situation with Tier 1 resources is quite similar to the situation PJM faced with regard to its capacity market. While resources were paid for capacity, unlike Tier 1 for SR, the inherent penalties for non-performance were insufficient to incentivize good maintenance and/or fuel procurement and storage practices such that when the resources were needed most, they were not available to the system. [14]

C. Combining Tier 1 and Tier 2 Synchronized Reserve into a Single Market with Identical Treatment is Just and Reasonable and will Promote Improved Reliability Through Common Incentives and Improves Operational Visibility for Operators

32. PJM proposes to eliminate the Tier 1 and Tier 2 distinctions and have a single SR market in which all resources receive the same price and face the same performance obligations and penalties. Additionally, a single SR market will improve market transparency regarding reliability needs such that prices are consistent with reliability needs. A single SR market will also improve operational visibility for PJM operators such that there will be stronger incentives to respond to contingency events now that all resources are being paid to serve as SR and face penalties for poor performance. This change will enhance reliability.

[14] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

33. Eliminating the discrepancy between compensation and performance penalties eliminates the current discriminatory treatment of resources providing SR. But an important aspect of this is that now resources that may be running for energy, but not fully loaded and providing SR, have a stronger incentive to respond according to their ramp rate capability due to penalties for non-performance. By extension, this will give operators more confidence in the amount of reserves they have committed and should recue the need for out-of-market reserve commitments.

34. A simple example shows this incentive. Consider a 100 MW resource that is operating for energy at 80 MW and reports a ramp rate of 2 MW/minute. This implies a SR capability of 20 MW, up to its maximum output. In the current Tier 1 construct if a contingency occurs and the resources can only ramp at 1 MW/minute, it will show only a 50 percent performance rate, leave operators short of covering the loss of a large generator during the event, but there would be no consequence for the perceived under-performance resource. Under the new construct, if the resource knew that operationally could only ramp at 1 MW/minute, it can update this information, and then additional reserves could be committed. Or in the alternative, the resource now being compensated for reserves and subject to penalties will respond at 2MW/minute and over time operators will gain confidence that the market-based reserve commitments can and will respond. There will be a reduced need to commit resources out of market from the operator perspective. Then during a contingency event, the resource responds to its true capability and avoids a penalty for non-performance on reserves it likely could not deliver.

35. This single and uniform treatment of resources providing SR will help give operators better information on reserve capability throughout the operating day, and over time limit

the uncertainty over generator performance and response to ensure the most cost-effective set of resources are providing SR and avoiding the need to commit additional reserves outside the market based on expected performance during contingency events. And in this way the price of SR will be consistent with the reliability needs of the system.

IV. IT IS JUST AND REASONABLE FOR PJM TO HARMONIZE THE RESERVE MARKETS ACROSS DAY-AHEAD AND REAL-TIME HORIZONS TO GET TIME CONSISTENT PRICES THAT ARE CONSISTENT WITH RELIABILITY AND OPERATIONAL NEEDS

36. Under the current PJM Market design in the Day-ahead Energy Market ("DAM"), PJM does not commit or clear any ancillary services that are actually procured and committed in the Real-time Energy Market ("RTM"). The only capacity that is cleared in the DAM are commitments for Day-ahead Scheduling Reserves ("DASR") that are available to PJM operators within 30 minutes, and the DASR commitments do not entail any requirements for resources in the RTM, nor do the DASR commitments carry any serious penalties for non-performance. First, being committed to DASR in the DAM does not require resources to carry these reserves in real-time operations. Second, it appears the only penalty is losing DASR payments if the generator does not start as requested by PJM in real -time operation.

37. With no real-time performance requirements but for starting at PJM's request within 30 minutes and losing on average only $0.39/MWh in DASR payments,[15] this market does little if anything to try and mirror PJM operations in the real-time energy market. If anything, the rationale for the DASR, which is to account for under-forecasted load forecast error and generator forced outages, the DASR is meant to account for uncertainty

[15] 2018 State of the Market Report, Section 11 at 480, Table 10-27.

that has led to the biasing of cases by operators in real-time operation. PJM operators must commit at least 5.29 percent of peak load to account for load forecast and generating performance uncertainty.[16] On average PJM commits 5,689.9 MW of DASR each day.[17]

A. The Current DAM Design Does Not Allow Energy and Reserve Price Formation that Would Allow Reserve Shortage Conditions to be Anticipated in the DAM

38. In the current DAM, while there may be interaction and substitution effects between energy pricing and DASR pricing, there is no current ORDC to signify the value of shortage of DASR in the DAM. This is in sharp contrast to ORDCs being defined for being short total Primary Reserve (SR + NSR), and also being short SR in the RTM. As a result, prices in the RTM can rise higher than are possible in the DAM.

39. The maximum price that could be reached in the DAM is $2000/MWh if that were the highest cost-based offer submitted, and there are no reserve penalty factors for going short DASR. In the RTM under the current design, it is possible for prices to rise to $3700 per MWh with a maximum cost-based energy offer of $2000/MWh plus being short both Primary Reserves and SR each with maximum penalty factors of $850/MWh each to signify the reserve shortage. And as more intermittent resources enter commercial operation, we could expect to see such price differences between the DAM and RTM due to transient reserve shortages.

40. Consequently, the same physical conditions could exist in both the DAM and RTM, yet the energy prices in the DAM could never rise to the level they would in the RTM due to the lack of time consistency between DAM and RTM prices. Such an outcome cannot be

[16] PJM Manual 13 at 18.

[17] 2018 State of the Market Report, Section 11 at 478.

just and reasonable with the same physical conditions leading to very different pricing outcomes.

41. The above example is the most extreme case. But under normal conditions there is no reason to expect the DAM and RTM prices to be the same under identical load and generator availability conditions since the RTM defines and clears market that do not exist in the DAM.

42. For example, in the RTM, there is an explicit tradeoff that must occur between providing energy and SR and energy and Regulation. As resources are committed for regulation and SR, other more expensive must be ramped up to provide energy raising the energy prices and the SR and Regulation prices until all prices are market clearing and individually rational and prices reflect the reliability needs in the RTM.

43. The same interaction cannot occur in the DAM with DASR only requiring that resources need to be available within 30 minutes, and in most hours the prices of DASR are zero.

B. The Lack of Time Consistency Can Allow Significant Financial Arbitrage between the DAM and RTM based upon Model Differences Alone

44. Given the model differences that lead to price differences even under the same supply-demand conditions, financial players can arbitrage the simple model differences, especially in the most extreme cases, when reliability is at its most vulnerable. Consider the example above where energy prices in the DAM are \$2000/MWh, but energy prices can rise as high as \$3700/MWh in the RTM due to modeling differences. A financial player can clear Decremental Bids ("DEC"), which are financial bids to buy energy in the DAM for \$2000/MWh, and then sell back that position in the RTM at \$3700/MWh.

45. Even during a normal operating day, it still may be possible to arbitrage the reserve market model differences under the current design. In the RTM with energy, Regulation,

SR, and NSR markets there is an explicit trade-off being made with respect to energy and reserves that will be reflected in energy prices in the RTM. No such tradeoffs are likely to happen in the current DAM construct.

46. Consequently, such financial arbitrage cannot be efficiency enhancing or result in efficient price convergence due to the modeling differences between the DAM and RTM. The DASR market only covers 30-minute reserves and cannot guarantee that there will be sufficient SR and NSR that can respond with 10 minutes available in the RTM. In the extreme, the DASR requirement that is currently in place could be satisfied in total with reserves that can only respond in more than 10 minutes but less than 30 minutes. The implication is that in the RTM, dispatch and commitments will change from the DAM to ensure sufficient SR and NSR as well as Regulation that is not committed or defined in the DAM. In this way, it would be difficult during normal operating conditions for Virtual Transactions to facilitate DAM and RTM price convergence.

47. Finally, absent any of the proposed changes offered by PJM, this inefficient arbitrage of modeling differences would only become more prevalent as there is increasing penetration of renewable resources whose output is intermittent and highly variable. As overall generation output becomes more uncertain, absent changes there will be an even greater tendency to commit resources out-of-market to ensure reliable operations leading to even greater price differences between the DAM and RTM.

C. Differing Dispatch Patterns Due to Reserve Market Modeling Differences Can Lead to Significant Positive or Negative Balancing Congestion that Must be Borne by Real-time Load and Can Lead to Inefficient Arbitrage through Up-To Congestion ("UTC") Transactions

48. Since the reserve markets do not match up between the DAM and the RTM, even for the same load and the same generator availability, there can easily be differences in the real-

time dispatch and commitment of reserves than would be indicated by DAM commitments. This has two related effects on congestion differences between the DAM and RTM.

49. First, Real-time load could likely be exposed to positive or even negative congestion within the RTM. If the congestion is “negative”, meaning that in the RTM generation is paid more than loads pays, this will be an uplift charge to Real-time Load that cannot be hedged by load in any meaningful way. If congestion is positive, the additional congestion rents accrue the Real-time load. But the direction of balancing congestion is uncertain In either case, the changing dispatch between the DAM and RTM due to the differences in reserve markets changes the balancing congestion charges that are paid by load.

50. Second, for UTCs, the reserve market modeling differences may create incentives for inefficient arbitrage between DAM and RTM congestion. Such arbitrage is inefficient in the sense that it that only seeks to arbitrage the model differences in much the same way that financial market participants can arbitrage model differences with INCS and DECs as explained above

D. PJM’s Proposal to Align Reserve Markets Between the Day-Ahead Energy Market and Real-Time Energy Market is Just and Reasonable and Resolves the Time Consistency Problem Inherent in the Current Design

51. PJM proposes to add Regulation and Frequency Response, SR, NSR, and a 30-minute reserve product to the DAM and add the 30-minute reserve product to the RTM so that the suite of energy and ancillary service markets is identical between the DAM and RTM.

Each of the reserve products will have the same ORDC in both the DAM and RTM as proposed by PJM.[18]

52. Given this change, the DAM and RTM will be time consistent. That is, for a given load and generator commitments in the DAM for energy and ancillary services, if nothing changes between the DAM and RTM, the pricing, dispatch, and reserve commitment outcomes will be the same.

53. As explained above, the time consistency between the DAM and RTM will efficiently and properly signal reserve shortage conditions in the DAM that are expected to be encountered in the RTM. Such time consistency of price signals then allows market participants to make decisions that are economically rational that will also have the effect of helping ensure reliability in real-time operations. For example, if the DAM indicates an impending reserve shortage condition through the DAM, loads can make decisions to reduce consumption in the RTM to sell back their position to help alleviate their position and at the same time reducing load helping reduce real-time reserve shortages.

54. Bringing in the inherent uncertainty that exists in real time operations due to load forecast and error and generator performance and outages brings the heretofore opaque commitment of resources whether through the "biasing" of cases its intra-day commitment software known as IT SCED[19] as explained by PJM,[20] or long lead time commitments into the open in a transparent manner into the DAM through the use of

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[18] PJM Filing at 73-74.

[19] IT SCED stands for Intermediate Term Security Constrained Economic Dispatch and is a tool used by PJM Operators to look ahead up to two hours and decide when to commit additional resources with up to two-hour start times, and see what dispatch may look like in a future window. Biasing an IT SCED case means that the operators change the short-term load forecast input into IT SCED to commit additional resources they believe they will need due to errors in load forecast or generator performance.

[20] Pilong Affidavit P 8-11.

ORDCs. The new ORDC proposed by PJM will bring the commitments due such uncertainty ahead into the DAM in an open transparent manner that is reflected in energy and reserve pricing in the DAM. Consequently, time consistency between the DAM and the RTM is restored.

55. Another result by bringing time consistency between the DAM and RTM and using the same ORDC in the DAM, is to avoid the need to resort to out-of-market, non-transparent commitments through the biasing of IT SCED cases or at any point in time between the close of the DAM and real-time dispatch. And to the extent that any additional commitments may need to be made, these will also be transparently reflected through the ORDCs in the RTM and associated pricing.

56. Furthermore, the time consistency between the DAM and RTM will have the effect of eliminating arbitrage based upon modeling differences between the DAM and RTM as enumerated previously. Arbitrage can then serve its intended function of bringing convergence between the DAM and RTM based on overall market fundamentals and supply-demand balance.

57. Finally, the time consistency between the DAM and RTM will reduce the potential for significant positive or negative balancing congestion due to difference in DAM and RTM modeling that can affect balancing congestion charges paid by load and should help minimize this exposure to uncertainty due to balancing congestion resulting from model differences..

V. PJM'S CURRENT OPERATING RESERVE DEMAND CURVES ARE UNJUST, UNREASONABLE, AND UNDULY DISCRIMINATORY

58. PJM's current set of ORDCs, while practical, simple, and a dramatic improvement at the time they were approved by the Commission and implemented by PJM, have outlived

their usefulness. In fact, since PJM first implemented their ORDCs in 2012, PJM has twice made changes to the ORDCs reflecting the need for broader changes to the ORDC paradigm and the flaws in the implicit assumptions made in developing the first generation of ORDCs.[21] For all the specific reasons discussed below, the current set of ORDCs are unjust and unreasonable and unduly discriminatory.

A. The Vertical Nature of the Current ORDC Does Not Reflect the Value of Reserves Beyond the Minimum Reserve Requirement.

59. The original set of ORDCs were represented by a vertical demand curve, where prices ranged from the $0/MWh to the penalty factor price of $850/MWh at the quantity of the reserve requirement, now referred to as the minimum reserve requirement ("MRR"). This ORDC was simply reflecting the way in which PJM had operated its Tier 2 Synchronized Reserve market previously, and this was transferred to the additional market for Non-Synchronized Reserve Market developed with a vertical demand curve.

60. These vertical demand curve suffer from the flaw that they do not value reserves beyond the MRR. The Commission has long held that capacity beyond the installed reserve margin target has value in the capacity market context. Reserves share similar traits to capacity, but yet the value of reserves beyond the MRR are zero.[22]

61. From both an economic and reliability perspective reserves beyond the MRR must have some value, though that value is diminishing at the margin as the increasing amounts of reserves are held on the system. It seem ludicrous on its face that for a 1000 MW MRR the 999th MW has a value at $850/MWh (MRR is not met and if this were the last MW,

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[21] PJM Filing at 24-25

[22] This is not to imply that an ORDC construct is a replacement for the current PJM capacity market construct. But it is simply to draw the similarities for valuing capacity or reserves beyond the target level of procurement.

we would be in a reserve shortage), the 1000th MW has a value of $5/MWh (assuming this is the opportunity cost), and the 1001th MW has a value of zero to the system. Such huge step changes in the value of reserve also has impacts on reserve price formation.

B. There is a Mismatch Between the Value of Reserve beyond the MRR Shown by PJM Operators and the Value Defined in the Market

62. It is abundantly clear that PJM Operators find there is significant reliability value to holding reserves in excess of the MRR. As PJM has stated, Operators are biasing IT SCED cases or even committing long lead time resources outside of the IT SCED window in real-time operation to account for short-term load forecast error and generator performance and outages.

63. From a reliability perspective this is completely logical. Considering the purpose of holding reserves is to be able to maintain energy balance in case of a contingency such as the loss of a large generator, additional load beyond the load forecast or small reductions in generator performance are observationally equivalent to the loss of large generator on the system. But in this case, the "contingency" (higher load than forecast, lower generator output) happens in slow motion rather than the sudden loss of a large generator, but over time the two cases are observationally equivalent.

64. Consequently, PJM Operators have recognized there is real reliability value to holding more reserves beyond the MRR. The MRR is designed to meet the sudden, large contingency. Reserve beyond the MRR have value because they can help PJM meet the challenges of the "slow motion contingency" such that energy balance can be maintained and the Areas Control Error ("ACE") can be kept at zero.

65. In effect, the "true demand" for reserves from an operational reliability perspective is much greater than the market demand which only reflects the MRR to meet the sudden

loss of a generator. And this mismatch renders the current ORDC unjust, unreasonable, and unduly discriminatory.

C. The Current ORDCs in Combination with PJM Operator Practice Can Result in Large Step Changes in Reserve and Energy Pricing That May not be Reflective of Actual System Conditions and Could Jeopardize Reliability

66. PJM's original ORDC was a single step, vertical line at the MRR. In the event of transient reserve shortages, if PJM is only holding the MRR in reserve and no more, extreme ramping events could swing prices of reserves from $0/MWh to $850/MWh with similar effects on energy prices over short periods of time. In response to Order No. 825, PJM implemented a 190 MW step beyond the MRR in an effort to smooth out energy and reserve price swings due to possible transient shortages recognizing the inherent price volatility associated with the vertical ORDC.[23]

67. PJM has provided analysis that shows how often there would have been transient reserve shortages absent operator actions to hold additional reserves outside the market. In 2018 there would have been 29 percent of 5-minute intervals in which PJM would have experienced a transient shortage of reserves had operators not committed extra resources to provide reserves.[24] Clearly operator actions that are non-transparent, but necessary for reliability are affecting market prices as the additional reserves are not transparently reflected in price formation.

68. From a reliability perspective, PJM's analysis indicates that absent operator actions, in 29 percent of 5-minute intervals, PJM would have been at risk for involuntarily shedding firm load had it been short reserves and the largest contingency had occurred. Yet, the

[23] PJM Filing at 24-25

[24] Pilong Affidavit P 16, Table 1.

cost for avoiding these scenarios is also not reflected in reserve and energy market prices as they should be. In effect, load is not facing the "true cost" in the form of prices consistent with the reliability needs, while generation is not receiving the "true marginal value" provided to the system for avoiding these reliability risks.

69. In effect, PJM Operator actions, consistent with reliability needs, is helping to avoid unnecessary price volatility due to transient shortages with vertical ORDCs, yet these actions are not being reflected in price formation. The combination together is unjust, unreasonable, and unduly discriminatory.

D. The Current Penalty Factor for being Short Reserves is Inconsistent with The Cost of Operator Actions to Maintain Reserves at the MMR and Implicitly Shifts Risks between Market Participants.

70. The current penalty factor for going short reserves is $850/MWh. At the time the ORDC was first implemented in PJM, this was estimated to be the cost of operator actions taken to ensure sufficient reserves based on a $1000/MWh offer cap and actions taken back in 2007. Much has changed in the interim rendering the current penalty factor inconsistent with the cost of operator actions.[25]

71. First, the energy offer cap can be as high as $2000/MWh so long as the costs up to that level can be supported. This means that PJM operators can take actions through dispatch of resources with costs higher than $850/MWh to maintain the MRR. Second, short-lead time demand response can be utilized at offers up to $1849/MWh, far in excess of the current penalty factor in order to maintain the MRR. In short, the current $850 penalty

[25] For a review of how PJM viewed shortage pricing originally, *See* Sotkiewicz 2010 Shortage Pricing Affidavit.

factor for being short reserves is inconsistent with the costs of reliability needs of the system to maintain the MRR.

72. Leaving the penalty factor at the current level of $850/MWh, in addition to resulting in prices that are not consistent with reliability needs, also has the effect of inefficiently shifting reliability and market risk between different sets of market participants. By keeping the reserve penalty factor at the $850/MWh level, energy prices cannot rise sufficiently to induce loads with a value of lost load ("VOLL") at prices higher enough to induce economically rational load reductions to preserve reliability. In effect the "price risk" for loads who may face the efficient higher prices is being transformed into "reliability risk" that is non-transparently shifted to some loads with much higher VOLL and then face involuntary curtailments.

73. Furthermore, retaining the $850/MWh penalty factor when more expensive operator actions can be taken to maintain reserves at the MRR results in an inefficient transfer of energy market surplus from suppliers to load while at the same time resulting in a reduction in overall surplus in the market overall. Some suppliers are no longer receiving the marginal cost for providing energy and reserves but are being "paid as bid" in a non-transparent manner. Loads that wish to pay as low a price as possible even in the face the reliability needs of the system in real-time operation are on the receiving end of this transfer. But like all surplus transfers due to inefficient pricing, there is a "deadweight loss", which is the aforementioned reduction in overall market surplus from such a strategy. [26]

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[26] *See* Sotkiewicz 2010 Shortage Pricing Reply Affidavit at 9-12, Figures 2a and 2b as an example of this kind of impact.

74. A convenient way to think about this loss of surplus is moving water from one trough to another with a bucket. In moving the water from one trough to another, water may spill out of the bucket, or there may be holes in the bucket that result in a loss of water in moving the water from one trough to another. In effect, the loss of market surplus due to the inefficient transfer of surplus from one group to another is just a "leaky bucket problem". The way to avoid the leaky bucket is to avoid the transfer of surplus from suppliers to load.

75. The "leaky bucket" analogy also applies to the transfer of surplus from one set of loads to another in the transfer of price risk into reliability risk for those loads that have high VOLL. In this instance, the loads that value the energy most may be involuntarily curtailed in favor of lower prices for those loads with a lower willingness to pay for energy. This results in a loss of overall surplus due to transfers between different loads.

VI. OPERATING RESERVE DEMAND CURVES THAT REFLECT THE VALUE OF RESERVES BEYOND THE RESERVE REQUIREMENT IS JUST AND REASONABLE AND CONSISTENT WITH ECONOMIC PRINCIPLES AND RELIABILITY NEEDS

76. PJM's proposed ORDCs cure the flaws in the current ORDC paradigm to arrive at ORDCs that are just and reasonable and reflect the reliability needs of the system by reflecting the following facts: 1) There is a value to reserves beyond the MRR as reflected by PJM Operator actions; 2) Reflects in the reserve markets the need for reserves beyond the MRR to meet load forecast error and changes in expected generator performance; 3) Smooth out reserve and energy price changes that better reflect changing system conditions; and 4) Result in prices that are consistent with Operator actions that prevents the inefficient shifting of risk and surplus between market participants.

77. PJM Operators through their actions have shown there is a reliability and economic value to reserves beyond the MRR to meet "slow motion" contingencies based on errors in load forecasts and unanticipated changed in generator performance and outages. The proposed ORDCs reflect this value and by accounting for the need for extra reserves should minimize out-of-market operator actions to maintain operational reliability that cannot be reflected in market prices.

78. The downward sloping ORDC allows for a much smoother pricing transition to reflect ever tightening system conditions. As the amount of reserves beyond the MRR declines with a tightening supply-demand balance, the price of reserves and energy should increase, but in a much more orderly manner until the reserve levels reach the MRR. In this way, both load and generation are getting more advanced warning of tightening system conditions as reserve and energy prices rise. For load, this is an indication that there may be opportunities to voluntarily reduce consumption as prices rise. For generators, it is a signal to be prepared to provide as much energy as possible to the system with the economic incentives through higher prices to ensure optimal performance and output.

79. With a reserve penalty factor that reflects the cost of operator actions to maintain reserves at the MRR, market price and reliability risk is appropriately assigned to those loads based upon their willingness to pay for energy. With reserve prices allowed to rise to the cost of operator actions, those loads with lower values to energy consumption have an incentive to economically reduce consumption while loads with high willingness to pay can continue to consume energy, albeit at higher prices.

80. Moreover, with reserve prices allowed to rise to the proposed $2000/MWh penalty factor in the event of a reserve shortage, generators are being compensated at the marginal cost of energy considering the reliability implications of being short the MRR. In this case, inefficient transfers between load and generation are avoided with the total market surplus being maximized.

VII. SIMULATIONS RUN BY PJM AND THE IMM SHOW THE DIRECTIONAL LEVEL OF INEFFICIENT PRICING DUE TO OPERATOR ACTIONS TO MAINTAIN RELIABILITY OUTSIDE THE CURRENT MARKET CONSTRUCT

81. PJM in its filing has provided simulation results showing the impact of committing resources within the market paradigm as well as the stand-alone effect of implementing its proposed ORDC framework.[27] The IMM has also released its own set of simulations showing the effects of adding PJM's proposed ORDC under slightly different assumptions.[28] In both cases, the simulations show that price formation under PJM's ORDC proposal improves and predictably shows the pricing effects of accounting for committing resource through the ORDC rather than out of market.[29]

82. PJM breaks it simulations down into a decomposition showing the effect of simply committing resources within the market framework and then within the market framework with its proposed ORDCs. In the first step of the decomposition, what PJM

[27] Keech Affidavit PP 33-46

[28] MA, IMM for PJM, *ORDC Simulation Results: Version 2*, May 10, 2019. Available at http://www.monitoringanalytics.com/reports/Reports/2019/IMM_ORDC_Simulation_Results_Version_2_20190510.pdf. ("IMM ORDC Simulation").

[29] The IMM shows price impacts of Moving to an ORDC with full unit commitment, but the ORDC differs based on only using 15-minute uncertainty window and comes up with a total price impact of $1.81/MWh. PJM's total impact using a slightly different 30-minute uncertainty window to define the ORDC comes up with a total price impact of $1.96/MWh. See IMM ORDC Simulation, Table 1 at 3.

calls Case B, it is assumed that unit commitment can be run in real-time to show the pricing effects of committing resources within the market, but with the current ORDCs.[30] Committing resources within the market without any other changes shows the impact of operator actions outside the market. Energy and reserve prices increase reflecting the additional commitments within the market.[31]

83. PJM then runs what it calls Case C, which is the case with the proposed ORDCs in place in which units will be committed for reserves or dispatched for energy based on the ORDCs.[32] Implicitly, the ORDCs account for the fact that extra units may be committed for reserves and energy as in Case B, but with the new ORDCs in place. The price difference between Case B and Case C is relatively small showing that the major benefits of PJM's proposal is to commit units within the market framework rather than outside the market as is done today.[33] The addition of the ORDCs handles both the in-market commitment and the addition of a downward sloping ORDC that values reserves beyond the MRR.

84. The IMM shows similar pricing results in a directional sense. The IMM has run what it calls its Case C, similar to PJM's Case C with ORDCs, but with the ORDCs defined slightly differently. While the IMM disagrees with PJM's use of its Case B to run unit commitment in real-time,[34] PJM's decomposition is a useful and informative analysis

[30] Keech Affidavit P 39.

[31] Keech Affidavit PP 38-40 and Table 3.

[32] Keech Affidavit PP 41-42.

[33] Kecch Affidavit P 43 and Table 4.

[34] IMM ORDC Simulation at 2.

that shows the impact of ensuring the commitment of resources within the markets absent the proposed ORDCs.

85. In the final analysis, the simulations results from both PJM and the IMM really do not differ in showing the effect of moving from the current market environment to implementing PJM's proposed ORDCs. Both sets of simulation show improved price formation that reflects the real-time uncertainty in load and generation performance and the need to hold reserves to meet the uncertainty of these "slow motion contingencies."

VIII. THE ENERGY AND ANCILLARY SERVICE OFFSET ALREADY HAS AUTOMATIC ADJUSTMENTS EMBEDDED AND NO CHANGES ARE REQUIRED DUE TO THE PJM FILING

86. During the PJM stakeholder process, it was suggested by the IMM, and later adopted by PJM, to propose that there should also be a "credit" provided back to consumers on RPM Capacity Market revenue for market already cleared to reflect increases in energy revenues that will be earned by supply resources due to these changes.[35] The Commission should resist any such "siren calls" for such a claw-back mechanism for multiple reasons.

87. First, supply offers into offers into any RPM Base Residual Auction ("BRA") for a commitment three years into the future are likely based on forward expectations of expected net energy and ancillary service revenues. The actual realization of net energy and ancillary service revenues can change from the forward expectation for a multitude of reasons. Realized energy demand could be higher or lower, fuel prices may be higher

[35] Joe Bowring and Catherine Tyler, Monitoring Analytics ("MA"), Independent Market Monitor for PJM, "Reserve Market Design and Energy Market Price Formation," Presented to the Energy Price Formation Senior Task Force ("EPFSTF"), November 1, 2018 at 21. Available at https://pjm.com/-/media/committees-groups/task-forces/epfstf/20181101/20181101-item-06-reserve-market-design-and-simulation-results-imm-proposal.ashx. This proposal was adopted by PJM shortly thereafter. *See* PJM Interconnection, LLC, "Proposed Reserve Market Enhancements", Presented at EPFSTF, December 14, 2018 at 58-59. Available at https://pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-04-price-formation-proposal-overview.ashx.

or lower, and or the configuration of market supply due to retirements or new entry can have an effect on prices.

88. If net energy and ancillary service revenues are lower than expected due to changing market fundamental, no load or consumer has proposed to "make generators whole", nor have load or consumers groups asked to "be made whole" if market conditions change that result in higher revenues. Such talk sounds like a return to the "bad old days" of cost-of-service regulation with poor incentives for cost cutting on the part of suppliers, and poor incentives for loads to manage their consumption wisely. Any mechanisms that returns wholesale power markets toward cost-of-service regulation must be rejected out of hand given the superior incentives provided by well-designed markets.

89. Second, the Net Energy and Ancillary Service Offset ("Net EAS Offset") as used in the RPM Capacity market for the purposes of calculating the Net EAS Offset revenue for the Reference Resource, a combustion turbine, as a historic three-year rolling average has just been reaffirmed by the Commission in the latest Quadrennial Review Order as just and reasonable.[36] As the PJM proposed changes go into effect and are allowed to work, the underlying changes in the Net EAS Offset revenues will be updated over a three-year horizon so that all suppliers and demand-side market participants can work these new expectations into the supply offers and demand bids. Just as changes in underlying gas prices and generator dispatch have been worked into expectations in recent years.

[36] PJM Interconnection, L.L.C, 167 FERC ¶ 61,029 (2019) ("2019 Quadrennial Review Order") P 119. The Commission stated, "We recognize PJM's concern regarding the inherent difficulty of estimating energy market revenues that will be realized in future years and the risk of variance between estimated and actual EAS revenues. We find that PJM's election to continue using historic data to calculate the EAS Offset is a reasonable method by which to account for the EAS revenues earned by generators. Furthermore, the existing historic EAS Offset calculation methodology, which PJM does not propose to change, has previously been accepted as just and reasonable."

90. Third, from an ancillary service revenue perspective, nothing will change for the Reference Resource. The current level of ancillary service revenue built into the Net EAS Offset for the Reference Resource is a fixed dollar value of $2,199/MW-year associated with payment through an average FERC-approved cost-of-service rates to provide Reactive Power and Voltage Support service as required under the PJM Interconnection Service Agreement ("ISA").[37] So, the change in ancillary service prices as projected under the PJM proposal would not affect the Reference Resource ancillary service revenues in any case.

* *

91. This concludes my affidavit.

[37] PJM Tariff in Attachment DD, Section 5.10 (a) (v) A).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER19-1486-000**
PJM Interconnection, L.L.C.	**)**	**Docket No. EL19-58-000**
		(Not consolidated)

AFFIDAVIT OF PAUL M. SOTKIEWICZ, PH.D.

Paul M. Sotkiewicz, Ph.D., being duly sworn, deposes and states that the statements contained in the foregoing Affidavit of Paul M. Sotkiewicz, Ph.D. are true and correct to the best of his knowledge and belief.

Paul M. Sotkiewicz, Ph.D.

Subscribed and sworn to before me
this 15th day of May 2019

R Shah
Notary Public for
the State of IL

My Commission expires: 7/16/2019

"This is an original document"

State of Illinois - County of Cook
This instrument was acknowledged before me on 5/15/2019 (Date) by
Paul Sotkiewicz

R Shah
"OFFICIAL SEAL"
R. SHAH
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES 7/16/2019

Exhibit 1

to the

Affidavit of Paul M. Sotkiewicz

PAUL M SOTKIEWICZ, Ph.D.
President and Founder, E-Cubed Policy Associates, LLC
5502 NW 81st Avenue, Gainesville, FL 32653
E-mail: drpaulg8r@gmail.com Phone: +1-352-244-8800 Mobile: +1-610-955-2411

EDUCATION

PhD, Economics, University of Minnesota, 2003
M.A., Economics, University of Minnesota, 1995
B.A. (High Honors), History/Economics, University of Florida, 1991

PROFESSIONAL AND ACADEMIC EXPERIENCE

2016- President and Founder, E-Cubed Policy Associates, LLC, Gainesville, FL

- Founded to provide expert advice, testimony, and policy research to private sector and government clients at the intersection of energy, environmental, and economic policy and regulation
- Provided capacity market design expertise to the Alberta Electric System Operator in 2017 as they started their transition from an energy-only market to a combined energy and capacity market
- Authored a Meter Data Study for the NYISO encompassing a survey of metering requirements for demand resources and distributed energy resources in key ISO/RTO markets, the current use of demand response baseline methodologies and possible use of such baselines for distributed energy resources in the context of REV in New York.
- Work with clients in generation and merchant transmission development projects in different parts of PJM related to helping them through the interconnection process, understanding market rules, and regulatory policy and economic advice in the face of changing market rules.
- Supporting clients in docketed proceedings at FERC and at the Florida Public Service Commission providing expert testimony and analysis to be used in regulatory proceedings. These proceedings include need determinations, rate filings, RTO market design changes, and policy related proceedings.
- Supporting US government initiatives in exporting knowledge and experience regarding US electric power market development to the Chinese government as they undertake green energy initiatives and look to improve the overall efficiency of the power system.

2015-2016 Contractor, YOH Inc. and working under the title of Senior Economic Policy Advisor, PJM Interconnection, L.L.C., Audubon, PA
2010-2015 Chief Economist, Market Services Division, PJM Interconnection, L.L.C., Audubon, PA
2008-2010 Senior Economist, Market Services Division, PJM Interconnection, L.L.C., Audubon, PA

- Provide analysis and advice with respect to the PJM market design and market performance including demand response mechanisms, intermittent and renewable resource integration, market power mitigation strategies, capacity markets, ancillary service markets, and the potential effects of environmental policies on the PJM markets.
- Co-authored papers related to effects of the proposed Waxman-Markey climate change bill in 2009, the implementation of the Mercury and Air Toxics Standards (MATS) and Cross State Air Pollution Rule in 2011, and the potential effects of the EPA-proposed Clean Power Plan in 2015.
- Led the Stakeholder Process to implement reserve shortage pricing in PJM in 2009-2010 and provided expert testimony associated with FERC filings in 2010.
- Co-authored paper to explain various market and policy concepts for PJM and its stakeholders including a paper explaining generator costs and compensation in 2010, a paper on possible routes to take on transmission cost allocation in 2010, and a whitepaper on capacity market issues in 2012.
- Advised PJM executives on market power mitigation issues related to the Three Pivotal Supplier test and cost-based offers used for market power mitigation in the PJM Energy Market in 2008-2009

- Advised PJM executives and Board of Managers on demand response compensation prior to the issuance of FERC Order 745.
- Supported and advised the Capacity Market Operations staff and PJM executives on all matters related to the Reliability Pricing Model (RPM) capacity market including implementation of the Minimum Offer Pricing Rule in its various iterations, determinations and/or reasonableness of Market Seller Offer Caps during disputes between Capacity Market Sellers and the Independent Market Monitor.
- Provided advice to Capacity Market Operations staff and PJM executives on the RPM Triennial Parameter Review Process in 2011 and in 2014 including supporting legal staff in making filings, providing expert testimony, and providing expert advice during the 2011 and 2012 hearing and settlement process at FERC.
  Supported and provided advice to Capacity Market Operations staff and PJM executives on Capacity Performance through stakeholder presentations, regulatory filings, and working jointly with the IMM in developing many of the ideas and concepts taken from ISO New England's Pay for Performance design for us in PJM.
- Supported the Federal State Government Policy outreach through by providing subject matter expertise during one-on-one meetings with regulatory staff and Commissioners related to any issues of mutual interest and import between PJM and state commission, state environmental regulators, FERC staff, and EPA staff as needed.
- Co-authored and co-led PJM's responses to the Independent Market Monitor's (IMM's) *State of the Market Reports* as well as remaining in communication with the IMM on various matters of concern and interest related to PJM market performance and design.
- Led technical and non-technical external outreach efforts to promote PJM markets or explain PJM positions on policy or market design issues of current interest to industry stakeholders including academic audiences, and invited presentations at industry sponsored events.
- Provided support in gas/electric coordination discussions within PJM and the between the power and gas industries, as well as operations support during critical operating periods in January 2014 through calls and inquiries to PJM generators and pulling environmental permits to better understand generator operating limitations on back-up fuel.
- Provided periodic reports on market performance and the state of PJM's markets to the PJM Board of Managers Competitive Markets Committee including the relationship between PJM's markets and major fuel market, environmental policy, and macroeconomic trends.
- Acted in the role of an internal consultant and advisor to all PJM departments and divisions, as needed, to address any questions or concerns surround market performance, market design, and general economic or environmental policy questions.
- Supported development and issuance of the PJM Renewable Integration Study by outside vendors.

2000–2008 Director of Energy Studies, Public Utility Research Center and Lecturer,
Department of Economics, University of Florida, Gainesville, FL

- Designed and delivered executive education and outreach programs in electric utility and regulatory policy and strategy for professionals in government, regulatory agencies, and industry primarily for developing countries.
- Responsible for electricity regulatory policy curriculum for the *PURC/World Bank International Training Program on Utility Regulation and Strategy* offered twice per year for 65 to 95 industry and regulatory professionals in each course.
- Acted as the electricity expert and liaison to the Florida electric utilities who were contributing members of PURC.
- Developed electricity related topics and obtained speakers for the PURC Annual Conferences held each February on matters related to environmental policy, wholesale market restructuring, so-called "hurricane hardening" of power systems after the 2004-2005 hurricane seasons, and other policy related matters of interest to the state of Florida.

- Served the PURC liaison to the consultants retained by PURC to evaluate the hardening of electricity infrastructure in the wake of the 2004 and 2005 hurricane seasons.
- Conducted original academic research related to electricity regulation and policy and published in peer reviewed academic and policy journals
- Developed customized regulatory training courses or sessions jointly prepared with other organizations for on-site delivery in Panama, Trinidad & Tobago, Brazil, Mexico, Peru, Bolivia, Argentina, Grenada, South Africa, Zambia, Namibia, and Cambodia
- Served as an advisor and subject matter expert on wholesale restructuring and market issue to Florida Governor Jeb Bush's *Energy 2020 Study Commission* 2000-2001.
- Taught classes as needed in the Economics Department on environmental economics, regulatory economics, and a large lecture class of managerial economics

1999–2000 Economist, Office of Markets, Tariffs, and Rates, United States Federal Energy Regulatory Commission, Washington, DC

1998–1999 Economist, Office of Economic Policy, United States Federal Energy Regulatory Commission

- Provided analysis and research related to filings made by ISO/RTO markets as they commenced operations as centralized wholesale power markets.
- Led the economic analysis and evaluation of the NYISO wholesale power market in its initial filings of its market design and subsequent filings after operations commenced.
- Led economic analysis and evaluation of multiple filings by the California ISO related to requested market design changes filed after starting operations in 1998.
- Supported analysis and evaluation of other ISO/RTO markets as needed.
- Supported and provided analysis on merger applications as needed.
- Conducted original research while on the staff of the Chief Economic Advisor in the Office of Markets, Tariffs, and Rates related to unit commitment models used in day-ahead electricity markets and pricing in the presence of lumpy decisions and operational characteristics (technically known as non-convexities).

1992–1998 Instructor, Department of Economics, Augsburg College, Minneapolis, MN

- Taught small classes of introductory microeconomics, labor economics, money and banking, and environmental economics

1992–1998 Instructor, Department of Economics, University of Minnesota, Minneapolis, MN

- Taught large lecture classes of primarily introductory microeconomics to classes of up to 600 students 3 times per year, managing a staff of teaching assistants and graders and developing curriculum and exams.
- Taught smaller classes of introductory microeconomics as well as environmental economics

PUBLICATIONS AND BOOK CHAPTERS

Covino, Susan, Andrew Levitt, and Paul Sotkiewicz, "The Fully Integrated Grid: Wholesale and Retail, Transmission and Distribution", in *Future of Utilities- Utilities of the Future: How Technological Innovations in Distributed Energy Resources Will Reshape the Electric Power Sector*, Fereidoon P. Sioshansi, editor, Chapter 22, pp.417-434, 2016.

M. Ahlstrom; E. Ela; J. Riesz; J. O'Sullivan; B. F. Hobbs; M. O'Malley; M. Milligan; P. Sotkiewicz; J. Caldwell, "The Evolution of the Market: Designing a Market for High Levels of Variable Generation", *IEEE Power and Energy Magazine*, Volume: 13, Issue: 6, 2015, Pages: 60 – 66.

Bresler, Stuart, Paul Centollela, Susan Covino, and Paul Sotkiewicz, "Smarter Demand Response in RTO Markets: The Evolution Towards Price Responsive Demand in PJM", in *Energy Efficiency: Towards the End of Demand Growth*, Fereidoon P. Sioshansi, editor, Chapter 16, pp.419-442, 2013.

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P. M. Sotkiewicz, "Value of Conventional Fossil Generation in PJM Considering Renewable Portfolio Standards: A Look into the Future", *Power and Energy Society General Meeting, 2012 IEEE*

R. F. Chu; P. F. McGlynn; P. M. Sotkiewicz, "Transmission Planning for Generation at Risk due to Environmental Regulations and Public Policy Initiatives" *Power and Energy Society General Meeting, 2012 IEEE*

P. M. Sotkiewicz; J. M. Vignolo, "The Value of Intermittent Wind DG under Nodal Prices and Amp-mile Tariffs", *Transmission and Distribution: Latin America Conference and Exposition (T&D-LA), 2012 Sixth IEEE/PES*

Helman, Udi, Harry Singh, and Paul Sotkiewicz, "RTOs, Regional Electricity Markets, and Climate Policy", in *Generating Electricity in Carbon Constrained World,* Fereidoon P. Sioshansi, editor, Chapter 19, pp.527-564, 2010.

J. C. Smith; S. Beuning; H. Durrwachter; E. Ela; D. Hawkins; B. Kirby; W. Lasher; J. Lowell; K. Porter; K. Schuyler; P. Sotkiewicz, "The Wind at Our Backs", *IEEE Power and Energy Magazine*, Volume: 8, Issue: 5, 2010 Pages: 63 - 71

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Sotkiewicz, Paul M. and Vignolo, J. Mario, "Towards a Cost Causation Based Tariff for Distribution Networks with DG." *IEEE Transaction on Power Systems,* Vol. 22, No. 3, August 2007, pp. 1051-1060.

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Sotkiewicz, Paul M. and Vignolo, Jesus Mario "Allocation of Fixed Costs in Distribution Networks with Distributed Generation," *IEEE Transaction on Power Systems*, Vol. 21, No. 2, May 2006, pp. 1013-1014.

Sotkiewicz, Paul M., and Lynne Holt, "Public Utility Commission Regulation and Cost Effectiveness of Title IV: Lessons for CAIR." *Electricity Journal* 18(8): 68-80, October 2005.

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O'Neill, Richard P., Helman, Udi, Sotkiewicz, Paul M., Rothkopf, Michael H., and Stewart, William R. Jr., "Regulatory Evolution, Market Design, and the Unit Commitment Problem" The Next Generation of Unit Commitment Models, B. Hobbs, M. Rothkopf, R. O'Neill, and H.P. Chao editors. 2001.

Sotkiewicz, Paul M. "Opening the Lines", Forum for Applied Research and Public Policy, Special Issue on the Role of Public Power in Utility Restructuring, Summer 2000, pp. 61-64.

SELECTED WORKING PAPERS AND UNPUBLISHED MANUSCRIPTS

Holt, Lynne, and Paul M. Sotkiewicz. "Understanding Fuel Diversity Trade-Offs and Risks: Making Decisions for the Future (pdf)" University of Florida, Department of Economics, PURC Working Paper, 2007.

O'Neill, Richard P., Sotkiewicz, Paul and Rothkopf, Michael. "Equilibrium Prices in Exchanges with Non-convex Bids." PURC Working Paper, January 2006, updated September 2007.

Sotkiewicz, Paul M. "Cross-Subsidies That Minimize Electricity Consumption Distortions" University of Florida, Department of Economics, PURC Working Paper, 2003.

CONSULTING AND ADVISING EXPERIENCE PRIOR TO JOINING PJM IN 2008

2007 Advisor to the Government of Vietnam regarding the design and experience of wholesale electricity markets as Government looked at the creation of US style ISOs to attract investment in generation assets for IPPs

2007 Independent Expert in the Matter of the Public Utilities Commission of Belize Initial Decision in the 2007 Annual Review Proceeding for Belize Electricity Limited

2006 Advisor to the Division of Air Resource Management, Florida Department of Environmental Protection (FDEP) Regarding Implementation the Clean Air Interstate Rule (CAIR)

HONORS AND AWARDS

2007	Fulbright Senior Specialist Grant in Economics with a specific request for expertise in electricity markets, electricity regulation, and distribution tariff design, Universidad de la República, Montevideo, Uruguay.
2007	Principal Investigator, PPIAF/World Bank Grant to conduct two on-site training courses on the regulation of the electric power sector and on independent power producers and power purchase agreements for the Electricity Authority of Cambodia. Grant award $59,900.
2006	"Efficient Market Clearing Prices in Markets with Non-Convexities" published in *European Journal of Operational Research* received New Jersey Policy Research Organization Bright Idea Research Award in Decision Sciences.
2003	Transportation and Public Utilities Group, Ph.D. Utilities Dissertation Award for "The Impact of State-Level Public Utility Commission Regulation on the Market for Sulfur Dioxide Allowances, Compliance Costs, and the Distribution of Emissions"
1992-97	Distinguished Instructor, Department of Economics, University of Minnesota
1995-96 1994-95 1993-94 1992-93	Walter Heller Award for Outstanding Teaching of Economic Principles, Department of Economics, University of Minnesota
1991-92	Distinguished Teaching Assistant, Department of Economics, University of Minnesota
1991	Phi Beta Kappa, University of Florida

Referee and Review Experience

IEEE Transactions on Power Systems

Ecological Economics

Environmental Science and Technology

Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure, prepared for The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II, September 28, 2006 Washington, DC

National Research Council of the National Academy of Sciences report entitled "Changes in New Source Review Programs for Stationary Sources of Air Pollutants", February 2006

California Energy Commission (CEC) Energy Innovations Small Grant (EISG) Program

Energy Journal

Journal of Environmental Economics and Management

IEEE PES Letters

IASTED International Journal of Power and Energy Systems

The Next Generation of Unit Commitment Models B. Hobbs, M. Rothkopf, R. O'Neill, and H.P. Chao editors

2001.

Professional Affiliations

American Economic Association
International Association for Energy Economics
Association of Environmental and Resource Economists
IEEE Power and Energy Society

EXPERT TESTIMONY

PJM Interconnection, L.L.C. FERC Docket No. ER09-1063-004, Affidavit in Support of PJM's Compliance Filing with Order No. 719 and Order on Compliance Filing *PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,250 (2009). June 18, 2010
In support of its compliance filing to establish a mechanism that ensures appropriate pricing during periods of operating reserve shortages, as required by the Commission's Order No. 719, I provided the following: 1) A high-level overview of PJM's markets, planning, and operations, including a description of what is meant by an operating reserve shortage, and how such shortages arise; 2) An overview of PJM reserve requirements, current reserve market structure, and data on PJM's prices and operations at times when the grid it manages has experienced operating reserve shortages; 3) A showing why PJM's then current scarcity pricing not satisfy the Commission's Order No. 719 criteria for operating reserve shortage pricing mechanisms; 4) Description of the main elements of PJM's proposal to comply with Order No. 719's shortage pricing policy, and how PJM's proposal satisfies the six criteria for reserve shortage pricing set by Order No. 719.

PJM Interconnection, L.L.C. FERC Docket No. ER09-1063-004, Affidavit in Support of Answer to Comments and Motion for Leave to Answer to Protests, August 23, 2010. The purpose of this affidavit is to provide the following regarding PJM's proposed shortage pricing mechanism: 1) The complementary relationship between capacity adequacy in the Reliability Pricing Model ("RPM") and shortage pricing; 2) Additional evidence showing why PJM' shortage pricing proposal leads to energy prices that reflect the cost and/or value of energy, allocates energy to those who value it most, enhance operational reliability, and leads to efficient market outcomes while the alternate proposal from the Independent Market Monitor (IMM) fails to achieve any of these goals; 3) An explanation of how the proposed mechanism is consistent with shortage pricing mechanisms in the New York Independent System Operator ("NYISO") and ISO New England ("ISO-NE") that the Commission has already approved as Order 719 compliant.

PJM Interconnection, L.L.C. FERC Docket No. ER12-513, Affidavit in Support of Filing to Update its RPM Auction Parameters (aka Triennial Review) December 1, 2011. This affidavit was submitted in support of three aspects of PJM's proposed changes related to PJM's capacity market, known as the Reliability Pricing Model ("RPM") including: 1) the continued use of a nominal levelized approach to calculating the estimated Cost of New Entry ("CONE") that is used in RPM's Variable Resource Requirement ("VRR") Curve; 2) retention of a combustion turbine ("CT") as the Reference Resource.

PJM Interconnection, L.L.C. FERC Docket No. ER-14-2490, Affidavit in Support of Filing to Update its RPM Auction Parameters (aka Quadrennial Review) September 25, 2014 This affidavit was submitted in support of five aspects of PJM's proposed changes related to PJM's capacity market, known as the Reliability Pricing Model ("RPM"): 1) adoption of The Brattle Group's ("Brattle") recommended VRR Curve shape right shifted by 1% of the Installed Reserve Margin ("IRM"); 2) continued use of a nominal levelized approach to calculating the estimated Cost of New Entry ("CONE") that is used in RPM's Variable Resource Requirement ("VRR") Curve; 3) retention of a combustion turbine ("CT") as the Reference Resource; 4) use of a composite of Bureau of Labor Statistics ("BLS") indices to adjust Gross CONE estimates in between periodic VRR parameter reviews; and 5) adoption of the labor estimates provided by the PJM Independent Market Monitor ("IMM") to determine Gross CONE values.

Grid Reliability and Resilience Pricing FERC Docket No. RM18-1, Affidavit in Support of the Electric Power Supply Association (EPSA), October 23, 2017. This affidavit provides evidence the Department of Energy Notice of Proposed Rulemaking ("NOPR" or "Proposal") released on September 28, 20171 and appearing in the Federal Register on October 2, 2017 does nothing to enhance reliability or "resiliency" of the bulk power system and will only succeed in distorting wholesale power markets while also raising costs. Consequently, my affidavit supports EPSA's contention the NOPR should be rejected outright by the Commission.

ISO New England Inc. and New England Power Pool Participants Committee, FERC Docket No. ER18-620-000, Affidavit in Support of the Protest of the New England Power Generators Association, Inc. January 29, 2018. In summary, my affidavit explains that the proposed updated DDBT from $5.50/kW-month to $4.30/kW-month: 1) Relies on a flawed and logically inconsistent methodology that differs from the DDBT methodology approved by the Commission three years ago; 2) Sets a dangerous precedent in ISO-NE taking a position on the direction of its Forward Capacity Market ("FCM") in terms of supply-demand balance and expected market prices that could anchor expectation of market participants. The anchoring of such expectations can change FCA bidding and operational behavior that could harm reliability; 3) The previous methodology approved by the Commission of using Static De-List Bids from oil steam and oil combustion turbine generators remains the appropriate methodology for determining the DDBT; and 4) The cost-based DDBT is likely higher than for FCAs 10-12 given that net going forward costs for oil steam and oil combustion turbine units has likely increased given their age, and other risks and opportunity costs that may be coming into play. My affidavit concludes that the current DDBT should be retained until such time as a new DDBT threshold and be determined using the current Commission-approved methodology following the discovery of the actual costs and risks faced by oil units.

Petition for Determination of Need for Seminole Combined Cycle Facility in Docket No. 20170266-EC and Joint Petition for Determination of Need for Shady Hills Generating Facility in Docket No. 20170267-EC, January 29, 2018. Testimony and Exhibits on Behalf of Quantum Pasco Power, LP, Michael Tulk, and Patrick Daly. My testimony supports the notion that there is no need for either combined cycle facility as Seminole Electric has consistently over-forecast its load growth since the "great recession" and that once correcting for these large errors, there is no need to build two new combined cycle facilities when there where other lower cost merchant generator facilities that offered their capacity to Seminole.

PJM Interconnection, L.L.C. FERC Docket No. E18-34, Affidavit in Support of EPSA's Filing and Comments in PJM's Fast Start Pricing Proposal, March 14, 2018 My affidavit in this proceeding provides support for PJM's desire to allow resources with up to two-hour start up times to be considered "fast start" resources and to set price in accordance with the fast start pricing principles the Commission has enumerated in its Fast Start Pricing NOPR. I explain PJM's use of IT SCED and request to allow two-hour start time resources to set prices as fast start resources is entirely consistent with the ideas the Commission has enumerated with respect to fast start pricing.

PJM Interconnection, L.L.C. Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, FERC Docket No. ER18-1314-000, Affidavit is Support of Comments of American Petroleum Institute, JPower USA Development, Ltd., and Panda Power generation Infrastructure Fund, LLC May 7, 2018. My affidavit provides evidence that 1) The PJM Capacity Repricing Proposal is not just and reasonable and is unduly discriminatory and results in an inefficient commitment of resources; 2) The alternative proposal from PJM, MOPR-Ex, is just and reasonable and results in the most efficient and cost-effective se of resource commitments; and 3) The current and previous iterations of the MOPR are not just and reasonable and are unduly discriminatory because they do not apply to existing resources and they only apply to gas-fired resources. Furthermore, my affidavit provides evidence that MOPR has always been viewed as a market power mitigation mechanism that was originally intended to thwart or mitigate the exercise of buyer-side market power. I show in this affidavit that MOPR, and in particular MOPR-Ex, still is a powerful market power mitigation tool that mitigates exercise of supplier market power that are facilitated by the current round of state subsidies to generation. Moreover, I show that Capacity Repricing helps facilitate the exercise of supplier market power through three different means.

Grid Resilience in Regional Transmission Organizations and Independent System Operators, FERC Docket No. AD18-7-000, Affidavit is Support of Comments of the American Petroleum Institute, May 9, 2018. This affidavit focuses of the comments submitted by PJM and: 1) Supports the idea that in the context bulk power system markets and operation resilience and reliability are indistinguishable and that markets and well-designed incentives are the best avenue to achieve a resilient and reliable bulk power system; 2) Explains why market mechanisms rather than suspension of market and command and control regimes are better at achieving resiliency/reliability even during emergency conditions and that PJM has not made a case for being given the authority to suspend markets; 3) That PJM has not made the case that price formation through integer relaxation is linked to resilience/reliability while other price formations that are crucial to reliability/resilience such as shortage pricing and fast start pricing are being considered concurrently; and 4) So-called "fuel security" is only a minimal contributor to resilience/reliability while transmission and distribution assets are the leading causes for shedding firm load and gas-fired units have been shown to not even being the leading category of generation outages. With respect to generator reliability/resilience, simply providing additional compensation (or minimize penalties) to generators in wholesale markets, without any ties to generator performance, does nothing to enhance reliability/resilience of generators to withstand or minimize the impact of adverse events on the bulk power system. Experience in PJM prior to, and following the discussion and implementation of capacity performance has shown this to be the case as generator performance has improved even in the face of lower energy market prices.

New England Power Generators Association, Complainant v. ISO New England Inc., Respondent. FERC Docket No. Docket No. EL18-154-000, Affidavit in Support of Complaint and Request for Expedited Consideration of the New England Power Generators Association, Inc. May 24, 2018 This affidavit in support of NEPGA's complaint shows the impact of treating Mystic Units 8 and 9 as a price taker on the ISO-NE markets as well as NEPGA's proposed alternative to accommodating the participation of the Mystic units. Discussions include: 1) treating Mystic and other resources retained for fuel security as price takers will do significant harm to the competitiveness of the FCM market and is inconsistent with the first principles of capacity markets articulated by the Commission; 2) the proposal to insert an above market cost resource into the FCM as a price taker does exactly the same harm as an exercise of buyer-side market power, which he Commission has found to be unjust, unreasonable, and unduly discriminatory; and 3) the proposed remedy offered by NEPGA does not distort the results of the Forward Capacity Auction, results in competitive pricing outcomes in FCA, does not displace otherwise economic resources, and provides better reliability outcomes for ISO-NE load than the current ISO-NE proposal.

New England Power Generators Association, Complainant v. ISO New England Inc., Respondent. FERC Docket No. Docket No. EL18-154-000, Affidavit in Support of the Motion for Leave and Answer of the New England Power Generators Association, Inc. June 19, 2018. This affidavit in support of NEPGA's answer refutes the answer of ISO-NE and protesters and responds that nothing in ISO-NE's answer to the Complaint or the protests to the Complaint provides a basis for ignoring that treating the Mystic Units as price takers would suppress prices below competitive levels and inefficiently displace otherwise economic resources in a manner that is observationally equivalent to the harm done by an exercise of buyer-side market power.

Panda Stonewall, LLC. FERC Docket No. ER17-1821-002, Testimony is Support of Panda Stonewall, LLC Reactive Power Filing, July 2, 2018. This testimony supports Panda Stonewall's reactive power rate case that has gone to hearing and in particular supports the inclusion of firm gas pipeline transportation, the use of proxy cost of capital values from the PJM CONE study, and supports the inclusion of other administrative and overhead costs consistent with fixed, going forward costs incurred by Panda Stonewall to remain in commercial operation. Furthermore, the testimony puts the costs of reactive power into the context of the wider PJM market and other opportunities for compensation and well as providing historical context around the Commission-approved AEP Methodology for reactive power rates.

ISO New England Inc. FERC Docket No. ER18-2364-000, Affidavit in Support of the Protest of the New England Power Generators Association, Inc. September 21, 2018. This testimony supports NEPGAs protest that the proposed ISO-NE treatment of resources held for winter fuel security as price takers in the FCA makes no sense since winter fuel security is not associated with overall resource adequacy which is based on the summer peak. Moreover, the testimony shows clearly the artificial price suppression that would occur based on ISO-NE proposed treatment of resources held for winter fuel security in the FCA.

Calpine Corporation v. PJM Interconnection, L.L.C. Docket No, EL16-49; PJM Interconnection L.L.C. Docket No. ER18-1314-000, ER18-1314-001, EL18-178 Affidavit in Support of the Electric Power Supply Association, October 2, 2018. This testimony refutes the idea that the Commission proposed remedy a resource specific FRR Alternative equally removes both demand and supply from the market and therefore does no harm. Such a mechanism is the equivalent of an exercise of buyer side market power, artificially reduces price below competitive levels, inefficiently displaces lower cost, economic resources with higher cost resources, shifts cost and benefits between market participants, and reduces overall market efficiency. Additionally, PJM market simulations for scenarios from the 2020/2021 auction show the kind of damage that can be done to the market through the proposed remedy or equivalently buyer sider market power by showing prospective price decreases and generation displacement, and the level of subsidy that could be used to facilitate a successful exercise of buyer-side market power.

Panda Stonewall, LLC. FERC Docket No. ER17-1821-002, Rebuttal Testimony is Support of Panda Stonewall, LLC Reactive Power Filing, October 12, 2018. This rebuttal testimony supports Panda Stonewall's reactive power rate case responding to interveners and FERC staff and in particular supports the inclusion of firm gas pipeline transportation, the use of proxy cost of capital values from the PJM CONE study, and supports the inclusion of other administrative and overhead costs consistent with fixed, going forward costs incurred by Panda Stonewall to remain in commercial operation. Furthermore, the testimony puts the costs of reactive power into the context of the wider PJM market and other opportunities for compensation and well as providing historical context around the Commission-approved AEP Methodology for reactive power rates.

In the Matter of the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, New Jersey Board of Public Utilities, BPU Docket No. EO 18080899, Testimony in Support of PJM Power Providers, October 22, 2018. This testimony responds to questions posed by the BPU in this docket and provides analysis showing that the nuclear units in New Jersey seeking ZECs are not in need of them to remain in commercial operation. The testimony shows that these resources, given know forward prices for energy and capacity prices are able to cover their going forward costs in the absence of subsidies in the form of ZECs and will remain in commercial operation in spite of warnings these resources will retire in the absence of ZEC payments.

Calpine Corporation v. PJM Interconnection, L.L.C. Docket No, EL16-49; PJM Interconnection L.L.C. Docket No. ER18-1314-000, ER18-1314-001, EL18-178 Affidavit in Support of the Electric Power Supply Association, November 6, 2018. This testimony responds to the Illinois Commerce Commission's protest that suggests the RPM Capacity Market be eliminated and replaced by an energy-only market construct because the capacity market is not a market at all. It also responds to the notion that markets should account directly for environmental policy and because they do not, the Illinois zero emission credit program for nuclear resources is justified. The testimony refutes these ideas by describing in detail that all markets have administrative rules and that markets can account for environmental policies when properly formulated to put a price on emissions rather than subsidizing resources out-of-market. Moreover, this testimony provides evidence of the need for the RPM Capacity Market to maintain resource adequacy as an energy only construct would not result in sufficient resources covering going forward costs in the energy market alone.

Alberta Utilities Commission, Consideration of ISO Rules to Implement and Operate the Capacity Market, Proceeding No. 23757, Evidence in Support of ENMAX Corporation, February 28, 2019. This evidence outlines the elements of the Alberta Electric System Operator (AESO) proposed capacity market framework that require changes to make align the capacity market with fair, efficient, and openly competitive market principles. The evidence addresses the resource adequacy model, capacity value of resources, penalties and bonuses, market power mitigation, Net CONE determination, and interactions with the energy market framework. The evidence also provides a high-level overview of the objectives of a capacity market and how it should interact with the energy and retail markets in Alberta.

In the Matter of the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, New Jersey Board of Public Utilities, BPU Docket No. EO 18080899, Response to Staff Questions on Accounting for Risk in Support of PJM Power Providers, March 8, 2019. This is a response to BPU staff questions regarding market risk. This response discusses the mitigation of overall market risk based on changing conditions, optimal energy market offers and mitigation of energy market operational risk, and optimal offers and risk mitigation in the capacity market that are available to all generation resources including nuclear resources.

In the Matter of the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, New Jersey Board of Public Utilities, BPU Docket No. EO 18080899, Reply Testimony in Support of PJM Power Providers, March 19, 2019. This reply testimony responds to PSEG comments regarding the need for ZECs for New Jersey's nuclear units. This reply testimony updates the economic analysis showing New Jersey nuclear units are currently profitable and expected to remain profitable in the future. Furthermore, this reply points out that PSEG did not dispute the costs used in the initial analysis or the idea that new entry of combined cycle gas generation can reduce emissions at zero cost at the margin given these resources will enter the market absent subsidies. The reply argues, contrary to what is stated by PSEG, that the threat to retire is not credible given the statements and evidence provided by PSEG in its Securities and Exchange Commission (SEC) filings. This reply also provides evidence that it would be infeasible for PSEG to buy out of its capacity commitments in Incremental Auctions (IAs) given the supply and demand conditions present in IAs to date.

Alberta Utilities Commission, Consideration of ISO Rules to Implement and Operate the Capacity Market, Proceeding No. 23757, Reply Evidence in Support of ENMAX Corporation, April 4, 2019. This evidence replies to the comments of other interveners regarding various elements of the Alberta Electric System Operator (AESO) proposed capacity market framework. The reply evidence responds to intervener comments on elements of the Net CONE determination, capacity and energy market power mitigation, the capacity value of resources inconsistencies between the resource adequacy model and offered supply, and penalties and bonuses.