UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER21-2582-000**

PROTEST OF THE PJM POWER PROVIDERS GROUP

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Pursuant to Rule 211 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules and Regulations,[1] the PJM Power Providers ("P3") submit this Protest,[2] along with supporting affidavits from Dr. J. Arnold Quinn ("Quinn Affidavit") (Attachment A) and Dr. Roy J. Shanker ("Shanker Affidavit") (Attachment B).[3] This Protest addresses the July 30, 2021 filing in this docket by PJM Interconnection, L.L.C. ("PJM") entitled Revisions to Application of Minimum Offer Price Rule ("PJM Filing").

P3 recognizes that certain stakeholders strongly object to the currently effective Minimum Offer Price Rule ("MOPR") because it frustrates certain states' ability to promote their particular preferences for new and existing capacity resources through out-of-market subsidies. P3 agrees that the electric grid is changing and that markets must adapt and evolve in response. P3 is also sympathetic to certain concerns that have been expressed by MOPR critics and believes that there are viable options for improving, or even replacing, the MOPR to adapt to the evolving marketplace. Unfortunately, the PJM Filing is not such an option. As discussed below, the PJM Filing contains numerous fundamental legal defects, would yield an unsustainable market structure and, therefore, must be rejected by the Commission.

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[1] 18 C.F.R. § 385.211 (2021).

[2] P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly designed and well-functioning electricity markets in the PJM Interconnection, L.L.C. ("PJM") region. Combined, P3 members own over 67,000 MWs of generation assets and produce enough power to supply over 50 million homes in the PJM region covering 13 states and the District of Columbia. For more information on P3, visit www.p3powergroup.com. The comments contained herein represent the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue.

[3] These affidavits do not require notarization under the July 26 waiver extension in Docket No. AD20-11.

P3 has reviewed the protest the Electric Power Supply Association ("EPSA") will submit concurrently in this proceeding. P3 supports and adopts the arguments in the EPSA Protest, including its supporting affidavit.

SUMMARY

PJM purports to address perceived flaws in the currently effective "Expanded MOPR." But the proposal PJM concocted here, variously described as a "focused" or "narrow" MOPR,[4] grossly overcorrects by eliminating reasonable "guardrails" against buyer-side market power that PJM itself concedes are mandated by the Federal Power Act ("FPA").[5] Indeed, PJM would remove essential protections against market power and undue discrimination the Commission has expressly held the PJM capacity market *must* have under FPA section 206.[6] PJM's proposed tariff changes are unjust, unreasonable, and unduly discriminatory. They also constitute a blatant collateral attack on orders the Commission is now defending on judicial review. Accepting PJM's revisions would flatly contravene more than a decade of unambiguous Commission determinations affirmed by reviewing courts that uneconomic entry enabled by out-of-market subsidies undermines market confidence and ultimately hurts consumers.[7] Moreover, the Commission's

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[4] *Compare, e.g.*, PJM filing at 1 ("focused MOPR") *and id.* at 20, 23 ("more focused MOPR") *with id.* Attach. C, Affidavit of Peter Cramton on Behalf of PJM Interconnection, L.L.C. ("Cramton Aff.") *passim* ("narrow MOPR" or "Narrow MOPR"). This Protest will use the term "Narrow MOPR" because it more accurate.

[5] *See, e.g.*, PJM Filing at 24 ("[A]ccommodation of state resource mix policies cannot be boundless. The capacity market must have guardrails to protect it from actions by the state or by sellers with Load Interests that would improperly intrude on the wholesale market-clearing price.").

[6] 16 U.S.C. § 824e; *see Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("June 2018 Order"), *order establishing just & reasonable rate*, 169 FERC ¶ 61,239 (2019) ("December 2019 Order"), *order on reh'g & clarification*, 171 FERC ¶ 61,034 (denying rehearing of June 2018 Order), "), *order on reh'g & clarification*, 171 FERC ¶ 61,035 (denying rehearing of December 19 Order), *order on reh'g & compliance*, 173 FERC ¶ 61,061 (2020) ("October 2020 Rehearing Order"*), order on compliance & clarification*, 174 FERC ¶ 61,036, *order vacating footnote*, 174 FERC ¶ 61,109 (2021) (collectively, the "Expanded MOPR Orders"), *appeals pending sub nom. Ill. Com. Comm'n v. FERC*, Nos. 20-1645, *et al*. (7th Cir. Apr. 20, 2020).

[7] *See, e.g.*, *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 (2011) ("2011 MOPR Order"), *reh'g denied*, 137 FERC ¶ 61,145 (2011) ("2011 MOPR Rehearing Order") (collectively, "2011 MOPR Orders"), *aff'd sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 96-97 (3d Cir. 2014) ("*NJBPU*") (adopting *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) ("*Connecticut PUC*")); *ISO New England Inc.*, 162 FERC

orders requiring the mitigation of state subsidies in PJM have been cited and quoted with approval by the United States Supreme Court in its *Hughes* decision finding that certain types of subsidies adopted by PJM states are facially preempted by the FPA.[8]

PJM's new proposals also directly contradict positions that PJM has repeatedly taken over the last decade. In 2011, PJM successfully urged the Commission to revise the MOPR because it was too easily evaded by state-mandated out-of-market subsidies to promote new natural gas-fired resources. PJM further warned the Commission about the dangers of creating "obvious pathways" for self-suppliers to avoid mitigation that would result in the MOPR never being applied.[9] In 2018, PJM again argued emphatically that state subsidies for new and existing capacity resources—this time, existing nuclear and new renewable generation—were having critical adverse market impacts and that Commission action to strengthen the MOPR was essential.[10] Now, however, PJM is proposing to effectively dismantle the MOPR guardrails by restricting review and

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¶ 61,205, at P 21 & n.32 (2018) ("CASPR Order"); *ISO New England, Inc.*, 135 FERC ¶ 61,029, at P 170 (2011) ("2011 ISO-NE MOPR Order"), *reh'g denied*, 138 FERC ¶ 61,027 (2012), *aff'd sub nom. New Eng. Power Generators Ass'n v. FERC*, 757 F.3d 283, 293-295 (D.C. Cir. 2014) ("*NEPGA*"); *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211, at P 110 (2008) (rejecting exemption of New York City because that "would lead to artificially depressed capacity prices" and "caus[e] existing generators to be under-compensated"), *order on reh'g*, 124 FERC ¶ 61,301 at P 29 (2008) (rejecting limitation of buyer-side controls to "net buyers" because "all uneconomic entry has the effect of depressing prices below the competitive level."), *pet'n for rev. voluntarily dismissed sub nom. Astoria Generating Co., L.P. v. FERC*, No. 08-1369, 2014 WL 6725262 (D.C. Cir. Nov. 17, 2014); *see also* December 2019 Order at P 7 & nn.19-24 (collecting cases); June 2018 Order at PP 67-69 & nn.111-116 (same).

[8] *See Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1296 (2016) ("*Hughes*") (citing 2011 MOPR Order and quoting 2011 MOPR Rehearing Order, 137 FERC ¶ 61,145 at P 3 ("Our intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives. We are forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's [capacity auction] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity."); *see also* December 2019 Order at P 7 & n.23 (describing the Supreme Court's reliance on the 2011 MOPR Orders in *Hughes*). The fact that *Hughes* expressly invoked those orders belies PJM's claims that having an effective MOPR is an attempt to "hermetically seal" the capacity market from state policies in a manner that is somehow incompatible with *Hughes*. *See, e.g.*, PJM Filing at 2, 7-8, 11-12.

[9] *See PJM Interconnection, L.L.C.*, Docket No. ER11-2875-000 at 16 (Feb. 11, 2011) ("PJM 2011 Filing"); *see also infra* Part I.B.2.

[10] *See* PJM Interconnection, L.L.C., Docket No. ER18-1314 Capacity Repricing or in the Alternative MOPR-Ex Proposal: PJM Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Apr 9. 2018 ("PJM 2018 Filing"); *see also infra* Part I.C.

mitigation to a vanishingly small or null set of circumstances. PJM has not, and cannot, show how erasing any effective control on out-of-market subsidies will result in just and reasonable rates.

Furthermore, there are no changed circumstances that justify PJM's radical reversal of market power mitigation rules the Commission directed under FPA section 206 in December 2019, reaffirmed on rehearing for a second time in October 2020, and is presently defending on judicial review. The only Reliability Pricing Model ("RPM") annual Base Residual Auction ("BRA") held under the "Expanded MOPR" rules was held just a few months ago and resulted in significantly lower clearing prices, high levels of reliability, orderly exits by uncompetitive (mostly coal) facilities, a smaller amount of purchased capacity, and steady improvements in decarbonization through the significant entry of new renewables and retention of existing renewables.[11] Colorfully dire predictions of exorbitant price increases that would "ossify" the resource mix to "bailout" thermal resources and block renewable growth were simply wrong.[12] Rather than acknowledge the actual results of the May 2021 BRA, the changed circumstance PJM instead relies upon is its

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[11] *See* Commissioner James Danly, White Paper: *Results of The PJM Capacity Auction (2022/2023 RPM Base Residual Auction* at 2 ("Danly BRA Results Whitepaper") (Attachment F) (noting, *inter alia*, that the last auction produced a clearing price of $50/MW-day, which is only 36% of the $140/MW-day price from the prior auction, while wind and solar resources increased by 62% (1,111 MW) over the prior auction), https://www.ferc.gov/news-events/news/white-paper-commissioner-james-danly-results-pjm-capacity-auction-20222023-rpm#; PJM, 2022/2023 RPM Base Residual Auction Results (June 2, 2021), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx; PJM, Press Release, *PJM Successfully Clears Capacity Auction to Ensure Reliable Electricity Supplies: Auction Attracts Diverse and Efficient Resources at Lower Wholesale Costs*, https://www.pjm.com/-/media/about-pjm/newsroom/2021-releases/20210602-pjm-successfully-clears-capacity-auction-to-ensure-reliable-electricity-supplies.ashx; PJM, May 2021 BRA Clearance Data by Resource Type and MOPR Status, https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-bra-mopr-results.ashx; Monitoring Analytics, *2021 Quarterly State of the Market Report for PJM: January through June* (Aug. 12, 2021), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021q2-som-pjm-sec5.pdf. The BRA Results Whitepaper, PJM reports and press release, and IMM report are appended as Attachments F, G, H, I, and J to make them part of the record in this proceeding.

[12] *See, e.g.*, December 19 Order at P 1 (Glick, Comm'r, dissenting) ("From the beginning, this proceeding has been about two things: Dramatically increasing the price of capacity in PJM and slowing the region's transition to a clean energy future. Today's order will do just that."); *id.* P 3 ("The order amounts to a multi-billion-dollar-per-year rate hike for PJM customers, which will grow with each passing year. It will increase both the capacity price in the Base Residual Auction as well as the already extensive quantity of redundant capacity in PJM. It is a bailout, plain and simple."); *id.* P 4 ("The order will also ossify the current resource mix. It is carefully calibrated to give existing resources a leg up over new entrants and to force states to bear enormous costs . . . .").

second pass at an Effective Load Carrying Capability ("ELCC") proposal the Commission accepted on the same day the instant MOPR proposal was filed.[13] PJM offers scant support for this claim beyond the bare assertion that its new ELCC methodology will help to "right-size the capacity accreditation" for intermittent and storage resources that cannot control the timing or quantity of their electric output.[14]

PJM's claim that the recent ELCC reform alone requires the Commission to erase any effective control on out-of-market subsidies for capacity resources is absurd. By definition, the ELCC proposal only applies to a small subset of resources "that are unable to maintain output at a stated capability continuously on a daily basis without interruption."[15] The ELCC reform does nothing to confront out-of-market state subsidies for major new or existing thermal capacity resources, including the subsidies for new natural gas resources that animated the Commission's elimination of the state mandate exception from the MOPR in 2011[16] or the subsidies for existing nuclear resources that animated the Expanded MOPR in 2019.[17] The purpose of the ELCC reform

[13] *See PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056 (2021) ("Updated ELCC Order"). The Commission rejected PJM's original proposal on October 2020 and accepting PJM's revised proposal allowed the Commission to close its related investigation under FPA section 206. *See id.* PP 1-3.

[14] Transmittal Letter at 19 & n.59 (quoting Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C. (Attach. D) ¶ 13 ("Keech Aff.")).

[15] Updated ELCC Order, 176 FERC ¶ 61,056 at P 2. The Commission's belated acceptance of PJM's revised ELCC proposal was hardly an endorsement of its merits, relying on PJM's commitment to review and repair the ELCC proposal. *See id.* P 63; *see also id.* P 11 (Christie, Comm'r, dissenting) ("[T]here is no urgency to replace the current rules and there is no reason to approve an ELCC at this time that is not as good as it needs to be. Further, I think the prospect that PJM will revisit this proposal in the near term to fix the flaws identified is fanciful."); *id.* P 1 & n.1 (Danly, Comm'r, concurring) (agreeing with Commissioner Christie's concerns on the merits, but concurring because "the fact that there might be a better approach does not change the standard we must apply under section 205").

[16] *See Hughes*, 136 S. Ct. at 1290-91 (describing the Maryland Public Service Commission's preempted effort to promote new natural gas resources through contracts for differences, which New Jersey similarly required through state legislation); *NJBPU*, 744 F.3d at 1294-95; *see also infra* Part I.C discussing the elimination of the state mandate exemption).

[17] *See, e.g.*, June 2018 Order at P 1 ("What started as limited support primarily for relatively small renewable resources has evolved into support for thousands of megawatts (MWs) of resources ranging from small solar and wind facilities to large nuclear plants."); *id.* PP 103, 105, 114-15, 131, 135-37, 151 (noting that state subsidies for nuclear resources were the basis for Calpine's amended complaint and preemption litigation against the Illinois Zero

is to properly count the reliability contribution of various resources, not mitigate the price suppression of those resources if they have received a discriminatory out of market subsidy.

In any event, it is clear that PJM's grossly overstated reliance on ELCC is a make-weight. PJM's primary argument is not that the Narrow MOPR is justified by changed circumstances, but rather that a Narrow MOPR is needed to accommodate certain states' *unchanged* desire to move forward with promoting the preferred resources through out-of-market subsidies regardless of whether *their own* decisions to provide financial support for preferred new or existing resources causes their constituent-consumers to "pay twice" for capacity. PJM leads its proposal with the argument that "state support for renewable resources has become a well-established determinant of supply in the PJM Region" and that the Commission should not "attempt[] to 'hermetically seal' the capacity market from the reality of state policies that support certain resources" because the MOPR now in effect "has created substantial conflicts between PJM's capacity market and both state policies and self-supply business models."[18]

There are several fundamental problems with PJM's approach. First, while accommodating state policy preferences for specific generation resources is a high-minded goal, judicial precedent is crystal clear that accommodating state generation preferences is not required under the FPA. More specifically, the Commission is not required to rescue states' constituent consumers from the financial consequences of their policymakers' deliberate choices to acquire capacity outside the competitive market, especially when those choices were made with full knowledge of the Expanded MOPR Orders' directives.[19] If states or utilities wish to procure

Emissions Credit (ZEC) program and describing the threat posed by a similar proposal in New Jersey according to PJM, the Market Monitor, the Electric Power Supply Association (EPSA), and others).

[18] PJM Filing at 2.

[19] *See, e.g.*, *NJBPU*, 744 F.3d at 97-98 ("[E]ven if the states' preferred generation resources fail to clear the auction, the states are free to use them anyway; the only caveat is that the states cannot use the resources to offset their capacity obligations in the RPM, as such obligations can only be satisfied by resources that are demanded by the

capacity from select resources to further their own economic or environmental goals, those extra-statutory considerations cannot trump the Commission's primary statutory responsibility to ensure just and reasonable rates,[20] which requires the Commission to acknowledge and mitigate market power in a market-based rate regime.[21]

Moreover, the Expanded MOPR Orders did not disturb PJM's Fixed Resource Requirement ("FRR") alternative.[22] States and utilities that wish to select a particular resource mix may assume direct responsibility for maintaining resource adequacy by electing to exit the capacity market through the FRR mechanism.[23] P3 prefers that utilities and states choose the competitive market over the FRR and a recent proceeding revealed some misunderstandings about the FRR process that may require clarifying tariff changes.[24] Nevertheless, under PJM's current tariff, the FRR is an available vehicle for accommodating state generation preferences by allowing states to take responsibility for their capacity obligations.

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capacity market at a price reflecting their cost. Thus, as in *Connecticut Department of Utility Control*, New Jersey and Maryland are free to make their own decisions regarding how to satisfy their capacity needs, but they "will appropriately bear the costs of [those] decision[s]," *id.* at 481, including possibly having to pay twice for capacity. . . . [W]hat FERC has actually done here is permit states to develop whatever capacity resources they wish, and to use those resources to any extent that they wish, while approving rules that prevent the state's choices from adversely affecting wholesale capacity rates. Such action falls squarely within FERC's jurisdiction.").

[20] *See, e.g.*, *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 669-70 (1976) (explaining that the Commission's role under the FPA and NGA is economic regulation, not social regulation); *Grand Council of Crees v. FERC*, 198 F.3d 950, 957-58 (D.C. Cir. 2000) (holding that complaints motivated by environment considerations are not within the zone of interests regulated under the FPA).

[21] *See, e.g.*, *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir.1990).

[22] *See, e.g.*, December 2019 Order at P 12 ("Public power and vertically integrated utilities that prefer to craft their own resource adequacy plans remain free to do so through the FRR Alternative option already present in the existing PJM Tariff."); *accord, e.g.*, *id.* at PP 202, 204.

[23] *See, e.g.*, December 2019 Order at P 12 ("Public power and vertically integrated utilities that prefer to craft their own resource adequacy plans remain free to do so through the FRR Alternative option already present in the existing PJM Tariff."); *accord, e.g.*, *id.* at PP 202, 204.

[24] *See LS Power Dev., LLC v. PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,021 (2021) ("FRR Complaint Order").

PJM's instant proposal, by contrast, goes beyond accommodation to supplication by effectively authorizing any form of out-of-market support that is not already facially preempted or otherwise unlawful. That is the essence of PJM's new "Conditioned State Support" approach,[25] which would allow certain states to abuse their jurisdiction to promote preferred generation resources through out-of-market support by forcing competitive suppliers to underwrite those subsidies through artificially suppressed market-wide clearing prices.[26] Still worse, PJM's proposal would allow certain states to shift the costs imposed by their public policy subsidy programs to other states with different priorities—a proposal that undermines the Commerce Clause and defeats the core reason for the enactment of the FPA.[27] Why would PJM reverse years of advocacy for transparent competition in this manner? Because PJM apparently views the threat that more utilities will exit the PJM capacity market (or PJM itself) as a more dangerous or embarrassing problem than administering a dysfunctional and unduly discriminatory capacity market.

In short, if the Commission were to allow the PJM Filing to go into effect it would be unlawfully abdicating its core statutory responsibility to ensure that jurisdictional markets produce just and reasonable rates. Doing so would also be arbitrary and capricious because PJM has failed to provide a reasoned basis for overturning years of Commission and judicial precedents confirming that the Commission cannot simply turn a blind eye to artificial price suppression caused by uneconomic entry.[28]

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[25] *See* PJM Filing at 2, 25, 42-47 (describing the Conditioned State Support element of its proposal).

[26] Thus, competitive suppliers would be immediately harmed while price suppression would ultimately result in wealth transfers from consumers to the recipients of subsidies.

[27] *See infra* Part III.B.2.

[28] *See, e.g.*, *supra* note 7 (collecting cases); *infra* Part I.A (discussing the Commission's statutory duty to recognize and mitigate market power as applied in organized capacity markets).

The Commission must therefore reject the PJM Filing. In doing so, the Commission should provide specific guidance as to how PJM can better balance accommodation of state policy preferences against the Commission's statutory obligation to ensure that markets rely on transparent, non-discriminatory competition to produce just and reasonable rates. As PJM's Independent Market Monitor, Monitoring Analytics, LLC ("IMM"), recently observed, "[i]t is possible to retain a clear MOPR rule while recognizing state authority over the generation facilities in each state. PJM's proposed approach to MOPR reforms does not meet that test."[29]

In the alternative, if the Commission does not reject the PJM Filing outright, the Commission must, at a minimum, establish paper hearing procedures under FPA section 205 or FPA section 206 to examine multiple factual issues raised in the PJM filing that P3 disputes.[30] As explained below, Dr. Quinn and Dr. Shanker identify numerous fundamental flaws in the testimony presented by PJM, including, but not limited to, unexplained assumptions about the likely market impacts of implementing a "Narrow MOPR." For example, the self-described "sophisticated modeling" in the Cramton Affidavit is based on an obscure study that PJM did not provide, or discuss with stakeholders, for over eighteen months. The model incorporates several dubious assumptions—for example, that carbon prices will escalate by $3/ton per year from $2/ton in 2019 to $65/ton in 2040[31] and that "[s]tate sponsored resources, including nuclear, are assumed to stay in the market regardless of their economics."[32]

[29] Monitoring Analytics, LLC, *2021 Quarterly State of the Market Report for PJM: January through June* (Aug. 12, 2021) at 3.

[30] *See, e.g.*, June 2018 Order at PP 6-8 n.9 (explaining that "[a] rate proposal proceeding may also be transformed into Commission-initiated complaint proceeding when the record indicates that is necessary or appropriate" and listing numerous examples).

[31] *See* Cramton Aff. ¶ 47.

[32] Shanker Aff. ¶ 44 n.32 (quoting Cramton Working Paper at 55); *see also* Shanker Aff. at ¶¶ 13-20, 48-60 (identifying various flaws in the Cramton Affidavit's analysis that were readily discernible despite the Cramton Affidavit's failure to adequately explain its modeling and assumptions).

In short, PJM's proposal provides flimsy support for an ill-conceived and radical abandonment of any meaningful mitigation of out-of-market subsidies that distort and artificially suppress the price of capacity paid to competitive generators.

Dr. Quinn concludes that PJM: (i) makes no attempt to address the other important policy considerations, principally the need to address the harm of price suppression, beyond an overly constricted definition of buyer-side market power; (ii) fails to address the balance between confidence in capacity market outcomes and accommodating state policies; (iii) would wrongly focus on excusing the market impacts of "legitimate" "state policies" instead of the effect state policies have on wholesale market outcomes; (iv) proposes a Conditioned State Support test that does not address any issues relevant to the MOPR; (v) offers Buyer-Side Market Power provisions that suffer from multiple fatal deficiencies; (vi) has not justified under-mitigation on policy grounds or based on its theory that buyer-side and seller-side market power are "asymmetrical." Overall, Dr. Quinn recommends that the Commission reject the PJM Filing but provide guidance on what a revised MOPR must achieve in order to help shape a possible future proposal.

Dr. Shanker similarly concludes that: (i) price suppression below the competitive level is a serious problem that continues to warrant mitigation under the MOPR regardless of whether it is associated with intentional exercises of buyer-side market power (as PJM, and the author of one of the PJM Filing's affidavits, have previously stated); and (ii) the Cramton Affidavit cannot possibly be relied upon because it is undocumented, untested, inadequately explained, built on false or unstated assumptions, and reaches conclusions that appear to be driven by the author's own subjective preferences.

Competitive power producers cannot endure a constant whipsaw of regulatory uncertainty, which dramatically increases the cost of capital necessary to construct new resources of any kind.

The market requires a durable solution to years of tension between state policies and the Commission's role under the FPA. P3 is eager to support that effort and believes there is common ground for the immediate adoption of certain reforms. For example, P3 supports elimination of the unique rules for new natural gas resources that PJM calls the "Legacy MOPR,"[33] so long as those new natural gas resources certify that they are not supported by out-of-market payments. Indeed, because P3's focus has always been to promote transparent competition, P3 has repeatedly advocated a "No Subsidy Off-Ramp" for *all* new resources for more than a decade.[34] Unfortunately, PJM has proposed an all-or-nothing approach that declines to accept any material modifications,[35] leaving rejection of the instant PJM Filing as the only lawful option in this proceeding.

I. STATUTORY AND REGULATORY BACKGROUND

As noted in the Quinn Affidavit, it is important to review the relevant statutory and regulatory background in order to "place PJM's proposal in the context of the Commission's evolving [MOPR] policy."[36] Doing so clearly reveals that the Narrow MOPR "does not represent a just and reasonable rate because it has not been shown to balance the policy objectives FERC considers when addressing out-of-market actions."[37]

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[33] PJM Filing at 3; *id.* at 19-20.

[34] *See, e.g.*, 2011 MOPR Order, 135 FERC ¶ 61,022, at P 117 ("P3 suggests what it calls a 'No-Subsidy' Off-Ramp, which would mean that any resource of any type would avoid the conduct screen altogether if it establishes that it has not received any discriminatory payment.").

[35] PJM Filing at 48 & n.56 (citing *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 115 (D.C. Cir. 2017)).

[36] Quinn Aff. ¶ 5.

[37] *Id.*

A. The Federal Power Act Mandates that Commission-Jurisdictional Markets Must Have Adequate Protections Against Both Buyer-Side and Seller-Side Market Power

As PJM acknowledges, capacity markets are intended to send "price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources"[38] and to "encourage capacity investment where it is most valuable."[39] The Commission has stated that the first principles of capacity markets are to "facilitate robust competition for capacity supply obligations, provide price signals that guide the orderly entry and exit of capacity resources, result in the selection of the least-cost set of resources that possess the attributes sought by the markets, provide price transparency, shift risk as appropriate from customers to private capital, and mitigate market power."[40] The Commission has also held that "[w]here participation of resources receiving out-of-market state revenues undermines those principles, it is our duty under the FPA to take actions necessary to assure just and reasonable rates."[41] PJM has strongly endorsed these holdings in the past.[42]

The Commission's duty to ensure just and reasonable rates is a core obligation under the FPA. It predates the extensive body of Commission precedent addressing capacity market power mitigation over the past fifteen years. Instead, it is rooted in the earliest decisions addressing cost-of-service rates under the Natural Gas Act (NGA) and other decisions predating federal regulation under the FPA and NGA.[43] Those decisions indisputably established that ratemaking under the

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[38] PJM Filing at 5 n.8 (quoting June 2018 MOPR Order at P 156).

[39] *Id*. (quoting *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at P 80 (2015)).

[40] *ISO New England, Inc*., 162 FERC ¶ 61,205 at P 21 (2018) ("CASPR Order").

[41] *Id*. (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 143 (2011) ("While the Commission acknowledges the rights of states to pursue legitimate policy interests . . . it is our duty under the FPA to assure just and reasonable rates in wholesale markets.")).

[42] *See, e.g.*, 2018 PJM MOPR Filing at 2-3.

[43] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va*., 262 U.S. 679 (1923). Federal courts have long held that cases

just and reasonable standard requires that "FERC must choose a method that entails an appropriate 'balancing of the investor and the consumer interests.'"[44] "Both interests are economic and tied directly to the transaction regulated: 'the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated,' while there is a 'consumer interest in being charged non-exploitative rates.'"[45] In short, it is black letter law that the Commission must ensure *both* that consumers do not pay unreasonably high rates *and* that sellers are not compelled to provide service at unreasonably low rates.

This legal principle is the foundation of the Commission's oversight of jurisdictional electricity markets and its market-based rate program, including the PJM capacity market. The electric utility sector was traditionally dominated by regional monopolies with substantial vertical and horizontal market power. Given those conditions, cost-of-service ratemaking prevailed for decades. In 1990, however, the United States Court of Appeals for District of Columbia Circuit held in *Tejas Power* that it could be permissible to set rates based on the interplay of market forces if the Commission has reasonable assurance that there is "a competitive market, where *neither buyer nor seller* has significant market power."[46] Thus, market-based rates cannot satisfy the just and reasonable standard if the Commission fails to acknowledge or mitigate marker power by sellers or buyers.[47]

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construing the "just and reasonable" standard under the FPA and NGA may be cited interchangeably. *See, e.g.*, *Emera Maine v. FERC*, 854 F.3d 9, 20 (D.C. Cir. 2017) (citing, *inter alia*, *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) (citing *Permian Basin Area Rate Cases*, 390 U.S. 747, 820–821 (1968); *FPC v. Sierra Pac. Power Co*., 350 U.S. 348, 353 (1956))).

[44] *Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty., Wash.*, 554 U.S. 527, 532, (2008) (quoting *Hope Natural Gas*, 320 U.S. at 603).

[45] *Grand Council of Crees*, 198 F.3d at 956 (citations omitted) (quoting *Hope Nat. Gas Co.*, 320 U.S. at 603; *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1178 (D.C. Cir. 1987)).

[46] *Tejas Power*, 908 F.2d at 1004 (emphasis added),

[47] *See id.*; *accord, e.g.*, *Pub. Citizen, Inc. v. FERC*, No. 20-1156, 2021 WL 3438374, at *3 (D.C. Cir. Aug. 6, 2021); *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1, 13 (D.C. Cir. 2015) ("[T]he Program occurred outside of the usual ISO New England energy markets, and the Commission made no effort to define the relevant market or

After *Tejas Power*, the Commission has always sought to confirm that market participants do not have market power or that any potential market power has been effectively mitigated before allowing market-based pricing. For example, Order No. 697, which established the Commission's market-based rate regulations applicable to sellers of electric energy, ancillary services, and capacity, requires sellers to demonstrate that they do not have the ability to exercise market power that could enable them to distort the markets.[48] When Order No. 697 was issued in 2007, organized capacity markets were a brand-new phenomenon[49] and the Commission declined to address buyer-side market power concerns "without specific evidence of monopsony power and a clear delineation of the state-federal jurisdiction issues that would arise in the context of a specific seller and specific set of circumstances."[50] Since then, however, the Commission and reviewing courts have consistently applied the same legal principles described in *Tejas Power* to ensure that "buyer-side" market power does not distort prices in Commission-jurisdictional capacity markets.[51]

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determine the participants' market power. The Commission's reference to a 'competitive as-bid program,' without further explanation, is simply a talismanic phrase that does not advance reasoned decision making."); *Mont. Consumer Counsel v. FERC*, 659 F.3d 910, 916-17 (9th Cir. 2011); *Blumenthal v. FERC*, 552 F.3d 875, 882 (D.C. Cir. 2009) ("In other words, what matters is whether an individual seller is able to exercise anticompetitive market power, not whether the market as a whole is structurally competitive."), *adopted in Mont. Consumer Counsel*, 659 F.3d at 916; *Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 262 (D.C. Cir. 2007); *NSTAR Elec. & Gas Corp. v. FERC*, 481 F.3d 794, 803-04 (D.C. Cir. 2007) ("But the Commission does not explain its basis for believing that the ISO's actions satisfied the statutory requirement. . . . ISO–NE's scrutiny could work as a substitute only if ISO–NE had both incentive and ability to bargain for 'reasonable' rates (i.e., rates not materially exceeding the range needed to assure availability of the needed generating capacity)."); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004); *Mo. Pub. Serv. Comm'n v. FERC*, 337 F.3d 1066, 1076 (D.C. Cir. 2003); *Grand Council of Crees*, 198 F.3d at 957-58.

[48] *See Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity, & Ancillary Servs. by Pub. Utils.*, Order No. 697, 119 FERC ¶ 61,295 *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g and clarification*, Order No. 697-A, 123 FERC ¶ 61,055, *order on reh'g and clarification*, 124 FERC ¶ 61,055, *order on reh'g and clarification*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'g and clarification*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g & clarification*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom. Mont. Consumer Counsel*, 659 F.3d 910.

[49] PJM held its first regional capacity auction in 2007 followed shortly thereafter by two other organized markets. *See infra* Part I.B.1 (discussing the creation and evolution of the capacity market in PJM and neighboring Regional Transmission Organizations).

[50] Order No. 697, 119 FERC ¶ 61,295 at P 463.

[51] This body of orders is too voluminous to comprehensively list here, but key Commission orders and judicial opinions are cited throughout this protest. *See, e.g.*, *supra* note 7.. A useful review of relevant precedent is also found

Although buyer-side market power in organized capacity markets is sometimes described as a form of monopsony market power, it bears emphasizing that the manner in which it is exercised differs from the conventional monopsony concepts.[52] Monopsony power is traditionally understood to be the mirror image of monopoly power. It involves "predatory bidding;" essentially withholding by a dominant buyer to drive up market prices and drive weaker competitors out of business. This tactic is not possible in the Commission-jurisdictional capacity markets because demand curve mechanisms specify the quantity of capacity that buyers must procure and the prices that they must pay.[53] Instead, buyer-side market power can be exercised in capacity markets by subsidizing owners of generation to sell capacity into the markets. Below-cost offers artificially suppress prices in two ways: "(1) if a subsidized resource would have submitted the marginal cost

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in a series of whitepapers recently published by Commissioner Danly. *See* Commissioner James Danly, Whitepaper, *The Requirement that Competitive Markets be Protected from the Exercise of Market Power Applied to RTO Capacity Markets* (May 20, 2021) ("Danly Market Power Whitepaper"), https://www.ferc.gov/news-events/news/danly-office-white-paper-requirement-competitive-markets-be-protected-exercise#; Commissioner James Danly, Whitepaper Supplement 1, *The Requirement that Competitive Markets be Protected from the Exercise of Market Power Applied to RTO Capacity Markets* (June 17, 2021) ("Danly Market Power Whitepaper Supp. 1") (rebutting semantic arguments that state subsidies "cannot constitute the exercise of buyer-side market power because the states are not acting as buyers of power as their subsidies generally go to sellers, not buyers" and concluding that "[e]ither way, state subsidies artificially and unreasonably suppress capacity prices in an unduly preferential and discriminatory manner that must be mitigated to protect the integrity of a capacity market premised on competition"), https://www.ferc.gov/news-events/news/white-paper-commissioner-james-danly-requirement-competitive-markets-be-protected#; Commissioner James Danly, Whitepaper Supplement 2, *The Requirement that Competitive Markets be Protected from the Exercise of Market Power Applied to RTO Capacity Markets* (June 17, 2021) ("Danly Market Power Whitepaper Supp. 2") (rebutting arguments "that the Commission is barred from mitigating the effects of state support for certain resources on RTO capacity markets under Federal Power Act (FPA) section 201(b)(1)" because reviewing courts have consistently held that "this statutory limit on the Commission's jurisdiction does not prevent the Commission from acting to mitigate market-distorting state support of generation resources to ensure that the rates produced by FERC-jurisdictional wholesale markets are just and reasonable"), https://www.ferc.gov/news-events/news/white-paper-commissioner-james-danly-requirement-competitive-markets-be-0#. These whitepapers are appended to this Protest as attachments C, D, and E to make them part of the record in this proceeding.

[52] Consequently, Commissioner Danly has suggested that it might be more accurate to describe state subsidies as incentivizing resources to exercise seller-side market power in order to reduce prices. *See* Danly Whitepaper Supp. 1 at 2. But whether or not the term buyer-side mitigation is used, the Commission's obligation to ensure that capacity market prices are not distorted by market power remains the same. *See id.*

[53] *See* Danly Whitepaper Supp. 1 at 6. *See also* Affidavit of David B. Patton on behalf of New York Independent System Operator, Inc. Attachment 1 to filing entitled Compliance Filing of New York Independent System Operator, Inc. Regarding the New York City ICAP Market Structure, Docket No. EL07-39-000 at ¶¶ 62-63 (Oct. 4, 2007).

offer had it not been subsidized, offering that resource's capacity below its marginal cost would cause the market clearing price to be lowered to the price offered by the next highest cost offer; and (2) if the cost of a subsidized resource is higher than the market clearing price, then offering the resource below its cost will lower the supply curve, thereby lowering the point of intersection of the supply curve and the demand curve and lowering the resulting capacity price."[54]

As discussed below in Section I.B, buyer-side capacity market power mitigation measures have been in place in PJM to address this risk since 2006. PJM's mitigation measures evolved over time as flaws were identified and new buyer-side market power issues emerged. The same process has occurred in the other two regional grid operators that administer mandatory capacity auctions, *i.e.*, ISO New England, Inc. ("ISO-NE") and the New York Independent System Operator, Inc. ("NYISO").

As the Commission consistently held over many years, these measures were not optional. They were necessary to avoid artificial price suppression regardless of a seller's underlying intent.[55] Price suppression harms not just the short-terms interests of suppliers, but also the long-term interest of consumers. If ignored, it would render capacity market prices unjust, unreasonable, and unduly discriminatory in contravention of the FPA.[56] There is thus more than a decade of Commission precedent holding that price suppression associated with uneconomic capacity offers is a serious problem that must be addressed if capacity market prices are to be just and reasonable.

The Commission has repeatedly explained that PJM, ISO-NE, and the NYISO must have buyer-side capacity market power mitigations that neither over-mitigate nor under-mitigate. Over-

[54] Danly Whitepaper Supp. 1 at 6.

[55] *See* December 2019 Order.

[56] *See* June 2018 Order and December 2019 Order.

mitigation would result in prices that were unjustly and unreasonably high. Under-mitigation would result in prices that were unjustly and unreasonably low.[57] These rulings are tied directly to the balancing of interests required by the just and reasonable standard. Capacity market power mitigation rules cannot be just and reasonable, and thus cannot be accepted by the Commission, if they do not strike this balance.

B. Evolution of the PJM Capacity Market and Buyer-Side Mitigation Prior to the Expanded MOPR

1. The Beginnings of the RPM and the MOPR

PJM's existing capacity market framework, the RPM, was adopted after the Commission found the prior capacity market design "to be unjust and unreasonable because the market revenues received by capacity providers were likely to be insufficient to sustain the continued and future investment in capacity resources, potentially causing multiple reliability violations."[58] After a lengthy settlement process, the original version of the RPM was conditionally approved by the Commission in 2006[59] and implemented in 2007. RPM provides for Base Residual Auctions ("BRAs") to be conducted every year to procure capacity three years in advance of the year in which the capacity will be provided and supply offers for annual locational capacity obligations

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[57] *See, e.g.*, *See, e.g.*, *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 (2008) at P 103 ("While a strategy of investing in uneconomic entry and offering it into the capacity market at a low or zero price may seem to be good for customers in the short-run, it can inhibit new entry, and thereby raise price and harm reliability, in the long-run. Under the FPA, the Commission must ensure that rates are just and reasonable. The courts have long held that establishing just and reasonable rates involves a balancing of consumer and investor interests."); *New York State Public Service Commission, et al. v. N.Y. Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,088 at P 31(reiterating the importance of balancing "the need to mitigate the exercise of buyer-side market power to ensure just and reasonable ICAP market prices with the risk of over-mitigating new entrants."); *Consolidated Edison Co. of New York, Inc. v. N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,139 at P 4 (2015); *New York Independent System Operator, Inc.*, 143 FERC ¶ 61,217 at P 77 (2013) (noting that buyer-side market power mitigation rules must "appropriately balance the need for mitigation of buyer-side market power against the risk of over-mitigation.")

[58] *Md. Pub. Serv. Comm'n v. PJM Interconnection, L.L.C.*, 124 FERC ¶ 61,276, at P 2 (2008).

[59] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006).

are cleared against a downward sloping demand curve, also called the Variable Resource Requirement curve ("VRR curve").

Since its inception, the RPM has included a MOPR. When the Commission first accepted the RPM Settlement it stated that the MOPR "addresses the concern that net buyers might have an incentive to depress market clearing prices by offering some self-supply at less than a competitive level."[60] Under the original MOPR, "[s]ubject to certain exemptions, if the supply offer of a net buyer falls below certain specified levels, and if its net purchases exceed certain specified levels, and if it does not convince the PJM Market Monitor that the offer is cost-justified, the Market Monitor may establish an alternative higher bid."[61] The Commission found that the MOPR was "a reasonable method of assuring that net buyers do not exercise monopsony power by seeking to lower prices through self supply."[62] It also upheld an exception for reliability projects built under state mandate (the "State Mandate Exemption") "because it enables states to meet their responsibilities to ensure local reliability."[63]

In 2009, the Commission rejected a proposal to eliminate the MOPR and leave it to the IMM to determine whether a seller's new generation resource offer constituted an exercise of market power. The IMM would have been required to determine whether (i) the seller's offer would result in a significant price decrease compared to the price that would otherwise have resulted from a competitive offer; (ii) the seller had an incentive to reduce price; and (c) the offer was an attempt to exercise market power. If the IMM found that those standards were met, it

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[60] *Id.* at P 103.

[61] *Id.*

[62] *Id*. P 104.

[63] *Id.*

would report to PJM which would then file with the Commission to seek relief.[64] This proposal was rejected because it gave the IMM "unfettered discretion to determine whether an offer violates the MOPR."[65] The Commission pointed to its prior holdings that "to provide needed certainty to all participants, PJM must provide objective tariff provisions that will determine when mitigation measures will be applied, including application of the MOPR rule."[66]

2. The 2011 MOPR Revisions – Strengthening the MOPR by Eliminating the State Mandate Exemption, the Net Short Requirement, and the Impact Screen

In 2011, PJM made a Section 205 filing to "update and simplify" the MOPR and "to conform that rule to the Commission's recent precedents on similar rules in New York and New England."[67] The PJM 2011 Filing was, in part, a reaction to a complaint filed by P3, which demonstrated that the original MOPR was ineffective in deterring buyer-side market power.[68] In particular, the P3 Complaint highlighted the need for expedited reforms in light of New Jersey and Maryland initiatives to support new generation entry through out of market payments. PJM broadly agreed that there were problems with the MOPR as it then-existed. It stated that:

> PJM has conducted seven Base Residual Auctions, covering seven Delivery Years, since RPM was implemented, and the MOPR has never been triggered. PJM is concerned that, despite the potential for below-cost bidding to adversely affect the capacity market, the MOPR in its current form may never be applied, and may not be adequate to serve the purposes for which it was approved by the Commission. For example, the Commission has seen that state programs intended to support new generation entry through out-of-market payments to the generator can raise the price-suppression concerns that MOPR-type provisions are intended to address. However, the current "net short" requirement likely puts such programs beyond the reach of PJM's MOPR, unless the buyer and seller in such contracts happen to be

[64] *See PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 183 (2009) ("2009 MOPR Complaint Order").

[65] *Id*. P 190.

[66] *Id*. (citing 117 FERC ¶ 61,331 at P 115).

[67] *PJM Interconnection, L.L.C.*, Docket No. ER11-2875-000 (Feb. 11, 2011) ("PJM 2011 Filing").

[68] *See PJM Power Providers Group v. PJM Interconnection, L.L.C.*, Complaint and Request for Clarification Requesting Fast Track Processing, Docket No. EL11-20-000 (Feb. 1. 2011).

> affiliates. This is significant, as some states in the PJM region have begun to implement generation procurement programs similar to the state programs in New England that have prompted ISO-New England, Inc. to substantially revise its MOPR-type provision.[69]

PJM proposed to address concerns about state subsidy programs by replacing the State Mandate Exemption with a rule that would require parties seeking a state policy-based exemption from the MOPR to make a Section 206 filing.[70] Among other things, PJM suggested that this change would relieve it of the burdens of having to evaluate the merits of state programs.[71]

The Commission agreed in its 2011 MOPR Order that the State Mandate Exemption should be eliminated because of the "mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules that could allow uneconomic entry . . . ."[72] But the Commission rejected PJM's alternative approach because it merely restated a statutory right to make a Section 206 filing that parties already had.[73] The Commission emphasized that it "has previously found, and we reiterate here, that uneconomic entry can produce unjust and unreasonable wholesale rates by artificially depressing capacity prices, and therefore the deterrence of uneconomic entry falls within our jurisdiction."[74] On rehearing, the Commission held that eliminating the State Mandate Exemption would "not interfere with states or localities that, for policy reasons, seek to provide assistance for new capacity entry if they believe such expenditures are appropriate for their state."[75] The Commission added that its objective was "to

[69] PJM 2011 Filing at 3.

[70] *Id.* at 14-16.

[71] *See id.* at 15-16.

[72] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 at P 139 (2011).

[73] *Id*. P 140.

[74] *Id.* P 141.

[75] *See* 2011 PJM MOPR Rehearing Order, 137 FERC ¶ 61,145 at P 89.

ensure the reasonableness of the wholesale interstate prices determined in the markets PJM administers."[76]

The 2011 MOPR Order also rejected a commenter's recommendation that "only if the IMM or other party can demonstrate that a project resulted from a state-mandated process intended solely to suppress wholesale capacity prices should it be mitigated."[77] The Commission acknowledged "the rights of states to pursue legitimate policy interests, and while, as we have said, any state is free to seek an exemption from the MOPR under section 206, it is our duty under the FPA to assure just and reasonable rates in wholesale markets."[78]

In addition, the 2011 PJM Filing proposed to eliminate the original MOPR's "net short criterion," which restricted the application of the MOPR to sellers (including their affiliates) that were "effectively buying substantially more capacity from the auction than they are selling into it."[79] PJM explained that the idea behind the net short limitation was "to focus the MOPR on parties that have an incentive to use a low-price offer for a (presumably marginal) new entrant to reduce the clearing price that the seller (in its role as buyer) will pay for capacity committed in the auction."[80] But in practice, "this precondition on application of the MOPR opens considerable opportunities for a seller/buyer with exactly that incentive to structure the new entry transaction in way that achieves the desired price-lowering effects without triggering the MOPR's protective provisions."[81] In short, the "current 'net short' provision renders the MOPR too easily gamed, and

[76] *Id*.

[77] *Id*. P 143.

[78] *Id*.

[79] PJM 2011 Filing at 16.

[80] *Id*.

[81] *Id*.

may create such obvious pathways for evading the MOPR that the rule in its current form might never be applied."[82]

PJM emphasized that this proposed change was consistent with precedent involving NYISO, which originally proposed to include a "net buyer" requirement equivalent to PJM's "net short" criterion in NYISO's own version of the MOPR. The Commission had initially accepted NYISO's net buyer requirement but reversed itself on rehearing holding that "*all* uneconomic entry has the effect of depressing prices below the competitive level and . . . this is the key element that mitigation of uneconomic entry should address."[83] The Commission had also agreed with the NYISO and others that sought rehearing because of gaming fears, finding that "defining net buyers raises significant complications and provides undesirable incentives for parties to evade mitigation measures."[84]

The 2011 MOPR Order accepted PJM's proposal to eliminate the "net-short" provision, agreeing that "the net-short requirement is ineffective and unnecessary."[85] The Commission recognized that "the net-short requirement can be gamed, and the evasion can come in a variety of forms," and found that an "exemption from the MOPR based on the perceived incentives of an entity will be ineffective at protecting against buyer market power."[86] The Commission also rejected claims that eliminating the "net-short" provision would result in "over-mitigation."[87]

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[82] *Id*.

[83] PJM 2011 Filing at 17 (citing *N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,301, at P 29 (2008) (emphasis added)).

[84] *Id*.

[85] 2011 MOPR Order, 135 FERC ¶ 61,022 at P 84.

[86] *Id*. P 88.

[87] *Id.* P 89.

Finally, the 2011 MOPR Order: (i) accepted PJM's proposal to remove an "impact screen" under which the MOPR would not apply unless a mitigated offer would have had a significant price impact[88] on its own because it would allow uneconomic offers to escape the MOPR, was unnecessary to prevent "over-mitigation," and did not address the impact of multiple uneconomic offers;[89] (ii) required PJM to develop procedures that would allow it and the independent market monitor to review unit-specific cost justifications for sell offers that would otherwise be mitigated by the MOPR;[90] and (iii) accepted that the MOPR should only apply to new natural gas-fired plants because they were the only resource type likely to be used to exercise buyer-side market power. The 2011 PJM MOPR Order also explained that the existing Fixed Resource Requirement ("FRR") construct in the PJM Tariff provided a mechanism for "states seeking full independence in resource procurement choices" to "implement a form of capacity procurement that complements the RPM or . . . opt out of the RPM."[91]

In 2013, to address the effects of new, state-supported natural gas-fired entrants on its capacity market, PJM submitted proposed Tariff revisions reflecting a compromise among PJM's stakeholders to replace a non-transparent process of unit-specific review by PJM and the Market Monitor with two categorical exemptions, namely, a competitive entry exemption in exchange for self-supply exemption.[92] The Commission initially accepted those exemptions, but only in addition to the unit-specific review process that the stakeholder-supported categorical exemptions

[88] *See id.* P 101 (describing a significant decrease as 20-30% or $25/MW-day, depending on the zone).

[89] *Id*. P 106 ("Therefore, even if one were to accept that a below-market offer with no material effect on prices should not be mitigated because it does no harm, such a position provides no comfort as the combined effects of several such offers might well affect prices.").

[90] *See id.* P 121.

[91] *Id.* P 141 n.76: *accord id.* P 193.

[92] *See* June 2018 Order, 163 FERC ¶ 61,236 at P14.

were meant to replace, and those orders were vacated by the United States Court of Appeals for the District of Columbia Circuit, which held the Commission had exceeded its FPA section 205 authority by modifying PJM's proposal.[93] On remand, the Commission rejected PJM's competitive entry exemption and self-supply exemption, effective December 8, 2017.[94] As a result, unit-specific review became "the only way for a new natural gas-fired resource subject to PJM's MOPR to obtain an exemption from that rule."[95]

C. The Need for and Establishment of the Expanded MOPR

In March 2016, a group of independent generation owners filed a complaint against PJM. They alleged that the MOPR had become unjust and unreasonable because it allowed for the artificial suppression of prices caused by below-cost offers from existing resources whose continued operation was being subsidized by state-approved out-of-market payments.[96]

The Commission took no immediate action on that complaint, but instead convened a technical conference in May 2017, in Docket No. AD17-11-000, to explore the impact of out-of-market support for specific resources or resource types in PJM as well as the adjacent regional markets operated by NYISO and ISO-NE.[97] The Commission identified "five potential paths forward," listing the spectrum from "(1) a limited, or no MOPR approach; (2) an approach that would accommodate resources receiving out-of-market support; (3) retention of the status quo; (4)

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[93] *See NRG,* 862 F.3d at 117.

[94] *See PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,252 (2017); *PJM Interconnection, L.L.C.*, Docket No. ER13-535-006 (Feb. 23, 2018) (delegated letter order accepting compliance filing).

[95] June 2018 Order, 163 FERC ¶ 61,236 at P 14.

[96] *See id*. P 15.

[97] *See id*. P 16.

an approach that would balance state policy goals and the needs of a centralized capacity market; and (5) an extension of the MOPR to apply to both new and existing resources."[98]

In April 2018, PJM made a Section 205 filing that took the fifth path, urging the Commission to act to address the adverse impacts of rapidly proliferating state subsidies on the RPM.[99] PJM's transmittal letter devoted more than thirty-five pages to describing the ways in which such subsidies presented a critical threat. PJM stated unequivocally that, "if a material fraction of resources price their capacity offers relying on their selective receipt of subsidies, then:

• other sellers in PJM's interstate market that do not receive subsidies will receive an artificially suppressed, unjust and unreasonable rate;

• competitive entry will face a significant added barrier;

• new subsidies will be encouraged; and

• one state's policy choices could contribute to a 'crowding out' of other competitive resources and resulting policy choices on which other states rely."[100]

PJM closed its discussion of the threats posed by subsidies by warning that:

> Commission action is needed now. The circumstances are similar to those that confronted the Commission in 2011 when it eliminated the blanket MOPR exemption for state-supported new entry: the "prospect of thousands of megawatts of . . . generation, [offered] under arrangements that would explicitly subsidize the resources regardless of Auction price, potentially being offered into the PJM [m]arket at zero bid [brings] into focus the distortive effect . . . that the state [programs] could have on markets for all capacity. The principle applies equally here; the only difference is that in 2011, the concern was new entry, natural gas projects; today the concern arises from state programs to maintain and support existing resources and (to a lesser degree) induce entry of alternate energy resources. In such circumstances, where "participation of resources receiving out-of-market state revenues undermines [the first] principles of capacity markets, the

[98] *Id*.

[99] *See* PJM Interconnection, L.L.C., Docket No. ER18-1314 Capacity Repricing or in the Alternative MOPR-Ex Proposal: PJM Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Apr 9. 2018 ("PJM 2018 Filing").

[100] *Id*. at 4.

> Commission has a "duty under the FPA to take actions necessary to ensure just and reasonable rates."[101]

PJM proposed two alternative, mutually exclusive "jump ball" sets of tariff provisions to address the problems that it had identified. These options were "Capacity Repricing, a two-stage pricing mechanism, and MOPR-Ex, an extension of PJM's existing MOPR to apply to both new and existing resources that receive a Material Subsidy."[102]

PJM's urgent call for action was supported by an affidavit from Adam J. Keech who was then PJM's Executive Director, Market Operations.[103] Mr. Keech emphasized that tariff revisions were essential to "fill a gap in the current capacity market rules, which have no mechanism to address the price suppressive effects of below-cost offers from a number of resource types that receive substantial subsidies under various state programs."[104] He also testified that subsidized offers from uneconomic existing resources would have significant, and harmful, price suppressive effects.[105]

In its June 2018 Order, the Commission found, based on the record from both the generators' 2016 complaint under FPA section 206 and PJM's May 2018 "jump ball filing" under FPA section 205, "that it has become necessary to address the price suppressive impact of resources receiving out-of-market support."[106] The Commission found that the PJM MOPR was no longer just and reasonable because it applied only to new natural gas-fired resources and failed

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[101] PJM 2018 Filing at 36 (citing CASPR Order at P 21).

[102] June 2018 Order, 163 FERC ¶ 61,236 at P 20.

[103] *See* Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C. Attachment E to filing entitled Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Docket No. ER18-1314-000 (Apr. 9, 2018). This 2018 affidavit is appended as Attachment K to make it part of the record in this proceeding and demonstrate the extraordinary reversal in Mr. Keech's position now.

[104] 2018 Keech Aff. at 2.

[105] 2018 Keech Aff. at 3-4.

[106] June 2018 MOPR Order at P 5.

to mitigate price distortions caused by out-of-market support granted to other types of entrants or to existing capacity resources of any type.[107] As the Commission explained,

> [T]he PJM Tariff allows resources receiving out-of-market support to significantly affect capacity prices in a manner that will cause unjust and unreasonable and unduly discriminatory rates in PJM regardless of the intent motivating the support. We are compelled by the evidence presented by PJM, Calpine, and other parties to these consolidated proceedings to conclude that out-of-market payments by certain PJM states have reached a level sufficient to significantly impact the capacity market clearing prices and the integrity of the resulting price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources. We cannot rely on such a construct to harness competitive market forces and produce just and reasonable rates. The PJM Tariff, therefore, is unjust and unreasonable.[108]

The Commission "propose[d] that the replacement rate include an expanded MOPR that covers out-of-market support to all new and existing resources, regardless of resource type" because the record demonstrated "that state-subsidized resources—not just entities exercising buyer-side market power—can cause significant price suppression."[109] In the Commission's view, "[a]n expanded MOPR, with few or no exceptions, should protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[110] However, the Commission could not make a final determination regarding a just and reasonable replacement rate based on the record presented and initiated a paper hearing to allow the parties to submit additional arguments and evidence regarding the replacement rate.[111]

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[107] *See id*.

[108] *Id.* P 156 (footnote omitted).

[109] *Id.* P 158.

[110] *Id.*

[111] June 2018 Order at P 149.

In December 2019, the Commission directed PJM to establish a just and reasonable replacement rate "that retains PJM's current review of new natural gas-fired resources under the MOPR and extends the MOPR to include both new and existing resources, internal and external, that receive, or are entitled to receive, certain out-of-market payments."[112] The Commission required "three categorical exemptions to reflect reliance on prior Commission decisions" for "(1) existing self-supply resources, (2) existing demand response, energy efficiency, and storage resources, and (3) existing renewable resources participating in RPS programs."[113] The Commission reestablished "a fourth exemption, the Competitive Exemption, for new and existing resources that are not subsidized" and also allowed "new and existing suppliers that do not qualify for a categorical exemption to justify a competitive offer below the applicable default offer price floor through a Unit-Specific Exemption."[114] The Commission reaffirmed the June 2018 MOPR Order's holding that "[a]n expanded MOPR with few or no exceptions, should protect PJM's capacity market from the price-suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[115] The Commission explained that the "replacement rate does not purport to solve every practical or theoretical flaw in the PJM capacity market," emphasizing that the Commission was seeking to solve the "core problem' identified by both PJM and the complainants, "that is, the manner in which subsidized resources distort prices in a capacity market that relies on competitive auctions to set just and reasonable rates."[116]

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[112] December 19 Order at P 2.

[113] *Id.*

[114] *Id.*

[115] *Id.* P 5.

[116] *Id*.

PJM's compliance filings implementing these directives were accepted by the Commission in 2020 and implemented by PJM in 2021.[117] The PJM Filing refers to the currently-effective version of the replacement rate as the "Expanded MOPR."

D. The May 2021 BRA Results

On June 2, 2021, PJM announced the results of the Base Residual Auction ("BRA") for the 2022/2023 Delivery Year.[118] This was the first annual auction to be held with the Expanded MOPR in place. As PJM explained, "[p]rices were significantly lower than in the previous auction."[119] Specifically, the RTO-wide price of $50 was approximately 36% of the $140 RTO-wide price from the previous auction for the 2021/2022 delivery year. This was the lowest RTO-wide price in more than a decade and the fourth lowest RTO-wide price ever. The constrained local delivery area (LDA) prices were higher than $50, but nevertheless lower than the corresponding prices in the prior BRA and on the low side of constrained LDA prices in all previous auctions.[120]

Furthermore, cleaner energy resources made significant gains. "Renewables, nuclear and new natural gas generators saw the greatest increases in cleared capacity, while coal units saw the largest decrease."[121] Specifically, "1,728 MW of wind cleared in the auction, representing an increase of 312 MW over the previous capacity auction," while "[s]olar increased by 942 MW over the previous capacity auction, with 1,512 MW clearing."[122] There were also significant

[117] *See supra* note 6 (listing compliance orders).

[118] *See infra* Attach. G, 2022/2023 RPM Base Residual Auction Results. The BRA for the 2022/2023 Delivery Years was originally supposed to be held in May 2019, but was postponed until PJM could implement the 2019 MOPR.

[119] *See infra* Attach. H, PJM Press Release, at 1.

[120] *See infra* Attach. F, Danly BRA Results Whitepaper at 1 & nn.3-6.

[121] *See infra* Attach. H, PJM Press Release, at 1.

[122] *Id*.

changes in nuclear and coal-fired resource utilization under the new rule, including FRR elections, such that "[n]uclear generators cleared an additional 4,460 MW when compared to the last auction," while "[c]oal generators," by contrast, "cleared 8,175 fewer megawatts than in the previous auction."[123]

Contrary to the dire predictions of those who opposed adoption of the Expanded MOPR, application of the new rule did not present an insuperable barrier to new entry or compel the failure of resources supported by out-of-market subsidies. The overwhelming majority of capacity offered into the 2021 BRA was not subject to the Expanded MOPR at all. 167,698 MW of capacity was offered into the auction and 155,669 MW (approx. 93%) of those offers was expressly exempt or otherwise unaffected by the Expanded MOPR.[124] 10,220 MW (approx. 6%) of the total offered was subject to the State Subsidy MOPR and only 1,810 MW (approx. 1%) of the total offered was subject to the New Entry MOPR.[125] Moreover, 8,404 MW (82%) of the offers subject to the State Subsidy MOPR cleared and 513 MW (28%) of the offers subject to the New Entry MOPR cleared.[126]

Renewable resources subject to the Expanded MOPR were more successful than thermal resources subject to the Expanded MOPR. 633 MW of wind, solar, and hydrolelectric offers were subject to the Expanded MOPR and 477 MW (approx. 75%) of those renewable resource offers cleared; by contrast, 2,009 MW of natural gas-fired resources were subject to the Expanded MOPR and 788 MW (approx. 39%) of those gas-fired resources cleared.[127]

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[123] *Id.* at 2.

[124] *See infra* Attach. I, May 2021 Supplemental BRA Clearance Data tbl.1

[125] *See id.*

[126] *See id.*

[127] *See id.* tbl.3.

Indeed, only 157 MW of renewable resources subject to the Expanded MOPR failed to clear the auction and that result is roughly comparable with the clearance rate for renewable resources that were *not* subject to the Expanded MOPR. The percentage of MOPR-exempt renewable resources that cleared was about 84% (6,920 MW of 8,224 MW), while the percentage of renewable resources subject to the Expanded MOPR that cleared was approximately 75% (477 MW of 633 MW).[128] In other words, some renewable resources that were *not* subject to the Expanded MOPR must have offered above the $50/MW-day clearing price—most likely because of the need to incorporate Capacity Performance risk—and it is probable that the small quantity of renewable resources subject to the Expanded MOPR that failed to clear may have failed to clear for the same reason. In all events, the quantity of renewable generation subject to the Expanded MOPR that failed to clear was quite small and there is no basis in the publicly available data to claim that the Expanded MOPR is what caused that small quantity of resources to fail to clear.

These results belie the various concerns and warnings expressed by the Expanded MOPR's critics. PJM offered various potential explanations for the auction results. But it is no longer possible to assert that the Expanded MOPR must necessarily result in higher capacity prices, harm clean energy resources, or impede state energy policy choices. The auction results also indicate that there is no need for PJM's premature rush to implement a complete reversal of the Expanded MOPR to avoid such consequences, much less to eviscerate the longstanding policy against state subsidies that has been in effect since 2011 in PJM and even longer in other regions. Finally, the available information indicates that PJM, at the very least, overstates its case[129] when it claims that

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[128] *See id.*

[129] *See, e.g.*, Quinn Aff. ¶ 16 ("The vast majority of existing capacity and new entry in PJM does not receive out-of-market support and in order for this unsubsidized investment to continue, confidence in wholesale market prices is essential. The IMM reports that 77 percent of new capacity additions between delivery years 2007/08 and 2021/22 were based on market funding.")

"state support for renewable resources has become a well-established determinant of supply in the PJM Region, and that the Expanded MOPR "ignores the region's actual supply-demand fundamentals.[130]

II. ELEMENTS OF PJM PROPOSAL

PJM proposes to terminate, effective with the 2023/24 Delivery Year, both the existing MOPR for natural gas resources (what PJM calls the "Legacy MOPR") and the Expanded MOPR. PJM also would eliminate, effective with the 2023/24 Delivery Year, the rule that a new resource claiming a Competitive Exemption in its first year of operation will be prohibited from participating in the RPM Market if it subsequently accepts a State Subsidy.

In place of the Legacy MOPR and the Expanded MOPR, PJM proposes to implement its "focused" MOPR, which would apply only in two limited circumstances: first, any actual "Exercise of Buyer-Side Market Power"; and second, any instance of "Conditioned State Support." Under this approach, "Buyer-Side Market Power" is defined to mean the "[a]bility of market participant(s) with a load interest to suppress market clearing prices for the overall benefit of their portfolio." PJM defines "Exercise of Buyer-Side Market Power" to mean "'anti-competitive behavior' by a Capacity Market Seller with a Load Interest of any kind, i.e., a 'responsibility for serving load within the PJM Region,' whether through its own load service obligations, that of an affiliate, or through a contractual arrangement with a LSE 'for the overall benefit of the Capacity Market Seller's (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest."[131] Thus, "only Generation Capacity Resources

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[130] PJM Filing at 2, 7.

[131] PJM Filing at 24.

of Capacity Market Sellers with a 'Load Interest' could be subject to the MOPR based on buyer-side market power concerns."[132]

PJM plans to screen for the "Exercise of Buyer-Side Market Power" primarily through an attestation, to be submitted by a seller prior to an RPM Auction, stating that the seller is not uneconomically planning to lower its capacity market offer in order to suppress market clearing prices for the overall benefit of the seller's portfolio or for the portfolio of any load serving entity. PJM states that if a seller executes and submits the attestation, it will not be subject to the MOPR unless either PJM or the Independent Market Monitor, using a case-by-case review, identify the seller as engaging in the Exercise of Buyer-Side Market Power." PJM clarifies further that such case-by-case reviews will only focus on sellers that have a "net short" position (i.e., the seller buys more than it sells in the RPM). Even if a seller is in a net short position, PJM states that it will be deemed to have the ability to exercise market power only if it actually has the ability to impact capacity prices, as determined by the application of specified screens.

PJM would expressly exclude from the definition of the "Exercise of Buyer-Side Market Power" a series of activities, many of which have been prohibited by the Commission's MOPR policies. These include merchant generation supply resources not contracted to load, and resources acquired through a fully competitive and non-discriminatory process open to new and existing units. These also include any generation resources (whether owned or contracted for) of a Self-Supply Entity that are demonstrated to be consistent with or included in the Self-Supply Entity's long-range resource plan which is approved or otherwise accepted by the Relevant Electric Retail Regulatory Authority, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices. PJM also would

[132] *Id.*

exclude from the definition of Exercise of Buyer-Side Market Power any support of resources aligned with well-demonstrated customer preferences.

"Conditioned State Support," the other practice prohibited by the proposed MOPR, is defined as "[o]ut-of-market payments or other financial benefit from a state, or political subdivision of a state acting in its sovereign capacity, provided in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM auction." PJM's definition provides further that the "term 'conditioned on clearing in any RPM auction' refers to directives as to the price level at which a resource must be offered in the capacity market or directives that the unit is required to clear in any capacity auction." Thus, "Conditioned State Support" is essentially limited to circumstances where a state engages in the conduct held to be preempted under *Hughes*. Under the PJM proposal, certain state programs would be expressly excluded from the definition of "Conditioned State Support," including state-level environmental initiatives (for example, Renewable Energy Credits and Zero Emissions Credits), state and local tax incentives, state retail default service auctions, fuel supply incentives, and (v) federal programs administered by states (for example, elements of the Public Utility Regulatory Policies Act of 1978). The PJM proposal also provides that "legacy" state policies enacted prior to September 1, 2021 will not be subject to the MOPR.

III. PROTEST

The PJM Filing must be rejected in its entirety. It contains multiple fundamental legal flaws and urges radical policy changes that would destroy the foundation of the capacity market. The PJM Filing goes far beyond accommodation of state generation preferences. The instant filing would destroy the foundation of the capacity market by replacing fuel-neutral competition for least cost resources with a new regime that embraces discrimination based on extra-statutory policy preferences. It wrongly provides a pathway to state interference with competitive markets by permitting states to engage in any form of state-subsidization that is not expressly preempted by federal law. And, in doing so, it defies explicit Commission directives in numerous prior orders, including determinations previously affirmed on judicial review and determinations the Commission is presently defending on judicial review.

The PJM Filing represents a complete and unjustified reversal of PJM's consistent support for effective market power "guardrails" over the last two decades. PJM's attempt to justify its retreat relies mostly on the fact that stakeholders support it. But stakeholder support does not relieve the Commission of its obligation to independently determine the merits of Section 205 filings based on substantial evidence. The other rationalizations that the PJM Filing offers to support its proposal are likewise insufficient.

The Commission cannot accept the PJM Filing without abrogating its precedents and abandoning its statutory duty to ensure just, reasonable, and non-discriminatory practices in interstate commerce. PJM's proposal is also shockingly poor public policy. It is effectively worse than a straightforward elimination of the MOPR and will expose the market to the very distorting state actions that PJM decried in 2018 and FERC demanded that PJM address.

A. It Would Be Unlawful, and Directly Contrary to More than a Decade of Commission Precedent, for the Commission to Ignore Artificial Price Suppression

As P3 recently advised the PJM Board of Managers, Commission and appellate2-3. precedent makes clear that FERC cannot simply ignore the exercise of buyer-side market power out of a desire to avoid interfering with state policy prerogatives."[133] Capacity markets cannot be just and reasonable under the law absent provisions designed to protect against the exercise of both

[133] PJM Power Providers Group letter to the PJM Board at 1-2 (June 1, 2021) https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210602-p3-letter-re-minimum-offer-price-rule.ashx.

seller-side and buyer-side market power, including buyer-side market power exercised by the states.[134] Commissioner Danly has written at length on this subject in a series of White Papers that focus specifically on the application of this fundamental principle in the specific context of capacity markets.[135] Commissioner Danly's work on this subject should inform the Commission's approach here. He correctly observes that the Commission and the courts have long found that it is appropriate to mitigate the price suppressive effects of state actions to subsidize generation. And he correctly concludes that it is the Commission's duty under the FPA to acknowledge and mitigate the price suppressive effects of state subsidies in order for capacity market prices to be just and reasonable in a market-based regime.

As detailed later in this Protest, the tariff modifications proposed in the PJM Filing violate this core legal requirement in several ways. The two chief components of PJM's Narrow MOPR proposal—its Conditioned State Support and Buyer-Side Market Power changes—are defined so narrowly that they will necessarily fail to acknowledge or address significant artificial price suppression caused by out-of-market subsidies and other market behavior that unduly discriminate against competitive, non-subsidized capacity resources.[136]

The Conditioned State Support proposal compounds that fundamental legal error by setting the bar on prohibited state conduct far too low, embracing all forms of state intervention in the market that are not already preempted under the Supreme Court's decision in *Hughes*. If accepted, this would essentially abdicate the Commission's statutory duty to prevent or correct unjust, unreasonable and unduly discriminatory practices by both private actors and by states. The Buyer-

[134] Id at 2-3.

[135] *See* Attachments C, D, and E.

[136] *See infra* Part III.C (addressing Conditioned State Support); *infra* Part III.D (addressing Buyer Side Market Power).

Side Market Power proposal falls short in a similar way, establishing a conduct screen that resurrects a form of intent-based analysis the Commission has repeatedly rejected.[137] In short, the Commission should find the PJM Filing unjust, unreasonable, and unduly discriminatory as a matter of law.

B. The PJM Filing is an Impermissible Collateral Attack on the Expanded MOPR Orders and 2011 MOPR Orders

PJM proposes to eliminate mitigation of several broad categories of market behavior in straightforward defiance of Commission directives imposed on PJM under FPA section 206 and in a manner that completely reverses PJM's previous position in two FPA section 205 filings on the exact same subject.[138] PJM may not collaterally attack express Commission directives under FPA section 206 by exploiting the Commission's more passive role under FPA section 205.[139] As the Commission has previously held in many cases, "[c]ollateral attacks on final orders and relitigation of applicable precedent by parties that were active in the earlier cases thwart the finality and repose that are essential to administrative efficiency and are strongly discouraged."[140]

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[137] *See, infra* Part III.D.2.

[138] *See supra* Part I.B.2 and C (discussing PJM's 2011 and 2018 MOPR filings).

[139] *See* PJM Filing at 3, 20-21.

[140] *San Diego Gas & Elec. Co*., 134 FERC ¶ 61,229, at P 15 & n.28 (2011) (quoting *Entergy Nuclear Operations, Inc. v. Consol. Edison Co*., 112 FERC ¶ 61,117, at P 12 (2005) (denying rehearing of an order granting a complaint) (citing *EPIC Merchant Energy NJ/PA, L.P. v. PJM Interconnection, L.L.C.*, 131 FERC ¶ 61,130 (2010) (dismissing as an impermissible collateral attack a complaint that merely sought to re-litigate the same issues as raised in the prior case citing no new evidence or changed circumstances)); *accord, e.g*., *Cent. Vermont Pub. Serv. Corp.*, 123 FERC ¶ 61,128, at P 35 (2008) (citing *Entergy Nuclear Operations*); *KeySpan Ravenswood, Inc. v. New York Independent System Operator, Inc*., 107 FERC ¶ 61,142, at P 22 & n.25 (2004) ("*KeySpan IV*") (citing *Univ. of Tenn. v. Elliot*, 478 U.S. 788, 797-99 (1986); *United States v. Utah Constr. & Mining Co*., 384 U.S. 394, 421-22 (1966) ("When an administrative agency is acting in a judicial capacity and resolved disputed issues of fact properly before it which the parties have had an adequate opportunity to litigate, the courts have not hesitated to apply res judicata to enforce repose.")); *see also, e.g*., *Cal. Indep. Sys. Operator Corp.*, 120 FERC ¶ 61244, 62018 (2007) (denying rehearing request because the Commission "cannot provide Imperial with unlimited opportunities to attack the Commission's threshold findings in the April 19 Order and rehearing thereof")*; Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,049, at P 200 (2014) (denying complaint as "a collateral attack on Order No. 679-A"); *Cal. Indep. Sys. Operator Corp*., 117 FERC ¶ 61,148, 61,804 (2006) ("[W]e note that the Commission has already denied rehearing on this exact issue and therefore PG&E's Offer of Settlement constitutes a collateral attack on the Commission's July 1, 2005 and August 26, 2005 Orders."); *Pac. Gas & Elec. Co.*, 116 FERC ¶ 61,004, at P 34 (2006) (finding "that PG&E's complaint is a collateral attack on the January 27, 2006

The collateral attack rule is not confined to protests, complaints, or rehearing requests. It applies with equal force to new filings under FPA section 205 unless the proponent of the new rate proposal is able to adduce new evidence or a material change in circumstances.[141] As the Commission originally explained when it confronted this issue for the first time more than four decades ago, "[i]n the absence of new or changed circumstances requiring a different result, there appears no reason why substantive ratemaking principles, once established, should not continue to be applied."[142] Moreover, the changed circumstances must be significant enough to provide a

Order and the rate proceeding established in that Order"); *Niagara Mohawk Power Corp*., 111 FERC ¶ 61,120, at P 19 (2005) ("Raising the issue again on rehearing of the November 19 Order is a collateral attack on findings that the Commission made in earlier station power cases, and is a collateral attack being made by the same party that was active in those earlier proceedings. . . . . As discussed in *KeySpan IV*, collateral attacks on final orders and relitigation of applicable precedent by parties that were active in earlier cases thwart the finality and repose that are essential to administrative (and judicial) efficiency." (footnotes omitted)); *Cal. Indep. Sys. Operator Corp*., 94 FERC ¶ 61,147, 61,558 (2001) (rejecting protest as "a collateral attack on the Commission's findings in Docket No. EL00-105-000, wherein we found Vernon's proposed TRR, as modified, to be just and reasonable"); *Exxon Co., U.S.A. v. Amerada Hess Pipeline Corp*., 83 FERC ¶ 63011, 65,096 (1998) ("The Commission's position on relitigation of issues is one where in the absence of new or changed circumstances requiring a different result, "it is contrary to sound administrative practice and a waste of resources to relitigate issues in succeeding cases once those issues have been finally determined." (quoting *Alamito Co.*, 41 FERC ¶ 61,312, at 61,829 (1987) (quoting *Cent. Kan. Power Co.*, 5 FERC P 61,291, at 61,621 (1978))).

[141] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc*., 133 FERC ¶ 61,221, at P 440 (2010) ("While there have been some changes since the Commission eliminated rate pancaking between Midwest ISO and PJM, we do not find that such changes are sufficient to mitigate the RTO scope and configuration concerns that led the Commission to find that pancaked rates between Midwest ISO and PJM are unjust and unreasonable. Furthermore, to the extent that Filing Parties are arguing that the Commission's decision to eliminate rate pancaking is now incorrect, making such an argument in this section 205 filing represents an impermissible collateral attack on prior Commission orders."); *Entergy Servs., Inc*., 130 FERC ¶ 61,026, at P 38 n.48 (2010) ("We agree with Joint Parties that the policy against relitigation of issues (or requiring changed circumstances) applies to section 205 filings as well as section 206 complaints."); *Cent. Vt. Pub. Serv. Corp*., 123 FERC ¶ 61,128, at P 35 (2008) ("At the outset, the filing is a collateral attack . . . . [T]he Filing Parties present no materially changed circumstances that would merit a revisiting of either of these Commission orders [approving the FCM Settlement Agreement]. Collateral attacks on final orders and relitigation of applicable precedent, especially by parties that were active in the earlier case, thwart the finality and repose that are essential to administrative efficiency, and are therefore strongly discouraged."); *Minn. Power & Light Co*., 13 FERC ¶ 63,014, 65,030 (1980); *Cent. Kan. Power Co.*, 5 FERC ¶ 61,291 at 61,621; *cf. Entergy Servs., Inc*., 130 FERC ¶ 61,026 at PP 41-42 (finding that "changed circumstances" were not required because the parties had not litigated labor costs in earlier proceedings).

[142] *Cent. Kan. Power Co.*, 5 FERC ¶ 61,291 at 61,621.

persuasive reason for the Commission to decide that a "substantive ratemaking principle" already decided by the Commission should be changed.[143]

Here, PJM proposes that the Commission completely reverse the Expanded MOPR rules that the Commission itself imposed on PJM under FPA section 206 on the basis that those rules were required to prevent unjust, unreasonable, and unduly discriminatory price suppression in PJM's capacity market. The replacement rate directed by the Commission in December 2019 was the product of a complaint lodged in 2016, which prompted a technical conference in 2017, which in turn prompted PJM's 2018 MOPR filing that took precisely the opposite position that PJM (as well as one of PJM's current witnesses, Mr. Keech) is now advancing in this case. After the Commission found PJM's 2018 proposal insufficient to protect the capacity market against out-of-market subsidies for both new and existing resources in the June 2018 Order, litigation to set the replacement rate took eighteen months, followed by more than a year of repeated refinements on rehearing and compliance. In all, eight separate Commissioners voted on the seven Expanded MOPR Orders spanning from June 2018 to February 2021. The quantity of Commission and private resources expended in that effort is inestimably large and the Commission is still defending the Expanded MOPR orders on judicial review. Worse, PJM also proposes that the Commission effectively reverse its orders eliminating the state mandate exemption in 2011, notwithstanding the affirmance of those orders on judicial review. The Commission has never had a stronger basis to

[143] *Minn. Power & Light Co.*, 13 FERC ¶ 63,014 at 65,030 ("[I]t is not every "new factual assertion" or every "new argument" which would permit relitigating a substantive ratemaking principle. There must be sufficient substance to the "new" material so that there is a reasonable possibility the Presiding Judge or the Commission would decide the substantive ratemaking principle should be changed." (footnotes omitted)); *see also, e.g.*, *CNG Transmission Corp.*, 51 FERC ¶ 63,003, at 65,007 (1990) ("[W]here a party seeks to relitigate issues previously ruled on by the Commission, without showing any new or changed circumstances requiring a different result, summary disposition is appropriate with respect to those issues.").

reject a filing under FPA section 205 as a collateral attack on substantive ratemaking principles decided by litigation among the same parties.

1. The PJM Filing Is Not Justified By Changed Facts or Circumstances

PJM's collateral attack on the Commission's prior orders, like PJM's stunning reversal of a position it had taken since 2011, could be justified if PJM were able to point to significant new facts or circumstances warranting such a radical shift, but PJM's attempt to make that case is devoid of merit.

a. PJM Ignores the 2011 BRA Auctions Results

The PJM Filing asserts that the Narrow MOPR is just and reasonable because it is necessary to correct a host of asserted evils associated with the Expanded MOPR that the Commission directed PJM to adopt under FPA section 206.[144] But PJM flatly ignores the best available empirical evidence about how the market is performing under the Expanded MOPR: the May 2021 BRA for the 2022-2023 Delivery Year. As previously discussed, that auction witnessed a dramatic reduction in capacity prices, high levels of reliability, orderly exits by uncompetitive facilities, a smaller amount of purchased capacity, and steady improvements in decarbonization through the significant entry of new renewables and retention of existing renewables.[145] As compared to the previous auction, significantly higher quantities of nuclear (4,460 MW increase), wind (312 MW increase), and solar (942 MW increase) resources cleared the market, while coal-fired resources fell precipitously (8,175 MW decrease).[146] The overwhelming majority of capacity offers (93%) were not subject to the Expanded MOPR at all.[147] Moreover, 8,404 MW (82%) of the offers

[144] *See, e.g.*, PJM Filing at 2.

[145] *See supra* at Part I.D.

[146] *See infra* Attach. H, PJM Press Release, at 1-2.

[147] *See infra* Attach. I, May 2021 Supplemental BRA Clearance Data tbl.1

subject to the State Subsidy MOPR cleared and 1,810 MW (28%) of the offers subject to the New Entry MOPR cleared.[148] Indeed, 75% of the renewable resource offers subject to the Expanded MOPR cleared the auction, while 39% of the natural-gas fired resource offers subject to the Expanded MOPR cleared the auction.[149]

These results starkly conflict with PJM's assertions that the Expanded MOPR ignores state support for renewable resources, "attempt[s] to 'hermetically seal' the capacity market from the reality of state policies," and "create[s] substantial conflicts between PJM's capacity market and both state policies and self-supply business models."[150] On the contrary, as Commissioner Danly aptly observed:

> This past auction shows that the extended MOPR, as presently implemented, allows renewable resources to be competitive even when capacity prices are at historic lows. Consequently, widely raised concerns that PJM's extended MOPR would increase capacity prices and unduly interfere with state policy choices were substantially unjustified and needlessly alarmist.[151]

That assessment is correct. PJM's failure to grapple with the only empirical evidence of new facts or changed circumstances—the 2021 BRA results—is a glaring omission that fails to communicate an accurate representation of the status quo. PJM's hapless recycling of pre-auction arguments and rhetoric, as if the auction had never occurred, is inconsistent with the expectation that PJM will function as an independent and impartial market administrator.[152]

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[148] *See id.*

[149] *See id.* tbl. 3.

[150] PJM Filing at 3.

[151] Danly BRA Results Whitepaper at 3.

[152] *See, e.g.*, Shanker Aff. ¶¶ 38-48.

b. The ELCC Order Does Not Justify the Narrow MOPR's Sweeping Changes

Rather than acknowledge the actual results of the May 2021 BRA, PJM instead claims that circumstances have changed because the Commission accepted PJM's revised ELCC proposal on the same day the Narrow MOPR proposal was filed.[153] PJM asserts that its new ELCC methodology will help to "right-size the capacity accreditation" for intermittent and storage resources, which, according to Mr. Keech, means that the Commission's concerns about increased entry by state-subsidized renewable resources were "overstated."[154] While P3 appreciates tariff refinements that more accurately assess the performance of intermittent resources—in particular, the recognition of "diminishing returns associated with greater levels of deployment for most ELCC Resource types to ensure the region does not become overdependent on a single resource type with inherent limitations"—the ELCC reform only applies to a small subset of resources "that are unable to maintain output at a stated capability continuously on a daily basis without interruption."[155] Mr. Keech does not contend that recent ELCC changes will make out-of-market actions, price suppression, and related harms disappear. He merely contends that these issues may be less severe due to ELCC.

It is absurd for PJM to claim that the ELCC reform justifies its sweeping proposal to adopt a Narrow MOPR that erases any effective control on price-suppressing out-of-market subsidies.

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[153] *See* PJM Filing at 19.

[154] *Id*. at 19 & n.59 (quoting Keech Aff. ¶ 13).

[155] Updated ELCC Order, 176 FERC ¶ 61,056 at PP 2, 18; *see also id.* P 70 ("ELCC Resource classes that produce energy during the same hours may provide diminishing capacity value as incremental MW of that resource class are added to the system."). The Commission's belated acceptance of PJM's revised ELCC proposal was hardly an endorsement of its merits, relying on PJM's commitment to review and repair the ELCC proposal. *See id.* P 63; *see also id.* P 11 (Christie, Comm'r, dissenting) ("[T]here is no urgency to replace the current rules and there is no reason to approve an ELCC at this time that is not as good as it needs to be. Further, I think the prospect that PJM will revisit this proposal in the near term to fix the flaws identified is fanciful."); *id.* P 1 & n.1 (Danly, Comm'r, concurring) (agreeing with Commissioner Christie's concerns on the merits, but concurring because "the fact that there might be a better approach does not change the standard we must apply under section 205").

The ELCC reform might have some effect on the capacity valuations of subsidized intermittent resources, but it does nothing to confront out-of-market state subsidies for new or existing thermal capacity resources, which constitute a much larger share of PJM capacity and have historically been the primary vehicles for buyer-side market power the Commission sought to mitigate by eliminating the state mandate exemption in 2011 and directing the Expanded MOPR replacement rate in 2019.[156] As Dr. Quinn observes, the evolution of the Commission's buyer-side mitigation policy with respect to new entry "was born out of the practical experience with out-of-market actions by Connecticut, New Jersey, and Maryland to sign uneconomic, out-of-market contracts with natural gas plants for the sole or primary purpose of reducing their states' consumers' total capacity payment," while "[i]n practice, the out-of-market retention of existing resources has almost exclusively been effectuated via out-of-market payments to nuclear units."[157]

c. Deterring Utility Election of the FRR Alternative or Departure from PJM Is Not a Valid Basis for the Narrow MOPR

Looking past PJM's grossly overstated reliance on ELCC as a changed circumstance, PJM's constant refrain about avoiding "conflicts between PJM's capacity market and both state policies and self-supply business models" demonstrates that PJM's real concern is "a serious risk (already realized in part) for significant loads to be removed from the capacity market altogether."[158] There are three fundamental problems with that objective. First, it represents an

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[156] *See Hughes*, 136 S. Ct. at 1290-91 (describing the Maryland Public Service Commission's preempted effort to promote new natural gas resources through contracts for differences, which New Jersey similarly required through state legislation); *NJBPU*, 744 F.3d at 1294-95; *see, e.g.*, June 2018 Order at P 1 ("What started as limited support primarily for relatively small renewable resources has evolved into support for thousands of megawatts (MWs) of resources ranging from small solar and wind facilities to large nuclear plants."); *id.* PP 103, 105, 114-15, 131, 135-37, 151 (noting that state subsidies for nuclear resources were the basis for Calpine's amended complaint and preemption litigation against the Illinois Zero Emissions Credit (ZEC) program and describing the threat posed by a similar proposal in New Jersey according to PJM, the Market Monitor, the Electric Power Supply Association ("EPSA"), and others); *see also supra* Parts I.B & I.C (discussing the Commission's prior MOPR reforms).

[157] Quinn Aff. ¶¶ 8, 42.

[158] PJM Filing at 2.

abject surrender of PJM's unique responsibility as the neutral administrator of a competitive market to actively facilitate certain states' *unchanged* desire to move forward with promoting the preferred resources through out-of-market subsidies regardless of whether *their own* decisions to provide financial support for preferred new or existing resources causes their constituent-consumers to "pay twice" for capacity. In short, it is those states' unwillingness to accede to the capacity market's function of ensuring reliability at least cost that is creating the conflict PJM now ostensibly seeks to avoid. Second, the FRR Alternative is a long-standing right expressly set out in PJM's tariff. Tellingly, while PJM clearly does not want utilities to exercise the FRR option, PJM has not requested that the FRR Alternative be reformed or removed. Third, so long as an FRR plan fulfills the tariff's requirements to maintain resource adequacy, or a departing utility satisfies its financial obligations, PJM has no basis under its currently effective tariff to second-guess the wisdom of FRR elections.

Dr. Shanker examines this question at length in his affidavit, where he explains the deep flaws in the way PJM now focuses on deterring departure from the capacity market or PJM itself. In his view, this newfound focus expressed throughout the PJM Filing and in the testimony of its witnesses "seems to be a determination based more on political expedience and concern about perpetuation of PJM as an institution, rather than trying to fulfill PJM's basic function of being neutral and independent and enforcing the Tariff."[159] Dr. Shanker goes on to address PJM's witness testimony as follows:

> Aside from what I believe are the reasonably transparent political considerations underlying PJM's proposal, Mr. Keech did offer a number of flawed arguments to justify this changed approach. Mr. Keech argues that the states or self-supply entities may leave the capacity market if the capacity that they have subsidized to meet their policy objectives is not recognized.[160] He also suggests that this would

[159] Shanker Aff. ¶ 38.

[160] PJM Filing, Attachment D, Keech Affidavit at paras. 7-8.

result in higher costs to FRR entities because they would utilize alternative procurement methods that might not be as efficient as the existing PJM market in meeting the full requirements of the state or self-supply mandates. Mr. Keech and Dr. Cramton also claim that the broad MOPR results in over-procurement, resulting in market prices that do not reflect the true supply demand conditions. These arguments fail and are questionable for four reasons.

First, PJM's filing states that "irrespective of the MOPR, there is scant prospect that states in the PJM Region will discontinue their programs that lend financial support to resources that advance the states' energy and other policy goals."[161] PJM's belief that, when faced with a choice the states will pursue their policy objectives regardless of costs, is supported by the fact that states have continued to expand their subsidy programs after the Commission's December 2019 order requiring PJM to implement the broad MOPR (e.g., Dominion has elected to be an FRR entity, while Maryland and New Jersey continue to move forward and have already begun their procurement of off-shore wind resources). In this sense, the state choices and costs are fixed – that is, the states are committed, and will willingly go forward and incur additional costs to procure certain out of market attributes even if their chosen resources do not clear in the capacity market. If this is the case, then the behavior is settled, and we should therefore ignore it and focus on getting the appropriate non-discriminatory pricing in the market under the status quo broad MOPR.[162]

Second, if such procurement is not truly set in stone, then we should recognize that there a game of "chicken" going on here, with the states posturing to modify PJM's behavior, which should be that of a neutral RTO/ISO, rather than trying to promote some state(s) preferences at the expense of others.

Third, if PJM does not believe it is appropriate to interfere with state policies for clean energy attributes, it appears incongruous for Mr. Keech to then argue that the narrow MOPR must be implemented to prevent states from procuring other resources inefficiently. Moreover, PJM still does not explain why concern or deference to local political initiatives now exceeds PJM's previous recognition of the range of harms that occur due to the suppression of prices via large quantities of subsidized resources.

Fourth, Mr. Keech also expressed the tired "pay twice" logic (paragraph 7). He ignores the fact that, if the state action is actually fixed as PJM claims, the state knowingly is procuring resources for *attributes other than capacity*, with the full knowledge that those resources may not be utilized in the PJM market to satisfy

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[161] PJM Filing at 7.

[162] Note that this is effectively what Dr. Cramton has assumed in his analyses. When referring to intermittent and subsidized nuclear units he stated: "The MW amount of state-sponsored resources entering each year is based on PJM estimates and reported in Table 6.5. State-sponsored resources, including nuclear, are assumed to stay in the market regardless of their economics." Cramton Working Paper at 55.

capacity obligations. They are knowingly undertaking this risk and apparently value the environmental attributes sufficiently to accept that outcome.

Equally important, the problem with the "Conditioned State Support" aspect of PJM's proposal is revealed by PJM's argument that adopting a narrow MOPR will mean no double payment. This argument is repeated in one form or another by virtually every PJM witness. If this is the case, the entire proposition of having a "Conditioned State Support" provision in the proposed MOPR is a sham and accomplishes nothing. PJM apparently knows and intends that no state will ever have to "pay twice" despite the "Conditioned State Support" rule. This recognition shows that PJM has concluded that the "Conditioned State Support" provision has no bite, and that PJM anticipates it will be easy for a state to avoid mitigation and as such will not impact the states' desired results, regardless of the ultimate impact on the PJM markets. This is exactly the type of consideration that drove the Commission to support mitigation of uneconomic entry in the first place.[163]

2. Acceptance of the PJM Filing Under FPA section 205 Cannot Relieve the Commission of Its Duty to Recognize and Explain Its Departure From Existing Precedent

If the Commission chooses to accept the PJM Filing under FPA section 205 on the ground that PJM is not required to prove the existing rate set by the Commission under FPA section 206 is unjust and unreasonable, that expedient will not relieve the Commission of its own duty to explain its necessary disavowal of the Expanded MOPR Orders and the 2011 MOPR Orders. And that is not the end of it: the Commission would likewise be disavowing a host of similar orders governing the mitigation of buyer-side market power in neighboring regional markets,[164] including the "first principles of capacity markets" described in the Commission's CASPR order.[165] It is a

[163] Shanker Aff. ¶¶ 43-48.

[164] *See, e.g.*, *supra* note 7 (listing representative cases).

[165] *See* CASPR Order, 162 FERC ¶ 61,205 at P 21 ("A capacity market should facilitate robust competition for capacity supply obligations, provide price signals that guide the orderly entry and exit of capacity resources, result in the selection of the least-cost set of resources that possess the attributes sought by the markets, provide price transparency, shift risk as appropriate from customers to private capital, and mitigate market power."); Shanker Aff. ¶ 35; Quinn Aff. ¶ 13. Dr. Quinn emphasizes that the Commission's CASPR orders "indicated a preference for prioritizing investor confidence if no reasonable balance of policy objectives could be achieved through stakeholder efforts," and "explained that the focus on investor confidence is consistent with both investor and consumer interest." Quinn Aff. ¶ 13. As the Commission wrote:

> "Investor confidence" is not a one-sided, supplier-only consideration. On the supplier side of the ledger, allowing the primary FCM auction to set the capacity price paid to all but those resources that clear the substitution auction helps ensure that prices will not be so low as to fail to attract

bedrock requirement of administrative law that the Commission "must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."[166] The Commission may not "depart from a prior policy *sub silentio* or simply disregard rules that are still on the books."[167] While agency that is reversing policy "need not always provide a more detailed justification than what would suffice for a new policy created on a blank slate," it must provide a detailed justification "when, for example, its new policy rests upon factual findings that contradict those which underlay its prior policy; or when its prior policy has engendered serious reliance interests that must be taken into account."[168]

Accepting the PJM Filing would squarely implicate both of these concerns, and the failure to address them would be "arbitrary and capricious" *per se* under Supreme Court precedent.[169] The Commission cannot accept the PJM Filing without reversing express factual findings that underlay the 2011 MOPR Orders and the Expanded MOPR Orders. Here, for example, the Commission would need to determine that out of market subsidies do not artificially suppress prices paid to unsubsidized competitors, contrary to the uniform weight of economic scholarship[170]

> investment in new capacity when needed. On the customer side of the ledger, the Commission found that, when investor confidence is sustained and the FCM continues to attract and maintain resource investment as needed, customers reap the benefit of resource adequacy, and suppliers do not need to include significant risk premiums – the costs of which would ultimately be passed on to customers – in their capacity offers.

CASPR Rehearing Order, 173 FERC ¶ 61,161 at P 47, *quoted in* Quinn Aff. ¶ 13.

[166] *Motor Vehicle Mfrs. Assn. of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (internal quotation marks omitted).

[167] *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) (citing *United States v. Nixon*, 418 U.S. 683, 696 (1974)).

[168] *Id.* (citing *Smiley v. Citibank (South Dakota), N.A.*, 517 U.S. 735, 742 (1996)); *accord, e.g.*, *Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117, 2125 (2016)).

[169] *Id.* at 515-16 ("It would be arbitrary or capricious to ignore such matters. In such cases it is not that further justification is demanded by the mere fact of policy change; but that a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy.").

[170] It is beyond legitimate argument that subsidies disrupt competition, distort market prices, and harm non-subsidized resources. The Commission has long held "that all uneconomic entry has the effect of depressing prices below the competitive level and that this is the key element that mitigation of uneconomic entry should address." *N.Y.*

and contrary to the Commission's express determination that failing to mitigate out-of-market subsidies provides an undue preference to subsidized resources and unduly discriminates against competitive resources.[171] At a minimum, the Commission would need to provide a valid reason why the amount of price suppression caused by out-of-market subsidies is no longer unjust and unreasonable or unduly discriminatory.[172] As a matter of law, that reason cannot be the promotion of environmental benefits, which is a task delegated to other federal agencies and is an extra-statutory consideration under the FPA.[173]

Indep. Sys. Operator, Inc., 124 FERC ¶ 61,301 at P 29 (2008). This position is so well-settled that the Commission has repeatedly found it make rely on economic theory alone to find that subsidies suppress competitive prices and it is therefore unnecessary "to build an evidentiary record by pinpointing instances of 'but for' relatively low offers due specifically to subsidies." December 2019 Order at P 29 & n.94 (citing judicial precedent that affirmed the Commission's reliance on economic theory in other proceedings). This valve is not reversible. That is, the Commission may not rely on economic theory to find that out-of-market subsidies are some form of economic enhancement. The foundational principle that subsidies are anti-competitive is directly incorporated into the statutes the Commission administers, *see, e.g.*, FPA section 203, 16 U.S.C. § 824b(a)(4), and it is incorporated throughout the Commission's policies under the FPA and NGA, *see, e.g.*, *Cross-Subsidization Restrictions on Affiliate Transactions*, Order No. 707, FERC Stats. & Regs. ¶ 31,264, *order on reh'g*, Order No. 707-A, FERC Stats. & Regs. ¶ 31,272 (2008); *Certification of New Interstate Nat. Gas Pipeline Facilities*, 88 FERC ¶ 61,227, 61,745 (1999) ("[T]he threshold question applicable to existing pipelines is whether the project can proceed without subsidies from their existing customers.").

[171] *See, e.g.*, December 2019 Order, 169 FERC ¶ 61,239 at ¶¶ 24-25 & nn.56-60 (quoting June 2018 Order, 163 FERC ¶ 61,236 at PP 64, 100, 156).

[172] There are ways to do this that can survive judicial review, but the PJM Filing does not provide them. For example, in *NextEra Energy Res., LLC v. FERC*, 898 F.3d 14 (D.C. Cir. 2018), the court affirmed the Commission's orders creating a renewable entry exemption where the quantity of the exemption was tied to anticipated load increases in order to minimize price suppression for existing resources. *See ISO New England Inc.*, 147 FERC ¶ 61,173 (2014), *reh'g denied*, 150 FERC ¶ 61,065 (2015), *order on voluntary remand*, 155 FERC ¶ 61,023 (2016), *reh'g denied*, 158 FERC ¶ 61,138 (2017).

[173] The D.C. Circuit comprehensively addressed this question in *Grand Council of Crees* as follows:

> In interpreting the statutory provision, "just and reasonable," the Supreme Court has emphasized that "the Commission [is] not bound to the use of any single formula or combination of formulae in determining rates." *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944). But the Court has articulated the interests that must be protected through such a determination: "[T]he fixing of 'just and reasonable' rates[ ] involves a balancing of the investor and the consumer interests." *Id.* at 603. Both interests are economic and tied directly to the transaction regulated: "the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated," *id.*, while there is a "consumer interest in being charged non-exploitative rates." *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168, 1178 (D.C. Cir. 1987). Where (as here) the grant of ratemaking authority stems from congressional concern over market power (which justifies the agency's relaxing its grip when such power is absent), *see, e.g.*, *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990) ("In a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal cost, such that the seller makes

only a normal return on its investment."), the object may be stated as to set "prices equal to those that the firm would set if it did not have monopoly power; that is, to replicate a 'competitive price.'" Stephen G. Breyer, Richard B. Stewart, Cass R. Sunstein & Matthew L. Spitzer, *Administrative Law & Regulatory Policy* 228 (4th ed.1999). Unsurprisingly, the Supreme Court has never indicated that the discretion of an agency setting "just and reasonable" rates for sale of a simple, fungible product or service should, or even could, encompass considerations of environmental impact (except, of course, as the need to meet environmental requirements may affect the firm's costs).

> Following the judicial lead, the Commission has affirmatively forsworn environmental considerations. In *PSI Energy, Inc.*, 55 FERC ¶ 61,254 (1991), it reviewed an interconnection agreement and rates to be charged thereunder. Certain petitioners raised various "siting, health, safety, environmental [and] archaeological problems" associated with the line through which the power would flow, but the Commission said that such factors were "beyond the Commission's authority to consider under sections 205 and 206 of the Federal Power Act." *Id.* at 61,811. "In a case such as this one, the Commission's authority is limited to review of the rates, terms and conditions of jurisdictional agreements to ensure that they are just and reasonable and not unduly discriminatory or preferential." *Id.*; *see also Monongahela Power Co.*, 39 FERC ¶ 61,350 at 62,096 (1987) ("Congress has not granted the Commission authority to reject rate filings on environmental grounds.").
>
> The Commission's understanding of its duty under § 205(a) leads us toward a resolution of the zone-of-interests test. The test embraces interests "'arguably ... to be protected' by the statutory provision at issue," *National Credit Union Admin. v. First Nat'l Bank & Trust Co.*, 522 U.S. 479, [489] (1998) (quoting *Data Processing*, 397 U.S. at 153), which in turn is inherently linked to the question of what interests the statute actually protects. Thus, if the Commission's view of § 205(a) is valid, it would appear that persons asserting interests excluded under that view could be "arguably" within the requisite zone only if those interests were so congruent with actually protected interests as to make their possessors "suitable challenger[s]" of the agency's purported exercise of its authority. *Mova Pharmaceutical Corp.*, 140 F.3d at 1075. Thus, the petitioners are outside the relevant zone of interests if (1) FERC's refusal to consider environmental issues under § 205(a) is valid, and (2) environmental interests are not "congruent" with the issues that are pertinent under § 205(a).
>
> FERC's exclusion of environmental claims is valid. In the face of congressional silence we defer to an agency's reasonable interpretation of statutes it is charged with administering. *Chevron U.S.A. Inc. v. NRDC*, 467 U.S. 837, 842–43 (1984). Although rates have environmental consequences (increases in the price of electricity, for instance, may at the margin lead to substitution of fuel oil), it seems pointless to weave such issues into setting "just and reasonable" rates for electric power. The environmental issues posed by construction and operation of energy facilities will invariably be reviewed under other provisions; if those reviews (or other forces such as liability risks or firm commitment to environmental quality) cause the utility to incur costs, such costs would feed into the Commission's normal rate calculation. *See Iroquois Gas Transmission System, L.P. v. FERC*, 145 F.3d 398 (D.C. Cir. 1998) (remanding to the Commission for a finding whether utility's legal defense costs resulting from a federal investigation into environmental violations were "prudently incurred," and thus could be included within the rate base); *cf. NAACP v. Federal Power Commission*, 425 U.S. 662, 668 (1976) (finding that the Federal Power Commission was authorized to exclude from rates those costs that result from discriminatory practices of regulatees, just like " any other illegal, duplicative, or unnecessary labor costs"). Beyond that, additional focus on environmental elements would seem to complicate an already complex process, with little or no offsetting benefit to the public. So, at least, FERC could reasonably decide.

198 F.3d 950, 956–58 (parallel citations omitted).

Nor can the Commission accept the PJM Filing without disrupting "serious reliance interests" that the Commission's existing MOPR policies have "engendered."[174] Here, for example, the Commission's 2011 MOPR Orders and Expanded MOPR Orders have induced power suppliers to spend billions of dollars constructing and maintaining generation assets with decades-long useful lives to enter or remain in the PJM market with the expectation of competing on a level playing field, where buyer-side market power is identified and mitigated as required in any market-based construct under the FPA.[175] Accepting the PJM Filing will destroy those expectations.

And that is not the end of it. The FPA was enacted under the Commerce Clause to prevent states from injuring one another by enforcing self-serving policies that unfairly shift costs and other burdens on other states.[176] Preventing those abuses as a neutral arbiter is one of the Commission's core functions.[177] PJM's Narrow MOPR proposal claims to be motivated by a desire to accommodate state policy preferences,[178] but it does nothing to prevent or mitigate states

[174] *Fox Television Stations, Inc.,* 556 U.S. at 515.

[175] *See, e.g.*, *Tejas Power Corp.*, 908 F.2d at 1004; Danly Market Power Whitepaper *passim*; *id.* at 15 ("[S]tate buyer-side market power must be mitigated in the RTO capacity markets. This is not a policy-driven position that can be changed by changing the Commission's policy. Rather it is a mandate dictated by the statutory requirement that the prices that result from RTO capacity markets must be just and reasonable."); *see also supra* Part I.A.

[176] *See FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 266 (2016) ("*EPSA*") (describing the "*Attleboro* gap" resulting from the decision in *Public Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927), and how Congress responded "by passing the FPA in 1935"); *New York v. FERC*, 535 U.S. 1, 20–21 (2002) ("It is clear that the enactment of the FPA in 1935 closed the "*Attleboro* gap" by authorizing federal regulation of interstate, wholesale sales of electricity—the precise subject matter beyond the jurisdiction of the States in *Attleboro*. . . . It is, however, perfectly clear that the original FPA did a good deal more than close the gap in state power identified in *Attleboro.* The FPA authorized federal regulation not only of wholesale sales that had been beyond the reach of state power, but also the regulation of wholesale sales that had been *previously subject* to state regulation.").

[177] Cost allocation between among states within the Entergy (formerly Middle South Utilities) system is perhaps the most notorious and long-lived example. *See, e.g.*, *Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354, 357–69 (1988) (recounting the Commission's orders addressing allocation of Grand Gulf nuclear plant costs); *La. Pub. Serv. Comm'n v. FERC*, 761 F.3d 540, 557 (5th Cir. 2014) ("In view of these considerations, and based on the record, FERC reasonably concluded that it would be inappropriate [t]o allow Louisiana to shift the escalating costs of the Vidalia contract to other states on the Entergy System and not accept responsibility for its own decision making." (quoting *La. Pub. Serv. Comm'n v. FERC*, 522 F.3d 378, 396 (D.C. Cir. 2008).

[178] *See, e.g.*, PJM Filing at 2.

from exporting the costs and burdens of their idiosyncratic policy preferences on other states.[179] The Commission cannot allow that to happen.[180]

Several states in PJM do not share other states' appetites to promote preferred generation resources through out-of-market subsidies.[181] Moreover, states that have enacted subsidies don't share the same policy preferences and their preferences often change: Illinois specially supports nuclear power; New Jersey previously supported natural gas-fired resources, and now continues to support nuclear power even as it engages in an ambitious program to build offshore wind; Maryland has largely followed New Jersey's lead minus support for nuclear power; and Ohio

[179] The problem of interstate cost-shifting is not limited to conflicts arising under the FPA. It has an independent basis under Commerce Clause jurisprudence across the spectrum of economic activity. P3 has reviewed a protest prepared by the Electric Power Supply Association (EPSA) for submission in this docket. Rather than present the Commission with duplicative arguments in this protest, P3 adopts the arguments set out in the EPSA protest as its own and further adopts the affidavit of EPSA's witness,

[180] *See Hughes*, 136 S. Ct. at 1296 (citing 2011 MOPR Order and quoting 2011 MOPR Rehearing Order, 137 FERC ¶ 61,145 at P 3 ("Our intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives. We are forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's [capacity auction] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity."); *see also* December 2019 Order at P 7 & n.23 (describing the Supreme Court's reliance on the 2011 MOPR Orders in *Hughes*).

[181] As Dr. Quinn explains, "[i]t is important to remember that the focus on wholesale market effects also protects those states that choose to rely on the wholesale market to drive resource mix decisions. When the Commission originally removed the state policy exemption from the PJM MOPR, it did so mindful of the fact that one state's policy decisions effect other states' policy decisions." Quinn Aff. ¶ 28. Dr. Quinn cites several examples of state objections to interstate cost-shifting. *See, e.g.*, Pennsylvania Public Utilities Commission letter to the PJM Board, July 7, 2021, https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210706-pa-puc-letter-regarding-minimum-offer-price-rule.ashx ("Pennsylvania was one of the first restructured states in PJM that embraced the promise of competition in the wholesale generation market and then spent considerable time and effort developing a burgeoning retail electricity market built on the expectations and benefits of a properly functioning wholesale market. . . . More recently, our concerns have centered around PJM's proposal to accommodate state policies at all costs, to the potential detriment of the two foundational principles upon which PJM's capacity market was built—reliability and competition."); Comments of the Pennsylvania Public Utilities Commission, Docket Nos. EL11-20-000 & ER11-2875, at 13 (May 4, 2011) ("Pennsylvania is committed to the competitive market structure and would be harmed by any action by another state within PJM that subsidized a participant in PJM's interstate wholesale electric capacity market, absent an effective mitigation mechanism in PJM's RPM."); Testimony of New Hampshire Public Utilities Commissioner Kathryn Bailey, *Modernizing Electricity Market Design*, Docket No. AD21-10-000, Tech. Conf. Tr. at 52 ll.8-15 (May 25, 2021) ("If you eliminate the MOPR initially it will result in lower capacity prices, but that's going to lead to early retirement of the reliability resources that we need. So eventually when all those unsponsored resources are no longer in the capacity market, the price of capacity is going to increase substantially. And I think that's where the costs will be shifted to other states.").

spread its support for in-state resources across the spectrum from nuclear to coal.[182] Accepting the PJM Filing would only perpetuate a vicious circle of subsidization. As the Market Monitor observed in his most recent State of the Market Report for PJM: "Subsidies are contagious. Competition in the markets could be replaced, and is now being replaced, by competition to receive subsidies. Competition to receive subsidies is now a reality and is accelerating in PJM."[183]

3. The Commission Will Permanently Damage Its Legitimacy and Severely Undermine Investor Confidence If It Permits PJM to Employ A Filing Under FPA Section 205 to Evade Commission Mandates Under FPA Section 206

As set forth above, the Commission would be acting consistently with longstanding policy to reject the PJM Filing as a collateral attack on the Expanded MOPR Orders and the 2011 MOPR Orders. The manifest defects in the PJM Filing detailed throughout this Protest must therefore come as a disappointment to those who have urged PJM to pursue this unfortunate departure from settled law and sound market design. Commission action on the PJM Filing thus presents a hard choice between core administrative law principles and the desire for MOPR reform.

P3 is serious about its commitment to explore alternative approaches to reforming the Expanded MOPR, and, as we explain elsewhere herein, there is ample time for the Commission to assemble a record that better supports modifications to PJM's capacity market rules,[184] which the PJM falls far short of achieving. In the absence of a judicial remand or vacatur of the Expanded MOPR Orders, the correct way to implement those reforms is through an FPA section 206 proceeding that methodically identifies the specific holdings in the Expanded MOPR Orders and

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[182] *See* Quinn. Aff. at ¶¶ 17, 42.

[183] *Infra* Attach. J., Monitoring Analytics, State of the Market Report for PJM, Ch. 5, at 286; *accord, e.g.*, December 2019 Order at P 29 ("[T]he June 2018 Order emphasized the significant and continued growth of out-of-market support. As this growth continues, more subsidized resources will have the ability to offer below their costs and suppress prices. The forward nature of the capacity market necessitates that the Commission proactively work to ensure the market is adequately protected against the distortive impacts of state subsidies.").

[184] *See infra* Part III.F.

2011 MOPR Orders the current Commission finds unjust and unreasonable. P3 believes the Commission will permanently damage its legitimacy as an adjudicatory body, and severely undermine investor confidence, if the Commission permits PJM to employ a filing under FPA section 205 to circumvent express Commission mandates under FPA section 206, particularly when one group of orders the PJM Filing intends to overturn is still pending on judicial review.[185]

C. The Conditioned State Support ("CSS") Prong of the Narrow MOPR Is Unjust, Unreasonable, and Unduly Discriminatory

PJM claims that its capacity market "does not require the Expanded MOPR's broad protection from price suppression to ensure just and reasonable outcomes." But PJM admits "that this does not mean that the market does not require a MOPR."[186] According to PJM, the RPM only needs a MOPR that will "protect the market from actions that improperly affect the market clearing price." Consequently, PJM's Narrow MOPR would only prevent state actions that PJM believes meet that standard, *i.e.*, "(1) the actual Exercise of Buyer-Side Market Power and (2) improper state actions that would have a direct effect on capacity market clearing prices."[187] The Keech Affidavit observes that "[b]oth such types of actions are plainly impermissible [and] should not be permitted to have a detrimental effect the market."[188]

P3 agrees that the two categories targeted by PJM would improperly suppress clearing prices and involve activities that are "plainly impermissible." The problem is that PJM defines these categories so restrictively, and proposes so many exclusions from them, that the Narrow

[185] Tinkering with precedent and procedure to expedite near-term objectives often backfires. For example, former Senate Majority Leader Reid must regret his decision to modify the filibuster rules for judicial appointments, as doing so paved the way for president Trump to install a Republican majority on the Supreme Court. The Commission should carefully consider the consequences of lowering the bar on reversing landmark precedents and the uncertainty that would unleash as political winds shift.

[186] PJM Filing at 21.

[187] *Id*. at 22.

[188] *Id*. (citing Keech Aff. ¶ 16).

MOPR will be easily avoided and may never be triggered at all. PJM's proposal may appear at first glance to establish meaningful protections against buyer-side market power. A more careful review reveals that the Narrow MOPR will turn a blind eye to significant price suppression. RPM auctions cannot be just and reasonable if the guardrails against buyer-side market power are as weak as the Narrow MOPR.

1. The CSS Proposal Eliminates Any Meaningful Review of State Action that Would Result in Price Suppression and Would Authorize Any State Interference with Competition that is Not Already Preempted Under the FPA

PJM proposes to "generally accommodate both state policies regarding generation resource mix and the long-standing business models of public power entities"[189] while purportedly recognizing that "accommodation of state resource mix policies cannot be boundless."[190] PJM's understanding of "boundless accommodation," however, is extremely constricted. The only restraint that PJM would place on state intrusion into the Commission-jurisdictional RPM would be to apply the MOPR to state programs that the United States Supreme Court has already found to be preempted under the FPA.

Specifically, PJM would define "Conditioned State Support" as "any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, provided outside of PJM markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction."[191] "[C]onditioned on clearing in any RPM Auction" would encompass "directives as to the price level at which a Generation Capacity Resource must be offered in the RPM Auction or directives that the Generation Capacity Resource

[189] PJM Filing at 24 (citing Morelli Aff. ¶ 7).

[190] PJM Filing at 24.

[191] PJM Filing at 25 (quoting Proposed Tariff, Definitions – C-D (Conditioned State Support)).

is required to clear in any RPM Auction."[192] PJM sometimes refers to state directives that would fall within the definition of "CSS State Support" as "bid to clear" requirements.

PJM accurately recites the Supreme Court's holding in *Hughes* that "'condition[ing] payment of funds on capacity clearing the auction' to be a 'fatal defect,' because that 'improperly sets the rate [a seller] receives for interstate capacity sales to PJM.'"[193] The Court, however, did not find the challenged state bid to clear requirement to be unjust and unreasonable under the FPA. Instead, the "fatal defect" had to do with preemption. The Maryland program at issue in *Hughes* was unlawful because it effectively sought to establish wholesale market prices that are subject to the Commission's exclusive jurisdiction under the FPA. Such preempted state practices are illegal. By reducing the universe of state actions subject to buyer-side mitigation to those that are already preempted, PJM has created a toothless mitigation measure. There is no point to prohibiting practices that are already unlawful while ignoring all state actions that have not previously been found to be preempted. Buyer-side market power rules are intended to ensure that Commission-jurisdictional rates remain just and reasonable. Whether a state program is preempted has nothing to do with whether it will result in unjust and unreasonable rates.

Dr. Quinn clearly identifies that "PJM's proposal misses a very basic and obvious fact – a state policy need not be conditioned on clearing the capacity market to constitute an exercise of market power."[194]

> The fact that state support has been conditioned say nothing about the degree of wholesale market impact and thus the impact on investor confidence. It is possible for a state to write an ill-advised contract that would trigger the [CSS] provision but have so little impact on the wholesale market and investor confidence that subjecting the action to the MOPR would not be appropriate. It is equally possible

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[192] *Id*.

[193] PJM Filing at 25 (citing *Hughes*, 136 S. Ct at 1299).

[194] Quinn Aff. ¶ 31.

for a state to take actions that have an outsized impact on the wholesale market, but nonetheless avoid the CSS provisions.[195]

PJM "is aware of the critique" that its Conditioned State Support "standard" is "the same one applied by the courts for determining whether a state policy is preempted by the FPA, and therefore, such a MOPR standard is unnecessary . . . ."[196] PJM insists, however, that its proposed rule is needed because judicial review can be time-consuming and "may not be able to protect the market in a timely manner."[197] In addition, PJM claims that the Conditioned State Support standard will be beneficial because courts are likely "to void all or the offending portion" of a preempted law or regulatory order.[198] PJM fears that this could have the "unintended effect of harming non-utility entities who may also benefit from that particular state law or program."[199] By contrast, "PJM's proposed MOPR allows the statute to remain in effect and applies a more surgical solution."[200]

The fact that it may take time to successfully pursue a federal preemption challenge is not a reasoned basis for tying the scope of the MOPR to past Supreme Court preemption rulings. It might be appropriate for PJM to add a formal process to its tariff for bringing state laws or regulations that warranted preemption to the Commission's attention. But it is a fundamental mistake to confuse that process with a buyer-side market power "standard."[201] The United States

[195] Quinn Aff. ¶ 32.

[196] PJM Filing at 43.

[197] *Id.*

[198] *Id.*

[199] *Id.*

[200] *Id.*

[201] *See PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 253 (3d Cir. 2014) (distinguishing between the just and reasonable and preemption standards by rejecting an argument that "conflates the inquiry into LCAPP's field of regulation with an inquiry into the reasonableness of the Standard Offer Capacity Rates. Here, whether the Standard Offer Capacity Agreements pick "just and reasonable" capacity prices is beside the point. What matters is that the Agreements have set capacity prices in the first place.").

Court of Appeals for the Seventh Circuit highlighted the distinction in *Electric Power Supply Ass'n v. Star*.[202] There the court observed that the mere fact that a state subsidy program is not preempted does not mean that the state program is just and reasonable. Similarly, if the Commission decides to change the market rules to prevent state subsidies from making prices unjust and unreasonable then the Commission has not diminished the states' authority to regulate generation.[203]

PJM's strange desire to salvage state laws that should be preempted under *Hughes* out of concern for the possible impacts of their invalidation on non-utilities also has nothing to do with buyer-side market power. Nor is it relevant to PJM's mission and role as an RTO. PJM should instead be focused on its, and the Commission's, responsibility to ensure just and reasonable rates by having a MOPR that neither over-mitigates nor under-mitigates.

In addition, the underlying premise of PJM's definition of "Conditioned State Support" is based on a misreading of *Hughes* and related precedents. Writing for the majority, Justice Ginsburg stated:

> Our holding is limited: We reject Maryland's program only because it disregards an interstate wholesale rate required by FERC. We therefore need not and do not address the permissibility of various other measures States might employ to encourage development of new or clean generation, including tax incentives, land

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[202] 904 F.3d 518, 524 (7th Cir. 2018).

[203] *Id.* at 524 ("[B]ecause states retain authority over power generation, a state policy that affects price only by increasing the quantity of power available for sale is not preempted by federal law. . . . This does not imply that PJM, MISO, and the Commission are unconcerned about the effect of state programs designed to subsidize producers of electricity. PJM has asked the Commission to approve changes to its auction design in order to improve the system's price-discovery and output-allocation effects in the wake of laws such as the one Illinois enacted. Recently the FERC declined to approve PJM's proposal and opened a new proceeding so that the Commission may determine for itself what changes, if any, should be made to auctions for interstate sales of electricity. . . . Plaintiffs insist that the need to revamp the auction system shows that the Illinois statute must be preempted. But that's not what the Commission said. Instead of deeming state systems such as Illinois' to be forbidden, the Commission has taken them as givens and set out to make the best of the situation they produce. . . . As the Supreme Court remarked in *Hughes*, the exercise of powers reserved to the states under § 824(b)(1) affects interstate sales. Those effects do not lead to preemption; they are instead an inevitable consequence of a system in which power is shared between state and national governments. Once the Commission reaches a final decision in the ongoing proceeding, the adequacy of its adjustments will be subject to judicial review; the need to make adjustments in light of states' exercise of their lawful powers does not diminish the scope of those powers.")

> grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector.[204]

Hughes likewise noted that "[b]ecause the reasons we have set out suffice to invalidate Maryland's program, we do not resolve whether, as the incumbent generators also assert, Maryland's program is preempted because it counteracts FERC's refusal to extend the NEPA's duration, or because it interferes with the capacity auction's price signals."[205] In other words, *Hughes* does not stand for the proposition that "bid to clear" rules are the only kind of state programs that could be preempted by the FPA.

Justice Sotomayor's concurring opinion in *Hughes* is particularly relevant to this point. She emphasized the Court's "general exhortation not to rely on a talismanic pre-emption vocabulary" because there is no "infallible constitutional test or an exclusive constitutional yardstick" in preemption analysis, especially with respect to a statute like the FPA which contemplates some degree of federal-state regulatory "interdependence."[206] Thus, even if it were appropriate for PJM to link the scope of the MOPR to a preemption standard, its Conditioned State Support test would still be too narrow. PJM's proposal would exempt from the MOPR state programs that warrant preemption, but do not involve bid to clear requirements.[207]

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[204] *Hughes*, 136 S. Ct. at 1299.

[205] *Id.* at 1299 n.13; *see also PPL Energy Plus, LLC v. Nazarian*, 753 F.3d 467, 478 (4th Cir. 2014).

[206] *Id.* at 1300 (Sotomayor, J., concurring) (quoting *Hines* v. *Davidowitz*, 312 U. S. 52, 67 (1941)).

[207] Relevant examples of preempted state policies that have nothing to do with bidding and clearing requirements are not difficult to find, much less imagine. For example, a state requirement to purchase energy and capacity only from renewable resources located within that state would come into direct conflict with the Commerce Clause. *See Ill. Com. Comm'n v. FERC*, 721 F.3d 764, 776 (7th Cir. 2013) ("Michigan cannot, without violating the commerce clause of Article I of the Constitution, discriminate against out-of-state renewable energy.") (listing authorities).

2. The CSS Proposal Impermissibly Ignores Express Commission Directives Regarding the Scope of the MOPR

Besides its conflation of the pre-emption and just and reasonable standards, the CSS proposal also flouts Commission directives that were issued under Section 206 of the FPA. Specifically, the December 2019 Order found that "that any resource, new or existing, that receives or is entitled to receive a State Subsidy, and that does not qualify for an exemption, should be subject to the [MOPR]."[208] The Commission required PJM to adopt the following definition of "State Subsidy":

> State Subsidy shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is a result of any action, mandated process, or sponsored process of a state government, political subdivision or agency of a state or an electric cooperatives formed pursuant to state law, and that (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or (2) will support the construction, development, or operation of new or existing Capacity Resource; or (3) could have the effect of allowing a unit to clear in any PJM capacity auction.[209]

The CSS proposal would exclude countless state actions from the MOPR despite their unambiguously counting at "State Subsidies" under the Expanded MOPR Orders. As discussed above, PJM may not casually circumvent a Commission mandate under Section 206 through the expedient of proposing a different rule under Section 205.[210] PJM may not casually circumvent a Commission mandate under Section 206 through the expedient of proposing a different rule under Section 205. The Commission itself may only reverse the State Subsidy determination in the

[208] *See Calpine Corp. v. PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,036 (2021) at P 3 (footnote omitted) (citing December 2019 Order, 169 FERC ¶ 61,239 at P 9.)

[209] 174 FERC ¶ 61,036 at n.7 (2021) (citing PJM Tariff, OATT Definitions—R-S (State Subsidy Definition).

[210] *See supra* Part I.A.

Expanded MOPR Orders if it provides a reasoned explanation based on substantial evidence. The PJM Filing provides no justification for the Commission to do so.

3. The CSS Proposal Is Unlikely to Prevent Any Actual Exercises of Buyer-Side Market Power

In addition to the CSS Proposal's foundational legal flaws it is also riddled with practical defects that render it wholly ineffectual. First, the CSS test could easily be bypassed by a state or load interest that intentionally sought to exercise buyer-side market power. This is not a hypothetical concern. Actual and deliberate state efforts to suppress prices were the very problem that *Hughes* addressed. There are many ways that state or load interests that intend to suppress prices could purposefully incentivize a supplier to submit uneconomic offers without using bid to clear requirements. As Dr. Quinn warns, "the bottom line is that mitigation under the proposed Conditioned State Support is so easy to avoid by drafting state policies in a certain manner that the likelihood of these provisions ever being triggered is virtually zero."[211] The CSS Proposal completely ignores this danger.

Second, PJM proposes to establish a self-certification process. Sellers would be required to certify "whether, at the time of certification, their 'Generation Capacity Resource is receiving or expected to receive" CSS.[212] CSS mitigation would only be triggered if a seller *confessed* that it was receiving support from a state program that violated *Hughes*. Self-certifications would not have to be repeated in subsequent auctions "unless there is a change in expectation of receiving [CSS]."[213] Sellers would only have to update their certifications if there were a "material change

[211] Quinn Aff. ¶ 33.

[212] PJM Filing at 28 (quoting Morelli Aff. ¶ 26.)

[213] *Id.* at 29 (citing Proposed Tariff, Attach. DD, § 5.14(h-2)(1)(C).)

in status" within thirty days of the change.[214] Sellers that make the required self-certification would be "presumed innocent" of receiving state support. If PJM or the IMM is "aware of" CSS that a resource "may receive" PJM or the IMM "may inquire" with the seller which "may result" in the MOPR being triggered.[215]

The Commission has accepted self-certification requirements as an initial market power screen is other settings. But PJM's proposed CSS self-certification rules are weaker than existing measures and would not help to mitigate buyer-side market power. PJM's proposal to give itself and the IMM an option not to begin an inquiry if they become aware of a state subsidy program that violates *Hughes* is in conflict with the Commission's core market monitoring precedents. PJM and the IMM should be held to the same requirement that is applied under 18 C.F.R. § 35.28, and PJM's Tariff, which mandate that suspected market violations market flaws must always be brought to the Commission's attention immediately.[216]

Similarly, PJM's proposal to allow sellers thirty days to decide for themselves whether a "material change" has occurred is far too lenient. The self-certification rule that is part of the NYISO's Competitive Entry Exemption from buyer-side mitigation is an analogous example. Under the NYISO rule, entities that self-certify they are not receiving subsidies must, "notify the ISO if information in a certification ceases to be true, within two (2) business days after the earlier

[214] Oddly, PJM would require periodic recertifications in advance of each RPM auction under the BSMP prong. PJM's explanation for this distinction is that "given the importance and reliance on the Capacity Market Sellers' certification, it is reasonable that all Capacity Market Sellers certify in advance of each auction whether it intends to exercise Buyer-Side Market Power." PJM Filing at 29. This seems to imply that PJM does not believe that CSS self-certifications are of any great importance. Given the legal and practical flaws that render the CSS provisions an ineffectual mitigation measure, P3 would agree that this is the case.

[215] PJM Filing at 31.

[216] *See* 18 C.F.R. § 35.28(iv) (Protocols on Market Monitoring Unit referrals to the Commission of suspected violations); *id.* § 35.28(v) (Protocols on Market Monitoring Unit Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes).

of the date that it learned that the information had ceased to be true or the date that it should have reasonably determined that the information was likely no longer to be true."[217]

Third, PJM would not take any concrete action to mitigate even a newly-minted state program that included "bid to clear" requirements without the Commission's express fact-specific authorization. PJM believes that "the Commission should be the arbiter, and only upon a Commission determination will a resource receiving [CSS] be subject to the MOPR."[218] PJM would only "identify for the Commission those policies and programs it suspects may provide Conditioned State Support."[219] PJM would submit a Section 205 filing proposing that the Commission determine whether the policy or program in question fell under the CSS provision. Commission approval of a PJM filing would subject any resource receiving support under the identified policy or program to the MOPR.

PJM notes that it does not want to be responsible for determining whether a state policy improperly intrudes on price formation and suggests that the Commission is better suited to make such decisions. PJM tries to defend its proposal by claiming that interested stakeholders would be able to comment on any PJM Section 205 filing. PJM also contends that "since the state action might impact more than one market participant" the PJM approach "ensures states and sellers can present their arguments to the Commission in the first instance and will not need to resort to submitting complaints against PJM before or during the auction." This will supposedly create "certainty in auction outcomes, provides a clear due process vehicle for all affected parties,

[217] NYISO Market Administration and Control Area Services Tariff §23.4.5.7.9.2.

[218] PJM Filing at 43.

[219] *Id*.

including the states, and minimize the likelihood of auction results being questioned through a misapplication of the MOPR."[220]

PJM's due process concerns focus on states and sellers that receive state subsidies. But PJM has not proposed protections for other stakeholders. The ability to file comments supporting a Section 205 filing that identifies a transparently *Hughes*-violating state program is not a significant procedural right. PJM has not provided opportunities for other parties to raise concerns about state subsidies to the Commission beyond the statutory right to file complaints that already exist under FPA sections 206 and 306.[221]

PJM is not typical public utility, but has instead taken on a special responsibility to administer centralized markets on behalf of numerous market participants in a fair and objective manner. Given the ongoing obligation to report actual or suspected violations of mere market rules,[222] it makes no sense whatsoever that PJM now proposes to ignore clear or suspected violations of the FPA and the Supremacy Clause and "pass the buck" to market participants and the Commission to resolve through protest and complaint proceedings.

Fourth, PJM's passive regime cannot work for several reasons. Unlike PJM and the IMM, market participants do not have access to confidential offer-related information. Market participants can only obtain such information, if at all, through the protracted process of discovery in a hearing. There will also rarely, if ever, be sufficient time to complete a hearing before the relevant auction occurs. This situation would be considerably worse than long-standing concerns about the opacity of unit-specific review that stakeholders attempted to address through bright-line rules in 2013. If PJM is allowed to take a completely passive role in protecting the integrity of

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[220] PJM Filing at 45 (citing Morelli Aff. ¶¶ 15-16).

[221] *See* 16 U.S.C. §§ 824e, 825e.

[222] *See* 18 C.F.R. § 35.28(iv)-(v).

capacity auctions from out-of-market subsidies, that leaves competitive generators with only one rational administrative option to defend themselves against subsidized resources: to blanket the Commission with complaints against every putative self-assessment and insist on retroactive modifications of auction results if and when those complaints are vindicated. In short, PJM's proposal guarantees a future of increased litigation and uncertainty.

Fifth, PJM proposes to specify a non-exhaustive list of state programs that would expressly not qualify as CSS:

> Examples of such government policies may include, but are not limited to: policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., Cross State Air Pollution Rule).[223]

Once again, PJM would exclude state actions from the definition of CSS that the Expanded MOPR Orders prohibit it from ignoring. The only rationale offered for exempting them from the MOPOR is that they do not involve bid to clear requirements. Stated otherwise, PJM's proposed list of safe harbors is just another way of making sure that the CSS will not apply to any state program that is not already illegal under *Hughes*.

Sixth, PJM proposes that CSS "shall not be determined solely based on the business model of the Capacity Market Seller."[224] PJM specifically identifies "the business model of each Self-Supply Entity" as not constituting Conditioned State Support "for the simple reason that such support is not conditioned on specific bidding behavior."[225] PJM's argument here should be

[223] PJM Filing at 46 n.151 (quoting Proposed Tariff, Attach. DD, § 5.14(h-2)(2)(A)(i)).

[224] *Id.* at 46.

[225] PJM Filing at 46 (citing Proposed Tariff, Attach. DD, § 5.14(h-2)(2)(A)(i)).

afforded no weight because it is tautological. The fact that PJM has devised a definition for CSS that excludes the "long-standing business models of public power entities" does not justify PJM's choice to exclude those entities. Moreover, the Expanded MOPR Orders devoted considerable attention to distinguishing self-supply arrangements that could be permitted and those that were likely to result in price suppression. As with other parts of the PJM Filing, PJM may not undo decisions that the Commission made under FPA Section 206 via a Section 205 filing.

Finally, PJM proposes to "categorically exclude" from the definition of Conditioned State Support any "Legacy Policies" that are currently "on the books or effective."[226] Exempting these "Legacy Policies" is purportedly reasonable because "it is least disruptive to the states and efficiently allows states to craft future policies and programs to avoid improperly interfering with the capacity markets."[227]

The Commission cannot possibly accept this aspect of the PJM Filing. It is legally indefensible. As discussed above, the CSPP would only apply to state programs that are expressly pre-empted by *Hughes*. Such programs were unlawful in the past, are unlawful today, and would continue to be unlawful even if the PJM Filing becomes effective. Neither PJM nor the Commission itself has any authority to somehow make a state program that violates *Hughes* permissible under the FPA. PJM and the Commission likewise cannot create a "grandfathering exemption" to federal preemption through a tariff change. The fact that *Hughes* was decided more than five years ago also means that there is no reason why states would need more time to learn how to design programs and policies so that they are not unambiguously preempted.[228]

[226] *Id.* at 46-47.

[227] *Id*. at 47.

[228] The Expanded MOPR Orders grandfathered certain resources that either already existed, or had crossed certain development thresholds, because they arguable relied on prior Commission rulings that declined to subject

Moreover, by enshrining PJM's "see no evil" approach into a filed tariff, accepting PJM's proposal will undermine well-justified preemption complaints by creating a new filed rate doctrine defense to claims of conflict preemption and thereby channel complaints into facial or field preemption.[229] As the Supreme Court has stated in numerous contexts, "it is to be assumed when Congress enacts a statute that it does not intend to make its application dependent on state law."[230] It is not acceptable for the Commission to undermine preemption actions and force the courts to enforce preemption principles in situations where the Commission would prefer to acquiesce and look the other way.[231]

In sum, PJM's CSS proposal is opaque and unverifiable. It has all the same flaws in that regard as the unit specific review process, but it is worse because it is crafted so narrowly that it will rarely, if ever, be applied. As Dr. Shanker observes, the fact that PJM repeatedly claims that the Narrow MOPR will not result in double payments reveals that CSS will have "no bite."[232] PJM could only make such claims if it anticipates that no state will ever "pay twice" for capacity because the CSS rule will be so easily evaded. PJM is essentially proposing to abdicate its duty to recognize and mitigate buyer-side market power exercised through out-of-market subsidies. The

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them to the MOPR. [Cites] By contrast, there has been no reasonable basis since at least 2016 for states to imagine that programs that included bid to clear requirements would be acceptable under *Hughes*.

[229] *See, e.g.*, *Hughes*, 136 S. Ct. at 1299 n.13 (declining to address conflict preemption arguments in light of facial preemption determination); *accord PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 254 (2014); *cf. Nazarian*, 753 F.3d at 479 (finding conflict preemption in addition to facial preemption).

[230] *Adams Fruit Co. v. Barrett*, 494 U.S. 638, 646 (1990) (workers' compensation) (quoting *NLRB v. Nat'l Gas Util. Dist, of Hawkins Cty.*, 402 U.S. 600, 603 (1971) (recognition of state political subdivisions) (quoting *Jerome v. United States*, 318 U.S. 101, 104 (1943) (criminal law))).

[231] *See S. Union Co. v. FERC*, 857 F.2d 812 (D.C. Cir. 1988) (setting aside a Commission declaratory order where the Commission declined to enforce preemption against a state damages award as required by the Supreme Court in *Ark. La. Gas Co. v. Hall*, 453 U.S. 571 (1981)).

[232] *See* Shanker Aff. ¶ 44.

result can only be rampant prices suppression and perpetual litigation before the Commission until effective buyer-side market power mitigation protections are restored.

D. The Buyer-Side Market Power ("BSMP") Prong of the Narrow MOPR Is Unjust, Unreasonable, and Unduly Discriminatory

The Narrow MOPR would define "BSMP" so restrictively and erect so many obstacles to mitigation that the Narrow MOPR will be incapable of checking BSMP. As Dr. Quinn notes, "the application of buyer-side of the market power provisions is far too narrow"[233] and "errs on the side of under-mitigation."[234] The long series of mitigation exclusions that are the defining feature of the BSMP test are addressed in subsection E.1. Additional legal and policy problems that the BSMP proposal poses are set forth in subsections E.2, E.3, and E.4.

1. The BSMP Prong Is So Limited In Scope and Includes So Many Exclusions and Exceptions that It Cannot Possibly Be An Effective Check on Buyer-Side Market Power

BSMP would be defined as "the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load."[235] As with the CSS, the BSMP proposal would rely in the first instance on self-certifications by sellers. In the BSMP context, sellers would attest that they did not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power and acknowledge that doing so was not permitted.[236] Just like the CSS version of these rules, the BSMP self-certification requirements ask too little of sellers and are too general in scope.

They also conflict directly with Commission precedent on the need for stringent certification requirements as a condition of obtaining a buyer-side market power exemption. In

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[233] Quinn Aff. ¶ 38.

[234] *Id.* ¶ 39.

[235] PJM Filing at 32 (citing Proposed Tariff Definition __ A-B (Buyer Side Market Power).

[236] I*d.* at 28 (citing Proposed Tariff, Attach. DD, § 5.14(h-2)(1)(A)(ii).)

2015, the Commission approved a competitive entry exemption from the NYISO's version of the MOPR.[237] The Commission rejected "streamlined" certification requirements – under which sellers seeking to qualify for the competitive entry exemption would attest to certain facts which the NYISO could then rely on in evaluating competitive entry exemption requests. A generic certification was insufficient to ensure that the competitive entry exemption was implemented in a just and reasonable manner. Certifications needed to be sufficiently detailed to give the NYISO a reasonable basis for concluding that a seller qualified for the exemption. The Commission emphasized that:

> Because NYISO will be relying in large part on the certifications to determine a new entrant's eligibility for the competitive entry exemption, a more stringent certification requirement—one that requires additional important certifications regarding, for example, direct and indirect contracts, exposure to civil penalties, and parent and affiliate obligations—is reasonable because it provides for greater assurance that the applicant meets the criteria for obtaining a competitive entry exemption.[238]

If PJM and/or the IMM have "a reasonable basis to initiate an inquiry into whether a Capacity Market Seller *may* commit an Exercise of Buyer-Side Market Power with respect to a certain resource, PJM or the IMM *may* initiate a fact-specific review," but PJM would not establish a "bright-line test for when it may initiate an inquiry."[239] Instead, an inquiry *might* begin "if a Capacity Market Seller intends to offer a resource or technology believed to be uneconomic, in a location where the [Capacity] [M]arket [S]eller and/or its affiliates have a net short position (that is, more load than generation in a given Locational Deliverability Area ("LDA"))."[240] As with the CSS rules, the Commission should not authorize PJM or the IMM to look the other way if they

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[237] *Consol. Edison Co. of N.Y., Inc. v. N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,139, *order on reh'g & clarification*, 152 FERC ¶ 61,110 (2015).

[238] *Id.* at P 79.

[239] PJM Filing at 33 (emphasis added).

[240] *Id.* at 33 (quoting Graf Aff. ¶ 20).

have reason to believe that there is a reasonable basis for an inquiry. They should be required to investigate in that scenario as they would under any other facet of the Commission's market monitoring regulations and precedents.

PJM also proposes to set forth in its tariff a "non-exhaustive list of circumstances that would not support an inquiry into or a demonstration that a resource may be used in an Exercise of Buyer-Side Market Power."[241] The identified cases are: (i) merchant generation supply resources that are contracted to an entity with a Load Interest, (ii) Generation Capacity Resources that are acquired or contractually controlled by sellers through a competitive and non-discriminatory procurement process; (iii) the resource is owned by or contracted to a Self-Supply Seller, is part of a long-range resource plan, and is not tied to an obligation to submit uneconomic offers to deliberately lower prices or otherwise exercise BSMP.[242] PJM and Dr. Graf assert that this is because "each of these listed circumstances, by themselves, do not raise concerns of Buyer-Side Market Power."[243] Dr. Quinn explains, however, that the competitive procurement exemption should be more location- and technology-neutral. "Some out-of-market actions are structured nominally as competitive procurements but are in practice constructed to provide an advantage to certain technologies or locations."[244]

In the event that PJM or the IMM decide to commence an inquiry it would "not mean that the MOPR is triggered automatically." Instead, there would be a fact-specific review of the seller's ability and incentive to exercise market power.

[241] *Id.* at 40.

[242] *Id.* at 40-41; Proposed Tariff, Attach. DD, § 5.14(h-2)(2)(B)(i)(b); PJM Filing at 40.

[243] PJM Filing at 41; Graf Aff. ¶ 25.

[244] Quinn Aff. ¶ 40.

"Ability" to impact prices would be determined by assessing whether a seller was sufficiently large for it to make uneconomic offer to reduce clearing prices in the area where it is located.[245] PJM and/or the IMM would:

> [P]erform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.[246]

Even if a seller were found to have the ability to exercise buyer-side market power, it would not be subject to the MOPR unless it were also deemed to have an incentive to do so. For there to be any possibility of finding the requisite incentive, the seller must first have, or be serving, a Load Interest that would benefit from lower capacity prices.[247] If that initial threshold is satisfied, PJM and/or the IMM would look more closely at the incentive question to determine whether a seller would derive a net benefit from submitting uneconomic offers.[248] PJM and/or the IMM would:

> [P]erform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation

[245] PJM Filing at 35.

[246] Proposed Tariff, Attach. DD, § 5.14(h-2)(2)(B)(ii)(a); *see also* PJM Filing at 36-37; Graf Aff. ¶ 22.

[247] *See* PJM Filing at 37.

[248] *See id.* at 38.

> Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically.[249]

PJM and/or the IMM's analysis must also "consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices."[250] PJM suggests that these factors must be accounted for because they prevent a seller from profiting from price suppression and thus leave it without an incentive to exercise buyer-side market power.[251]

However, if an offer could be "justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not to have the incentive to exercise Buyer Side Market Power with respect to that resource."[252] According to Dr. Graf's characterization, "PJM will consider additional rationales provided by the Capacity Market Seller to support a resource offer as competitive. An offer that is only economically rational when considering the benefit of price suppression to the participant's portfolio would be interpreted as evidence of intent to suppress prices below the competitive level."[253] This aspect of the BSMP test is overly permissive and deferential to sellers capable of exercising buyer-side market power. As Dr. Quinn explains, the proposed tariff's use of the word "otherwise" open up essentially unlimited opportunities to justify buyer-side market power abuses. PJM and/or the IMM would be placed in the position of judging the legitimacy of a seller's intentions instead of the price impact of a seller's actions. Dr. Graf's suggestion that an

[249] Proposed Tariff, Attach. DD, § 5.14(h-2)(2)(B)(i)(b); s*ee also* PJM Filing at 38; Graf Aff. ¶ 23.

[250] Proposed Tariff, Attach. DD, § 5.14(h-2)(2)(B)(i)(b).

[251] *See* PJM Filing at 39.

[252] Proposed Tariff, Attach. DD, § 5.14(h-2)(2)(B)(i)(b).

[253] Graf Aff. ¶ 24.

uneconomic offer will not trigger mitigation unless the benefit of exercising buyer-side market power is the only rational justification for the offer is very troubling.[254] The implication is that PJM will accept justifications for offers that are little more than contrived excuses. PJM has not shown that this provision is reasonable, or even necessary, given that sellers may already use the unit-review process to justify offers below the default offer floor.

Furthermore, "out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review."[255] In other words, any state subsidy that does not fall under the definition of CSS, and as discussed above, it is likely that all future state subsidies will be structured to avoid CSS treatment, will not count for purposes of determining whether a seller has an incentive to exercise buyer-side market power. PJM claims that this aspect of its proposal is justified because it will "reduce ambiguity."[256] But as Dr. Quinn explains, excluding state actions when considering what constitutes buyer-side market power "is flawed and inconsistent with experience."[257] There is no rational basis for ignoring state actions when such actions have provided the most clear cut examples of buyer-side market power abuses in the past[258] and when states unquestionably have the ability to suppress prices in the future. There is likewise no basis for acting as though out-of-market compensation in the form of renewable energy credits or zero

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[254] *Id.*

[255] Proposed Tariff, Attach. DD, § 5.14(h-2)(2)(B)(i)(b).

[256] PJM Filing at 40.

[257] Quinn Aff. ¶ 38.

[258] *Id.* (Indeed, out-of-market contracts with natural gas plants initiated by Connecticut, New Jersey, and Maryland, are the best known instances of actions that [is] generally accepted as clear examples of buyer side market power.").

emission credits are irrelevant to the economics of a resource. PJM's desire to avoid "ambiguity" by having a rule that ignores major cause of price suppression is not a valid rationale for the Commission to accept its proposal.

Finally, "to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power."[259] PJM claims that this is appropriate because offers that reflect a customer's preference for a resource, or its attributes, "simply reflect an offer that considers a privately-ascribed value."[260] But Dr. Quinn highlights that this exception is completely open-ended.[261] It gives no indication of how responses to "authentic" customer preferences will be distinguished from rationalizations for uneconomic offers that harm the market.

Only after running the gauntlet of all of the foregoing tests and exclusions would uneconomic offers be subject to mitigation under the BSMP. It seems most likely that few, if any, sellers would actually trigger the BSMP even if they are making uneconomic offers that result in widespread price suppression. Accordingly, it seems impossible that the BSMP will adequately protect against buyer-side market power.

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[259] PJM Filing at 42; Graf Aff. ¶ 26.

[260] PJM Filing 42.

[261] Quinn Aff. ¶ 39.

2. The BSMP Prong Is Unjust and Unreasonable Because it Ties Mitigation to a Seller's Intent

It is inconsistent with Commission[262] and judicial[263] precedent to link the scope of buyer-side market power measures to a seller's intent. The intent of the states and the legitimacy of their reasons for offering subsidies is irrelevant to the question of whether the subsidies affect the reasonableness of capacity market prices. Discerning the intent behind state policy choices is also problematic at best and likely impracticable. As P3 recently argued in the Commission's proceeding on Modernizing Electricity Market Design:

> [M]oving to an intent-based evaluation is a slippery slope that should be avoided in Commission policy. Ascribing good or bad intention to a state actor is a subjective exercise which will most certainly lead to additional implementation challenges. For example, a state action could be motivated to preserve thousands of local power plant jobs and reduce a state's total capacity payments by hundreds of millions of dollars. Was the state motivated by the job retention benefits of the subsidy or the cost savings from the exercise of market power? Who gets to make that evaluation? PJM? The PJM IMM? FERC? The state?
>
> Moreover, any state could claim that the grid is more reliable if an uneconomic plant is retained, which could be justified as a state policy in pursuit of a more reliable grid. Just because a state "covers its tracks" as it relates to intention does not mean its actions are not market distortive or benignly motivated. The Commission should not set up a scheme that relies on some evaluation of state intent which really is irrelevant to the question of market impact and preservation of capacity market integrity. Instead, the Commission should focus on objective measures of market power combined with limitations on the ability to export policy choices to other states.[264]

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[262] *See, e.g.*, *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc*., 173 FERC ¶ 61,060 (2020) ("The Commission has also held that uneconomic new entry must not be permitted to suppress market prices, *regardless of intent*, finding that "all uneconomic entry has the effect of depressing prices below the competitive level," and that "this [was] the key element that mitigation of uneconomic entry should address."); *see also Calpine Corp. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,034 at P 47 (2020) ("The intent of the subsidy is immaterial–what matters is that out-of-market payments convey the ability to offer below cost."); *id.* at P 48 ("Regardless of what laudable intentions may motivate a state to provide subsidies for certain resources, state out-of-market support still has the effect of keeping otherwise uneconomic resources in operation, and supports uneconomic entry of new resources.").

[263] *See, e.g.*, *New England Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 294 (D.C. Cir. 2014) (*NEPGA*) ("capacity offered into the market through below-cost bids can suppress prices even when no actor has the intent to do so").

[264] *See* Comments of the PJM Power Providers Group, Docket No. AD21-10-000 (Apr 26, 2021) ("P3 Comments") at 9-10.

Whatever the intentions of a seller, or of a state that subsidizes a seller, it is the effect of buyer-side market power on Commission-jurisdictional rates that counts. The "legitimacy" of state programs is irrelevant to the question of whether they result in unjust and unreasonable rates under the FPA. "No matter how well-intentioned, a state action that has detrimental effect on the wholesale market should be addressed in some form within the wholesale market."[265]

Perhaps in order to try to side-step these difficulties, the PJM Filing does not explicitly say that it will only apply to intentional buyer-side market power abuses. At the same time, the PJM Filing and proposed tariff revisions unquestionably utilize intent-based criteria. Sellers would be required to self-certify that they do not "intend" to exercise market power. PJM would only begin a fact-specific inquiry if they concluded that a seller "intends to offer a resource or technology believed to be uneconomic." Similarly, PJM's review of Self-Supply arrangements would hinge on whether they were deliberately aimed at reducing prices. Dr. Graf asserts that PJM will accept seller-justifications for buyer-side market power unless proves to be the only rational explanation for their offers. These intent-based features make the BSMP proposal unjust and unreasonable. As noted below in Part III.D.4, they also would very likely contribute to making the Narrow MOPR totally unworkable.

The PJM Filing does openly consider a seller's incentive to exercise buyer-side market power. Of course, the fact that a test purportedly aimed at evaluating incentives also considers intent in areas referenced above raises concerns about what PJM's focus will actually be in practice. PJM also has not explained why it is just, reasonable, and not unduly discriminatory to have a buyer-side incentive requirement in the first place. There is no corresponding requirement in PJM's supplier-market power measures. Other existing buyer-side market power mitigation

[265] Quinn Aff. ¶ 28.

constructs do not consider incentives. Even assuming *arguendo* that it were possible for a hypothetical incentive screen to be just and reasonable,[266] the Narrow MOPR's proposal for evaluating seller incentives is unjust and unreasonable because it incorporates intent-based components. Moreover, as discussed below, PJM's proposal revives a "net short" standard that PJM correctly abandoned in 2011.

3. The BSMP Prong Recycles Rules that the Commission Previously Discarded Because They Weakened the MOPR Without Explaining Why They Should Be Acceptable Now

The BSMP test would only trigger mitigation if an individual seller is shown to have both the ability and incentive to exercise buyer-side market power. However, PJM's proposed ability and incentive screens both incorporate revived versions of rules that were once part of the MOPR but were removed in 2011 when it became apparent that they were undermining the effectiveness of mitigation.

Specifically, PJM's ability screen closely resembles the "impact screen" that PJM convinced the Commission to eliminate in 2011. As noted above in Section I.B.2, under the impact screen, the MOPR would not apply unless an offer would have had a significant price impact[267] on its own. The Commission agreed that this was unnecessary because it allowed uneconomic offers to escape the MOPR, was unnecessary to prevent "over-mitigation," and prevented the MOPR from addressing the impact of multiple uneconomic offers that might individually fall short of the impact threshold but could have a substantial aggregate impact.[268] Subsequent Commission

[266] *See* Quinn Aff. ¶ 25.

[267] *See* 2011 MOPR Order at P 101.

[268] *Id*. P 106 ("Therefore, even if one were to accept that a below-market offer with no material effect on prices should not be mitigated because it does no harm, such a position provides no comfort as the combined effects of several such offers might well affect prices.")

rulings in ISO-NE and the NYISO have reiterated that buyer-side market power rules must protect against combined effects of entry by numerous, small, subsidized resources.[269]

Similarly, the BSMP prong's incentive screen relies on a "net short" analysis. But again, the Commission accepted PJM's proposal to do away with the original net short requirement in 2011. PJM argued at the time that the original net short rule "renders the MOPR too easily gamed, and may create such obvious pathways for evading the MOPR that the rule in its current form might never be applied."[270] The Commission agreed that a "net-short requirement is ineffective and unnecessary"[271] and that the "the net-short requirement can be gamed, and the evasion can come in a variety of forms."[272] The Quinn Affidavit notes that net short rules continue to pose these risks and must, at a minimum, be carefully designed if they are to avoid them.[273]

The PJM Filing makes no mention of any of this history. PJM has made no showing that resurrecting the old impact and net short tests in a new form is just and reasonable. There is no reasonable basis for the Commission to overturn its past rulings and accept the re-introduction of these standards now.

[269] *See, e.g.*, *N.Y. Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,119, at P 39 (2020) ("buyer-side market power mitigation is driven not by the size of individual projects, but by the aggregate amount of generating capacity that receives out-of-market subsidies."); *N.Y. Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,121 at P 110 (2020) (accepting NYISO proposed certification requirements for self-supply exemption to guard against aggregation of resources in ways that could result in the exercise of buyer market power).

[270] *See supra* Part I.B.2.

[271] 2011 MOPR Order at P 84.

[272] *Id*. at P 86.

[273] *See* Quinn Aff. ¶ 35.

4. The BSMP Prong Is Opaque, Gives PJM Excessive Discretion, and Will Likely Result in Extensive Litigation and Uncertainty

Years of Commission market monitoring precedents make plain that mitigation measures must be reasonably transparent[274] and must not give the RTO administering them too much discretion.[275] The BSMP proposal is incompatible with both of these long lines of Commission decisions.

The BSMP test is opaque. PJM is not proposing to keep stakeholders apprised of its determinations or the reasoning behind them. By comparison, in New York, the NYISO must post a narrative example describing how it makes exemption and offer floor determinations. The NYISO must also post the results of its determinations when they are made. In addition, the NYISO's independent market monitoring unit must prepare and post a report evaluating the NYISO's decisions. There is nothing resembling these requirements in the BSMP proposal.

The BSMP test also gives PJM unfettered discretion to make key decisions unbounded from any tariff restraints. For example, PJM's proposed tariff establishes no standard or criteria to govern PJM's review when sellers that fail the incentive screen test offer alternative

[274] *Cal. Indep. Sys. Op. Corp.*, 147 FERC ¶ 61,231 at P 220 (2014) (Instructing the California Independent System Operator, Inc. to evaluate whether mitigation in its Energy Imbalance Market is warranted, and stating that, if tariff rules governing mitigation are filed, the Commission "will evaluate the extent to which the rules regarding real-time local market power mitigation on EIM interties are objective and clearly set forth in the tariff . . . ."); *Astoria Generating Co., L.P. v. N.Y. Indep. Sys. Operator, Inc.*, 139 FERC ¶ 61,244 at P 44 (2012) (granting, in part, complaint asserting that NYISO rules governing buyer-side mitigation were not sufficiently transparent or objective); *PJM Interconnection, L.L.C.,* 126 FERC ¶ 61,275, at P 190 (2009) (authorizing IMM to determine whether a seller's new generation resource offer constitutes an exercise of market power but requiring PJM to provide objective tariff provisions that will determine when mitigation rules will be applied); *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at PP 180-81 (2007) (reaffirming earlier holdings that PJM's market mitigation should not rely on the market monitor's discretion but rather, objective criteria should be developed so that predictable results will emerge).

[275] 2009 MOPR Complaint Order, 126 FERC ¶ 61,275, at P 190 (2009) (authorizing IMM to determine whether a seller's new generation resource offer constitutes an exercise of market power but requiring PJM to provide objective tariff provisions that will determine when mitigation rules will be applied); *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at PP 180-81 (2007) (reaffirming earlier holdings that PJM's market mitigation should not rely on the market monitor's discretion but rather, objective criteria should be developed so that predictable results will emerge).

justifications for their offers. PJM alone will ultimately decide whether sellers have an incentive to exercise market power that would trigger mitigation.

In Order No. 719, the Commission directed "RTOs and ISOs to review their mitigation tariff provisions with a view to making them as non-discretionary as possible, whether performed by the MMU or by the RTO or ISO, and to reflect any needed changes in their compliance filings."[276] Eliminating such discretion, in the Commission's view, "remov[es] the ability of either entity to act in a discriminatory manner, and will facilitate the monitoring and review of mitigation activities." The Commission has consistently adhered to the principle that the discretion of an RTO or market monitor in the implementation of market power mitigation should be minimized, whenever possible.[277] The BSMP proposal stands in direct conflict with these long-established principles.

Finally, if the Narrow MOPR is allowed to become effective the result will all but inevitably be an unprecedented onslaught of complaints challenging individual BSMP determinations and BRA results. PJM's proposal would allow buyer-side market power to suppress capacity market prices and provides other market participants with no recourse other than filing a complaint. Besides being unmanageably numerous, such complaints would be fact-intensive and challenging to resolve. Litigation would necessarily involve difficult questions concerning the intent of sellers and the legitimacy of state programs. The Commission would be

[276] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), 125 FERC ¶ 61,071, at P 379 (2008), *order on reh'g*, Order No. 719-A, 74 Fed. Reg. 37,776 (July 29, 2009), 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[277] *See, e.g.,* December 2019 Order at P 216 ("[W]e direct PJM to provide more explicit information about the standards that will apply when conducting this review as a safeguard against arbitrary ad hoc determinations that market participants and the Commission may be unable to reliably predict or reconstruct."); 2009 MOPR Complaint Order, 126 FERC ¶ 61,275, at P 190 (rejecting PJM proposal that would have given "unfettered discretion" to the IMM to determine whether an offer violated the MOPR).

forced to devote a significant part of its resources to deciding these proceedings and defending its rulings.

E. The Attempts to Justify the Narrow MOPR Based on Stakeholder Support and Supposed Flaws in the Expanded MOPR Lack Merit and Do Not Show that the Narrow MOPR Is Just and Reasonable

1. Stakeholder Support Does Not Make the PJM Filing Just and Reasonable

PJM's primary and repeated "justification" for its proposed tariff revisions is that they received super-majority support in the PJM stakeholder process.[278] But stakeholder support cannot cure the many foundational legal defects in PJM's proposal. Precedent is clear that the Commission may not simply trust in the fact that proposals have been vetted and approved through an RTO stakeholder process. Proponents of tariff revisions must demonstrate that their proposals are just, reasonable, and not unduly discriminatory. The Commission "must rely on evidence in the record to approve the applicant's proposals and may not merely rubber stamp" RTO decisions based on stakeholder support.[279] The Commission has frequently rejected RTO proposals that fall short of this standard[280] and should do so again here. Reviewing courts have not hesitated to

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[278] *See* PJM Filing at 3-4, 6, 53; Keech Aff. ¶ 21.

[279] *See N.Y. Indep. Sys. Operator,* Inc., 111 FERC ¶ 61,117 (2005) at P 85 (2005).

[280] *Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,071 at P 61 (2014) (rejecting proposal where "no studies or other evidence in the record that support" it were provided), *reh'g denied sub nom. Pub. Serv. Comm'n of Wis. v. Midcontinent Sys. Operator, Inc.*, 150 FERC ¶ 61,104 (2015), *order on reh'g*, 156 FERC ¶ 61,205 (2016), *aff'd sub nom. Verso Corp. v. FERC*, 898 F.3d 1 (D.C. Cir. 2018); *Southwest Power Pool, Inc.*, 147 FERC ¶ 61,201 at P 141 (2014) (declining to order tariff revisions where the proponent had "not provided adequate evidence to support [its] assertion"), *on reh'g*, 151 FERC ¶ 61,235 (2015); *ISO New England Inc.*, 118 FERC ¶ 61,224, at P 11 (2007) (finding that "the Applicants have not provided the Commission with adequate information to determine that the proposed tariff revision is just and reasonable and not unduly discriminatory or preferential"); *ISO New England Inc.*, 113 FERC ¶ 61,055, at P 28 (2005) (stating that, "[a]lthough ISO-NE in its technical conference comments asserted that its proposal was just and reasonable, when we analyze the record in this case, we reaffirm our finding . . . that there was insufficient evidence to satisfy the burden of justifying this proposal").

overturn Commission orders that are not based on the Commission's own independent review of substantial record evidence.[281]

The Commission should likewise not accept the PJM Filing's claims that the Narrow MOPR is an indispensable solution to the needs and priorities of the PJM states. Although some PJM states support the Narrow MOPR others have serious concerns.[282]

2. PJM's Concerns Regarding the Potential Difficulty of Administering the Expanded MOPR Do Not Make the Narrow MOPR Just and Reasonable

PJM contends that some of its implementation responsibilities under the Expanded MOPR are burdensome[283] and suggests that this is a reason for moving from the Expanded MOPR to its Narrow MOPR. The relative difficulty of PJM's implementation tasks should not be a material factor in the Commission's analysis of whether different mitigation rules adequately check buyer-side market power. Ease of administration does not necessarily correlate with effectiveness. Even if it were true that the Expanded MOPR can be harder to administer than the Narrow MOPR that fact would be irrelevant to the question whether the Narrow MOPR provides for just and reasonable RPM prices.

Moreover, as discussed above in Part III.C.4, the implementation of the Narrow MOPR would very likely be more burdensome for PJM, not less, given the number of complaints and challenges that Narrow MOPR would inevitably provoke.

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[281] *See, e.g.*, *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1, 4 (D.C. Cir. 2015) (remanding to Commission where "the record upon which FERC relied is devoid of any evidence" on challenged issue); *Kentucky Utils. Co. v. FERC*, 766 F.2d 239, 250 (6th Cir. 1985) (vacating and remanding where the Commission "did not cite to the record evidence" supporting its finding).

[282] Pennsylvania Public Utilities Commission Letter to the PJM Board of Managers, July 7, 2021, https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210706-pa-puc-letter-regarding-minimum-offer-price-rule.ashx.

[283] *See, e.g.*, PJM Filing at 27, 30, Morelli Aff. ¶¶ 9, 23.

3. PJM's Concerns About Potential Capacity Market Withdrawals Are Overstated and PJM Has Not Shown How Those Concerns Justify the Narrow MOPR

PJM claims that the Expanded MOPR encourages capacity market withdrawals that will harm the capacity market more than the conduct that the Expanded MOPR is meant to address.[284] The Keech Affidavit argues that "evidence suggests that states and self-supply entities are more likely to exit the capacity market to meet their policy and business objectives than remain in the capacity market and curtail those objectives."[285]

P3 believes that "it is incumbent upon the Commission, PJM, and its stakeholders to build upon the benefits of PJM's capacity market, rather than weaken its foundation."[286] P3 prefers that the RPM be as large, and involve as many participants, as possible. At the same time, the fact that perceived flaws in the Expanded MOPR might cause some utilities to consider withdrawing from the RPM does not mean that the Narrow MOPR is the only option to prevent them from doing so. Other MOPR revisions could also help to prevent parties from exiting the capacity market without removing buyer-side market power protections that are needed for the capacity market to continue to produce just and reasonable rates.

Furthermore, PJM's suggestion that withdrawals from the capacity market would have greater price suppressive effects than "simply re-focusing the MOPR back on buyer-side market power"[287] depends on an assumption that the Narrow MOPR would be effective at preventing price suppression. More specifically, PJM asserts that if states directed LSEs to remove a sizable fraction of their demand from the capacity auctions that it would likely reduce capacity prices paid

[284] *See* PJM Filing at 12.

[285] *See* Keech Aff. ¶ 8; PJM Filing at 12.

[286] P3 Comments in AD21-10 at 5.

[287] Keech Aff. ¶ 10.

to remaining sellers in the auction by more than "if some narrow exercise of buyer-side market power managed to escape mitigation " under PJM's proposals. But the Narrow MOPR would not merely miss insignificant exercise of buyer-side market power; it would allow substantial price suppression. PJM has not shown that the price reducing impacts of multiple utilities choosing the FRR Alternative would surpass the price suppression that would occur under the Narrow MOPR.

Finally, as noted above, the FRR provides a tariff mechanism for "states seeking full independence in resource procurement choices" to "implement a form of capacity procurement that complements the RPM or . . . opt out of the RPM." The fact that a utility chooses to use the FRR is thus not necessarily a sign that the market is flawed or that over-mitigation is taking place. The Commission has also found that the risk that the Expanded MOPR might cause substantial exits from the capacity market is not an inherently bad outcome.[288]

4. PJM Has Not Shown How its VRR Curves or Effective Load Carrying Capacity Rules Make the Narrow MOPR Just and Reasonable

PJM asserts that it already has market rules in place that will ameliorate the risks of "moving beyond" the Expanded MOPR.[289] First, PJM suggests that the sloped VRR curve acts as a guardrail against buyer-side market power because it ensures the correct price signal is sent when supply is below the Installed Reserve Margin.[290] The sloped curve also provides a greater than zero price signal when supply exceeds the IRM.[291] The Cramton Affidavit echoes PJM's theory, stating that a "downward-sloping demand curve also weakens the incentive to exercise market power."[292]

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[288] *See* June 2018 Order at PP 160-62.

[289] *See* PJM Filing at 18.

[290] *Id*.

[291] *Id*.

[292] *Id*. (citing Cramton Aff. at ¶ 30).

PJM's claims do not support its position. It is true that sloped demand curves have an important advantage over vertical demand curves when it comes to signaling the value of capacity. But PJM has not shown how this characteristic of sloped demand curves makes them an effective check on buyer-side market power exercised through out-of-market subsidies to suppliers. As noted above, sloped demand curves prevent buyers from engaging in traditional exercises of monopsony power through "buyer withholding," but the primary effect of sloped demand curves is to deter the exercise of seller market power. But that deterrent effect is muted or destroyed if the seller is supported by out-of-market subsidies, in which case a sloped demand curve simply provides a roadmap to calculate the amount of out-of-market support necessary to ensure that a preferred resource will clear the market against unsubsidized, competitive resources. In short, the mere existence of a sloped demand curve does not deter subsidized uneconomic entry or subsidized uneconomic retention from causing artificial price suppression below just and reasonable levels in a manner that pointedly discriminates against competitive suppliers. On the contrary, a sloped demand curve only facilitates attempts to suppress prices through out-of-market subsidies by stabilizing one side of supply/demand interaction. As Dr, Quinn notes, it is clear that whatever ameliorative effect the VRRs may have on buyer-side market power, "it clearly does not do so to the point that no mitigation is necessary."[293]

Second, PJM contends that the Expanded MOPR did not account for PJM's recently accepted Effective Load Carrying Capacity ("ELCC") rules for more accurately determining the maximum capacity value of Variable Resources, Limited Duration Resources and Combination Resources.[294] The ELCC rules are expected to improve the capacity accreditation of solar, wind,

[293] *See* Quinn Aff. ¶ 45.

[294] *See PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056 (2021).

and storage resources in a way that will improve the accuracy of their capacity values as their penetration increases. The Keech Affidavit posits that "ELCC will take the necessary first step towards right-size the capacity accreditation for wind, solar, and storage, and in so doing will also mitigate price impacts of what looks to be continued growth of those asset classes."[295] PJM contends that the ELCC rules justify a fundamental re-evaluation of the 2018 PJM Filing and the Commission's Expanded MOPR Orders because the assumptions that they made about the auction price impacts of solar, wind, and storage resources were "likely overstated."

PJM's unwillingness to go beyond saying that these assumptions were "likely" overstated is revealing. P3 supported PJM's efforts to establish the ELCC construct but stressed that the rules were untested and that "details surrounding its methodology, assumptions, inputs and procedures must be properly designed and constructed and accurately calculated." The IMM protested the ELCC rules arguing that they were unjust and reasonable because, among other reasons, they used an averaging method for determining ELCC values instead of a marginal ELCC value. The IMM also noted that PJM had not demonstrated that it could accurately predict the amount of ELCC Resource capacity that would clear in the capacity auctions. Commissioner Christie agreed with the IMM and dissented from the order accepting the ELCC rules. PJM itself has committed "to conduct an initial review of the ELCC construct in the summer of 2022 and perform a comprehensive assessment of whether the ELCC model proposed herein is achieving its purpose of valuing and compensating capacity resources as accurately as practicable,"[296] Finally, the

[295] Keech Aff. ¶ 13.

[296] *See* 176 FERC ¶ 61,056 at P 39. As previously noted, *see supra* note Z, Commissioner Christie found this commitment "fanciful" and Commissioner Danly agreed with that assessment, although he found the acknowledged flaws in PJM's proposal insufficient to reject it under FPA section 205.

Keech Affidavit states that ELCC only represents the "first step" towards more accurate capacity valuations.

In short, it would be speculative and premature for the Commission to rely on the PJM Filing's claims regarding the ELCC construct. The ELCC rules have the potential to improve capacity valuation, but PJM has not shown that they will ever be effective enough to obviate the need for strong MOPR protections. The ELCC rules are also incomplete insofar as they do not apply to thermal resources, including as natural gas-fired and nuclear resource that certain states in PJM have previously chosen to support through targeted subsidies that artificially suppressed competitive prices in a manner this Commission's previous MOPR reforms were expressly designed to combat. ELCC is not intended in any way to address market power, rather it simply improves the "count" of different resources. The underlying concerns of market power and price suppression remain the same, only the specific magnitude and detail might be changed. Even PJM does not assert that the ELCC rules are certain to substantially reduce the auction price impacts of ELCC Resources. Given these circumstances, the Commission could not reasonably point to the ELCC rules as a basis for overturning its buyer-side mitigation precedents or otherwise concluding that the Narrow MOPR will be just and reasonable.

5. PJM's New Theory that Seller-Side and Buyer-Side Market Power Are "Asymmetrical" Cannot Justify the Narrow MOPR's Failure to Adequately Mitigate Buyer-Side Market Power

PJM acknowledges that a MOPR is still necessary to guard against buyer-side market power. At the same time, PJM offers the novel hypothesis that "a market mitigation provision for Buyer-Side Market Power does not need to be commensurate with seller side market power rules."[297] According to PJM and the Graf Affidavit, "Buyer-Side Market Power is not symmetrical

[297] PJM Filing at 22-23 (citing Graf ¶ 10).

to supplier-side market power in the PJM capacity market." Allegedly this is because supplier-side market power "is exercised by economic or physical withholding supply of capacity" whereas, "buyers with the ability and incentive to suppress prices cannot symmetrically and directly withhold demand for capacity from the market, as demand is determined through an administrative demand curve."[298]

The problem with this attempted justification is that differences in the way that supplier-side and buyer-side market power are exercised does not diminish the Commission's obligation to guard against them both. The Commission made this point in 2011 when addressing a claim that "buyer market power and seller market power should not be treated equivalently in fashioning mitigation."[299] The Commission stated that even if this were so, "that Commission and court precedent indicate that PJM needs to protect against both buyer market power and seller market power to ensure competitive, properly functioning markets" and that any differences in treatment must be justified on the record.[300]. Thus, even assuming that the potential impacts of supplier-side market power were greater than those of buyer-side market power, the latter must still be effectively mitigated for Commission-jurisdictional rates to be just and reasonable. PJM has not shown that the Narrow MOPR would provide the necessary check on buyer-side market power exercised through seller subsidies in the RPM.

As Dr. Quinn explains, PJM's "articulated distinction between buyer-side and seller-side market power is not convincing" and "even if there is a meaningful difference between buyer- and seller-side market power, the extreme asymmetry with which PJM is proposing to treat them is

[298] *Id*.

[299] 2011 MOPR Rehearing Order at P 98.

[300] *Id*. (citing *Tejas Power*, at 908 F.2d 998, 1004).

unreasonable."[301] PJM's entire premise that there is some fundamental difference between the two types of market power is misplaced and ignores practical experience with state actions.[302] Dr. Graf's additional attempts to justify PJM's position are flawed and unconvincing.[303] "Even if one were to assume, despite the lack of credible evidence from PJM, that there were a fundamental difference, PJM has not justified the level of asymmetric treatment that it proposes."[304] Dr. Quinn identifies several ways in which the Narrow MOPR would be materially, and unjustifiably, weaker than the three pivotal supplier test applicable to sellers. Specifically, the Narrow MOPR would: (i) give sellers a unique avenue to uncompetitive offers outside of the unit-review process; (ii) create a "presumption of innocence" for self-certifying unlike anything that exists under PJM's seller-side rules or any market's buyer-side rules, and (iii) provide far less protection against market power than the Three Pivotal Supplier test under the seller-side rules. In addition, Dr. Quinn explains that PJM has not addressed the asymmetry in the long-term effects of buyer-side and seller-side market power. The successful exercise of seller-side market power will affect the results of one auction and then be corrected prospectively; allowing capacity market prices to return to competitive levels. By contrast, under-mitigation of buyer-side market power will allow an uneconomic resource to enter the market and suppress capacity prices in all subsequent auctions.[305] "[E]rring on the side of under-mitigation has a lasting effect."[306]

There is also nothing new about the idea that seller-side and buyer-side market power mitigation measures are, to some extent, "asymmetrical." It has been understood since the advent

[301] Quinn Aff. ¶ 41.

[302] Quinn Aff. ¶ 42.

[303] *See* Quinn Aff. ¶¶ 42-44.

[304] Quinn Aff. ¶ 44.

[305] Quinn Aff. ¶ 45.

[306] *Id.*

of the Commission's MOPR policy that LSEs cannot engage in traditional withholding because sloped demand curves dictate the quantity of capacity that LSEs must purchase.[307] Supplier-side and buyer-side mitigation measures have always been structured differently because they are directed against different abuses. In fact, the Expanded MOPR itself was never "symmetrical" with PJM's supplier-side measures in the way that PJM appears to mean.

6. The Cramton Affidavit Lacks Any Probative Value

The Cramton Affidavit appears to be principally aimed at criticizing the Expanded MOPR rather than demonstrating the justness and reasonableness of the Narrow MOPR. The Cramton Affidavit's modeling, analysis, and conclusions ("Cramton Analysis") are therefore largely irrelevant to this proceeding. But even considered on its own terms, the Cramton Affidavit provides no support for the PJM Filing and no justification for allowing it to go into effect. As Dr. Shanker confirms, "[t]he modeling supporting Dr. Cramton's affidavit is not a reasonable basis for forming an expert opinion."[308]

PJM claims that the Cramton Analysis "shows that the Expanded MOPR 'results in more resources and more expense for consumers. '"[309] PJM acknowledges that the Cramton Analysis "does not show a dramatic difference in resource entry and exit decisions over a multi-decade period," but insists that "it does show that the Expanded MOPR would result in higher costs to consumers in states where the subsidies originate due to excluding resources that provide reliability

[307] *See, e.g.*, Danly White Paper; *see also* October 2007 Patton Affidavit in EL07-39, ("Typically, monopsony power is exercised by withholding purchases to drive down the market price paid on the remaining units purchased. Such direct exercise of market power is impossible given the auction design because the quantity that the LSEs must obtain is determined by a demand curve. However, uneconomic entry of new generation can artificially depress capacity prices.").

[308] Shanker Aff. ¶49.

[309] PJM Filing at 11 (citing Cramton Aff. ¶74).

from the capacity market."[310] Dr. Shanker and Dr. Quinn both reviewed the Cramton Affidavit and have described so many serious flaws and problems that the Cramton Affidavit cannot plausibly be afforded any evidentiary weight.[311]

It bears emphasizing that Dr. Shanker and Dr. Quinn were able to identify these weaknesses over the course of the few weeks that the Commission has allowed for comment. If they had more time, and if the Cramton Analysis did not depend on so many unexplained or unknown assumptions, they very likely would have catalogued even more defects. But even their preliminary findings are more than sufficient to make it impossible to rely on the Cramton Affidavit.

The Cramton Affidavit states that its projections are based on a "multi-decade model of the energy transition in PJM" that "allows researchers to study the market impacts of alternative market rules and policies."[312] The PJM Filing does not include any documentation or concrete explanation of how the modeling works. The Cramton Affidavit refers to a single external source, "Cramton et al. 2021," which is neither provided nor linked to. As Dr. Shanker notes "Cramton et al. 2021" appears to be a draft working paper dated July 2021.

Moreover, "the Cramton Affidavit lacks any real detail with respect to the function, design, testing/benchmarking of the model." What little information was available to actually review left Dr. Shanker with "a large number of questions that simply cannot be addressed without additional documentation example, data, work papers, and reviews."[313] "[T]here simply isn't sufficient benchmarking, documentation, validation, transparency or review by scholarly peers, market

[310] *Id*.

[311] *See* Shanker Aff. ¶¶ 13-20, 48-60; Quinn Aff. ¶¶ 18-23.

[312] Cramton Aff. ¶7.

[313] Shanker Aff. ¶15.

participants, or for that matter the Commission, to draw reasonable conclusions regarding the Cramton model's results.[314] Dr. Shanker goes on to explain that the Cramton Analysis has so many "unknown properties" that it appears to be:

> [I]nfeasible for anyone else to replicate the model or the model results given the lack of detail and extraordinarily large computational requirements. The model is, for all intents and purposes, a black box to the Commission, Stakeholders, and presumably anyone other than perhaps Dr. Cramton and his fellow authors. One simply cannot rely on the results as they currently stand to make a reasoned judgment regarding the broad versus narrow MOPR.[315]

Even given the limited information available, Dr. Shanker "found a number of underlying assumptions that are unclear, give cause for concern about the validity of the findings, or are simply opaque."[316] Dr. Cramton acknowledges that "[a]s with any simulation of this complexity, I have made many assumptions"[317] but does not describe or explain those assumptions. Dr. Cramton likewise acknowledges that "[c]alibration of the model is imperfect" and that "[m]iscalibration is especially apt to impact absolute results, such as price levels."[318] Dr. Shanker has compiled an extensive, but still preliminary, summary of material problems in the Cramton Analysis which emphatically show that Dr, Cramton was right to concede the "imperfections" in his analysis.[319]

PJM asserts that the Cramton Affidavit's "sophisticated modeling" shows that "the theory that subsidized resources will reduce clearing prices below the level needed to ensure that unsubsidized, otherwise economic, resources will clear the auction" and thereby impair reliability "may be overstated."[320] Dr. Shanker demonstrates that PJM's modest claim is the product of the

[314] Shanker Aff. ¶ 50.

[315] Shanker Aff. ¶ 51 (internal footnote omitted).

[316] *Id.* ¶ 16.

[317] *Id.* ¶ 53.

[318] *Id.*

[319] *See id.* ¶ 51-55.

[320] PJM Filing at 16.

"outcome-driven assumptions" used in the Cramton Analysis. "Dr. Cramton acknowledges that prices are somewhat lower under the narrow MOPR but this is exactly the problem, as what he sees as an advantage looks to others as price suppression."[321]

Dr. Cramton clearly believes that under-mitigation is less harmful than over-mitigation.[322] But Dr. Shanker observes that, "Dr. Cramton's support of the current PJM proposal appears to be based primarily on his subjective views of the dangers of over-mitigation versus under-mitigation, rather than reflecting the results of his model." Dr. Shanker notes that, "[t]he model certainly doesn't support this conclusion" and explains why Dr. Cramton's bias towards under-mitigation is unfounded.[323]

In short, Dr. Shanker and Dr. Quinn demonstrate that the Cramton Affidavit's conclusions are faulty and were effectively pre-ordained by the underlying assumptions and structure of the Cramton Analysis.[324] Given the evidence that Dr. Shanker and Dr. Quinn have provided it would be arbitrary and capricious for the Commission to rely on the Cramton Affidavit. The Commission cannot possibly be said to have engaged in reasoned decision-making if it accepts a "black box" analysis that cannot possibly be replicated without much more information and enormous computing resources.[325]

The Cramton Affidavit also claims that the Expanded MOPR "shifts revenues from the energy and ancillary services market to the capacity market thereby increasing the role of the

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[321] Shanker Aff. ¶ 17.

[322] *See* Cramton Aff. ¶¶ 13-14.

[323] Shanker Aff. ¶ 18-20.

[324] See Shanker Aff. ¶ 56-60; Quinn Aff. ¶¶ 18, 19.

[325] *See* Cramton Aff. ¶ 48 (describing the complexity associated with the model's "extensive computation," noting that "modeling was done on 22 computational servers running 24x7 for many months, creating an extensive database of market outcomes at the 5-minute level as a function of the resource structure and other parameters.")

capacity market in investment decisions" and that this "moves the market further from the ideal where the capacity revenues reflect the financial cost of the obligation to deliver energy and reserves during shortages."[326] This assertion ignores the detrimental effect on investor confidence that the Expanded MOPR is designed to address.[327] For instance, Dr. Cramton does not consider whether market resources will need to include a premium to their capacity offers to account from the additional risk imposed by the Narrow MOPR. Dr. Cramton does not consider whether the uncertainty surrounding the timing and level of state supported resource entry will be so significant that some investment will not occur regardless of the current capacity price. In short, the Cramton Analysis is incomplete.

F. The Commission Should Give PJM Additional Guidance Regarding Potential Future MOPR Revisions that Could Satisfy Section 205

As discussed above, given the numerous fundamental flaws in the PJM Filing it cannot be accepted as just and reasonable. Because the Commission's authority to condition or modify Section 205 filings is limited,[328] and because PJM has expressly declined to authorize partial acceptance of its proposal,[329] there is also no way to salvage PJM's proposals in this docket.[330] The PJM Filing must be rejected in its entirety.

The necessity of rejecting the instant filing does not preclude the possibility of MOPR improvements. P3 recognizes that the electric grid is changing and that markets must adapt and evolve consistent with those changes. P3 is sympathetic to many concerns that have been

[326] PJM Filing at 15-16, Cramton Aff. ¶ 15.

[327] *See* Quinn Aff. ¶ 20.

[328] *NRG Power Mktg,*, 862 F.3d at 114 ("Section 205 does not allow FERC to suggest modifications that result in an 'entirely different rate design' than the utility's original proposal or the utility's prior rate scheme." (quoting *Western Res. v. FERC*, 9 F.3d 1568, 1578 (D.C. Cir. 1993))).

[329] *See* PJM Filing at 48.

[330] PJM itself acknowledges that its Narrow MOPR proposals must be evaluated "within the bounds of Section 205" and that the Commission "may not approve material deviations" under *NRG*.

expressed by critics of the capacity market in general and the MOPR specifically and believes that there are viable paths forward to adapt to the evolving marketplace.

As noted above, the Expanded MOPR had a *de minimis* impact on prices and on state subsidized resources in the May 2021 BRAs. The same is likely to be true for the December BRA. "Most currently subsidized resources are exempt from the application of the MOPR, have default MOPR floors that are well below historical clearing prices, or can use the unit specific review process to establish default floor values below historical clearing prices."[331] These considerations should dispel any fears about the Expanded MOPR remaining in place in the near term. There is thus still time for a second attempt at developing MOPR revisions that satisfy the just and reasonable standard. There is no justification for acting precipitously to replace the existing rules, let alone for replacing them with an unjust and unreasonable Narrow MOPR.

The sense of urgency to implement the Narrow MOPR appears to be most strongly driven by the desire to smooth the entry of major offshore wind projects supported by New Jersey and Maryland. But neither group of projects is sufficiently developed to be offered into the 2023/2024 BRA scheduled for this December. The New Jersey projects reportedly may be ready to be offered into the 2024/2025 Delivery Year auction scheduled for June 2022, while the Maryland projects are not expected to participate, at the earliest, until the 2025/2026 Delivery Year auction that will take place in January 2023. It follows that having MOPR improvements in place for the June 2022 RPM auction should be more than sufficient to address the any legitimate concerns regarding state offshore wind priorities.[332]

[331] P3 Comments in AD21-10 at 5.

[332] *See id.*

To be clear, P3 supports timely action to resolve state-federal tensions and to eliminate market uncertainty concerning the status of the MOPR. P3 also continues to support moving ahead with PJM's RPM auctions, starting with the December 2021 BRA, and abiding by the revised auction schedule that PJM announced in November 2020.[333] The best way for Commission to support these objectives would be to give PJM concrete and specific guidance regarding the minimum legal requirements that a new MOPR proposal must meet.

Specifically, PJM should be instructed to address the following points:

- Recognize the reliability contributions of subsidized resources.
- Provide meaningful protections against the assertion of buyer-side market power that are similar to the protections in place against seller-side market power, because market-based rates are not lawful under the FPA's just and reasonable standard just and unless both buyer-side and supply-side market power are acknowledged and mitigated.
- Preserve the integrity of the capacity market price signal through either mitigation of subsidized resources or different compensation protocols for unsubsidized capacity suppliers. Despite PJM's revised stance, the issues PJM identified in 2011 and 2018 remain real and must be addressed if the capacity market is going to function properly.

[333] *See* <https://insidelines.pjm.com/pjm-reestablishes-capacity-auction-schedule/> (announcing re-scheduled dates for BRAs that were postponed while PJM developed and then prepared to implement the Expanded MOPR after PJM's prior MOPR rules were found to be unjust and unreasonable.)

- Address interstate cost shifts to "loads who should not be required to underwrite, through capacity payments, the generation preferences that other regulatory jurisdictions have elected to impose on their own constituents."[334]
- Address concerns of self-supply and public power in a manner that respects their business models while protecting the market from abusive decisions.

The PJM Filing states that the introduction of the Narrow MOPR would be followed by stakeholder discussions to examine whether other "reforms are needed to ensure that the PJM Region is able to get the reliability value from each Capacity Resource."[335] PJM is also "initiating a comprehensive review of the capacity market rules to ensure the continued reliability of the PJM system given the evolution of the PJM Region's resource mix and taking account of" the changes proposed by the PJM Filing.[336] Presumably, PJM could devise alternative MOPR revisions that reflect Commission guidance, and "take account" of them, at the same time that it explores broader capacity market design changes.

G. Alternative Request for Paper Hearing

In the alternative, if the Commission does not reject the PJM Filing outright, it must—at a minimum—initiate paper hearing procedures in this proceeding. The PJM Filing makes various

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[334] *See, e.g.*, *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 at P 67 (2018) ("PJM's Capacity Repricing proposal also represents an unjust and unreasonable cost shift to loads who should not be required to underwrite, through capacity payments, the generation preferences that other regulatory jurisdictions have elected to impose on their own constituents."); *id.* at P 162 ("the status quo requires consumers in some PJM states to subsidize the policy decisions of other PJM states."). An earlier PJM order emphasized that "[w]e are forced to act . . . when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's [capacity auction] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity." 2011 MOPR Rehearing Order, 137 FERC ¶ 61,145 at P 3, *quoted in Hughes*, 136 S. Ct. 1288, 1296.

[335] PJM Filing at 4.

[336] *Id.*

factual assertions that this Protest disputes. This Protest also presents evidence that raises genuine issues of material fact.

The basis for many of the PJM Filing's factual assertions is unclear or undeveloped. For example, PJM relies in part on the Cramton Affidavit. But as discussed in detail above and in the Shanker and Quinn Affidavits, there are numerous errors, faulty assumptions, and critical ambiguities in the Cramton Affidavit. The Cramton Affidavit could not possibly be given any evidentiary weight without further examination through paper hearing procedures.

Similarly, PJM's justification for its proposed MOPR revisions also relies in significant part on Dr. Graf's assertion that "the risks associated with supplier-side market power are not symmetrical to the risk associated with buyer-side market power."[337] According to Dr. Graf, "[g]iven the lower risk of buyer-side market power relative to supplier-side, it is reasonable to design a buyer-side market power mitigation mechanism that is more focused."[338] However, Dr. Graf's assertions regarding the asymmetry between supplier-side and buyer-side market power impacts are simply that – bare assertions otherwise unsupported by data or more extensive analysis.

The lack of clear support for the key testimony that underpins the PJM proposal is, as discussed above, a reason for rejecting the PJM filing. Without a clear explanation of Professor Cramton's model, including its assumptions, without a clear basis for Dr. Graf's assertions regarding the asymmetry between supplier-side and buyer-side market power, and without more evidence to support PJM's various other claims, it would be impossible for the Commission to reasonably conclude that the PJM's Filing's tariff revisions are just and reasonable.

[337] Graf Aff. ¶ 14.

[338] *Id.* ¶ 15.

If the Commission nevertheless determines that it will not reject the PJM Filing, it must set the proposed MOPR revisions for a paper hearing. P3 believes that the modeling results obtained by Professor Cramton, and the assertions by Dr. Graf regarding the asymmetry between supplier-side and buyer-side market power, are fundamentally flawed and highly inaccurate, and that they ultimately provide no support for PJM's proposed MOPR revisions. P3 has identified many other problems with the PJM Filing, as set forth above. If the Commission does not reject those revisions out of hand, it must afford P3 and other intervenors the opportunity to test and challenge the validity of PJM's supporting evidence through appropriate hearing procedures.[339]

The Commission has time to build the evidentiary record for a more rational and legally durable MOPR.[340] If the PJM Filing is not rejected, and PJM is not given specific guidance to help it develop a better proposal, then the Commission will probably need to direct changes under FPA section 206[341] given the inflexible approach PJM has taken under FPA section 205 to date.[342]

[339] As the Commission has explained, while "the FPA and case law require the Commission to provide parties with a meaningful opportunity for a hearing, the Commission is required to reach decisions on the basis of an oral, trial-type evidentiary record only if the material facts in dispute cannot be resolved on the basis of the written record, i.e., where written submissions do not provide an adequate basis for resolving disputes about material facts." *Cal. Indep. Sys. Op. Corp.*, 134 FERC ¶ 61,132, at n.81 (2011). In this case, the factual issues involve complex questions of modeling and economic assumptions, and can be resolved adequately on the written record, without the need for a trial-type hearing.

[340] The sense of urgency for MOPR reform appears to be most strongly driven by the desire to have a new rule in place to smooth the entry of major offshore wind projects supported by New Jersey and Maryland, but neither group of projects is sufficiently developed to be offered into the 2023/2024 Delivery Year auction scheduled for this December. The New Jersey projects are expected to be offered into the 2024/2025 Delivery Year auction scheduled for June 2022, while the Maryland projects are expected to be offered, at the earliest, into the 2025/2026 Delivery Year auction that will take place in January 2023. *See, e.g.*, U. Khalid, GE unit to supply 12-MW variant for Ørsted's offshore wind farm in New Jersey, S&P Global Mkt. Intel. (Jan. 18, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/ge-unit-to-supply-12-mw-variant-for-216-rsted-s-offshore-wind-farm-in-new-jersey-62159802; G. Wehner,, Ørsted wind farm to be operational in 2026, Ocean City Today (Mar. 5, 2021), https://www.oceancitytoday.com/news/rsted-wind-farm-to-be-operational-in-2026/article_cef539d8-7d19-11eb-b322-bbaaa3e6cb1a.html.

[341] *See, e.g.*, June 2018 Order at PP 6-8 n.9 (explaining that "[a] rate proposal proceeding may also be transformed into Commission-initiated complaint proceeding when the record indicates that is necessary or appropriate" and listing numerous examples).

[342] *See* PJM Filing at 48 & n.56.

A paper hearing would be a suitable mechanism to support future Commission determinations under FPA section 206.

Finally, given the substantial legal, policy, and financial impacts that significant MOPR revisions will inevitably have, it is imperative that the Commission issue an order addressing the PJM Filing, rather than allowing it to go into effect by operation of law. The past four years starkly illustrate the damage caused by regulatory uncertainty when the composition and leadership of the Commission is incomplete and unstable. Major Commission rulings will not be perceived as legally durable, or legitimate, if they become effective without an affirmative order. Implementing MOPR revisions without the support of a Commission majority would introduce substantial market uncertainty and raise the basis for claims of "regulatory hubris" to an entirely new level.[343] The results of auctions conducted under such circumstances would also be vulnerable to challenge under FPA section 205(g), which will surely be invoked to seek rehearing and judicial review if the Narrow MOPR goes into effect by operation of law. Given the manifest defects in the PJM Filing, this proceeding presents a worst-case scenario to test that statute on judicial review. Thus, if there is not majority support for a decision by the end of the sixty-day notice period, the Commission should set the PJM Filing for a paper hearing to produce a more complete record and enable the Commission to reach an agreement.

CONCLUSION

The Narrow MOPR would fail to protect the capacity market against buyer-side market power in direct violation of the FPA and both Commission and judicial precedent. The PJM Filing is unjust, unreasonable, and unduly discriminatory. Accepting the Narrow MOPR tariff revisions,

[343] December 2019 Order, 169 FERC ¶ 61,239 at P 5 (Glick, Comm'r, dissenting) (quoting June 2018 Order, 163 FERC ¶ 61,236 at P 5 (LaFleur, Comm'r, dissenting).

or allowing them to go into effect by operation of law, would be arbitrary and capricious. Consequently, the Commission must reject the PJM Filing, but should also give PJM specific guidance as to what would be required for an alternative proposal to be just and reasonable. In the alternative, the Commission should establish paper hearing procedures that would allow all parties to fully address, and the Commission to properly resolve, the numerous disputed issues of material fact in this proceeding.

Respectfully submitted,

On behalf of the PJM Power Providers Group

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August 20, 2021

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding in accordance with the requirements of Rule 2010 of the Rules of Practice and Procedure, 18 C.F.R. § 385.2010 (2020).

Dated at Washington, DC this 20th day of August, 2021.

By: *<u>/s/ Diane Slifer</u>*
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ATTACHMENTS

A. Affidavit of J. Arnold Quinn, Ph.D. on Behalf of the PJM Power Providers Group

B. Affidavit of Roy J. Shanker, Ph.D. on Behalf of the PJM Power Providers Group

C. Commissioner James P. Danly Whitepaper, *The Requirement that Competitive Markets be Protected from the Exercise of Market Power Applied to RTO Capacity Markets* (May 20, 2021)

D. Commissioner James P. Danly Whitepaper Supplement 1, *The Requirement that Competitive Markets be Protected from the Exercise of Market Power Applied to RTO Capacity Markets* (June 17, 2021)

E. Commissioner James P. Danly Whitepaper Supplement 2, *The Requirement that Competitive Markets be Protected from the Exercise of Market Power Applied to RTO Capacity Markets* (July 15, 2021)

F. Commissioner James P. Danly Whitepaper, *Results of The PJM Capacity Auction (2022/2023 RPM Base Residual Auction)* (June 17, 2021)

G. PJM, 2022/2023 RPM Base Residual Auction Results (June 2, 2021)

H. PJM, Press Release, *PJM Successfully Clears Capacity Auction to Ensure Reliable Electricity Supplies: Auction Attracts Diverse and Efficient Resources at Lower Wholesale Costs* (June 2, 2021)

I. PJM, May 2021 BRA Clearance Data by Resource Type and MOPR Status

J. Monitoring Analytics, *2021 Quarterly State of the Market Report for PJM: January through June* (Aug. 12, 2021)

K. Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C. Attachment E to filing entitled Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Docket No. ER18-1314-000 (Apr. 9, 2018)

Attachment A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER21-2582-000

AFFIDAVIT OF J. ARNOLD QUINN, PH.D.
ON BEHALF OF THE PJM POWER PROVIDERS GROUP

I. Qualifications and Experience

1. I am the Vice President, FERC-Jurisdictional Markets at Vistra Corp. where I direct Vistra's market policy advocacy at the Federal Energy Regulatory Commission (Commission or FERC) and manage market policy advocacy in the ISO markets in which Vistra participates. I have been with Vistra since June 2018. Vistra is a member of the PJM Power Providers Group (P3).[1]

2. Prior to joining Vistra, I was a member of Commission staff for over 14 years in a variety of roles in the Office of Enforcement and Office of Energy Policy and Innovation (OEPI). I joined the Commission in October 2003 in the Division of Audits. In August 2008, I became the Director of the Division of Energy Market Oversight within the Office of Enforcement. The Division's work focused on, among other things, identifying potential market manipulation and generally reporting on the functioning of the wholesale markets. I joined the Office of Energy Policy and Innovation when it was formed in May 2009 as one of the two Division Directors. I was the Office Director from December 2015 through May 2018. In OEPI, I supervised rule makings on energy price formation, removal of regulatory barriers to new technologies, merchant transmission, and interconnection rules. As Office Director, I supervised OEPI's engagement in all policy-relevant docketed cases. I also supervised the team that organized the Commission's May 2017 technical conference in Docket No. AD17-11-000 on the tension between wholesale markets and state policy perspectives.

3. Prior to joining FERC staff, I was an economist at The Brattle Group where my work focused on economic analysis to support litigation related to the Western energy crisis. I began my career at Laurits R. Christensen Associates, an economic consulting firm that specializes in developing and analyzing innovative retail rates.

4. I graduated with Honors with a B.S. in Economics from the University of Wisconsin and have a Ph.D. in Economics from the University of Minnesota.

[1] The view expressed in this affidavit are solely mine and do not necessarily represent the views of individual P3 members with respect to any issue.

II. Purpose of Affidavit

5. The purpose of my affidavit is to place PJM's Narrow MOPR[2] proposal in the context of the Commission's evolving Minimum Offer Price Rule (MOPR) policy to show that the Narrow MOPR does not represent a just and reasonable rate because it has not been shown to balance the policy objectives FERC considers when addressing out-of-market actions. I explain that PJM has lost sight of the relevant questions for the Commission to consider – what are the effects of out-of-market actions on the wholesale market and what should the Commission do to address those effects? I highlight that the Conditioned State Support provisions have no clear role in addressing any policy consideration the Commission has articulated as relevant to the MOPR. I evaluate PJM's buyer-side market power provisions and find that they could be a reasonable starting point but suffer from limitations that would prevent them from applying in the situations where the Commission has previously identified buyer-side market power. Finally, I suggest a path forward in which the Commission rejects PJM's filing and provides PJM with clear guidance for any future revisions to the MOPR.

III. PJM's proposal in the context of the Commission's MOPR policy

a. Evolution of MOPR Policy

6. The Commission's MOPR policy can be viewed as evolving from a policy focused exclusively on buyer-side market power mitigation to a policy concerned with any out-of-market action that may induce uneconomic entry/retention and suppress the capacity price, to a policy that recognizes the potential value of accommodating state policy decisions. If the buyer-side market power mitigation provisions in PJM's proposed Narrow MOPR were changed to remove some exemptions so that it applied uniformly to any activity that has historically been recognized as involving the exercise of market power, then PJM might argue that it was taking the MOPR policy back to the original focus. However, in proposing to narrow the focus to buyer-side market power, PJM does not attempt to address the other policy considerations the Commission has articulated as MOPR implementation and philosophy have evolved.

7. The original purpose of the MOPR in PJM was a "method of assuring that net buyers do not exercise monopsony power by seeking to lower prices through self supply."[3] The narrow focus on net buyers was seen at the time as a pragmatic approach to consider those that have an incentive to reduce the capacity market clearing price. Of note, the Commission expressly chose to exempt reliability projects built under state mandate. In hindsight, this narrow focus seemed to make sense within the historical context. The policy was developed in 2006, not long after the California energy crisis. The Commission's analysis of the crisis expressed concern that buyers were under-scheduling in the day ahead market to lower prices.[4] The Commission's and stakeholders'

[2] A MOPR that is limited to address only buyer-side market power is referred to in the PJM filing as both a "focused MOPR" and a "narrow MOPR." For the sake of consistency, I use the phrase "Narrow MOPR."
[3] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 104 (2006).
[4] See e.g., Final Report on Price Manipulation in Western Markets in Docket No. PA02-2 at I-12, March 23, 2003, ("A third major flaw was the underscheduling of load by the three California IOUs. Economic incentives to

experience with buyer-side market power at the time centered on the incentives of buyers with large load positions and actions they could take to lower their total cost.

8. The first evolution in the Commission's MOPR policy was to remove the exemption for state actions. This evolution was born out of the practical experience with out-of-market actions by Connecticut, New Jersey, and Maryland to sign uneconomic, out-of-market contracts with natural gas plants for the sole or primary purpose of reducing their states' consumers' total capacity payment. P3 documented the actions by New Jersey and Maryland in the Complaint that led in part to this evolution in the MOPR policy.[5] For instance, P3 explained that New Jersey had passed legislation directing the procurement of up to 2,000 MW of new generation.[6] P3 further highlighted the hearings on the New Jersey legislation focused exclusively on the capacity market cost savings associated with the procurement.[7] At the same time, Maryland issued a Request for Proposals for 1,800 MW of generation nominally designed to meet Standard Offer Service load.[8] In comments to the Maryland Public Service Commission, the PJM independent market monitor (IMM) cautioned that the subsidized entry of 1,800 MW of new generation:

> [W]ould affect the investment decisions of current owners of capacity and potential investors in capacity both in and outside of Maryland. The likely result is less investment in capacity. Depressing the price in Maryland would also mean that the required direct subsidy by Maryland ratepayers would increase with perhaps significant unintended consequences for the business and residential customers who would have to pay the subsidy.[9]

9. The relevant fact in each instance was that a state's consumers gained a portfolio benefit from execution of an uneconomic out-of-market contract. Under such a contract, consumers paid above market prices for the contracted capacity, but saved money on the net demand from the capacity market due to the price suppressive effect of the uneconomic entry. The net result was a net decrease in total capacity payments by the states' consumers. This is a textbook example of monopsony or buyer-side market power.

10. It is important to recognize how actions by buyers or states fit into the theory of monopsony power. It is accurate to recognize that the capacity demand curve is administratively determined and cannot be changed by the actions of any buyer or state. However, introducing a specified amount of capacity into the capacity *supply curve* with a zero priced offer has exactly the same effect on the capacity market outcomes as

underschedule tended to increase during high demand periods, which created operational and reliability problems for the Cal ISO and required it to obtain out-of-market energy at high prices. In its December 15, 2000 Order, the Commission established penalties for underscheduling load.")

[5] Complaint of the PJM Power Providers Group, *PJM Power Providers Group v. PJM Interconnection, LLC* Docket No. EL11-20-000 (Feb. 1, 2011) (P3 Complaint).

[6] P3 Complaint at page 3.

[7] P3 Complaint at page 57.

[8] P3 Complaint at page 4.

[9] Comments of the PJM Independent Market Monitor in Maryland Public Service Commission Case No. 9214, January 31, 2011 at page 4.

reducing the capacity market demand by the same amount. The actor is effectively changing the *net demand* through the forced entry of an uneconomic resource. Once the issue is recognized to be changing net demand, the monopsony theory follows as in other settings.

11. Over time, there was a general appreciation by the Commission and the ISOs that any subsidized uneconomic entry or retention would suppress the capacity market price. The fact that an otherwise uneconomic unit was displacing an economic unit in the capacity market became the economic harm. The IMM summarized this view in its comments on PJM's "jump ball" reform proposals in 2018 that culminated in the December 2019 PJM MOPR Order (2019 Order):

> The proposed subsidy solutions in all cases ignore the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. A decision to subsidize uneconomic units that are a significant source of energy and capacity has direct and significant impacts on other sources of energy; the opportunity costs of subsidies are substantial. Such subsidies suppress energy and capacity market prices and therefore suppress incentives for investments in new, higher efficiency thermal plants but also suppress investment incentives for the next generation of energy supply technologies and energy efficiency technologies. These impacts are long lasting but difficult to quantify precisely.[10]

This evolution placed less emphasis on whether the state received a portfolio benefit and focused simply on the existence of uneconomic entry and the associated price suppression.

12. As the MOPR evolved, tensions between states and ISOs and the Commission grew. In response to this tension, the ISOs and FERC began to discuss MOPR in terms of the desire to balance competing objectives – investor confidence in capacity market outcomes that will preserve reliability long-term and recognition of state supported resources. For instance, in the June 2018 Commission Order initiating the proceeding that culminated in the Expanded MOPR, the Commission acknowledged these two objectives. Specifically, the Commission found that the MOPR "should protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[11] The Commission also found that "it may be just and reasonable to accommodate resources that receive out-of-market support, and mitigate or avoid the potential for double payment and over procurement."[12]

13. In the Commission's order approving ISO-NE's Competitive Auctions with Sponsored Policy Resources (CASPR), it indicated a preference for prioritizing investor confidence

[10] Comments of the Independent Market Monitor for PJM in Docket No. ER18-1314, May 7, 2018 at pages 8-9.
[11] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 at P 158 (2018).
[12] *Id.* at P 160.

if no reasonable balance of policy objectives could be achieved through stakeholder efforts, stating "(a)bsent a showing that a different method would appropriately address particular state policies, we intend to use the MOPR to address the impacts of state policies on the wholesale capacity markets. However, we acknowledge that there can be more than one valid method of managing such impacts, and that methods may be tailored to the specific challenges posed by the state policies in a given region."[13] In the CASPR rehearing order, the Commission explained that the focus on investor confidence is consistent with both investor and consumer interest, finding:

> "Investor confidence" is not a one-sided, supplier-only consideration. On the supplier side of the ledger, allowing the primary FCM [Forward Capacity Market] auction to set the capacity price paid to all but those resources that clear the substitution auction helps ensure that prices will not be so low as to fail to attract investment in new capacity when needed. On the customer side of the ledger, the Commission found that, when investor confidence is sustained and the FCM continues to attract and maintain resource investment as needed, customers reap the benefit of resource adequacy, and suppliers do not need to include significant risk premiums – the costs of which would ultimately be passed on to customers – in their capacity offers.[14]

14. The Commission's 2019 Order went even further to exclusively focus on investor confidence in capacity market outcomes. PJM's current filing appears to be very much premised on the tension created by the balance, or perceived lack of balance, struck by the 2019 Order. For instance, PJM asserts that "the Expanded MOPR's broad reach and expanded definition of subsidies poses an increased risk that resources receiving such perceived subsidies will not clear the market, resulting in either (1) frustration of the state policy objective or Load Serving Entity ("LSE") resource strategy; or (2) customer payment for duplicative resources."[15]

b. PJM fails to address the balance between confidence in capacity market outcomes and accommodating state policies

15. Clearly, finding the balance between competing objectives is challenging and the mechanism for achieving the right balance will differ by region. However, in responding to that tension, PJM fails to grapple with the balancing of interests the Commission has adopted in implementing its current MOPR policy. Even if one accepts claims that the 2019 Order went too far, PJM does not explain whether the Narrow MOPR would sufficiently address investor confidence. PJM's statement that state actions are a "reality to be acknowledged"[16] appears to give no consideration to whether those actions will influence investment decisions. PJM's assertion that the Expanded MOPR price would

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[13] *ISO New England Inc.*, 162 FERC ¶ 61,205 at P 22 (2018)**,** *reh'g denied,* 173 FERC ¶ 61,161 (2020) ("CASPR Rehearing")**.**
[14] CASPR Rehearing at P 47.
[15] Submittal Letter at page 12.
[16] Submittal Letter at 7.

not result in just and reasonable prices because it doesn't recognize capacity on the system[17] reflects an economic argument in favor of recognizing resources with out-of-market compensation. But PJM does not balance that argument against the possible harm that could occur if resources that rely solely on market revenues lose confidence that they have a reasonable opportunity to recover invested capital.

16. It is relevant to consider the relative proportion of state supported resources and market-supported resources when evaluating how to balance the recognition of the capacity value of former and confidence in capacity market outcomes by resources that rely on market revenues alone. The vast majority of existing capacity and new entry in PJM does not receive out-of-market support and in order for this unsubsidized investment to continue, confidence in wholesale market prices is essential. The IMM reports that 77 percent of new capacity additions between delivery years 2007/08 and 2021/22 were based on market funding.[18] Nonetheless, PJM's submittal letter references the change in level of state support just since the December 2019 order as proof that the Expanded MOPR must change. PJM notes that "(t)hree years on, that policy support has only been expanded and extended."[19] PJM asserts that this increase in state support is evidence that "the Expanded MOPR has little chance of deterring state subsidy programs."[20] Notably, PJM does not express a view on the proportion of needed investment that will continue to rely solely on market revenues and thus does not attempt to evaluate the balance between state supported resources and market-supported resources.

17. In the context of the Commission's MOPR policy, the identified change and corresponding uncertainty in the level of state support are as relevant as the relative proportion. For instance, the state of Ohio passed legislation to subsidize two nuclear resources and then repealed those subsidies before they went into effect. Resource owners considering retirement or investment were required to incorporate these subsidies and then the repeal in a very short time period. This all begs the question of how investor confidence is affected by changes in state support.

18. PJM does not attempt to explain whether investor confidence in capacity market outcomes will be maintained if the Narrow MOPR is adopted. Rather, PJM presents evidence from Dr. Peter Cramton that it argues shows that reliability will be maintained under a Narrow MOPR. Dr. Roy Shanker raises compelling concerns about the modeling exercise the supports Dr. Cramton's conclusion. For instance, Dr. Shanker highlights the lack of "benchmarking, documentation, validation, transparency or review by scholarly peers, market participants, or for that matter the Commission." [21] Dr. Shanker also highlights the serious deficiencies in Dr. Cramton's test design, noting that a test design

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[17] Submittal Letter at pages 8-12.
[18] Monitoring Analytics, "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022 Delivery Years," September 15, 2020 ("In summary, of the 41,979.4 MW of generation capacity additions from new resources, reactivations, and uprates to existing generation capacity resources for the 2007/2008 through 2019/2020 Delivery Years, 32,333.9 MW (77.0 percent) were based on market funding and 9,645.5 MW (23.0 percent) were based on nonmarket funding.")
[19] Submittal Letter at page 7, citing programs in Virginia, Maryland, Delaware, and the District of Columbia.
[20] Submittal Letter at page 7.
[21] Shanker Affidavit at P 50.

that started with a "without anything" case and then incrementally added change cases would have illustrated whether Dr. Cramton's conclusions were driven by assumptions regarding carbon prices and the price insensitivity of state supported resources or were driven by the policy differences between an Expanded MOPR and a Narrow MOPR.[22] I build on Dr. Shanker's analysis to highlight why Dr. Cramton's affidavit and model results do not address much whether the Narrow MOPR will maintain investor confidence in capacity market results.

19. Dr. Cramton does not model the behavioral element of resource owners' choices under the proposed Narrow MOPR in order to directly assess whether the Narrow MOPR can maintain investor confidence. Indeed, it is not at all clear what Dr. Cramton assumes about out-of-market state support. His affidavit says nothing about the level of uneconomic entry supported by state mandates. The "Capacity Market and Exit and Entry Decision" section of the paper cited in Dr. Cramton's affidavit[23] states that the model calculates the net present value (NPV) for a set of new plants and continues adding new plants "until all technologies have negative NPV or the planned MW are above a threshold, or the ratio of capacity to peak load exceeds a threshold."[24] This suggests that all resources that enter are economic. The "Model Calibration" section of the paper has a table[25] that details state supported resources over time. This suggests the model does force uneconomic entry, though it is not clear how uneconomic the entry is. Specifically, the paper does not explain whether the full quantity of state supported resources could enter the market economically given the increasing carbon price and changes in entry costs over time. The paper explains that "(i)nitially, the only new technology with a positive net present value is onshore wind. The net present value turns positive in 2021 for batteries, 2024 for solar, and … (o)ffshore wind never becomes profitable but enters the market because of states' support."[26] Dr. Cramton's affidavit and the cited paper do not explain whether a rational investor could have expected the full level of state-supported entry (with the exception of offshore wind) based solely on market dynamics. Finally, and most important, the state supported resource assumptions appear to be static. Assuming a known amount of state supported resources entering the market assumes away one of the problems the MOPR is designed to address.

20. Specifically, the reality that resource owners and investors do <u>not</u> know when and how much state supported capacity will enter the market is a foundational element of the investor confidence concern. To directly assess whether the Narrow MOPR can maintain investor confidence, Dr. Cramton should have varied the possible amounts of state supported entry across different scenarios. Doing so would have allowed him to evaluate the probability an investment would not be able to recover a return of and on capital invested. He would have then been able to determine what risk premium a market

[22] *Id.* at P 53.
[23] Peter Cramton, et al., "Electricity Markets in Transition: A multi-decade micro-model of entry and exit in advanced wholesale markets," July 2021 accessed at http://www.cramton.umd.edu/papers2020-2024/cramton-electricity-markets-in-transition.pdf (Cramton Paper).
[24] Cramton paper at page 47.
[25] Cramton paper Table 6.5 at page 55.
[26] Cramton paper at page 66.

resource would need to enter the market or make investments to stay in the market. He would have been able to evaluate whether there is a point where investment appears so risky that it does not occur. However, Dr. Cramton does not run this experiment. He does not test the hypothesis that uncertainty regarding the timing and amount of state supported entry will undermine investor confidence so that capacity offers increase and investors defer investment. The fact that investment occurs in a model does not mean it will occur in reality.

21. It is equally noteworthy that Dr. Cramton assumes a region-wide carbon price that starts at $5/ton in 2020 and rises by $3/ton each year so it is $20/ton by 2025 and $35/ton in 2030. Even a modest carbon price would address some of the pressure for out-of-market support for existing clean energy resources. A $20/ton regional carbon price would almost certainly support the nuclear resources that are currently getting out of market support. It is also possible that this level of carbon price would support most on-shore wind and solar. The carbon price likely makes them significantly more economic than they would otherwise be. As Dr. Shanker noted, a test design that incrementally added the carbon price could have shed on the degree to which carbon pricing alone is driving the entry of state supported resources. Any modeling assumption that takes out-of-market support and brings it into the market will improve the functioning of the wholesale market overall and will also make MOPR less relevant as a means to support investor confidence.

22. Dr. Cramton's model has assumed away the problems that can impair investor confidence. The timing and level of state support are known with certainty in his model and the existence of a moderately high carbon price could rationalize much of the state supported entry he assumes. With nothing in the model to threaten investor confidence, the role of any MOPR – broad or narrow – is greatly diminished. Indeed, Dr. Cramton's paper acknowledges that "…renewable resources and storage are already economic or near-economic at the beginning of the simulation (except for offshore wind). Thus, the broad MOPR is unlikely to bind…."[27] Thus, it not surprising or informative when Dr. Cramton concludes there is no price suppression under a Narrow MOPR and that reliability will be maintained under a Narrow MOPR.

23. Finally, Dr. Cramton could argue that investor confidence will remain intact if the capacity price is high enough to induce investment when needed and allow market resources to cover any risk premium needed to invest when the timing and level of state support is uncertain. This would be an indirect test that the Narrow MOPR can maintain investor confidence. Dr. Cramton does not explicitly draw any inference about the modeled capacity prices in either his affidavit or the cited paper. To give Dr. Cramton the benefit of the doubt, it is noteworthy that his model projects capacity prices in the range of $300 to $450/MW-day as compared to the most recent capacity market clear of $50/MW-day in the PJM RTO region and a historic high of about $175/MW-day in the PJM RTO region.[28] Dr. Cramton's paper notes that "(c)apacity prices have to remain

[27] Cramton paper at page 68.
[28] Dr. Shanker explains (Shanker Affidavit at P 54) that modeled capacity prices at this elevated level "are troubling because of the lack of any effort to benchmark these results or attempt to explain their deviation from reality."

high to keep conventional resources from exiting the market."[29] To the extent these capacity price levels are used to draw any inference that investor confidence will remain intact and PJM's system will remain reliable under a Narrow MOPR, the Commission should be mindful of the nature of capacity market outcomes to which it is committing. If capacity market prices consistently in the range of $300 to $450/MW-day are deemed to be unacceptable by the states or the Commission, then PJM cannot rely on Dr. Cramton's model results to support the inference that investor confidence will remain intact.

24. To place Dr. Cramton's results in context, it is helpful to note several on-going and near-term PJM initiatives and matters pending before the Commission that have the potential to move capacity prices lower, not higher. The pending market seller offer cap (MSOC) proceeding has several proposed replacements for the current MSOC. The proposals by PJM, the Joint Consumer Advocates and the IMM would require unit-specific reviews for capacity seller offers at levels multiple times below Dr. Cramton's $300 to $450/MW-day clearing prices. It is possible that sellers will be able to cost-justify offers at this level, but the substantial difference between that level and recent capacity clearing prices suggest this will at best be contentious and time consuming. In addition, the upcoming variable resource requirement (VRR) update will reconsider issues like the relevant reference unit. Any change to the VRR that serves to lower demand will put downward pressure on capacity clearing price.

IV. The Commission's consideration of state policies should focus on the effect those policies have on wholesale market outcomes

25. PJM's filing is peppered with comments about the importance of accommodating well intentioned state policies noting, for instance, that "state policies are often designed to address externalities that are not accounted for in PJM's wholesale markets."[30] Dr. Graf expresses concern that the current MOPR "applies even when such state subsidies are economic and welfare enhancing for that state."[31] Dr. Graf further asserts that "the historic lack of federal policy in the area of decarbonization has forced multiple states to rationally search for alternatives to ensure the value of carbon-free resources is reflected in the revenues those resources receive. … Importantly, such policies can be entirely supported on economic grounds as welfare-enhancing."[32]

26. This sentiment is misplaced and, in some circumstances, dangerous. PJM's narrative would invite the Commission to consider whether a state policy is legitimate in the sense that the policy has a valid goal and thus warrants accommodation. That raises the question of whether FERC should apply the MOPR to state subsidies that it deems are not efficiency enhancing or designed to address unpriced externalities. For instance, should the Commission apply the MOPR to a subsidy for financially struggling coal resources because it does not address an unpriced externality? Alternatively, if the state

[29] Cramton paper at page 72.
[30] Submittal Letter at page 8.
[31] Graf Affidavit at P 16.
[32] Graf Affidavit at P 17.

could identify another rationale, e.g., economic development, should the Commission then avoid applying the MOPR because it deems economic development legitimate? What if the state concern was "reliability" and the state wanted to offer subsidies to certain plants so those plants wouldn't face retirement? These hypothetical questions are of course designed to highlight that the Commission should not put itself in the position where it is judging the legitimacy of state policy. The Commission's role is to focus on what happens in the wholesale market as a result of state policies.

27. The Commission can of course consider how its policies interact with state policies and seek accommodation where it is possible. The Commission's areas of interest will undoubtedly overlap with the states'. The Commission understandably would seek to avoid conflict where possible. The Commission has sought to find a balance in the context of the MOPR in other regions. For instance, the Commission approved ISO-NE's CASPR proposal as a middle ground to accommodate state policies.

28. That said, the Commission cannot lose sight of the effect state policies have on the functioning of the wholesale market. No matter how well intentioned, a state action that has a detrimental effect on the wholesale market should be addressed in some form within the wholesale market. It is important to remember that the focus on wholesale market effects also protects those states that choose to rely on the wholesale market to drive resource mix decisions. When the Commission originally removed the state policy exemption from the PJM MOPR, it did so mindful of the fact that one state's policy decisions effect other states' policy decisions. The Pennsylvania Public Utility Commission (PaPUC) spoke clearly in support of removal of the state exemption from the MOPR as being in Pennsylvania's best interest:

> Pennsylvania has recently restructured its retail electricity market and conducted competitive procurement to serve its retail consumers. Pennsylvania is committed to the competitive market structure and would be harmed by any action by another state within PJM that subsidized a participant in PJM's interstate wholesale electric capacity market, absent an effective mitigation mechanism in PJM's RPM.[33]

The PaPUC reiterated its views in a recent letter to the PJM Board, again noting that "Pennsylvania was one of the first restructured states in PJM that embraced the promise of competition in the wholesale generation market and then spent considerable time and effort developing a burgeoning retail electricity market built on the expectations and benefits of a properly functioning wholesale market."[34] The PaPUC went on to express that its "concerns have centered around PJM's proposal to accommodate state policies at

[33] Comments of the Pennsylvania Public Utilities Commission in Docket Nos. EL11-20-000 and ER11-2875, May 4, 2011 at page 13.
[34] Pennsylvania Public Utilities Commission letter to the PJM Board, July 7, 2021, available at https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210706-pa-puc-letter-regarding-minimum-offer-price-rule.ashx.

all costs, to the potential detriment of the two foundational principles upon which PJM's capacity market was built—reliability and competition."[35]

29. When the Commission remains focused on the effect on the wholesale market it avoids choosing one state's policies over another state's policies. PJM misses this point when it argues that "(s)uch state subsidies only lower total costs for consumers in other states."[36] PJM does not discuss whether those lower prices will affect entry and exit dynamics to the point that capacity prices rise in the long-run. Indeed, Dr. Cramton's model finds that capacity prices will rise to $300 to $450/MW-day under a Narrow MOPR. To the extent this is due to state supported resources forcing some existing generators out of the market, states that do not actively pursue out-of-market actions will bear the cost of these higher capacity prices. As New Hampshire Public Utilities Commissioner Kathryn Bailey cogently explained during the Commission's technical conference on evolving wholesale markets focused on New England:

> If you eliminate the MOPR initially it will result in lower capacity prices, but that's going to lead to early retirement of the reliability resources that we need. So eventually when all those unsponsored resources are no longer in the capacity market, the price of capacity is going to increase substantially. And I think that's where the costs will be shifted to other states.[37]

30. Finally, for state actions that constitute buyer-side market power, the Commission must act to mitigate the effect of the exercise of market power. Market power, whether it is buyer-side or seller-side market power, creates a deadweight loss that lowers overall market surplus and should therefore be mitigated. No mitigation regime will precisely identify every attempt to exercise market power or be able to avoid identifying actions that are not actually attempts to exercise market power. Thus, the Commission inherently balances various considerations when it designs a mitigation regime such that there may be some degree of under- or over-mitigation of market power. However, the fact that market power is exercised by a state, rather than by an entity with a load interest, should not be one of those considerations that warrants under-mitigation.

V. The Conditioned State Support provisions do not address any policy consideration the Commission has articulated as relevant to the MOPR

31. In the context of the Commission's MOPR policy, it is not clear what role the Conditioned State Support provision is playing under the Narrow MOPR. PJM characterizes the Conditioned State Support provisions as providing "guardrails" against market power. PJM recognizes that, while the Narrow MOPR is designed to accommodate state policies regarding generation resource mix, "accommodation of state resource mix policies cannot be boundless. The capacity market must have guardrails to

[35] *Id.*
[36] Submittal Letter at page 10, Graf Affidavit at n. 3.
[37] Transcript in Docket No. AD21-10-000, Modernizing Electricity Market Design, Technical Conference May 25, 2021, page 52, 8-15.

protect it from actions by the state or by sellers with Load Interests that would improperly intrude on the wholesale market-clearing price."[38] At the highest level, this sentiment is consistent with the Commission's evolving policy to balance investor confidence in capacity market outcomes and accommodation of state policies. However, PJM's Conditioned State Support proposal is poorly designed, seems to serve no purpose, and will not be an effective guardrail.

32. PJM's proposal misses a very basic and obvious fact - a state policy need not be conditioned on clearing the capacity market to constitute an exercise of market power. It is true that the actions Maryland and New Jersey took that are well understood to be the exercise of buyer-side market power were also conditioned state support. However, PJM is conflating that coincidence with some policy relevance. There were two distinct issues with the out-of-market contracts Maryland and New Jersey directed. First, the contracts paid an above market price to induce entry in constrained capacity zones where the reduction in the capacity price would more than offset the above market payment to the resources. That is, the states got a portfolio benefit from the out-of-market contract. Second, the contracts were constitutionally preempted because they had the effect of establishing the wholesale price for capacity. Had Maryland and New Jersey written the contracts so that they avoided preemption, the contracts would nonetheless have provided a portfolio benefit to the states.

33. More broadly, it is not clear why only Conditioned State Support would constitute state actions the Commission should consider when balancing competing policy objectives. The fact that state support has been conditioned says nothing about the degree of wholesale market impact and thus the impact on investor confidence. It is possible for a state to write an ill-advised contract that would trigger the Conditioned State Support provision but have so little impact on the wholesale market and investor confidence that subjecting the action to MOPR would not be appropriate. It is equally possible for a state to take actions that have an outsized impact on the wholesale market, but nonetheless avoid the Conditioned State Support provisions. The bottom line is that mitigation under the proposed Conditioned State Support is so easy to avoid by drafting state policies in a certain manner that the likelihood of these provisions ever being triggered is virtually zero. Moreover, as PJM acknowledges, in the unlikely event that a new state policy is created with a bid and clear requirement, that policy is illegal and can be invalidated by a court.

34. In short, the Conditioned State Support provisions are a legal standard that is wrongly portrayed as addressing an economic policy question.

[38] Submittal Letter at page 24.

VI. PJM's buyer-side market power provisions have a foundation that is solid in principle, but suffer some fatal deficiencies

a. Design foundation and implementation details

35. PJM's proposed buyer-side market power provisions reflect an essential framework that is economically sound in principle but veers too far in the direction of under-mitigation in practice. PJM correctly recognizes that it must address buyer-side market power. For instance, PJM states that buyer-side market power and Conditioned State Support:

> are plainly impermissible [and] should not be permitted to have a detrimental effect [on] the market. Mitigating the impact of these two influences on the capacity market on a technology neutral basis is appropriate. Thus, PJM's proposed MOPR will contribute toward a just and reasonable, and importantly sustainable, market structure and ensure capacity commitments and clearing prices are aligned with underlying supply and demand fundamentals.[39]

PJM's focus on an actor's incentive and ability to garner a portfolio benefit from out-of-market action is a reasonable economic standard. PJM would need to take care in identifying the relevant portfolio to avoid the problems related to the earlier "net short" standard used in the MOPR. Specifically, PJM realized by 2011 that the original "net short" standard could be gamed; for instance, if the buyer and seller were not sufficiently clearly related, which allowed sellers to evade mitigation. In applying a properly-designed portfolio benefit test, PJM will need to be thoughtful in defining the portfolio an actor is seeking to advantage. PJM would need to develop much more specific standards and include details in its tariff, both of which are missing from the Narrow MOPR. That said, an incentive and ability standard could avoid some of the problems with tying mitigation to seller's "intent" to exercise buyer-side market power. The focus should be on the impact of offers on the wholesale market and on the actor's portfolio, not on discerning the inner motivations of sellers or the states that support them.

36. This standard is more conservative than the standard applied to seller-side market power, which applies to all sellers regardless of whether the seller has been shown to be able to garner a portfolio benefit from bidding some resources above cost. As a result, this standard, if it were applied to all possible actions that may constitute buyer-side market, likely errs on the side of under-mitigating instances of buyer-side market power relative to the frequency of mitigating seller-side market power. If PJM can successfully implement the portfolio benefit test for buyers, it should consider adapting that standard to seller-side market power mitigation.

37. Given the avoidance of an intent-based standard, PJM should clarify statements that could be read to indirectly impose such a standard. For instance, the self-certification tariff language requires a seller to certify that it "does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power."[40]

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[39] Submittal Letter at page 22.
[40] Attachment DD, section 5.14 (h-2)(1)(A)(ii).

Further, PJM's submittal and Dr. Graf's affidavit indicate that PJM would initiate a review if PJM believes that a seller "intends" to exercise buyer-side market power.[41] The core of PJM's buyer-side market power analysis rightly focuses on a quantitative analysis of the effect on the capacity market price and the actor's portfolio's capacity costs. There is no need to introduce vague references to "intent" that appear divorced from the quantitative test, and would seem very likely to result in extensive and burdensome litigation over what particular entities intended.

38. While the Narrow MOPR's general approach has a sound foundation in economic theory, the actual scope of PJM's proposed tariff provisions is far too narrow. First and foremost, the exclusion of state actions from the consideration of actions that may constitute the exercise of buyer-side market power is flawed and inconsistent with experience. Indeed, out-of-market contracts with natural gas plants initiated by Connecticut, New Jersey, and Maryland are the best known instances of actions that are generally accepted as clear examples of buyer-side market power. There can be no basis to categorically exclude state actions when seeking to mitigate buyer-side market power. Similarly, there is no basis to unequivocally deem "[o]ut-of-market compensation (such as from renewable energy credits and zero emission credits)" as permissible and provide that it "may be used to support the economics of the resource under review."[42] In practice it is unlikely that renewable portfolio standards will be an effective means to exercise buyer-side market power, but these programs should be deemed acceptable based on the quantitative test PJM would use for any other action suspected on being exercise of buyer-side market power. Zero emissions credit (ZEC) programs may be more likely to trigger a buyer-side market power screen and should be subject of the market power test. Artful drafting at the state level could allow a ZEC or other "attribute" payment to become a Trojan horse for market power. There is nothing to prevent a state from setting the attribute payment at such a level. It appears that PJM is proposing these exclusions because it deems these "legitimate" state policies. As discussed above, the Commission should be focused on the wholesale market impact and avoid putting itself in the position of judging the legitimacy of state policies.

39. Second, the ability for a seller to justify its sell offer as not being an exercise of market power is overly broad and lacks any standard of review. The most troubling aspect of PJM's proposed tariff language is the provision that provides "(i)f a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not to have the incentive to exercise Buyer Side Market Power with respect to that resource."[43] In the description of PJM's approach to the justification provision, Dr. Graf states that "PJM will consider additional rationales provided by the Capacity Market Seller to support a resource offer as competitive. An offer that is ***only*** economically rational when considering the benefit of price suppression to the participant's portfolio would be interpreted as evidence of intent to suppress prices below the competitive level."[44] This

[41] Submittal Letter at page 33, Graf Affidavit at P 20-21.
[42] Submittal Letter at page 40.
[43] Attachment DD, section 5.14(h-2)(2)(B)(i)(b).
[44] Graf Affidavit at P 24 (emphasis added).

tariff language and Dr. Graf's description are overly deferential. "Otherwise" would appear to have no limits and would again put PJM and the Commission in the position of judging the legitimacy of an actor's intentions rather than focusing on the impact on the capacity price and the actor's portfolio. Dr. Graf's description that the offer will be viewed as an exercise of buyer-side market power only if exercising market power is the sole economically rational basis for the offer is extremely restrictive. Further, neither the tariff language or the submittal letter and testimony speak to the standard PJM will use to judge the seller's justification. Will PJM question a justification if the primary motivation behind the offer is to exercise market power but the seller can identify a secondary motivation? Dr. Graf's description suggests the answer is "yes." For instance, the Maryland and New Jersey out-of-market contracts that first instigated PJM and FERC to remove the state exemption from the MOPR were justified at the time by pointing to the potential threat to reliability in the absence of market entry. If the buyer-side market power provisions applied to state actions, this overly broad justification language would seem to allow the state to identify another motivation, like reliability. A resource has the opportunity for a unit specific review to justify an offer below the default offer floor. Another avenue to economically justify the offer is superfluous. Given that the incentive and ability framework is already conservative and errs on the side of under-mitigating, the simplest guidance on this issue the Commission could provide in rejecting PJM's filing would be to suggest PJM remove the justification language entirely. At the very least, the Commission could provide guidance that PJM should include tariff language that describes the standard used to review the justification and that standard should be high.

40. Other elements of PJM's buyer-side market power provisions are either unnecessary or inappropriate. First, the competitive procurement exemption[45] could be more location- and technology-neutral. Out-of-market actions could be structured nominally as competitive procurements but constructed to provide an advantage to certain technologies or locations. For instance, some zero emission credit programs are nominally competitive procurements but are practically limited to nuclear resources located with a state through public interest criteria that heavily favor in-state resources.[46] The simple solution is to apply the competitive procurement exemption only to procurements that are resource-, technology-, and location-neutral. Second, the provision that a resource "receiving compensation in support of characteristics aligned with well-demonstrated customer preferences would not, in and of itself, be a basis for the determination of Buyer-Side Market Power"[47] is vague. This exclusion would be appropriate if, for instance, it referred to an integrated competitive supplier supporting a retail product. However, the tariff language as written could apply more broadly to state selection of specific resources if states were not exempted in the first place. PJM should clarify how it will determine whether a seller is responding to an authentic customer preference.

[45] Submittal Letter at page 40.
[46] See e.g., Illinois Future Energy Jobs Act, Public Act 099-0906, Section (d-5) zero emission standard, available at https://www.ilga.gov/legislation/publicacts/99/PDF/099-0906.pdf.
[47] Submittal Letter at page 42, Graf Affidavit at P 26.

b. PJM has not justified under-mitigation on policy grounds

41. PJM goes on at some length to distinguish buyer- and seller-side market power. Though it is never stated explicitly, PJM appears to use this distinction to justify the differences in approach between buyer-side and seller-side market power. This approach is flawed because the articulated distinction between buyer-side and seller-side market power is not convincing. Moreover, even if there is a meaningful difference between buyer- and sellers-side market power, the extreme asymmetry with which PJM is proposing to treat them is unreasonable.

42. PJM's premise that buyer-side market power and seller-side market power are fundamentally different is not compelling and ignores practical experience with state actions.[48] First, PJM and Dr. Graf argue that buyer-side market power will be risky if executed through the construction of new generation because "other Capacity Market Sellers would adjust their capacity supply offers over time in response to the suppressed prices. This predictable economic response limits the extent to which uneconomic resources can suppress market prices in the long-run."[49] Dr. Graf appears to be arguing that generators in the future will have the ability to offer more than their net going forward costs, potentially to the point that they are exercising market power. There is very limited evidence that generators are currently able to exercise seller-side market power. The default market seller offer cap, currently pending before the Commission, permits offers up to the balancing ratio multiplied by Net CONE. Thus, sellers are able to offer significantly higher than recent capacity market clearing prices. Nonetheless, capacity prices in the most recent auction for the PJM Region cleared at near historic lows. This suggests that there is very limited ability to exercise market power.[50] Further, the introduction of a new (uneconomic) generator increases excess supply in the near-term. Even if some generation retires as a result, Dr. Graf does not explain why the quantity of generation that retires in response will be greater than the quantity of uneconomic capacity that entered. Thus, market dynamics will at most return to where they were at the time of the uneconomic entry with no change to the competitive pressure sellers experience. Finally, regardless of whether generators have been able to exercise market power in the past, the pending MSOC proceeding is presumably going to address this potential prospectively.[51] In total, Dr. Graf's description of why exercising buyer-side market power through the construction of a new resources poses risk to the actor is unconvincing.

43. Dr. Graf's discussion of why the retention of existing resources also poses risks is every bit as unconvincing. Dr. Graf starts with the premise that "most aging uneconomic resources are uneconomic precisely because continued operation requires costly capital

[48] Submittal Letter at pages 22-23, 27; Graf Affidavit at pages 3-4.
[49] Graf Affidavit at P 11.
[50] It is true that PJM currently has excess supply, so most generators should feel significant competitive pressure. However, the amount excess supply during the last auction is not meaningfully different than it has been in recent auctions, so it is difficult to argue that an increase in competitive pressure explains the most recent capacity market outcome. This suggests sellers have experienced meaningful competitive pressure for some time.
[51] Several of the proposed alternatives to the current default market seller offer cap would significantly reduce the default offer cap, reducing any ability to increase offers without PJM and the market monitor's approval.

expenditures."[52] This premise ignores the practical experience with out-of-market retention of existing resources. In practice, the out-of-market retention of existing resources has almost exclusively been effectuated via out-of-market payments to nuclear units. In Illinois, Ohio, and New Jersey the basis for these out-of-market payments has relied heavily on the general lack of market revenue, including lack of compensation for environmental attributes, and market and operational risks, not capital investments.

44. It is difficult to know with certainty what is driving the request for out-of-market support because the legislative and regulatory processes leading to out-of-market payments are opaque and specific cost and revenue data is kept confidential. The best information we have are public statements made by the companies seeking support. Those public statements typically point to general market conditions, not the need for large capital investments. For instance, in the press release announcing PSEG's application for the second round of ZECs, PSEG stated "Since the first ZECs eligibility period began, power markets have deteriorated significantly, thus the financial needs of New Jersey's nuclear plants have continued to grow."[53] Similarly, in seeking support for its Illinois nuclear units, Exelon stated "Dresden and Byron face revenue shortfalls in the hundreds of millions of dollars because of declining energy prices and market rules that allow fossil fuel plants to underbid clean resources in the PJM capacity auction."[54] The need for large capital expenditures is largely missing from the public statements accompanying requests for out-of-market retention we see in practice. Thus, Dr. Graf's argument that retention of existing resources is risky is not convincing.

45. Therefore, PJM has provided no credible evidence that buyer-side market power is fundamentally different than seller-side market power. As a result, PJM fails to support the notion that asymmetric treatment of buyer-side market power is justified. Even if one accepts for the sake of argument that there are meaningful differences between buyer-side market power and seller-side market power, PJM has not justified the level of asymmetric treatment that it proposes. First, the ability to justify an offer outside of the unit-specific review process is unique to buyer-side market power under PJM's proposal. No other market permits a seller to justify an uncompetitive offer except through that market's form of unit-specific review process. Second, the self-certification process is unique to the Narrow MOPR proposal. Sellers in other markets are not "presumed innocent" and allowed to avoid scrutiny simply by self-certifying that they do not intend to exercise market power.[55] Third, the three pivotal supplier test for sellers is more stringent than the incentive and ability test PJM proposes for buyers. Given the nature of PJM's capacity market, essentially every seller is identified as having market power. As mentioned above, the incentive and ability test PJM proposes for buyers is not unreasonable in

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[52] Graf Affidavit at P 12.
[53] Public Service Enterprise Group Press Release, October 1, 2020, available at https://investor.pseg.com/investor-news-and-events/financial-news/financial-news-details/2020/PSEG-Submits-Application-for-Zero-Emission-Certificates-to-Continue-to-Preserve-New-Jerseys-Largest-Source-of-Carbon-Free-Electricity/default.aspx.
[54] Exelon Corporation Press Release, August 27, 2020, available at https://www.exeloncorp.com/newsroom/exelon-generation-to-retire-illinois%E2%80%99-byron-and-dresden-nuclear-plants-in-2021.
[55] A seller may be allowed to self-certify that it is eligible for an exemption like the Competitive Entry Exemption in New York ISO. This is a fact-based certification that fundamentally different than certifying whether the seller is exercising market power.

principle, but it is inherently less stringent than the three pivotal supplier test and has various flaws and limitations that leave it much weaker than the three pivotal supplier test. Finally, PJM argues "the VRR curve itself is a guardrail against market power in that it ensures the correct price signal is sent when supply is below the Installed Reserve Margin (IRM) and provides an important price signal greater than zero when supply is greater than the IRM."[56] Of course, one could equally argue that the sloped VRR curve protects against seller-side market power. There is a plausible argument that the VRR curve mitigates the benefit of exercising market power to some extent, but it clearly does not do so to the point that no mitigation is necessary. Ultimately, the relatively less stringent elements of the buyer-side market proposal should stand on their own as reasonable or unreasonable; they cannot be justified by PJM's asserted differences between buyer-side and seller-side market power.

46. Finally, there is an important asymmetry between buyer-side and seller-side market power that PJM has not addressed. Under-mitigation of market power has very different long-run effects in the capacity market when it occurs for buyers rather than sellers. Under-mitigation of seller-side market power that is later identified and corrected will affect the market results for one auction. Following any rules changes, a resource that had previously been able to offer above a competitive level will be required to bid competitively and capacity market prices will return to competitive levels. Under-mitigating buyer-side market power, on the other hand, will allow an uneconomic resource to enter the market and reduce capacity prices below competitive levels for every capacity auction that follows. Once a resource has entered the market and cleared a capacity auction, widely accepted economic and policy principles argue in favor of mitigating the resource to its net going forward cost (rather than its net cost on new entry). For a relatively new resource, net going forward costs are likely very low. Thus, correcting the buyer-side market power rules after under-mitigation has been identified will not change the fact that the uneconomic unit is able to clear the capacity market and reduce the capacity clearing price for the indefinite future. As the Commission evaluates PJM's buyer-side market power provisions and considers how they could be adapted to be work effectively, it should remain mindful that erring on the side of under-mitigation has a lasting effect.

47. PJM's concern that "states and Self-Supply entities are more likely to exit the capacity market [via the Fixed Resource Requirement (FRR) Alternative] to meet their policy and business objectives, rather than remain in the capacity market and curtail those objectives"[57] creates a false dichotomy of no MOPR or all FRR that is especially inaccurate when it comes to buyer-side market power actions. A state is unlikely to use the FRR Alternative if its only aim is to exercise buyer-side market power. Buyer-side market power is only beneficial when the out-of-market action is small relative to the cost savings on the remainder of capacity market purchases. FRR moves all of the utility's or state's activities out-of-market. PJM seems to acknowledge this reality when it notes that

[56] Submittal letter at page 18.
[57] Submittal Letter at page 12.

> when an entity elects the FRR Alternative, it "generally must do so for100% of their load based on the current rules. By taking this step, they *may be able to meet their renewable objective* but because they must meet the remaining . . . obligation through non-market means such as self-supply or bilateral contracts, it is almost a certainty that not all of the remaining . . . load will be served by the most economic resources on the system.[58]

This argument is not accurate when the focus of the state action is to exercise buyer-side market power rather than to achieve a renewable energy objective. As PJM notes, some of the remaining capacity will be served by uneconomic units, raising the overall cost of capacity to the state's consumers and eliminating the price suppressive benefit of any out-of-market action. The Commission and PJM need not fear a state or utility electing the FRR if it is unable to exercise buyer-side market power as the result of a well-designed MOPR.

VII. Path Forward – Reject PJM's filing and provide guidance for further stakeholder discussions

48. PJM conducted the stakeholder discussions under the apparent presumption that it had received guidance to essentially remove the MOPR. The Commission should correct that presumption and provide guidance through a Commission order on what a revised MOPR must achieve.

49. The deficiencies in PJM's Narrow MOPR proposal could be addressed by a future submission that preserves workable and effective buyer-side market power mitigation. First, PJM would have to consider state actions even if the state action did not trigger the Conditioned State Support provisions. Second, PJM should remove the self-certification element. PJM explains it "will not simply take the self-certifications purely at face value as the proposed Tariff language includes the ability for PJM and the IMM to initiate a further inquiry" if either believes it a Seller may exercise of buyer-side market power.[59] In place of the self-certification, PJM should add tariff language that outlines the criteria PJM and the IMM will use to initiate the review to which it has already committed. Taking PJM's commitment at face value, it is clear that PJM believes it can articulate criteria and conduct a review in some reasonable fashion. Third, PJM should either eliminate or substantially narrow the language that allows a resource to justify an offer after it has been established that relevant buyer has the ability and incentive to exercise buyer-side market power. A well-designed unit-specific review is sufficient to address any concerns about over-mitigation. Finally, issues with the competitive procurement and well-document consumer preference exceptions discussed above should addressed.

50. The Commission should reject the Conditioned State Support provisions outright. As discussed, these provisions are not an appropriate screen for state activities that may constitute the exercise of buyer-side market power and do not otherwise advance any

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[58] Submittal Letter at page 13, *emphasis added.*
[59] Submittal Letter at page 30.

policy objective the Commission has articulated as relevant to the MOPR. The Commission should provide guidance that PJM should seek a solution that addresses the concerns related to impact of subsidies on the integrity of wholesale market pricing that PJM and FERC have articulated in the past.

51. The Commission should suggest that PJM discuss with stakeholders how investor confidence will be maintained in any alternative MOPR proposal. At the very least, PJM should provide analysis and seek stakeholder feedback to support the view investor confidence will be maintained under an alternative MOPR. That analysis and support should not assume the answer, but rather directly address the practical issues a resource owner faces when making investment decisions. PJM could also consider proposals that will maintain investor confidence in the face of an alternative MOPR. Many such proposals are likely part of PJM's proposed phase 2 stakeholder process. The Commission could provide guidance that any subsequent alternative MOPR proposal be paired with any market design changes identified during phase 2.

52. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER21-2582-000**

AFFIDAVIT

I, J. Arnold Quinn, do hereby swear and affirm under penalty of law that the statements in the foregoing Affidavit of J. Arnold Quinn, Ph.D. on behalf of the PJM Power Providers Group are true to the best of my knowledge, information and belief.

Executed this 19th day of August, 2021

J. Arnold Quinn

Subscribed and sworn to before me
this 19th day of August 2021
Notary Public for
the State of Maryland

SUSAN P. PRIESTER
NOTARY PUBLIC
MONTGOMERY COUNTY
MARYLAND
MY COMMISSION EXP. MAY 21, 2023

My Commission expires: ____________________________

NOTARY PUBLIC

Attachment B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER21-2582-000**

Affidavit

of

Roy J. Shanker, Ph.D.

On Behalf of the

PJM Power Providers Group

Submitted August 20, 2021

1. My name is Roy J. Shanker. My address is P. O. Box 1480, Pebble Beach, California, 93953.

2. I have been retained by the PJM Power Providers Group to review PJM Interconnection L.L.C.'s ("PJM") revised Minimum Offer Price Rule ("MOPR") proposal in this proceeding and present my findings in several selected areas based on that review.[1] Specifically, I will be commenting on how the proposal narrows the applicability of the MOPR only to seller actions that are deemed to be intentional attempts to reduce or suppress market prices[2] and the market distortions, transfers and other adverse impacts associated that proposed change. I will also address the findings offered by Dr. Cramton based on the new modeling results he has sponsored, and the significant problems that I have identified with his analyses. Such comments are preliminary in nature due to the fact that even though Dr. Cramton was apparently working on this model and analyses for PJM for approximately 19 months, this is the first time, to my knowledge, the model or its results have been put before PJM stakeholders in any fashion. As a result, no information regarding its use, development, assumptions, or related properties of the model has previously been presented in any context for stakeholder review.

I. QUALIFICATIONS AND EXPERIENCE

3. My resume, attached as Exhibit RJS-1, summarizes my experience in numerous regulatory proceedings before state commissions and the Commission. As detailed therein, I have over 47 years of experience covering a broad range of issues in the electric utility industry, and I have worked as an independent consultant for the past 39 years. I have worked extensively in the PJM and New York Independent System Operator ("NYISO") markets during their initial development, particularly with respect to the establishment of the capacity market designs. In both of these markets, I was involved from the very start

[1] To the extent that I do not address other areas it is not an indication of my agreement or concurrence with PJM's filing.

[2] Obviously, there is disagreement related to what conditions and actions should be considered in establishing a "competitive price" or deviations from such a price. Nonetheless, I use the term reduce in a neutral technical fashion related to the directional movement of capacity and/or energy market prices, while price suppression is used/applied in the context of actions that reduce prices below the competitive level. *See, e.g.*, PJM Filing, Attach. E, Graf Affidavit at ¶ 9.

with the formulation and underlying rationales for the capacity market designs. In PJM, this experience has included many incremental changes, including the introduction of the Reliability Pricing Model ("RPM"), the subsequent adjustments to limit the role of inferior capacity products, the MOPR, the Market Seller Offer Cap ("MSOC"), the Effective Load Carrying Capability ("ELCC") construct, the Capacity Performance construct, and continuing adjustments of market details.

4. My resume summarizes all the relevant engagements to this experience, including not only PJM and NYISO projects focused on capacity markets, but also extensive work in both the Midcontinent Independent System Operator ("MISO") and ISO New England ("ISO-NE") on capacity market design. I have worked extensively in the PJM and NYISO markets during their initial development, and most relevant to this proceeding, directly participated in the related stakeholder processes that initiated and evolved these Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") procedures for addressing the broad issue of mitigation of subsidized units in capacity markets, and related topics such as mitigation of buyer-side market power and related price suppression. Specifically, in addition to the MOPR proceeding in Docket No. ER18-1314 affidavit (that is a direct precedent here), I have offered testimony on this subject in Docket Nos. AD21-10 and No. AD17-11 as an invited speaker, and filed technical conference comments and post conference comments in Docket Nos. AD21-10, ER13-535, ER11-2875, EL11-20, and EL15-64. I also appeared before the New Jersey General Assembly in 2011, addressing related issues in discussions of Assembly Bill 3442 and Senate Bill 2381, regarding the impacts of state-directed and subsidized capacity procurement for new natural gas units. In ISO-NE, I testified in Dockets Nos. ER10-787-000, EL10-50-000, and EL10-57-000 addressing a similar mitigation issue.

5. A partial summary of relevant capacity market design-related engagements over just the last five years where I have submitted either written testimony, affidavits, or Amici Curiae briefs includes 20 engagements, mostly related to PJM (numbers in parentheses refer to the index number in Attachment A; designations of EL, AD, and ER refer to specific FERC Docket Numbers): AD21-10 (258); EL2-1278 (256); EL19-47 (259); EL21-7 (256); El-19-63 (251); EL19-47 (250); Amicus Curiae Brief before the Supreme Court

(249); EL18-178 (248); EL18-169 (247); EL18-1314; EL17-32 and EL17-36 (243); EL13-535 (242); Amicus Curiae Brief before the Second Circuit (241); Amicus Curiae Brief before the Seventh Circuit (240); AD-17-11 (239); EL17-32 (238); EL15-70,71, and 72 (235-6); EL15-64 (232); EL14-55 (228); RM10-17 (227). In the prior 226 engagements where testimony or an affidavit was submitted, I would estimate approximately another 50 were related to RTO/ISO capacity market design issues or the analytics of calculating capacity value.

6. I have been involved and continue to be involved in virtually all areas of market design and development, and I actively participate in stakeholder activities in PJM on behalf of various market participants. Much of this activity relates to RPM and adequacy-related concepts in the market design. I have also participated in all of the stakeholder processes related to capacity capability and capacity market design within PJM that directly have addressed ELCC, MSOC and MOPR issues. On multiple occasions, I have been invited to speak before the Commission in its technical sessions, many of which have addressed capacity markets in general and the PJM capacity market specifically.

7. I have a bachelor's degree from Swarthmore College and both a master's and doctorate degree from Carnegie-Mellon University.

II. CONCLUSIONS

8. I came to two major conclusions regarding PJM's filing and the proposed "narrow" MOPR. Each in turn is supported by a number of findings.

Conclusion 1. Price Suppression Below the Competitive Level Alone Is An Appropriate Concern To Require MOPR Mitigation

9. The suppression of prices below the competitive level based on out-of-market subsidies remains a material and valid concern that requires a broad MOPR. PJM's proposed narrow MOPR only addresses actions that suppress prices by out-of-market subsidies in the context of the exercise of buyer side market power. There are valid reasons for much broader mitigation of actions that lower prices below the competitive level.

10. Concerns regarding the exercise of buyer side market power are well established and have been described by Dr. Graf (at ¶ 20) and others, including myself. Buyer-side market power involves the ability to suppress market prices via the support/subsidy of resources that otherwise would be uneconomic. In turn, the party (or the intended benefactors) benefit to the extent that they achieve reduced prices on a sufficient amount of market resources that they would buy in the related auctions. The savings from lower prices on net purchases exceed the cost of the subsidy and is the source of the net benefit from the exercise of market power via such suppression of prices below the competitive level. PJM's proposed narrow MOPR only finds subsidies to be of concern if they are part of a provable attempt to benefit from the suppression of prices. In that case, mitigation will occur.

11. Even from the narrow view of the exercise of buyer-side market power, it has been recognized that such schemes are readily camouflaged, and in order to capture these instances, the main mechanism, price suppression, should be broadly mitigated. More importantly, regardless of whether there was an intent to benefit from suppressed prices, the point remains that price suppression resulting from out-of-market subsidies has adverse impacts and result in uncompetitive prices. They can also result in material and unjustified transfers between various market participants (existing generation supply, load, and new subsidized supply). These occur regardless of whether subsidies were provided with the goal of suppressing prices or not.

12. The Commission and PJM itself have strongly supported this conclusion in the past. PJM has been committed to this position since at least its filings in 2011 (if not earlier) and reinforced its strong concern about uneconomic entry and the difficulty of differentiating between intent to suppress price versus any other goals with respect to the sponsorship of uneconomic entry. Thus, PJM and the Commission broadened the scope of the MOPR to achieve the objective of limiting uneconomic entry in 2011, and then also sought to limit the retention of uneconomic capacity resources in 2018. As I discuss below, PJM has not put forward a valid basis for its abrupt change in position.

Conclusion 2-The Cramton Model Is Not Ready for Prime Time and the Model Has Material Flaws and/or Undocumented and Unexplained Assumptions and Properties

13. My second conclusion relates to Dr. Cramton's opinion, his model, and the model results.

14. With respect to the model used by Dr. Cramton (the Cramton Model), the model at this stage really has no sufficient provenance or demonstration of the validity of results to make its use reasonable at this time.

15. I could not even find any real documentation for the model. What appears to be the only substantive reference offered by Dr. Cramton is just a Working Paper dated July 2021, which is presumably not finished.[3] Further, the Cramton Affidavit itself lacks any real detail with respect to the function, design, testing/benchmarking of the model, and what I have been able to glean to this point from the Working Paper and other cited reference papers leaves a large number of questions that simply cannot be addressed without additional documentation, examples, data, work papers and review.

16. While I believe the above alone disqualifies the use of the Cramton Model and any resulting conclusions, I also found a number of underlying assumptions that are unclear, give cause for concern about the validity of the findings, or are simply opaque.

17. Given these flaws, the model results do not provide useful information for purposes of evaluating PJM's proposal. Dr. Cramton states that the model basically shows very similar results between the narrow MOPR and broad MOPR with respect to reliability and

[3] The Cramton Affidavit (at 12) references "Cramton, Peter, Emmanuele Bobbio, David Malec, and Pat Sujarittanonta (2021) 'Electricity Markets in Transition: A multi-decade micro-model of entry and exit in advanced wholesale markets,' Working Paper, University of Cologne." I found a paper with the same title on a University of Maryland website, but it is unclear if this is the same paper that was referred to in the Cramton Affidavit. *See* http://www.cramton.umd.edu/papers2020-2024/cramton-electricity-markets-in-transition.pdf ("Cramton Working Paper").

price. He does note a slightly higher reserve margin for the broad MOPR.[4] To a great extent, however, the similarity in the modeled results for the narrow MOPR and broad MOPR was to be anticipated based on the outcome-driven assumptions used in Dr. Cramton's model. Dr. Cramton acknowledges that prices are somewhat lower under the narrow MOPR, but this is exactly the problem: what he sees as an advantage looks to others as price suppression.[5] Moreover, and most critically, the model shows market exit but does not examine the underlying wealth transfers between resources and from resources to load that cause such exit.

18. In fact, Dr. Cramton's support of the current PJM proposal appears to be based primarily on his subjective view of the dangers of over-mitigation versus under-mitigation, rather than reflecting the results of his model. He states he would prefer the under-

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[4] *See* Cramton Working Paper for the following comments regarding the similarity of results: at 58 ("These portfolio changes over the next twenty years are similar under the narrow and broad MOPR scenarios."); *id.* at 59 (" Figure 4 shows capacity prices and reserve margins by year. Interestingly, MOPR has little impact on capacity prices. There is no evidence of 'price suppression' with narrow MOPR."); *id.* at 62 ("Figure 5 shows the average annual prices for energy and reserves by year. Energy prices are similar in the broad MOPR and narrow MOPR cases. Reserve prices are also similar in narrow and broad MOPR scenarios."); *id.* at 63 ("Figure 6 shows price duration curves by decade. The broad MOPR and narrow MOPR cases again are similar."); *id.* at 64 ("Figure 8 shows the frequency of price spikes—five-minute intervals with prices more than $100/MWh. The price spikes are similar in narrow and broad MOPR cases. Regardless of the MOPR choice, as the share of renewables grows, price spikes become more frequent, and real-time price spikes are more frequent and more extreme than day-ahead price spikes."); *id.* at 65 ("The main components of price are capacity and base energy. Uplift, reserves, and peak energy are much less significant. The broad MOPR and narrow MOPR cases are similar."); *id.* at 66 ("Once the surplus resources exit, profits return and are maintained through 2040. The broad MOPR and narrow MOPR cases are similar, although there is a drop in profits and all-in cost for the broad MOPR case toward the end of the analysis period."); *id.* at 67 ("For renewable resources and storage, capacity values are calculated using exponential smoothing. The broad MOPR and narrow MOPR cases show very similar performance results by resource type."); *id.* at 69 ("The net present value of incumbent resources is shown in Figure 14. Figure 15 shows the net present value for new entrants. The narrow MOPR and broad MOPR cases are again similar. The broad MOPR slightly harms solar and wind in the early years.").

[5] *Id.* at 74. Even here he indicates modest differences: "My analysis of entry and exit in PJM over the next two decades confirms this conclusion. Although both the broad MOPR and narrow MOPR bring reliability, the broad MOPR results in more resources and more expense for consumers. The difference is not dramatic. The main reason for the modest impact is little change in the resource schedule and dispatch. Energy and reserves prices stay about the same. Capacity prices are also about the same because the broad MOPR prevents the extra resources from reducing the capacity price. Thus, the advantage of narrow MOPR is reduced consumer cost."

mitigation of the new PJM proposal to what he characterizes as the over-mitigation of the status quo. *See* Cramton at ¶¶ 13-14. The model certainly doesn't support this conclusion, and I disagree with that subjective conclusion.

19. Consider the issue of over-mitigation in this specific context. What is the concern? The limitation imposed by the broad MOPR is ultimately whether the generation resource can demonstrate it is economically justified or not. This does not seem unduly burdensome, particularly when meeting a generic requirement for actions that should meet the just and reasonable standard. Also, we know empirically that the resources of interest can meet this standard, as reported by PJM in the most recent RPM/BRA:[6]

> 1,728.1 MW of wind resources cleared the 2022/2023 BRA as compared to 1,416.7 MW of wind resources that cleared the 2021/2022 BRA. Of the 1,728.1 MW of wind resources cleared in the 2022/2023 BRA, 1,057.5 MW were cleared as the annual Capacity Performance Product and 670.6 MW were cleared as the winter seasonal Capacity Performance product. The nameplate capability of wind resources that cleared in the 2022/2023 BRA as annual CP capacity and/or winter seasonal CP capacity is approximately 8,518.3 MW, which is 392.3 MW greater than the 8,126 MW of wind energy nameplate capability that cleared in the 2021/2022 BRA. (page 13)
>
> 1,511.6 MW of [new] solar resources cleared the 2022/2023 BRA as compared to 569.9 MW of solar resources that cleared the 2021/2022 BRA. Of the 1,511.6 MW of solar resources cleared in the 2022/2023 BRA, 1,501.7 MW were cleared as the annual Capacity Performance Product and 9.9 MW were cleared as the summer seasonal Capacity Performance product. The nameplate capability of solar resources that cleared in the 2022/2023 BRA as annual CP capacity and/or summer seasonal CP capacity is approximately 3,242.8 MW, which is 1,601.8 MW greater than the 1,641 MW of solar energy nameplate capability that cleared in the 2021/2022 BRA. (page 14)

20. If anything, the current MOPR is saving consumers money by avoiding unnecessary uneconomic entry and subsidies. Alternatively, under-mitigation such as PJM's proposal effectively leaves the door completely open to not only uneconomic entry, but also to buyer-side market power. The proposed mitigation strategy has no teeth and depends disingenuously on self-certification. Further, as PJM has made clear repeatedly,

[6] The auction results report is available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx:

its expectation is that no state program (presumably regardless of scienter) will be mitigated under the narrow MOPR. PJM indirectly confirms this by positing there will be no double payments for capacity linked to state programs. This could only be true if PJM anticipates no mitigation of any state program under their proposed criteria.

21. It is difficult to see how, with the above facts and logic, Dr. Cramton forms an opinion that under-mitigation is a desirable path for PJM within the context of the MOPR. And as discussed below, the unverified modeling and results don't/can't support such a conclusion as well.

III. IT IS APPROPRIATE TO APPLY A MOPR TO PREVENT PRICE SUPPRESSION

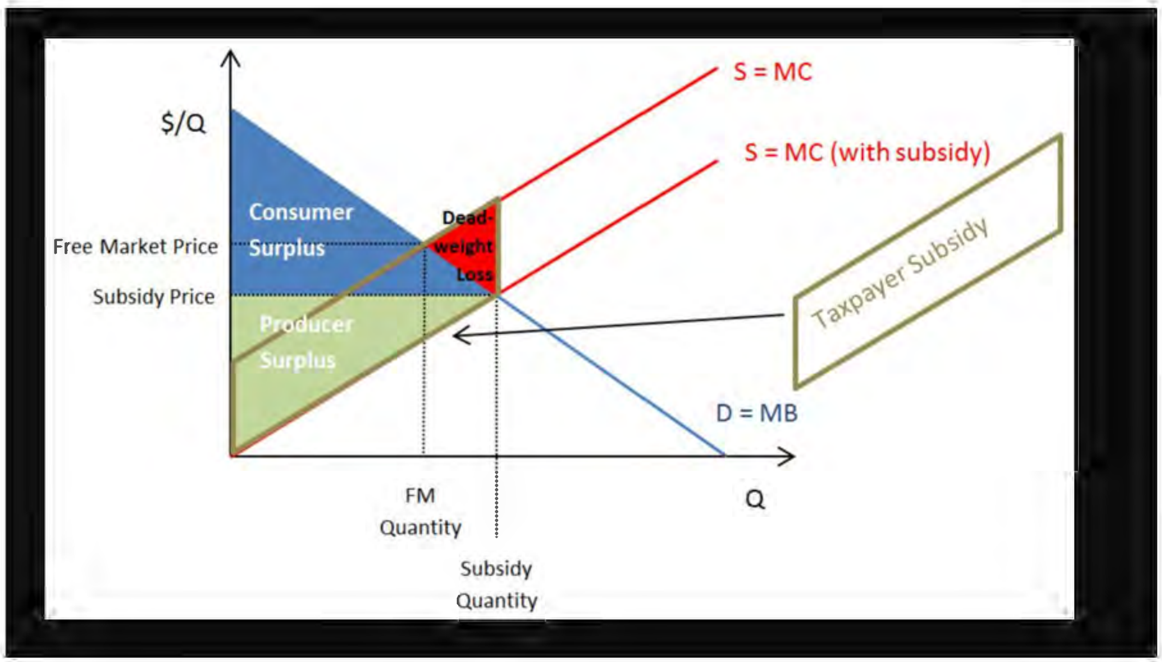
A. The Exercise of Buyer-Side Market Power Versus More Generalized Concerns Regarding Price Suppression

22. The mechanics of uneconomic entry via subsidies and the resulting suppression of prices below the competitive level are not complicated. Ordinarily, a generation resource would be expected to submit an offer that reflects its expected costs, so that if it clears, the resource is not forced to take on a capacity obligation at a loss. However, when a generation resource that is not otherwise economic (i.e., able to offer its capacity for sale into a clearing auction at a price consistent with its costs (inclusive of a return on and of capital) is provided with a subsidy, the resource is no longer dependent on the market to cover its costs, and can instead offer at a lower price that is designed to allow it to clear. The supply of capacity is increased (supply curve shifted to the right), and prices in the market and the associated payment to all other resources fall. There is no need to debate why the subsidy was given, simply that it occurred and the result was increased supply at a particular price point.

23. Similarly, the problems caused by the increased supply remain regardless of the justification for the subsidy. New resources that would otherwise have cleared, and some that were not only cheaper/more economic, but more efficient, and able to provide equal to or greater contributions to reliability, fail to clear at the lowered clearing price. These new resources may therefore never enter the market as suppliers. Some existing resources that also would have otherwise had a competitive cost advantage over the subsidized

resource are forced to retire at the lowered clearing price as the revenues necessary for them to remain in operations are reduced. The conclusion is simple: based on the uneconomic costs recognized within the market, we arrive at an inferior solution and waste resources due to the subsidies. Price signals for entry and exit are distorted, and overall, there is an over-consumption of the subsidized good/commodity or equally important an over-consumption of commodities with intensive use of electricity in production. This can be seen in the simple graphic below. The supply curve is shifted to the right by the subsidy. Consumption increases at lower price levels as consumers react to the artificial price reduction, and the highlighted triangle reflects the dead weight loss of the expense of the subsidies. In an equilibrium context the usual findings of the associated dead weight loss and the costs incurred for the subsidy itself apply.

Simple Graphic of Shift of Supply Due to Subsidies[7]



24. The single distorted clearing price is applied to all resources in the market, and as a result, even those suppliers that clear the auction are paid less. Purchasers (the consumers of the reliability offered by the dedicated Capacity Resources) pay less for the same or even

[7] From posted example https://neighborhoodeffects.mercatus.org/wp-content/uploads/2013/07/Subsidy.jpg

a more reliable set of resources (i.e., the demand curve in PJM procures more supply as the price declines, and has the property (slope) that total payments by consumers/load for the increased supply declines even as the quantity of supply and reliability increases). If one is solely focused on the price to consumers this might initially seem beneficial. But, as shown in the above graphic, the subsidy distorts prices and adversely impacts overall efficiency. Equally important is that, as discussed below, the impact on the underlying objective (less carbon emissions) is unknown.

25. While Dr. Cramton has expended a great deal of effort in the dynamic modeling of the impacts of subsidies over time (discussed below), these basic observations made above don't change. A simple example makes it clear. Dr. Cramton's model includes approximately 51,000 MW of new intermittent entry that presumably benefits from subsidies. It also includes all nuclear resources receiving subsidies regardless of their economics. (It should be also noted that there is no apparent retirement of the nuclear units regardless of age and economics).[8] Though derated to reflect their intermittent nature, it is not hard to conclude that if such large amounts of intermittent and nuclear resources were added all at once as price takers (zero offer prices) in both the energy and capacity market, market prices for both products would fall. The dynamic adjustment process discussed by Dr. Cramton that proceeds over time shouldn't blind the Commission to the basics. Moreover, from my perspective, the rationale underlying PJM's proposal is to accommodate state policies for picking winners and losers in the energy sector, not efficiency in production or efficiency in the pursuit of lower emissions.[9] This may be politically expedient for PJM, but the Commission's objective should be to create a level playing field for all parties while maintaining the opportunity (not guarantee) for suppliers to earn a reasonable return of, and on, capital. Embracing and facilitating the interference

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[8] Cramton Working Paper at Figure 6.5.

[9] I often summarize this as asking the question of who will get the most votes: i) the politician who promises to bring 1000 jobs to his state for a new wind farm or ii) the politician who promises to enhance economic efficiency for all the citizens of the state by properly pricing and internalizing externalities. The answer is sadly obvious.

with jurisdictional rates that causes a distortion to this objective cannot be considered just and reasonable.

26. In response to this basic observation, PJM claims that the subsidies are targeted at externalities (e.g., carbon emissions) and that the reduction of the emissions justifies the cost of the subsidy. There would be some merit to this argument if a charge for these externalities were applied uniformly across all markets, but this is not the case. There is no direct link between the value of the externalities themselves and the market subsidies, one is simply hypothesized. Also, the narrow MOPR is blind to the actual nature of the subsidy, which could be for wind or coal, an efficient plant or the retention of an inefficient and dirty plant. Further, these externalities are "captured" only within a single and limited sector of the economy. The electric sector itself produces only 27% of carbon emissions nationally (see Cramton) and, in this case, some vague link to the social cost of carbon is applied to only a small subset of resources, though the distortions are market-wide across all sectors. It is not difficult to see how very limited actions such as those under debate here can actually result in *increased emissions*. For example, as subsidies decrease electric prices, demand for electricity increases. Large polluting industries that consume electricity as a major input (e.g., paper mills) will be able to lower their prices and sell more paper due to the lower end prices to consumers. The mills will pollute more from overall paper production, cut down more trees that can absorb carbon etc. Absent a very strong analysis of actual impacts on the economy and overall production, there is not much merit to the inefficient process of encouraging individual states to select the politically favored winners of the clean energy race. This is exactly why people like Dr. Cramton and myself all favor very broad based carbon pricing over selective/discriminatory "pick a winner" policies.[10]

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[10] Dr. Cramton only expressed opinions about the superiority of general carbon pricing. *See* Cramton Affidavit at ¶ 18:

"From an economic perspective, the first-best policy would include the marginal social cost of each pollution externality in the electricity price. Regulators can achieve that first-best policy only with an effective national policy. The social cost of carbon would be best established and imposed at the federal level since it is a global pollutant. Even local pollutants like nitrogen oxides, sulfur dioxide, and particulates cross state borders, so national pricing of these pollutants is efficient."

27. Interestingly, while Dr. Graf appears to agree on the right general action, he makes the fatal flaw (addressed in the previous paragraph) of mistaking any reduction in an externality as welfare enhancing. As the simple paper mill hypothetical shows, this is not the case, and Dr. Graf has done no analyses to the contrary. His position would only be true if one could magically snap one's fingers and, with no cost or other price/quantity disruptions, make carbon emissions disappear.[11] It is surprising how many people seem to dismiss this fundamental concept in economics, while knowing full well the unknown properties of price "signals" as applied only to limited sectors of the economy.

28. PJM's new MOPR proposal retreats to a narrow application of looking at price suppressive actions only in the instances of the overt and direct exercise of market power. This approach is myopic and ignores the adverse impacts on important market price information and key market actions (entry and exit). Market participants place great reliance on the price signals emanating from both the capacity and energy markets in determining how to deploy their funds. Indeed the heart of Dr. Cramton's model (ignoring his inconclusive results) is driven by forecasts of prices for energy and capacity, and an associated decision logic regarding when to invest (when prices are estimated to support the full cost, recovery of all capital, return and operating costs) and when to retire (when such prices are insufficient). Yet PJM blithely ignores the fundamental importance of this decision process, and proceeds to allow a wide range of actions that distort the type of information that drives the entry and exit decisions.

B. The Commission and PJM Have Recognized the Problems with Price Suppression Independent of Buyer Side Market Power[12]

29. As far back as 2008, the Commission showed a broad concern regarding uneconomic entry and the price impacts on the market. In a 2008 order, the Commission reversed itself from an initial decision that had imposed a "net buyer" test with respect to buyer side market power and mitigation. (Note that the "net buyer" criterion is effectively

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[11] Graf Affidavit at ¶ 17.

[12] Much of the following comments were initially presented in my submissions in Docket AD21-10 and the earlier proceedings identified therein.

the equivalent of one of the conditions for PJM's proposed narrow MOPR). On rehearing the Commission recognized concerns about not just subsidies but the even broader issue of uneconomic investment in its entirety in its jurisdictional capacity markets.[13] The Commission was concerned about uneconomic entry in general, and the fact that it would be difficult to distinguish between a transparent exercise of buyer side uneconomic entry and a variety of different ploys that employed to obfuscate such actions. The Commission stated:

> Upon further review, for the reasons set forth in the requests for rehearing, the Commission will grant rehearing on this issue. *NYISO will not be required to modify its proposed market power mitigation rules for uneconomic entry so that they only apply to net buyers. We find that all uneconomic entry has the effect of depressing prices below the competitive level and that this is the key element that mitigation of uneconomic entry should address.* Parties requesting rehearing have convinced us that defining net buyers raises significant complications and provides undesirable incentives for parties to evade mitigation measures. Accordingly, we grant rehearing on this issue and thus will reject NYISO's compliance filing to the extent it reflects that the market floor only applies to net-buyers, and direct NYISO to file to reflect this ruling within 30 days of this order.[14]

30. In 2009, the Commission also made clear the broad basis of concern beyond simply buyer side market power in addressing the need for a broad MOPR in PJM. The Commission emphasized the importance of offering a stable investment environment to those parties seeking to support new entry (and, by implication, the retention of existing resources), stating:

> A capacity market will not be able to produce the needed investment to serve load and reliability if a subset of suppliers is allowed to bid noncompetitively to suppress market clearing prices….The lower prices that would result under …[the] proposal [to eliminate the MOPR] would undermine the market's ability to attract needed investment over time. Although capacity prices might be lower in the short run, in the long run, such a strategy will not attract sufficient private investment to maintain reliability…The MOPR does not punish load, but maintains a role for

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[13] *N Y Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,301 at P 29 (2008). FERC had imposed the "net buyer" requirement in a prior order, and in this order it granted requests by NYISO and others for rehearing.

[14] *Id* (emphasis added).

> private investment so that investment risk will not be shifted to captive customers over time.[15]

31. In Docket Nos. ER11-2875 and EL11-20, PJM and the Commission had to address large out of market procurements for new combined cycle facilities by both New Jersey and Maryland.[16] Those proceedings made it clear that state actions could influence pricing in the wholesale capacity markets, regardless of the underlying motives as well as be disruptive to the decisions and desires of other states.

32. The procurements by New Jersey and Maryland precipitated concerns by other states. The Pennsylvania Public Utilities Commission (PAPUC) was very articulate about the adverse effects that it would experience due to subsidy programs in other states. The PAPUC filed an amicus brief in support of the generator parties on narrow policy grounds that the integrity of the organized capacity market within PJM would be harmed by state-sponsored construction programs as proposed by New Jersey. In its brief, the PAPUC stated the following in support of an efficient market:

> The PAPUC contends that state-sponsored subsidies such as New Jersey's LCAPP are counterproductive and interfere with the efficient operation of RPM. Under the RPM mechanism, capacity prices respond to market conditions, increasing when and where capacity is scarce and decreasing when and where capacity is plentiful. When RPM's capacity prices are high, it indicates that there is demand for additional capacity and new capacity resources should be provided. When RPM's capacity prices are low, it indicates that there is no need for new capacity to enter the market and higher-cost capacity resources should be retired. These pricing signals help to ensure that there is sufficient capacity available to meet reliability requirements.
>
> State-sponsored subsidy programs like the LCAPP program distort these pricing signals and interfere with the proper functioning of the market. When state subsidies incent generators to enter the market below their true economic costs, capacity prices fall in the short term. This price decline affects not only the state where the subsidized generator is located but significantly impacts market operations across the PJM region and discourages capacity investment at cost-based prices. Although this

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[15] *PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,157, at P 90-91 (2009).

[16] Some of the background of these cases is provided in *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016).

> reduction in price of capacity investment may seem positive, the actual costs of distorting the market's pricing signals greatly outweigh perceived short term "benefits" resulting from lower capacity prices. Lower capacity prices reduce the incentive for new capacity to enter the market even if that new capacity would be more efficient than the subsidized generators and even if that new capacity is needed to ensure reliability. Because more efficient resources are excluded from the market by the subsidized participants, state subsidy programs result in higher prices in the long-term.[17]

33. The PAPUC also understood the consequences of such programs in terms of its own interest in interstate markets, particularly in the context of the MOPR. As a result, the PAPUC strongly supported PJM's proposals to strengthen the MOPR in response to the New Jersey and Maryland programs. In its Comments in that proceeding, the PAPUC stated:

> The PAPUC supports PJM's proposed MOPR revisions, as discussed below, and offers some additional constructive suggestions. As background, the PAPUC is a state Commission charged with the regulation of retail electricity markets in the Commonwealth of Pennsylvania. As a retail choice state, Pennsylvania's retail electricity market is dependent on a well-functioning and highly competitive wholesale electricity market. To date, Pennsylvania ratepayers have benefited from lower electricity prices as the result of a vibrant and effectively functioning capacity market administered by PJM since its formation as a Regional Transmission Organization (RTO) in 1997. Pennsylvania is also the location of a substantial number of electric generation facilities, especially gas-fired generation. For these reasons, the PAPUC has a particular interest in the applicability of PJM's MOPR tariff provisions and the outcome of this proceeding.
>
> The proposed revisions to the MOPR represent a practical rule-based approach that will avoid the potential exercise of market power that could result in market price fluctuation, which would be disruptive to an effectively functioning wholesale capacity market. If adopted, these changes should provide market participants with sufficient ability to react to changing market conditions while also achieving a level of price certainty.[18]

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[17] Comments of the Pennsylvania Public Utility Commission, Docket No. EL16-33, at 6-8 (Feb. 23, 2016) (footnotes omitted). The cited amicus brief was filed in *New Jersey Board of Public Utilities v. FERC*, 766 F.3d 241 (3d. Cir. 2014).

[18] *Id.* at 8 (footnotes omitted) (quoting the PAPUC's earlier comment originally filed in *PJM Power Providers Group v. PJM Interconnection, LLC*, Docket. Nos. EL11-20 and ER11-2875).

34. Clearly the offering of capacity at reduced prices due to state subsidies would allow otherwise uneconomic entry, and for over a decade the Commission was aware of the consequences of this in terms of reducing/suppressing rates in jurisdictional capacity markets. The PAPUC recognized these impacts in its comments, and many other parties, including myself individually as well as numerous clients I have represented, also understand these obvious impacts.[19]

35. In the ISO-NE CASPR Order,[20] the Commission identified the following "first principles of capacity markets," recognizing that capacity markets like those of ISO New England and PJM should:

- facilitate robust competition for capacity supply obligations,
- provide price signals that guide the orderly entry and exit of capacity resources,
- result in the selection of the least-cost set of resources that possess the attributes sought by the markets,
- provide price transparency,
- shift risk as appropriate from customers to private capital, and
- mitigate market power.[21]

36. The Commission's conclusions above were based on several common building blocks. First, there is a concern that uneconomic subsidized entry has the potential to allow the exercise of market power by buyers or collectively by agent(s) of the state to suppress prices. Such a subsidy is often accompanied by discriminatory "new only" procurement, specific technologies or both. Second, in pursuit of other objectives (e.g., "public policy"), state subsidies can distort and depress prices in a discriminatory manner independent of any direct objective to exercise a form of market power. Third, the Commission has, at

[19] *See e.g.,* Affidavit of Roy J. Shanker Ph.D. on Behalf of Cricket Valley Energy Center LLC and Empire Generating Company LLC in Docket No. EL21-7 (discussing the magnitudes of ZEC programs and anticipated subsidies for related clean energy programs in NYISO).

[20] *ISO New England, Inc.*, 162 FERC ¶ 61,205 (2018) ("CASPR Order").

[21] *Id.* at P 21.

times, also voiced a concern about uneconomic investment in any form, even if independent of direct subsidy. A common theme of the Commission's decision-making is the interference with economic entry and exit decisions.[22] A direct corollary of this observation is that the fundamental element of competition, a level playing field, is eliminated. Previously this was of great concern to Mr. Keech and also to the Commission.[23]

37. As PJM recognized, the "first principles of capacity markets" set forth in the CASPR Order make clear that price distortion by subsidies and the ensuing disruption of rational market entry and exit, are unacceptable. As PJM stated:

> Last month, addressing similar concerns in ISO New England, Inc., the Commission drew from its prior precedent several "first principles" of capacity markets, explaining that the ultimate goal of such markets "is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates." The Commission strongly affirmed that where "participation of resources receiving out-of-market state revenues undermines those principles," it is the Commission's "duty under the FPA to take actions necessary to assure just and reasonable rates."[24]

38. PJM confirmed that a targeted subsidy, independent of the underlying state rationale, violates these principles.

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[22] CASPR Order at P 21 (citations omitted).

[23] *See, e.g.*, June 29, 2018 Order, Docket Nos. EL16-49, *et al*., at P 150 ("We find, based on the evidence in Docket Nos. EL16-49-000 and ER18-1314-000, et al., that PJM's existing Tariff is unjust and unreasonable and unduly discriminatory. It fails to protect the integrity of competition in the wholesale capacity market against unreasonable price distortions and cost shifts caused by out-of-market support to keep existing uneconomic resources in operation, or to support the uneconomic entry of new resources, regardless of the generation type or quantity of the resources supported by such out-of-market support. The resulting price distortions compromise the capacity market's integrity. In addition, these price distortions create significant uncertainty, which may further compromise the market, because investors cannot predict whether their capital will be competing against resources that are offering into the market based on actual costs or on state subsidies. Ultimately, these problems with PJM's existing Tariff result in unjust and unreasonable rates, terms, and conditions of service. While the Commission in 2011 accepted PJM's proposal for a MOPR limited to new natural gas fired resources, the evidence put forward by PJM and the intervenors demonstrate that the price-distorting effects on wholesale capacity prices caused by resources that receive out-of-market support reach far beyond new natural gas-fired resources.").

[24] PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: PJM Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, at pp. 1-2, Docket No. ER18-1314-000 (filed Apr 9, 2018) ("PJM ER18-1314 Filing").

> But regardless of the state's specific policy motivation, retaining or compelling the entry of resources that the market *does not* regard as economic, suppresses prices for resources the market *does* regard as economic. This in turn suppresses revenues for resources that depend on these prices to support their continued operation or their economic new entry. Eventually, unless these resources too are given a subsidy or (if they are essential to preserving reliability) a Reliability Must Run ("RMR") arrangement, they will be crowded out.[25]
>
> PJM also stated:
>
> The question of state subsidy programs is not just a matter of respecting a state policy choice within its domain, it also imposes important and detrimental consequences on the federally regulated wholesale market. Advancing state policy by offering a subsidy tied to revenues received by a resource in PJM's markets effectively forces other participants in the wholesale market to pay for that objective. Therefore, this is not merely a case of discrimination between one party that enjoys a subsidy and one that does not. It is worse than that, because other wholesale market participants, excluded from the subsidy, are also effectively required to help pay for the favored party's subsidy. That forced enlistment of other wholesale market actors to help the state achieve its objective necessitates a response by the federal regulator of the wholesale market.[26]

C. PJM Itself Previously Made a Strident and Credible Statement Regarding the Materiality of Price Suppressive Actions

39. PJM's witness, Adam Keech, presented a particularly bleak view of the scale and impact of the existing and near future impacts of discriminatory subsidies in Docket ER18-1314. The following is a snippet of things Mr. Keech saw coming down the line from a 2018 perspective, and the potential levels of distortions that can occur from small changes, where the scenarios discussed by Mr. Keech represented only a lower bound on potential changes (the scenarios are a lower bound because no existing subsidized generation is accounted for or mitigated):

> 7. As can be seen, adding comparatively small quantities of subsidized offers disproportionately reduces the clearing prices paid to all resources. For example, for the 2020/2021 Delivery Year, the "3000 MW Outside MAAC" scenario adds zero-priced supply of less than 2%, but decreases clearing prices in the RTO unconstrained pricing area by roughly 10%. The "6000

[25] *Id.* at 14.

[26] *Id.* at pp. 31-32.

MW Outside MAAC" adds zero-priced supply of less than 4%, but decreases clearing prices in the RTO by 21%. See Attachment 1 at 3.

8. For the same Delivery Year, the "3000 MW Inside MAAC" scenario, which assumes about 1,000 MW of the added zero-priced supply is offered in the EMAAC LDA (which represents about 4% of supply in EMAAC), reduces clearing prices in that LDA by nearly 20%. *EMAAC clearing prices are reduced by about one- third in the second MAAC scenario*, which assumes about 2,000 MW of the 6,000 MW of added zero-priced supply (representing about 7% of supply in EMAAC) is offered in EMAAC. See Attachment 1 at 3.

9. Notably, these post-BRA sensitivity analyses do not test for how the clearing results would change if the subsidized offers that actually cleared in the subject BRA had submitted offers reflecting their competitive net costs. The sensitivities show only what would happen if additional subsidized offers were submitted in the BRA. *Therefore, the clearing price reductions—relative to what would happen if sellers with subsidies that offered below cost instead offered at a level sufficient to cover the net costs they need from the capacity market—would be even greater than shown here.*

10. PJM also has simulated capacity auctions that reprice—to zero—only two plants that cannot currently clear at competitive offers that recover their costs. As stated by Exelon in a public announcement, both the Quad Cities plant and Three Mile Island nuclear generating stations failed to clear PJM's May 2017 BRA.1 As shown in Attachment 2, allowing just these two plants to offer into the capacity auction at a subsidized price of zero would reduce the capacity revenues received by every seller in the unconstrained portion of the RTO by 2%. That 2% revenue reduction, experienced by every cleared seller in the unconstrained part of the RTO, is more significant than it sounds. A seller that clears a resource with 1,000 MW of unforced capacity, for example, would see a $547,500 reduction in its annual capacity market revenues for a that Delivery Year—due solely to the subsidy.

11. Sellers in the ComEd LDA would see their capacity revenues cut by nearly 10% due solely to allowing the subsidized offer. This would result in a reduction in annual capacity market revenues of $6.75 million for that same 1,000 MW resource.

12. In the MAAC LDA, the clearing price would drop by $1/MW-day, as a result of the zero offer from Three Mile Island in that LDA. While this too does not sound very significant, it represents a reduction of $365,000 in annual capacity market revenues for a resource with 1,000 MW of unforced capacity, and a reduction in total capacity market revenues for the MAAC region of approximately $24 million.

> 13. This analysis highlights an important point. Sellers are rational. Sellers that need to cover their costs submit offers at the level necessary to cover their costs. Cost-recovery offers for Quad Cities and Three Mile Island were submitted in the 2017 BRA—as we know because their offers proved too high to clear. Simply because these resources are operated at a high capacity factor, or are existing resources, does not mean that they have zero costs of committing as capacity or that all of their costs are recovered through energy market revenues. This example is instructive as a reminder of the fundamental economic principles that govern whether or not a rational, unsubsidized seller will submit a zero-price offer. [27]

40. While the Commission did not accept PJM's repricing proposal that was one of the options filed by PJM in Docket No. ER18-1314 and that was discussed in Mr. Keech's affidavit, Mr. Keech's conclusion is very informative. In light of his depressing conclusion, PJM appropriately recognized that it had a material problem and that doing nothing was not an option:

> As the U.S. Supreme Court recently recognized, states rightly may pursue "various . . . measures . . . to encourage development of new or clean generation" or other vital public policy goals. (Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1299 (2016)) Thus, the question raised by PJM's filing in this case is not whether states have the right to act but instead how the wholesale market should respond to such actions so that the goal of ensuring just and reasonable rates is not frustrated by an individual state's actions. To be clear, this filing does not seek any action by the Commission in preempting any state from making whatever policy choices it wishes. Rather, consistent with Hughes and the District Court's decision in Village of Old Mill Creek v. Star, *the sole issue is how PJM and the Commission can ensure that the market can address these actions by states in a manner that does not undermine the fundamental purpose of the wholesale market.*[28]

D. So Why Did PJM Change Its Mind In This Docket?

41. The problem identified in PJM's ER18-1314 Filing and discussed by Mr. Keech has not gone away. Instead, state subsidy programs have continued to grow, with tens of thousands of MWs of new on- and off-shore wind and solar planned or in procurement.[29]

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[27] *Id.*, Attachment E, Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C., ("ER18-1314 Keech Affidavit") at ¶¶ 7-13 (emphasis added).

[28] *Id*. at 4 (footnotes removed and emphasis added).

[29] There is a reported 30,000 MWs of offshore wind planned over the northern East Coast alone, much of which is sponsored by states in PJM. *See* https://e360.yale.edu/features/on-u-s-east-coast-

Given that these subsidies continue to create material threats of price suppression, a reasonable question is why have Mr. Keech and PJM changed their minds on how these subsidies should be treated?

42. The primary justification put forward in PJM's filing seems to amount to "price suppression has happened and will continue to happen, and we have concluded we should give up and support subsidies and the associated suppression of prices." This seems to be a determination based more on political expedience and concern about perpetuation of PJM as an institution, rather than trying to fulfill PJM's basic function of being neutral and independent and enforcing the Tariff.

43. Aside from what I believe are the reasonably transparent political considerations underlying PJM's proposal, Mr. Keech did offer a number of flawed arguments to justify this changed approach. Mr. Keech argues that the states or self-supply entities may leave the capacity market if the capacity that they have subsidized to meet their policy objectives is not recognized.[30] He also suggests that this would result in higher costs to FRR entities because they would utilize alternative procurement methods that might not be as efficient as the existing PJM market in meeting the full requirements of the state or self-supply mandates. Mr. Keech and Dr. Cramton also claim that the broad MOPR results in over-procurement, resulting in market prices that do not reflect the true supply demand conditions. These arguments fail and are questionable for four reasons.

44. First, PJM's filing states that "irrespective of the MOPR, there is scant prospect that states in the PJM Region will discontinue their programs that lend financial support to resources that advance the states' energy and other policy goals."[31] PJM's belief that, when faced with a choice the states will pursue their policy objectives regardless of costs, is supported by the fact that states have continued to expand their subsidy programs after the

has-offshore-winds-moment-finally-arrived. *See also* Cramton Working Paper, Figure 6.5 (reflecting PJM's current estimate of new intermittent resource entry amounting to over 51,000 MW).

[30] PJM Filing, Attach. DD, Keech Affidavit at ¶¶ 7-8.

[31] PJM Filing at 7.

Commission's December 2019 order requiring PJM to implement the broad MOPR (e.g., Dominion has elected to be an FRR entity, while Maryland and New Jersey continue to move forward and have already begun their procurement of off-shore wind resources). In this sense, the state choices and costs are fixed – that is, the states are committed, and will willingly go forward and incur additional costs to procure certain out of market attributes even if their chosen resources do not clear in the capacity market. If this is the case, then the behavior is settled, and we should therefore ignore it and focus on getting the appropriate non-discriminatory pricing in the market under the status quo broad MOPR.[32]

45. Second, if such procurement is not truly set in stone, then we should recognize that there a game of "chicken" going on here, with the states posturing to modify PJM's behavior, which should be that of a neutral RTO/ISO, rather than trying to promote some state(s) preferences at the expense of others.

46. Third, if PJM does not believe it is appropriate to interfere with state policies for clean energy attributes, it appears incongruous for Mr. Keech to then argue that the narrow MOPR must be implemented to prevent states from procuring other resources inefficiently. Moreover, PJM still does not explain why concern or deference to local political initiatives now exceeds PJM's previous recognition of the range of harms that occur due to the suppression of prices via large quantities of subsidized resources.

47. Fourth, Mr. Keech also expressed the tired "pay twice" logic (at ¶ 7). He ignores the fact that, if the state action is actually fixed as PJM claims, the state knowingly is procuring resources for *attributes other than capacity*, with the full knowledge that those resources may not be utilized in the PJM market to satisfy capacity obligations. They are knowingly undertaking this risk and apparently value the environmental attributes sufficiently to accept that outcome.

[32] Note that this is effectively what Dr. Cramton has assumed in his analyses. When referring to intermittent and subsidized nuclear units he stated: "The MW amount of state-sponsored resources entering each year is based on PJM estimates and reported in Table 6.5. State-sponsored resources, including nuclear, are assumed to stay in the market regardless of their economics." Cramton Working Paper at 55.

48. Equally important, the problem with the "Conditioned State Support" aspect of PJM's proposal is revealed by PJM's argument that adopting a narrow MOPR will mean no double payment. This argument is repeated in one form or another by virtually every PJM witness. If this is the case, the entire proposition of having a "Conditioned State Support" provision in the proposed MOPR is a sham and accomplishes nothing. PJM apparently knows and intends that no state will ever have to "pay twice" despite the "Conditioned State Support" rule. This recognition shows that PJM has concluded that the "Conditioned State Support" provision has no bite, and that PJM anticipates it will be easy for a state to avoid mitigation and as such will not impact the states' desired results, regardless of the ultimate impact on the PJM markets. This is exactly the type of consideration that drove the Commission to support mitigation of uneconomic entry in the first place.

IV. DR. CRAMTON'S CONCLUSIONS REFLECTING HIS MODEL AND ITS RESULTS ARE NOT SUBSTANTIATED AND SHOULD BE PRESUMED INVALID OR IRRELEVANT

A. For the Purposes of this Proceeding, the Cramton Model is a Black Box

49. The modeling supporting Dr. Cramton's affidavit is not a reasonable basis for forming an expert opinion.

50. The Cramton Model was apparently developed over 19 months prior to this filing with PJM support. At a high level, its function seems similar to the simple model introduced by PJM by Dr. Hobbs with the original 2005 PJM filing.[33] The intent was apparently to create a tool to review the impacts of different market design policies. It is conceivable that the Cramton Model may eventually be capable of doing that. But at this point, there simply isn't sufficient benchmarking, documentation, validation, transparency or review by scholarly peers, market participants, or for that matter the Commission, to draw reasonable conclusions regarding the Cramton model's results. The list of deficiencies and issues provided below (*see infra* ¶ 56) emphasizes the inability to rely on the model's results as well. Certainly the results here are not useful in any real way, and as

[33] Docket No. ER05-1410 EL05-148 Cite affidavit

I noted above, Dr. Cramton's recommendations rely more on his subjective preferences than anything else. In general Dr. Cramton finds the results of his broad and narrow MOPR cases similar (*see supra* note 4) and I explain why that is problematic and may be indicative of a fundamental flaw in Dr. Cramton's testing and validation approach to the use of the model. This issue is discussed below.

51. At this time, there are simply too many unknown properties of the Cramton Model with respect to both the experimental design and the details of operations and assumptions. It also seems infeasible for anyone else to replicate the model or the model results given the lack of detail and extraordinarily large computational requirements.[34] The model is, for all intents and purposes, a black box to the Commission, Stakeholders, and presumably anyone other than perhaps Dr. Cramton and his fellow authors. One simply cannot rely on the results as they currently stand to make a reasoned judgment regarding the broad versus narrow MOPR.

B. A Partial and High Level Summary of Issues with the Cramton Model

52. I have identified a number of serious concerns regarding the Cramton Model. First, as Dr. Cramton himself states, the model is complex and built on a large number of assumptions, but these assumptions are not fully explained or available, and some are only implied. Thus, there is no ability to judge the reliability of the model or accuracy/validity of the building block assumptions.

53. Second, with respect to test or experimental design, Dr. Cramton has failed to demonstrate that the metrics underlying his comparison of the broad versus narrow MOPR cases can be taken as a valid indication of the difference between the two cases. As far as I can tell, the model was neither benchmarked nor validated in any manner to suggest that such an interval comparison of the two cases is valid. A superior test design would first have established the validity or reasonableness of interval metric comparisons (e.g.,

[34] Cramton Affidavit at ¶ 48. "As described in [the Cramton Working Paper], the modeling requires extensive computation. The modeling was done on 22 computational servers running 24x7 for many months, creating an extensive database of market outcomes at the 5-minute level as a function of the resource structure and other parameters."

comparing a baseline with no MOPR at all, no carbon pricing, and no economically indifferent generation –that is, without Dr. Cramton's assumption that there would be 51,000 MW of intermittent generation and retention of approximately 6000 MW of nuclear generation, without regard to whether such generation is economic) to a series of change cases. This "without anything" case, describing the expansion and pricing of the PJM system without any of the policy actions of interest, would be Base Case 1. The change cases to establish the validity of the model for simple with/without comparison might be:

- Case 2 - Base Case 1 with the addition of the fixed resources;
- Case 3 – Base Case 1 with the addition of the carbon tax[35]; and
- Case 4 – Base Case 1 with both carbon pricing and fixed resources.

Then one would validate the level of results and the resulting changes in Cases 2, 3 and 4 versus Case 1 (e.g., was there more entry of clean resources and retirements of high carbon resources). At a minimum, this is intended to show that the model can detect expected differences (interval changes), and with values that make sense and are amenable to separate calculation and verification or at minimum logical tests regarding the changes that are observed. It would then make sense (assuming a reasonable test result of these first three comparisons) to look at the interval differences between what Dr. Cramton used as his baseline (Case 4) and a Case 5 (combining case 4 with the Broad MOPR) and a Case 6 (combining Case 4 with the Narrow MOPR). Only with this sort of progressive and reasoned incremental approach can one even begin to understand if the interval comparisons of the model case results (which ultimately are the basis of Dr. Cramton's conclusions that PJM relies on) are meaningful. As actually implemented, it appears that Dr. Cramton effectively calculated interval comparisons only between Case 4 versus Cases 5 and 6. He ignored the importance of a clean baseline (Case 1) and the potentially overwhelming impacts of his two assumptions that are captured in Cases 2 and 3. These two incremental changes, the addition of carbon pricing at material levels and the price

[35] I understand that the intent of Dr. Cramton was to use a carbon price adder as a sort of proxy for other charges, but under his assumptions it reaches a level sufficiently high that it may by itself be driving results in both MOPR cases. This type of evaluation is designed to parse out such impacts.

insensitivity of the representative subsidized units, are at the heart of the current debate. Without doing this, we don't even know if there is any meaning to the differences between the broad and narrow MOPR results, regardless of the direction or magnitude of those differences.

54. Third, on a related note, there is no indication that the model was benchmarked in any fashion. This is problematic as one of the key outputs of the model is the capacity market clearing price for the entire PJM footprint (somewhat incongruously no locational constraints are considered by the Cramton model). Yet even a cursory examination should raise eyebrows about the validity of the results and unknown assumptions embedded in the determination of the capacity prices. For example, in Figure 4 of the Cramton Affidavit, capacity prices under the status quo (the broad MOPR) for year 2022 are approximately \$250/MW-day and for 2023 approximately \$370/MW-day. This is compared to PJM's recent 2022-23 auction results of an RTO value of \$50/MW-day.[36] For 2028, the model estimates a broad MOPR price of approximately \$425/MW-day and a narrow MOPR price of \$475/MW-day. Given the recent prices and introduction of new zero offer price capacity and energy into the market, these prices seem, at minimum, suspicious. A similar troubling result occurs near the end of the forecast period. Again looking at Figure 4, we notice that the narrow MOPR Capacity prices stay flat from 2032-39 (seven years) at about \$450 per MW day, while during the same interval of time capacity prices under the broad MOPR go from approximately \$340 to \$450 and then decline to \$300. Variations like this, well after an initial adjustment period, should also give the Commission great pause when considering direct with/without metrics of purported differences in policy. *Both observations are troubling because of the lack of any effort to benchmark these results or attempt to explain their deviation from reality.* The absence of this type of minimal verification puts the entirety of the results in question. There is no reason at all to accept any assertions with respect to the absolute values he determines or the interval differences he calculates due to the lack of any semblance of verification.

[36] *See* Table 1, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx.

55. While Dr. Cramton himself has argued that the absolute values of his results may not be representative (what choice did he have with numbers like the above paragraph), he suggests that the difference between his two cases (broad and narrow MOPR) is a valid comparison or at least the reader should focus on them.[37] It eludes me, however, why one would focus on this comparison absent any proof of the underlying validity. Moreover, problems in the underlying model can, of course, affect the two cases in different ways, which can make any comparison invalid. Indeed, this seems to be what is happening in the capacity price observations discussed above (e.g. there may be other model limits or sensitivity thresholds that bind on one case but not the other, such as the retirement limit in the entry and exit logic).

56. Aside from the broader conceptual issues discussed above, I have also identified a number of other potential concerns regarding Dr. Cramton's model below. Again, this is only a preliminary and non-exhaustive list given the lack of information provided by PJM.

Additional Issues of Concern in the Cramton Model

- The inclusion of material amounts of clean resources (51,000 MW) and nuclear generation (approximately 6,000 MW) that do not respond to any changes in policy or economics. (See Cramton Working Paper, Table 6.5).

- The inclusion of carbon pricing in the base case without validation of its impacts[38].

[37] Cramton Affidavit at ¶ 53 ("As with any simulation of this complexity, I have made many assumptions. See Cramton et al. (2021) for details. Calibration of the model is imperfect. Miscalibration is especially apt to impact absolute results, such as price levels. It is less prone to affect relative results, such as comparison between scenarios. Thus, the reader should focus primarily on the differences between the broad and narrow MOPR scenarios.").

[38] Cramton Affidavit at ¶ 47 ("Climate policy is modeled with a carbon price. Investors in long-lived energy projects have an internal carbon price used in decision-making. A carbon price is the most coherent way to model climate policy. I employ a modest carbon price of $2/ton in 2019, which increases by $3/ton each year. In 2020, the implicit carbon price is $5/ton; in 2040, the carbon price is $65/ton.").

- The absence of any calculation of transfers between generation and load/demand to estimate short-term financial impacts due to price shocks of new subsidized entry.

- The unsubstantiated assumption of unlimited or non-binding transmission[39], particularly given the concentration of renewable resources. (See Cramton Working Paper, Figure 3.5).

- The absence of the recognition of the cost of the underlying out-of-market subsidy to consumers.

- The apparent use of only some sort of smoothed historic production output and capacity factor (near peak events) to approximate the results of PJM's ELCC accreditation process[40].

- The assumption of optimal scheduling/optimization of storage resources, which overstates their economic value. Similarly no consideration of business requirements of such storage resources and how they modify operations to reflect such financial requirements. Only 2 hour storage is considered.[41]

- The estimation of the key model driver, the profit function is complex and not validated. I believe the underlying response surface is likely not convex because of the varying interactions (e.g. the reversal of direction) between

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[39] *See* Cramton Working Paper at 13 ("A simplifying assumption of our initial model is that transmission is built to support the entry and exit as it occurs. We, therefore, assume that transmission congestion is the result of outages and other random events. Congestion does not persist.").

[40] Cramton Affidavit ¶ 67 ("I used fixed capacity values for thermal resources since this simple approach is apt to be more consistent with the ELCC method. For renewable resources and storage, capacity values are calculated using exponential smoothing. The broad MOPR and narrow MOPR cases show very similar performance results by resource type."). *See also* Cramton Working Paper at 43.

[41] Cramton Affidavit ¶ 46 ("The battery resources are optimally scheduled and dispatched to maximize profits. For simplicity, only two-hour batteries are considered.").

levels of storage and other intermittent resources. Not addressing this concern would be a material omission in his estimation of the key entry and exits decisions. Issue of this type were ignored, or if addressed not explained and included.

C. Dr. Cramton's Conclusions are Questionable

57. Given the problems with the model discussed above, Dr. Cramton's results cannot be relied upon.

58. Dr. Cramton's evaluation appears to conclude that in general there is no material difference between the proposed "narrow" new MOPR and the existing "broad" MOPR of the status quo other than with respect to reserve margins.[42] There are at least three elements that I identified that suggest this type of result was pre-ordained.

- **The fundamentals of the market.** Dr. Cramton himself describes the small differences between the broad and narrow MOPR cases as resulting from certain specific assumptions relating to market fundamentals. He offers an intuitive explanation of his results, stating:

> The introduction of the broad MOPR leaves net present values—and therefore entries, exits, and the evolution of the energy mix—largely unaffected. The broad MOPR lowers the net present value of onshore wind slightly in the first two years of the simulation and delays the date when storage and solar become economic by two years. These effects are small for two reasons. First, renewable resources and storage are already economic or near-economic at the beginning of the simulation (except for offshore wind). Thus, the broad MOPR is unlikely to bind, and once the resource clears, the offer floor drops from Net CONE to Net-ACR, which is much lower. Second, the capacity value of renewable resources drops over time as more renewable resources enter the market. Thus, capacity payments become less critical for renewables. Figures 8.9 and 8.10

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[42] Cramton Affidavit at ¶ 8 ("I then analyze PJM's MOPR proposal. I compare the likely market impact of the broad MOPR articulated in the December 2019 order of the Federal Energy Regulatory Commission (FERC) and PJM's current MOPR proposal. I refer to these two approaches as broad MOPR (FERC 2019) and narrow MOPR (PJM 2021a,b)"). See also the *nine* citations to Dr. Cramton's affidavit in note 4, *supra*, where Dr. Cramton states the results are similar.

> below show the profit components by technology and year and the performance and capacity values by technology and decade. Renewables rely less on capacity payments than traditional generation. Instead, the broad MOPR benefits combined cycle with carbon capture and sequestration. In the broad MOPR scenario, 1.5GW enters the market each year between 2021 and 2040 instead of 1.1GW in the narrow MOPR case. Perhaps surprisingly, the broad MOPR lowers the net present value of traditional technologies slightly. The broad MOPR reduces renewables' penetration, especially of onshore wind, but increases entry of combined cycle with carbon capture and sequestration, which is a much closer substitute. Also, as discussed below, the broad MOPR does not affect capacity prices significantly but leads to more resources in the market. Thus, traditional resources' energy profits suffer, offsetting any potential revenue increase in the capacity market. This result highlights a well-known tradeoff. While the capacity market ensures that the system operator achieves the target capacity level, it can lead to too many resources in the market, shifting money away from the spot market into the capacity market and exacerbating the missing money problem (Joskow, 2008, and Hogan, 2013).[43]

It seems that PJM went through a lot of time, trouble and expense to develop a policy model whose results effectively are "intuitive" and could have for the most part been anticipated. For example, most parties are aware of the dampening properties of the Variable Resource Requirement ("VRR") curve; the IMM and others all stated their expectations that the expanded (broad) MOPR would not bind in the last auction resulting in no net MOPR impact; and similarly the existing impact of subsidized resources already in the market. *The reality is that we do not know if the intuitive summary by Dr. Cramton is an explanation of the model's result, or that the model simply is insensitive to these items. Knowing that difference is the entire point of testing, validating and benchmarking the model.*

- **The VRR curve has a convergent design.** Dr. Cramton's model uses a statistical model based on selected model runs to estimate the profit function. In turn, he tests his entry/exit decision process that reflects the profit/loss expectations of investors against the VRR curve, and if reasonably close (reasonably is not defined) to a

[43] Cramton Working Paper at 68.

price/quantity pair on the curve he accepts the result of his model. (If not, the model is iterated again.)[44] Because a basic design premise of the VRR curve was to cause convergence towards the Installed Reserve Margin ("IRM") (plus a designated small criterion for reliability via its slopes/shape), it is not surprising that the results of the two cases Dr. Cramton examines are similar given they are both required to pass this testing and be close to and consistent with the VRR curve. Indeed this is one of the sources of my concern about his model's ability to produce meaningful interval performance metrics. If Dr. Cramton's profit function is matching up price quantity pairs to the demand curve, you would expect convergence of cases over a long time horizon, and the model would wash away actual differences in the underlying metrics within the model (prices, quantities, reserve margins etc.).

- **The role of the RPM market.** Dr. Cramton recognizes that the role of the RPM market itself is to maintain reliability. Thus, he states: "[R]eliability is the same with the broad MOPR as with the narrow MOPR. This result should be expected. In the narrow MOPR case, the capacity market already guarantees that the system operator procures adequate resources. The broad MOPR forces the system operator to exclude some units when assessing resource adequacy and procure more resources than needed."[45]

59. In light of the factors above that cause convergence in the model, there is no basis for Dr. Cramton's stated preference for under-mitigation as opposed to over-mitigation in terms of the specific model results beyond his statement that the narrow MOPR has lower costs than the broad MOPR, which of course goes to the heart of the price suppression debate. Even if the model were correct that the narrow MOPR results in lower costs (which would not be surprising given the expected price suppression), this tells us nothing about

[44] *Id.* at 47 ("We continue alternating between existing and prospective units until no plant wants to revise its decision. When this happens, we check the capacity offered in the market against the capacity demand curve. If the two curves cross at a price within a critical range of the announced price (equation) the algorithm stops. Otherwise, we restore the list of energy resources to their initial configuration and update the provisional price using bisection."). I note that the "critical range" is never specified or defined in any way.

[45] Cramton Working Paper at 73.

whether that is the right result in terms of overall efficiency and the actual achievement of the desired policy objectives related to carbon emissions. The analyses are simply not properly targeted to make such determinations. The model is not validated for making choices like this in the first place. Even aside from the modeling problems regarding interval comparisons, as discussed above, there are huge differences in the model forecasted capacity prices that are never addressed and go to the main driver of the model (entry and exit decisions) and the validity of a comparison based on the differences between model runs. In turn, as discussed these undercut the validity of any differences observed between cases developed using the model (e.g. the broad versus narrow MOPR cases.) Further, these types of comparisons are also unclear because of more detailed issues like the omission of considerations of the costs of the subsidies themselves, the extent of costs for new transmission (e.g., to integrate large scale off shore wind), which Dr. Cramton assumes is just somehow provided as needed and even something as basic as how Dr. Cramton determined the VRR curves he uses to validate the conclusions of his market entry and exit decisions which are the heart of the model. The list is almost endless as to what we are not told about assumptions made and where elements have or have not been tested and validated (see, e.g., footnote 38).

60. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER21-2582-000**

AFFIDAVIT

I, Roy J. Shanker, do hereby swear and affirm under penalty of law that the statements in the foregoing Affidavit of Roy J. Shanker, Ph.D. are true to the best of my knowledge, information and belief.

Executed this 20 day of August, 2021

Roy J Shanker
Roy J. Shanker

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present	Independent Consultant P.O. Box 1480 Pebble Beach, CA 93953 Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.
1979-81	Hagler, Bailly & Company 2301 M Street, N.W. Washington, D.C. Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.
1976-79	Resource Planning Associates, Inc.

1901 L Street, N.W.
Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2021

260—On behalf of LS Power Associates L.P. before the Federal Energy Regulatory Commission Docket No. ER21-2043. Affidavit discussing PJM's revised Effective Load Carrying Capability proposal, its limitations and associated PJM responses to previous comments regarding its initial proposal.

259—On behalf of Indicated Suppliers before the Federal Energy Regulatory Commission in Dockets No. EL19-47-000 and EL19-63-000 comments regarding the PJM proposed modification to its Market Seller Offer Cap in the Reliability Planning Model Base Residual Auction for Capacity Resources.

258—Written post conference comments in Federal Energy Commission Docket No. AD21-10. Discussion of the appropriate scope and range of actions for the Commission with respect to the PJM Minimun Offer Price Rate. Similar considerations of the legal scope of the Commission under the Federal Power Act.

257—Invited Speaker before the Federal Energy Energy Regulatory Commission Docket No. AD21-10. Comments before the Commissioners related to the role of subsidies and their impact in terms of the determination of satisfaction of just and reasonable rates under the Federal Power Act.

256—On behalf of LS Power Associates L.P. before the Federal Enegy Regulatory Commission Docket No. ER21-278-001. Affidavit discussing PJM's Effective Load Carrying Capability proposal, its limitations and associated PJM responses to the Commission's deficiency notice.

2020

256—On behalf of Cricket Valley Energy Center and Empire Generating Company before the Federal Energy Commission Docket EL21-7. Affidavit addressing the appropriate design of offer price floors in the NYISO Capacity market and associated mitigation and extension of the related rules to the entire state.

255—Invited speaker and written submission before the Federal Energy Regulatory Commission Docket AD20-14. Comments about the legal issues under the Federal Power Act relevant to the implementation of carbon pricing within the wholesale regional transmission organizations.

254—On behalf of Shell Energy North America before the Federal Energy Regulatory Commission, Docket EL20-49. Affidavit addressing bilateral trading of FTRs, associated agreements and the interaction with PJM's FTR Center reporting and Tariff.

2019

253—On behalf of White Oak Power Constructors before the United States District Court for the Eastern District of Virginia (Richmond Division). Expert report on proper calculation of damages and costs associated with the delay in commercial operations of a new electric power generation facility.

252—On behalf of the Public Service Companies before the Federal Energy Regulatory Commission, Docket ER19-1486. Affidavit regarding the PJM proposed operating reserve demand curve and other modifications to the reserve products market. Comments on missing elements within the proposal.

251—On behalf of Indicated Parties, (Calpine, Vestra, and Electric Power Supply Association) before the Federal Energy Regulatory Commission. Docket EL19-63. Affidavit regarding the complaint of the Joint Consumer Advocates regarding PJM's market seller offer cap, the potential exercise of market power in the capacity market and appropriate market design adjustments under the Capacity Performance paradigm.

250—On behalf of Indicated Parties, (Calpine, Vestra, and Electric Power Supply Association) before the Federal Energy Regulatory Commission. Docket EL19-47. Affidavit regarding the appropriate adjustment of penalties and the Market Seller Offer Cap within the PJM Capacity Performance paradigm.

249—Supreme Court of the United States. Brief of Energy Economists as Amici Curiae in Support Of Petitioners, Nos. 18-868 & 18-879. Discussion of the impact of subsidies in electric energy market structures and the relationship of the instant cases where a Writ of Certiorari is being sought to previous Supreme Court precedent regarding state actions that effect Federal Energy Regulatory Commission jurisdictional rates.

2018

248—On behalf of PJM Power Providers (P3). Federal Energy Regulatory Commission. Docket EL18-178. Affidavit addressing the appropriate mechanisms to address state/public policy subsidies in the PJM Reliability Planning Model capacity construct. Related comments with respect to a “Clean” Minimum Price Offer Rule.

247—On behalf of Calpine Corporation, Eastern Generating and CPV Power Holdings. Federal Energy Regulatory Commission. Docket No. EL18-169. Affidavit addressing the the establishment of a “clean” Minimum Offer Price Rule for capacity offers in the PJM markets.

246—On behalf of DC Energy LLC and Vitol Inc. Federal Energy Regulatory Commission. Docket No. ER18-1334. Affidavit on the CAISO proposals to limit source and sink pairs in its annual and monthly CRR auctions, as well as comments addressing appropriate coordination of transmission outage and constraint information.

245—On behalf of the PJM Power Providers. Federal Energy Regulatory Commission Docket No. ER18-1314-000. Affidavit on the PJM proposed mitigation alternatives for addressing out of market subsidies either by Repricing or a modified Minimum Offer Price Rule.

244—On behalf of Joint Commentors. Federal Energy Regulatory Commission Docket EL18-34. Participation in the preparation of comments addressing PJM’s proposed fast start pricing modifications and related price formation issues.

243—On behalf of the PJM Power Providers Group. Federal Energy Regulatory Commission Dockets EL17-32 and EL17-36. Pre-Technical Conference Comments and participant technical conference regarding seasonal capacity products and specific related reliability and forecasting questions from Commission Staff.

2017

242—On behalf of the PSEG Companies. Federal Energy Regulatory Commission Docket No. ER13-535-000. Affidavit regarding implementation of Court of Appeals remand to FERC of the PJM capacity market Minimum Offer Price Rule.

241-- In the United States Court of Appeals for the Second Circuit. Case No. 17-2654.Co-writer/sponsor of the Brief of Energy Economists as Amici Curiae in Support of Plaintiffs-Appealants-Reversal. Comments regarding the impacts of subsidies on the operation of organized electric markets.

240—In the United States Court of Appeals for the Seventh Circuit. No. 17-2433.Co-writer/sponsor of the Brief of Energy Economists as Amici Curiae in Support of Plaintiffs-Appealants. Comments regarding the impacts of subsidies on the operation of organized electric markets.

239—Invited speaker Federal Energy Regulatory Commission technical session, Docket AD17-11. Comments on the appropriate incorporation of state policies in wholesale electric markets. Submission of post technical session comments.

238—On behalf of PJM Power Providers. Federal Energy Regulatory Commission Dockets EL17-36 and EL17-32 addressing the current Capacity Performance design and criticisms related to the exclusion of an inferior seasonal capacity product. Explanation of how PJM establishes its adequacy targets and whether or not the asserted criticisms were valid.

2016

237- On behalf of DC Energy, Vitol, Intertia Power, Saracen Energy East. Federal Energy Regulatory Commission Dockets EL16-6, ER16-121. Submission of post technical session statement regarding PJM FTR market "netting" proposal.

236-On behalf of DC Energy, Vitol, Intertia Power, Saracen Energy East. Federal Energy Regulatory Commission Dockets EL16-6, ER16-121. Participant in two Technical Session Panels addressing PJM FTR market design and deficiency in the pending proposal to remove netting in the market settlement.

2015

235- On behalf of the Electric Power Supply Associaton. Federal Energy Regulatory Commission Dockets EL15-70, 71, 72, 82. Affidavit regarding MISO capacity market design and also addressing use of opportunity costs in offers.

234-On behalf of the Electric Power Supply Associaton. Federal Energy Regulatory Commission Dockets EL15-70, 71, 72, 82. Discussant in technical session addressing the establishment of opportunity costs as the basis for capacity reference pricing in the MISO Planning Resource Auctions.

233-On behalf of Dominion Virginia Power. Federal Energy Regulatory Commission Docket ER15-1966. Affidavit regarding changing economic incentives for suppliers associated with the modification of PJM's calculation of Lost Opportunity Costs.

232-On behalf of "Indicated Suppliers" Federal Energy Regulatory Commission Docket No. EL15-64-000. Testimony addressing the appropriateness of proposed changes to the NYISO buyer side mitigation exemptions.

231-On behalf of Hydro Quebec, Energy Services U.S. Federal Energy Regulatory Commission Docket No. ER15-623. Affidavit addressing the consistent treatment of energy imports under PJM's Capacity Performance proposal.

230-Before the Supreme Court of the United States, No. 14-995, On Petition for a Writ of Certiorari to the United States Court of Appeals for the Third Circuit. Brief of electrical engineers, scientists and economists as amici curiae in support of petitioners. Metropolitan Edison et al. versus Pennsylvania Public Utility Commission et al., http://www.americanbar.org/content/dam/aba/publications/supreme_court_preview/briefs_2015_2016/14-840_Borlick_et_al.pdf.

2014

229-On behalf of Benton County Wind Farm. United States District Court Southern District of Indiana, Indianapolis Division, Civil Action No. 1:13-cv-1984-SEB-TAB. Expert Reports addressing custom and practice in electric power purchase agreements.

228-On behalf of FirstEnergy Services. FERC Docket EL14-55. Affidavit related to the appropriate characterization of Demand Response in Capacity Markets reflecting performance as the reduction of retail energy consumption.

227-Federal Energy Regulatory Commission. Docket RM10-17. On my own behalf, a statement regarding the ability of the PJM capacity and energy markets to clear in the transition from any determination that demand response would be excluded jurisdictionally from wholesale markets. This could in turn result in a more appropriate representation of retail demand response.

226-Illinois Commerce Commission. Matter: No. 13-0657. On behalf of Commonwealth Edison Company. Testimony regarding the operation of the PJM regional transmission expansion planning process in general and particularly with regards to the preservation of long-term transmission rights (Stage 1A Auction Revenue Rights), and the consequences that occur when such mandated rights are infeasible.

225-Federal Energy Regulatory Commission. Docket ER14-1579. On behalf of H-P Energy. Affidavit explaining importance of property rights and associated contracts within the PJM transmission planning process, particularly as they pertain to Upgrade Construction Service Agreements.

2013

224-Federal Energy Regulatory Commission. Docket No. ER14-456. On behalf of NextEra Energy to analyze a proposed modification to the PJM Tariff allowing for "easily resolved constraints" to be address by transmission upgrades without any analyses of benefits.

223-Federal Energy Regulatory Commission. Docket No. ER14-504. Affidavit on behalf of PJM Power Producers addressing the interaction between the PJM adequacy planning processes and the formulation of saturation constraints on Limited and Extended Summer Demand Response products.

222-Federal Energy Regulatory Commission. Docket AD13-7. Invited speaker on the Commission's technical session regarding capacity markets in RTO's. Comments addressed basic principles of market design, market features, and consequences of market failures and deviations from design principles.

221-Federal Energy Regulatory Commission. Docket No. EL13-62 on behalf of TC Ravenswood LLC. Two affidavits addressing the treatment of reliability support services agreements and associated capacity in the NYISO capacity market design.

2012

220-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of First Energy Services Company. An affidavit and testimony addressing the appropriateness of the application of a proposed new MISO tariff provision after the fact to a withdrawing MISO member.

219-Federal Energy Regulatory Commission. Docket ER13-335. On behalf of Hydro Quebec U.S. Affidavit addressing appropriate application of ISO-NE Market Rule 1/ Tariff with respect to the qualification of new external capacity to participate in the Forward Capacity Market.

218-Federal Energy Regulatory Commission. Docket IN12-4. On behalf of Deutsche Bank Energy Trading. Affidavit regarding a review of specific transactions, related congestion revenue rights, and deficiencies in CAISO tariff implementation during periods when market software produces multiple feasible pricing solutions.

217-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of FirstEnergy Services Company. Affidavit regarding implementation of the MISO Tariff with respect to the determination of appropriate exit fees and charges related to certain transmission facilities.

216-Federal Energy Regulatory Commission. Docket No. IN12-11. On behalf of Rumford Paper Company. Affidavit regarding free riding behavior in the design of demand response programs, and its relationship to accusations of market manipulation.

215-Federal Energy Regulatory Commission. Docket No. IN12-10. On behalf of Lincoln Paper and Tissue LLC. Affidavit regarding relationship of demand response behavior and value established in Order 745 to claimed market impacts associated with accusations of market manipulation.

214-Federal Energy Regulatory Commission. Docket No. AD12-16-000. On behalf of PJM Power Providers, testimony regarding deliverability of capacity between the MISO and PJM RTO's and associated basic adequacy planning concepts.

213-United States Court Of Appeals, District of Columbia Circuit. Electric Power Supply Asociation, et al (Petitioners) v. Federal Energy Regulatory Commission et al (Respondents) Nos. 11-1486. Amici Curiae brief regarding the appropriate pricing of demand reduction services in wholesale markets vis a vis the FERC determinations in Order 745.

212-United States Supreme Court. Metropolitan Edison Company and Pennsyvalnia electric Company (Petitioners), Pennsylvania Public Utility Commission (Respondent) (No. 12-4) Amici Curiae brief regarding the nature of physical losses in electric transmission and relationship to proper marginal cost pricing of electric power and the marginal cost of transmission service.

2011

211-Federal Energy Regulatory Commission Docket No. ER12-513-000. On behalf of PJM Power Providers, testimony regarding the establishment of system wide values for the net cost of new entry related to modifications of the Reliability Planning Model.

210-Federal Energy Regulatory Commission Docket No. EL11-56-000, on behalf of First Energy Services. Affidavit regarding the appropriateness of proposed transmission cost allocation of Multi-Value Projects to an exiting member of the Midwest Independent System Operator.

209-Federal Energy Regulatory Commission Docket No. ER11-4081-000, on behalf of "Capacity Suppliers". Affidavit addressing correct market design elements for Midwest Independent System Operator proposed resource adequacy market.

208-Public Utility Commission of Ohio, Case Nos. 11-346-EL-SSO,11-348-EL-SSO,Nos. 11-349-EL-AAM, 11-350-EL-AAM, on behalf of First Energy Services. Testimony regarding the interaction between the capacity default rates for retail access under the PJM Fixed Resource Requirement and the PJM Reliability Planning Model valuations.

207-Federal Energy Regulatory Commission Dockets No. ER11-2875, EL11-20, Staff Technical Conference on behalf of PJM Power Providers, addressing self supply and the Fixed Resource Requirement elements of PJM's capacity market design.

206-New Jersey Board of Public Utilities, Docket Number EO11050309 on behalf of PSEG Companies. Affidavit addressing the implications of markets and market design elements, and regulatory actions on the relative risk and trade-offs between capital versus energy intensive generation investments.

205-Federal Energy Regulatory Commission Docket No. ER11-2875. Affidavit and supplemental statement on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry and recommendations for tariff revisions.

204-Federal Energy Regulatory Commission Docket No. EL11-20. Affidavit on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry.

203-Federal Energy Regulatory Commission Docket Nos. ER04-449. Affidavit and supplemental statement on behalf of New York Suppliers addressing the appropriate criteria for the establishment of a new capacity zone in the NYISO markets.

2010

202-New Jersey State Assembly and Senate. Statements on behalf of the Competitive Supplier Coalition addressing market power and reliability impacts of proposed legislation, Assembly Bill 3442 and Senate Bill 2381.

201-Federal Energy Reglatory Commission. Docket ER11-2183. Affidavit on behalf of First Energy Services Company addressing default capacity charges for Fixed Resource Requirement participants in the PJM Reliability Pricing Model capacity market design.

200-Federal Energy Regulatory Commission. Docket ER11-2059 Affidavit on behalf of First Energy Services Company addressing deficiencies and computational problems in the proposed "exit charges" for transmission owners leaving the MISO RTO related to long term transmission rights.

199-Federal Energy Regulatory Commission Docket RM10-17. Invited panelist addressing metrics for cost effectiveness of demand response and associated cost allocations and implications for monopsony power.

198-Federal Energy Regualtory Commission Consolidated Dockets ER10-787-000, EL10-50-000, and EL10-57-000. Two affidavits on behalf of the New England Power Generators Association regarding ISO-NE modified proposals for alternative price rule mitigation and zonal definitions/functions of locational capacity markets.

197-Federal Energy Regulatory Commission Docket No. ER10-2220-000. Affidavit on behalf of the Independent Energy Producers of New York. Addressing rest of state mitigation thresholds and procedures for adjusting thresholds for frequently mitigated units and reliability must run units.

196-Federal Energy Regulatory Commission Docket PA10-1. Affidavit on behalf of Entergy Services related to development of security constrained unit commitment software and its performance.

195-Federal Energy Regulatory Commission Docket No. ER09-1063-004. Testimony on behalf of the PJM Power Providers Group (P3) regarding the proposed shortage pricing mechanism to be implemented in the PJM energy market. Reply comments related to a similar proposal by the independent market monitor.

194-PJM RTO. Statement regarding the impact of the exercise of buyer market power in the PJM RPM/Capacity market. Panel discussant on the issue at the associated Long Term Capacity Market Issues Sympossium.

193-Federal Energy Regulatory Commission Docket No. ER10-787-000. Affidavit on behalf of New England Power Generators Association addressing proper design of the alternative price rules (APR) for the ISO-NE Forward Capacity Auctions. Second affidavit offered in reply. Supplemental affidavit also submitted

192-Federal Energy Regulatory Commission Docket No. RM10-17-000. Affidavit on behalf of New England Power Generators Association addressing proper pricing for demand response compensation in organized wholesale regional transmissiom organizations.

191-Federal Energy Regulatory Commission Docket No. RM10-17-000, Affidavit on my on behalf regarding inconsistent representations made between filings in this docket and contemporaneous materials presented in the PJM stakeholder process.

2009

190-Federal Energy Regulatory Commission Docket No. ER09-1682. Two affidavits on behalf of an un-named party regarding confidential treatment of market data coupled with specific market participant bidding, and associated issues.

189-American Arbitration Assoication, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.

188-Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

187-Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

186-American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

185-Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

184-Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

183-Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

182-Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

181-Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortion of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

180-Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

179-Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

178-Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

177-FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

176-FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

175-FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

174-FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

173-United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

172-FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

171-FERC Docket No. ER06-1474-000, FERC. Testimony on behalf othe PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

170-FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

169-FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

168-FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

167-FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

166-FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

165-American Arbitration Association Nos. 16-198-00206-03 16-198-002070.On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

164-Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

163-Federal Energy Regulatory Commission Docket No. EL03-236-003. Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

162-Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

161-Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

160-Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

159-Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

158-Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

157-Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

156-Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

155-Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

154-Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

153-American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cinergy Solutions regarding an energy services agreement related to a cogeneration facility.

152-Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

151-Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

150-Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

149-Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

148-Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

147-Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

146-Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

145-Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

144-Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

143-Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

142-United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

2002

141-Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

140-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

139-Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

138-Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacity credits.

137-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

136-Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

135-Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

134-Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

133-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

132-Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affadavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

131-Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacitywithin the New York Independent system operator.

130-Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

129-United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

128-Federal Energy Regulatory Commission. Docket Number ER01-2076-000. Testimony on behalf of Aquila Energy Marketing Corp and Edison Mission Marketing and Trading, Inc. relating to the implementation of an Automated Mitigation Procedure by the New York ISO.

2000

127-New York Independent System Operator Board. Statement on behalf of Hydro Quebec, U.S. regarding the implications and impacts of the imposition of a price cap on an operating market system.

126-Federal Energy Regulatory Administration. Docket No. EL00-24-000. Testimony on behalf of Dayton Power and Light Company regarding the proper characterization and computation of regulation and imbalance charges.

125-American Arbitration Association File 71-198-00309-99. Report on behalf of Orange and Rockland Utilities, Inc. regarding the estimation of damages associated with the termination of a power marketing agreement.

124-Circuit Court, 15th Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limted Partnerships et. al. Analyses related to commercial operation provisions of a power purchase agreement.

1999

123-Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.

122-Federal Energy Regulatory Commission. Docket RM99-2-000. Analyses on behalf of Edison Mission Energy relating to the Regional Transmission Organization Notice of Proposed Rulemaking.

121-Federal Energy Regulatory Commission. Docket No. ER99-3508-000. On behalf of PG&E Energy Trading, analyses associated with the proposed implementation and cutover plan for the New York Independent System Operator.

120-Federal Energy Regulatory Commission. Docket No. EL99-46-000. Comments on behalf of the Electric Power Supply Association relating to the Capacity Benefit Margin.

119-New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

118-JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

117-Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.

1998

116-Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

115-Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an applicaton for a certificate for new generation facilities.

114-Federal Energy Regulatory Commission. Analyses related to a number of dockets reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

113-U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

112-Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

111-Circuit Court, Fourth Judicial Circuit, Duval County, Florida. Analyses related to the proper implementation of a a power purchase agreement and associated calculations of capacity payments. (Testimony 1999)

1997

110-United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

109-United States District Court, Southern District of Florida, Case No. 96-594-CIV, Analyses related to anti-competitive practices by an electric utility and related contract matters regarding the appropriate calculation of energy payments.

108-Virginia State Corporation Commission. Case No. PUE960296. Testimony related to the restructuring proposal of Virginia Power and associated stranded cost issues.

107-Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New

York Power Pool and the implementation of locational marginal cost pricing.

106-Federal Energy Regulatory Commission Dockets No. OA97-261-000 and ER97-1082-000 Analyses and testimony related to the restructuring of the PJM Power Pool and the implementation of locational marginal cost pricing.

105-Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

104-American Arbitration Association. Case 79 Y 199 00070 95. Testimony and analyses related to the proper conditions necessary for the curtailment of Qualifying Facilities and the associated calculations of negative avoided costs.

103-Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.

102-New York Public Service Commission. Case 96-E-0897, Analyses related to the restructuring of Consolidated Edison Company of New York and New York Power Pool proposed Independent System Operator and related transmission tariffs.

1996

101-Florida Public Service Commission. Docket No. 950110-EI. Testimony related to the correct calculation of avoided costs using the Value of Deferral methodology and its implementation.

100-Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Testimony and Analyses related to the estimation of historic market rates for electricity in the Virginia Power service territory.

99-Circuit Court of the City of Richmond Case No. LA-2266-4. Analyses related to the incurrence of actual and estimated damages associated with the outages of an electric generation facility.

98-New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

97-State of New York Supreme Court, Index No. 94-1125. Testimony related to system planning criteria and their relationship to contract performance specifications for a purchased power facility.

96-United States District Court for the Western District of Pennsylvania, Civil Action No. 95-0658. Analyses related to anti-competitive actions of an electric utility with respect to a power purchase agreement.

95-United States District Court for the Northern District of Alabama, Southern Division. Civil Action Number CV-96-PT 0097-S. Affadavit on behalf of TVA and LG&E Power regarding displacement in wholesale power transactions.

1995

94-American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

93-Circuit Court City of Richmond. Law No. LX-2859-1. Analyses related to IPP contract structure and interpretation regarding plant compensation under different operating conditions.

92-Federal Energy Regulatory Commission. Case EL95-28-000. Affidavit concerning the provisions of the FERC regulations related to the Public Utility Regulatory Policies Act of 1978, and relationship of estimated avoided cost to traditional rate based recovery of utility investment.

91-New York Public Service Commission, Case 95-E-0172, Testimony on the correct design of standby, maintenance and supplemental service rates for qualifying facilities.

90-Florida Public Service Commission, Docket No. 941101-EQ. Testimony related to the proper analyses and procedures related to the curtailment of purchases from Qualifying Facilities under Florida and FERC regulations.

89-Federal Energy Regulatory Commission, Dockets ER95-267-000 and EL95-25-000. Testimony related to the proper evaluation of generation expansion alternatives.

1994

88-American Arbitration Association, Case Number 11 Y198 00352 94 Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a NUG facility.

87-United States District Court, Middle District Florida, Case No. 94-303 Civ-Orl-18. Analyses related to contract pricing interpretation other contract matters in a power purchase agreement between a qualifying facility and Florida Power Corporation.

86-Florida Public Service Commission Docket 94037-EQ. Analyses related to a contract dispute between Orlando Power Generation and Florida Power Corporation.

85-Florida Public Service Commission Docket 941101-EQ. Testimony and analyses of the proper procedures for the determination and measurement for the need to curtail purchases from qualifying facilities.

84-New York Public Service Commission Case 93-E-0272, Testimony regarding PURPA policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

83-Circuit Court for the City of Richmond. Case Number LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

82-New York Public Service Commission, Case 93-E-0958 Analyses of Stand-by, Supplementary and Maintenance Rates of Niagara Mohawk Power Corporation for Qualifying Facilities .

81-New York Public Service Commission, Case 94-E-0098. Analyses of cost of service and rate design of Niagara Mohawk Power Corporation.

80-American Arbitration Association, Case 55-198-0198-93, Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power generation facility.

1993

79-U.S. District Court, Southern District of New York Case 92 Civ 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

78-State Corporation Commission, Virginia. Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.

77-Federal Energy Regulatory Commission. Docket ER93-323-000. Evaluations and analyses related to the financial and regulatory status of a cogeneration facility.

76-Federal Energy Regulatory Commission. Docket EL93-45-000; Docket QF83-248-002. Analyses related to the qualifying status of cogeneration facility.

75-Circuit Court of the Eleventh Judicial Circuit, Dade County, Florida. Case No. 92-08605-CA-06. Analyses related to compliance with electric and thermal energy purchase agreements. Damage analyses and testimony.

74-Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

73-State of North Carolina Utilities Commission. Docket No. E-100 Sub 67. Testimony in the consideration of rate making standards pursuant to Section 712 of the Energy Policy Act of 1992.

72-State of New York Public Service Commission. Cases 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.

71-Pennsylvania Public Utility Commission. Docket No. A-110300f051. Testimony regarding the prudence of the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

1992

70-Pennsylvania Public Service Commission. Dockets No. P-870235,C-913318,P-910515,C-913764. Testimony regarding the calculation of avoided costs for GPU/Penelec.

69-Public Service Commission of Maryland. Case No. 8413,8346. Testimony on the appropriate avoided costs for Pepco, and appropriate procedures for contract negotiation.

1991

68-Board of Regulatory Commissioners, State of New Jersey. Docket EM-91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.

67-Public Service Commission of Wisconsin. Docket 05-EP-6. State Advance Plan. Testimony on the calculation of avoided costs and the structuring of payments to qualifying facilities.

66-State Corporation Commission, Virginia. Case No. PUE910033. Testimony on class rate of return and rate design for delivery point service. Northern Virginia Electric Cooperative.

65-State Corporation Commission, Virginia. Case No. PUE910048 Testimony on proper data and modeling procedures to be used in the evaluation of the annual Virginia Power fuel factor.

64-State Corporation Commission, Virginia. Case No. PUE910035. Evaluation of the differential revenue requirements method for the calculation of avoided costs.

63-Public Service Commission of Maryland. Case Number 8241 Phase II. Testimony related to the proper determination of avoided costs for Baltimore Gas and Electric.

62-Public Service Commission of Maryland. Case Number 8315. Evaluation of the system expansion planning methodology and the associated impacts on marginal costs and rate design, PEPCO.

1990

61-Public Utility Commission, State of California, Application 90-12-064. Analyses related to the contractual obligations between San Diego Gas and Electric and a proposed QF.

60-Montana Public Service Commission. Docket 90.1.1 Testimony and analyses related to natural gas transportation, services and rates.

59-State Corporation Commission, Virginia. Case No. PUE890075. Testimony on the calculation of full avoided costs via the differential revenue requirements methodology.

58-District of Columbia Public Service Commission. Formal Case 834 Phase II. Analyses and development of demand side management programs and least cost planning for Washington Gas Light.

57-State Corporation Commission, Virginia. Case No. PUE890076. Analyses related to administratively set avoided costs. Determination of optimal expansion plans for Virginia Power.

56-State Corporation Commission, Virginia. Case No. PUE900052. Analyses supporting arbitration of a power purchase agreement with Virginia Power. Determination of expansion plan and avoided costs.

55-Public Service Commission of Maryland. Case Number 8251. Analyses of system expansion planning models and marginal cost rate design for PEPCO.

54-State Corporation Commission, Virginia. Case No. PUE900054. Evaluation of fuel factor application and short term avoided costs.

53-Federal Energy Regulatory Commission. Northeast Utilities Service Company Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000,ER90-145-000 and El90-9-000. Analyses of the implications of Northeast Utilities and Public Service Company of New Hampshire merger on electric supply and pricing.

52-Public Service Commission of Maryland. Re: Southern Maryland Electric Cooperative Inc. Contract with Advanced Power Systems, Inc. and PEPCO.

51-Puerto Rico Electric Power Authority, Office of the Governor of Puerto Rico. Independent evaluation for PREPA of avoided costs and the evaluation of competing QF's.

50-State Corporation Commission, Virginia. Case No. PUE890041. Testimony on the proper determination of avoided costs with respect to Old Dominion Electric Cooperative.

1989

49-Oklahoma Corporation Commission. Case Number PUD-000586. Analyses related to system planning and calculation of avoided costs for Public Service of Oklahoma.

48-Virginia State Corporation Commission. Case Number PUE890007. Testimony relating to the proper determination of avoided costs to the certification evaluation of new generation facilities.

47-Federal Energy Regulatory Commission. Docket RP85-50. Analyses of the gas transportation rates, terms and conditions filed by Florida Gas Transmission.

46-Circuit Court of the Fifth Judicial Circuit, Dade County, Florida. Case No. 88-48187. Analyses related to compliance with electric and thermal energy purchase agreements.

45-Florida Public Service Commission. Docket 880004-EU. Analysis of state wide expansion planning procedures and associated avoided unit.

1988

44-Virginia State Corporation Commission. Case No. PUE870081. Testimony on the implementation of the differential revenue requirements avoided costmethodology recommended by the SCC Task Force.

43-Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

42-Virginia State Corporation Commission. Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

41-Montana Public Service Commission. Docket 87.8.38. Testimony on Natural Gas Transmission Rate Design and Service Provisions.

40-Oklahoma Corporation Commission. Cause Pud No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

39-Florida Public Service Commission. Docket No.8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

38-Arizona Corporation Commission. Docket No. U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987

37-Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factorapplication and relationship to avoided costs.

36-District of Columbia Public Service Commission. Formal Case No. 834 Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

35-Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

34-Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.

33-Florida Public Service Commission. Docket No. 860004 EU. Testimony in the 1986 annual planning hearing on proper system expansion planning procedures.

1986

32-Florida Public Service Commission. Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

31-Florida Public Service Commission. Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

30-U.S. Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

29-Public Utility Commission, New Hampshire Docket No. DR-86-41. Testimony on pricing and contract terms for power purchase agreement between utility and QFs. (Settlement Negotiations)

28-Florida Public Service Commission, Docket No. 850673-EU. Testimony on generic issues related to the design of standby rates for qualifying facilities.

27-Virginia State Corporation Commission. Case No. 860024. Generic hearing on natural gas transportation rate design and tariff terms and conditions.

26-Virginia State Corporation Commission. Commonwealth Gas Pipeline Corporation. Case No. 850052. Testimony on natural gas transportation rate design and tariff terms and conditions.

25-Bonneville Power Administration. Case No. VI86. Testimony on the proposed Variable Industrial Power Rate for Aluminum Smelters.

24-Virginia Power. Case No. PUE860011. Testimony on the proper ex post facto valuation of avoided power costs for qualifying facilities.

23-Florida Public Service Commission. Docket No. 850004 EU. Testimony on proper analytic procedures for developing a statewide generation expansion plan and associated avoided unit.

1985

22-Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.

21-Arkansas Louisiana Gas. Louisiana Docket No. U-16534. Testimony on proper cost of service procedures and rate design for natural gas service.

20-Connecticut Light and Power. Docket No. 85-08-08.
Assist in the development of testimony for industrial natural gas transportation rates.

19-Oklahoma Gas and Electric. Cause 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.

18-Florida Public Service Commission. Docket No. 840399EU. Testimony on self-service wheeling and business arrangements for qualifying facilities.

17-Virginia Electric and Power Company. General Rate application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.

16-Virginia Electric and Power Company. Fuel Factor
Proceeding No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

15-New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

14-Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

1984

13-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-serviceprocedures, class rate of return and rate design.

12-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

11-Virginia Electric Power Company. Application to Revise Rate Schedule 19 -- Power Purchases from Cogeneration and Small Power Production Qualifying Facilities. Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

10-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

9-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of BPA; interactions between rate design, demand, system expansion and operation.

1983

8-Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

7-Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

6-BPA Wholesale Rate Proceedings. Testimony on the theory and implementation of marginal cost rate design; financial performance of BPA; interactions between rate design, demand, system expansion and operation.

5-Idaho Power Company, PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

1982

4-Generic Conservation Proceedings, New York State. Case No. 18223. Testimony on the economic criteria for the evaluation of conservation activities; impacts on utility financial performance and rate design.

3-PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

2-PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

1-Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

Previous testimony before the District of Columbia
Public Service Commission, Maryland PSC, New York Public Service Commission, FERC; Economic Regulatory Administration

Attachment C

DANLY OFFICE WHITE PAPER

THE REQUIREMENT THAT COMPETITIVE MARKETS BE PROTECTED FROM THE EXERCISE OF MARKET POWER APPLIED TO RTO CAPACITY MARKETS

A fundamental element of the Commission's approval of market-based rates in the electric and natural gas industries is that "[i]n a competitive market, where *neither buyer nor seller has significant market power*, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment."[1]

This White Paper discusses the implications of this principle for RTO capacity market design and, in particular, for the support of resources based on state policy. The discussion is divided into three parts. Part 1 describes the evolution of the Commission's regulation from requiring cost-based rates in almost all circumstances to a regulatory regime that relies extensively on market forces to establish just and reasonable rates. Part 2 examines RTO capacity markets, how buyer-side market power is exercised in those markets and how, to date, those markets have included protections against the exercise of buyer-side market power through state subsidies. Part 3 explains why RTO capacity markets cannot be just and reasonable under the law absent provisions designed to protect against the exercise of both seller-side and buyer-side market power, including buyer-side market power exercised by the states.

I. EVOLUTION OF THE COMMISSION'S RATE REGULATION UNDER THE STATUTORY JUST AND REASONABLE STANDARD

The same statutory standard applies to the Commission's regulation of rates in the electric industry and the natural gas industry. In each case, the Commission is required to ensure that rates are "just and reasonable."[2] Although the just and reasonable standard is typically thought of as being intended to protect consumers from unreasonably high rates, it also protects sellers from being required to provide service at unreasonably low rates. As the Supreme Court put in in its seminal *Hope* decision, "[t]he rate-making process

[1] *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004) (quoting *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990)) (emphasis added).

[2] *See* 16 U.S.C. §§ 824d, 824e (Federal Power Act (FPA) sections 205 and 206); 15 U.S.C. §§ 717c, 717d (Natural Gas Act sections 4 and 5).

under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of *the investor and the consumer interests*."[3]

The Supreme Court has held on numerous occasions that, under the just and reasonable standard, "the Commission is not bound to any one ratemaking formula."[4] Nevertheless, prior to the 1990s, the Commission generally applied a cost-of-service approach, based on the service provider's costs plus a rate of return sufficient to attract necessary capital.[5] Although there are numerous forms of cost-of-service regulation, they all boil down, in some fashion, to establishing a rate based on the cost of providing service plus an added rate of return.

In the early 1970s—at a time when the Commission was charged with the formidable task of regulating the prices of all natural gas sold in interstate commerce—the Commission attempted to apply a market-based approach to regulating sales by small producers. This attempt was soundly rejected by the Supreme Court in 1974 in *Federal Power Commission v. Texaco*.[6] The Court's reasoning was as follows:

> For the purposes of the proceedings that may occur on remand, we should also stress that in our view *the prevailing price in the marketplace cannot be the final measure of 'just and reasonable' rates* mandated by the Act. It is abundantly clear from the history of the Act and from the events that prompted its adoption that Congress considered that the natural gas industry was heavily concentrated and that monopolistic forces were distorting the market price for natural gas. Hence, the necessity for regulation . . . . *In subjecting producers to regulation because of anticompetitive conditions in the industry, Congress could not have assumed that "just and reasonable" rates could conclusively be determined by reference to market price*.[7]

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[3] *Fed. Power Comm'n v. Hope Gas Co.*, 320 U.S. 591, 603 (1944) (emphasis added) (*Hope*).

[4] *Morgan Stanley Capital Grp. v. Pub. Util. Dist. No. 1 of Snohomish Cty., Wash*., 554 U.S. 527, 532 (2008) (citing *Mobil Oil Exploration & Producing Se., Inc. v. United Distribution Cos.*, 498 U.S. 211, 224 (1991); *Permian Basin Area Rate Cases*, 390 U.S. 747, 776-77 (1968)).

[5] *See id.*

[6] 417 U.S. 380 (1974) (*Texaco*).

[7] *Id.* at 397-99 (emphasis added).

This holding appeared to drive a stake into the heart of market-based pricing under the just and reasonable standard. However, twenty years later, the Commission turned again to market forces to aid in setting rates, and this time it met with more success reconciling the employment of market-based rates and the reasonable standard.

The first step came in a case—*Tejas Power Corp.*[8]—that did not actually involve a market-based rate. There, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) reviewed a natural gas pipeline rate settlement that had been approved by the Commission on the grounds that all of the pipeline's local distribution company (LDC) customers had agreed to it. The court observed that:

> In a competitive market, where *neither buyer nor seller has significant market power*, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal cost, such that the seller makes only a normal return on its investment.[9]

The court then went on to reject the Commission's approval of the settlement because it had not determined whether the pipeline had market power and there was thus no basis for the Commission to conclude that the LDCs' voluntary agreement demonstrated that the settlement rates were just and reasonable.[10] However, the court's observation that market-based rates *could* be just and reasonable "where neither buyer nor seller has significant market power"[11] pointed a way past the Supreme Court's holding in *Texaco* that "the prevailing price in the marketplace cannot be the final measure of 'just and reasonable' rates."[12] The Supreme Court's holding had been grounded on the then-prevailing market conditions, where "the natural gas industry was heavily concentrated and . . . monopolistic forces were distorting the market price for natural gas."[13] However, if the Commission could show that neither buyers nor sellers had significant market power, thereby demonstrating that monopolistic forces were not distorting market prices, then the prevailing market price would *not* be the "final measure," and the use of market-based rates could satisfy the just and reasonable

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[8] 908 F.2d 998.

[9] *Id.* at 1004 (emphasis added).

[10] *See id.* at 1004, 1006.

[11] *Id*. at 1004.

[12] *Texaco*, 417 U.S. at 397.

[13] *Id.* at 397-98.

standard. This insight in *Tejas Power* has been cited in almost every subsequent court decision addressing the legitimacy of the Commission's market-based rate regimes.[14]

In order to meet the requirements of *Tejas Power*, the Commission's subsequent orders granting market-based rates have all relied on a finding that the participants in the market either do not have market power or that any market power they possess has been mitigated. For example, in *Elizabethtown Gas Co.*, the D.C. Circuit described in detail the market analysis conducted by the Commission before approving Transcontinental Gas Pipe Line Company's (Transco) request that its merchant function be permitted to sell natural gas a market-based rates. From this, the court concluded the Commission's analysis "provides strong reason to believe that Transco will be able to charge only a price that is 'just and reasonable' within the meaning of § 4 of the NGA."[15]

Order No. 697,[16] in which the Commission issued its regulations governing market-based rate sales in the electric industry, similarly focuses on ensuring that market prices are not distorted by market power. Under Order No. 697, the Commission analyzes whether a seller has market power and, if so, requires mitigation.[17] Order No. 697 also requires sellers to comply with all market power mitigation measures instituted by RTOs.[18] The Commission recognized that monopsony power could also be an

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[14] *See, e.g.*, *Mont. Consumer Counsel v. FERC*, 659 F.3d 910, 916 (9th Cir. 2011); *Blumenthal v. FERC*, 552 F.3d 875, 882 (D.C. Cir. 2009); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d at 1013; *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870 (D.C. Cir. 1993) (*Elizabethtown Gas*).

[15] *Elizabethtown Gas*, 10 F.3d at 871.

[16] *Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, Order No. 697, 119 FERC ¶ 61,295, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011).

[17] Order No. 697, 119 FERC ¶ 61,295 at P 3.

[18] More recently, the Commission held that, because RTO mitigation measures adequately mitigate market power, sellers need not demonstrate a lack of market power in order to make market-based sales in RTO markets. *See Refinements to Horizontal Mkt. Power Analysis for Sellers in Certain Regional Transmission Orgs. & Indep. Sys. Operator Mkts.*, Order No. 861, 168 FERC ¶ 61,040 (2019), *order on reh'g and clarification*, Order No. 861-A, 170 FERC ¶ 61,106 (2020).

important issue, but at the time of issuance there was insufficient evidence to confirm what was then a theoretical problem, and the Commission reserved taking action until monopsony power issues were raised in a market-based rate proceeding or in a complaint.[19] On appeal, the Ninth Circuit held: "By screening for market power before authorizing market-based rates, and by continually monitoring sellers for evidence of market power, FERC has adopted a permissible approach to fulfilling its statutory mandate *to ensure that rates are just and reasonable.*"[20]

In sum, as the Supreme Court has made clear, "the prevailing price in the marketplace *cannot be the final measure of 'just and reasonable' rates*."[21] Instead, in order for sales at a market-based rate to be just and reasonable, the sales must be made in a market "where neither buyer nor seller has significant market power."[22] Where buyers or sellers do have market power and that market power is not mitigated, market-based rates cannot satisfy the just and reasonable standard.

II. THE EXERCISE OF BUYER-SIDE MARKET POWER IN RTO CAPACITY MARKETS THROUGH STATE SUBSIDIES

As the Supreme Court has explained, buyer-side market power, more commonly known as monopsony market power, "is market power on the buy side of the market."[23] The Court went on to observe that "monopsony is to the buy side of the market what a monopoly is to the sell side and is sometimes colloquially called a 'buyer's monopoly.'"[24] Further, "[M]onopoly and monopsony are symmetrical distortions of competition from an economic standpoint."[25]

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[19] Order No. 697, 119 FERC ¶ 61,195, at P 463.

[20] *Montana Consumer Counsel*, 659 F.3d at 919 (emphasis added).

[21] *Texaco*, 417 U.S. at 397.

[22] *Tejas Power*, 908 F. 2d at 1004.

[23] *Weyerhaeuser Co. v. Ross-Simmons Hardwood Lumber Co., Inc.*, 549 U.S. 312, 320 (2007) (citing Blair & Harrison, *Antitrust Policy and Monopsony*, 76 Cornell L.Rev. 297 (1991).

[24] *Id.*, 549 U.S. at 320 (citing Piraino, *A Proposed Antitrust Approach to Buyers' Competitive Conduct*, 56 Hastings L.J. 1121, 1125 (2005)).

[25] *Id.* at 322 (quoting *Vogel v. American Soc. of Appraisers*, 744 F.2d 598, 601 (7th Cir. 1984).

In most markets, buyer-side market power is exercised through the prices offered by the buyer of a product. For example, the claim examined by the Supreme Court in *Weyerhaeuser* was that a buyer with monopsony power artificially raised the price it paid for saw logs, thereby raising the market price for the logs and driving a competing lumber company out of business.[26] Such a tactic is known as "predatory bidding."[27]

Buyer-side market power in RTO capacity markets, while similarly distorting competition, is exercised in a completely different manner. This is because of the relative lack of the ability of buyers to directly influence capacity prices through the submission of offers to purchase at a certain price. Instead, the demand curves used by RTOs to set capacity prices are administratively derived by the RTOs. This is necessary because there is very little price-elasticity of demand for capacity in the RTO markets, especially during the peak periods used to determine the level of demand in the capacity auctions.[28]

Buyer-side market power can be exercised in RTO capacity markets not through altering the price offered for purchases by a buyer, but rather by subsidizing or otherwise paying owners of generation to submit below cost offers to sell capacity into the RTO capacity markets. The submission of below cost offers into a capacity auction can artificially suppress the resulting price derived by the market for capacity in one of two ways: (1) if a subsidized resource would have submitted the marginal cost offer had it not been subsidized, offering that resource's capacity below its marginal cost would cause the market clearing price to be lowered to the price offered by the next highest cost offer; and (2) if the cost of a subsidized resource is higher than the market clearing price, then offering the resource below its cost will lower the supply curve, thereby lowering the point of intersection of the supply curve and the demand curve and lowering the resulting capacity price.

The Commission and the RTOs recognized the potential for the exercise of buyer-side market power to reduce capacity prices almost from the first RTO capacity auctions. For example, in its 2006 order first approving PJM's Reliability Pricing Model (RPM) that, as subsequently modified, forms the basis for PJM's capacity market today, the

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[26] *Id.* at 314-16.

[27] *Id.* at 320.

[28] The complex reasons for this are beyond the scope of this White Paper, but include that: (1) at present, there is little storage capacity for electricity, which otherwise must be consumed when generated; (2) electricity is an essential commodity that most consumers demand with little regard to price; (3) most consumers do not know the price of the electricity at the time they are consuming it; and (4) most consumers are charged an average rate for the electricity over a period of time, such as one month, and therefore do not pay the cost of the electricity they consume at the time they consume it.

Commission approved PJM's proposed Minimum Offer Price Rule (MOPR)—intended to mitigate buyer-side market power—on the following grounds:

> The Commission finds the Minimum Offer Price Rule a reasonable method of assuring that net buyers *do not exercise monopsony power by seeking to lower prices* through self supply.[29]

The Commission also approved buyer-side market power mitigation provisions in early versions of the ISO-New England and New York ISO capacity markets.[30]

The first iteration of PJM's tariff governing the RPM capacity auction did not apply the MOPR to generation resources subsidized by states, as opposed to load serving entities. The Commission approved this exclusion because it "enables states to meet their responsibilities to ensure local reliability."[31] However, in 2011, the Commission approved PJM's proposal to eliminate the exclusion of state-supported resources from its MOPR.[32] The Commission explained that:

> *The mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules* that could allow uneconomic entry has caused us to reexamine our acceptance of the existing state exemption, which we approved as part of the 2006 RPM Settlement Order. For these reasons, we accept as just and reasonable PJM's proposal to eliminate the current state exemption.[33]

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[29] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 104 (2006).

[30] *See Devon Power LLC.*, 115 FERC ¶ 61,340, at P 113 (2006) ("when loads own new resources, they may have an interest in depressing the auction price, since doing so could reduce the prices they must pay for existing capacity procured in the auction."); *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211, at P 103 ("Markets require appropriate price signals to alert investors when increased entry is needed. By allowing net buyers to artificially depress prices, these necessary price signals may never be seen."), *order on reh'g* 124 FERC ¶ 61,301, at P 27 (2008) ("the proposed rules, as modified herein, assure that uneconomic new capacity will not be allowed to distort market supply curves and inefficiently depress market clearing prices below a competitive level.").

[31] *PJM*, 117 FERC ¶ 61,331 at P 104.

[32] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 (2011).

[33] 135 FERC ¶ 61,022 at P 139 (emphasis added).

Based on this evidence, the Commission approved the elimination of the state exclusion because "we are statutorily mandated to protect the RPM against the effects of such entry."[34]

The Commission's approval of the elimination of the state exclusion was upheld on appeal to the Third Circuit.[35] First, the court found that the Commission had jurisdiction to apply the MOPR to state supported resources because "it is undisputed that New Jersey and Maryland's plans to introduce thousands of megawatts of new capacity into the Base Residual Auction would have had an effect on the prices of wholesale electric capacity in interstate commerce."[36] The Court went on to find that the Commission's decision to apply the MOPR was reasonable because:

> [T]he actual prospect of thousands of megawatts of new generation, developed under arrangements that would explicitly subsidize the resources regardless of Auction price, potentially being offered into the Reliability Market at a zero bid brought into focus the distortive effect—no longer "theoretical"—that the state exemption could have on market prices for all capacity.[37]

The Commission made clear at about the same time that state-sponsored resources would also be subject to buyer-side market power mitigation in the ISO-New England and New York ISO capacity markets.[38] The Commission subsequently permitted certain limited exemptions from the MOPR for state supported resources on the grounds that the

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[34] *Id.* at P 143.

[35] *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 96-102 (3d Cir. 2014).

[36] 744 F.3d at 96 (citing *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 374 (1988)).

[37] *Id.* at 100.

[38] *See ISO New England Inc.*, 142 FERC ¶ 61,107, at P 96 (2013) ("We will accept [ISO-New England's] MOPR proposal that applies mitigation to all new resources offering into the FCM, including renewables that are procured pursuant to state policy initiatives to meet Renewable and Alternative Portfolio Standards."); *N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,301 at P 38 (2008) ("at this time, the NYPSC has provided inadequate justification either for a general exemption [from the MOPR] or for a finding that the appropriate mechanism for supporting its goals is, in fact, an exemption from the price floor for new capacity.").

limited exception would not lead to significant price suppression.[39] However, the Commission has never found that it is appropriate to grant a blanket exemption to state supported resources from the buyer-side market power mitigation provisions applied to RTO capacity markets, and its refusal to do so has been upheld by the courts.[40]

Today, PJM, ISO-NE, and the New York ISO all have buyer-side market power mitigation provisions applicable to state-supported resources that protect the competitiveness of their capacity auctions.[41] These provisions are controversial and subject to mounting criticism. But they all reflect the Commission's consistent determination to date that it is necessary to protect against the state exercise of buyer-side market power in order for RTO capacity market prices to be just and reasonable.

III. RTO CAPACITY MARKETS MUST BE PROTECTED AGAINST BOTH SELLER-SIDE AND BUYER-SIDE MARKET POWER IN ORDER FOR THE RESULTING CAPACITY PRICES TO BE JUST AND REASONABLE

The need for RTO capacity markets to be protected against the exercise of market power is not optional. As I have explained, the Supreme Court has held that "the prevailing price in the marketplace *cannot be the final measure of 'just and reasonable'*

[39] *See, e.g., ISO New England Inc.*, 147 FERC ¶ 61,173, at PP 81-88 (2014) (approving exemption for 200 MW/year of state-supported Renewable Technology Resources), *order on reh'g*, 150 FERC ¶ 61,065 (2015); *order on remand*, *ISO New England Inc.*, 155 FERC ¶ 61,023, at P 33 (2016), *order on reh'g*, 158 FERC ¶ 61,138, at PP 43, 48 (2017), *aff'd sub nom*. *NextEra Energy Res., LLC v. FERC*, 898 F.3d 14 (D.C. Cir. 2018).

[40] *See, e.g. New England Power Generators Ass'n v. FERC*, 757 F.3d 283, 295 (D.C. Cir. 2014) ("We defer to the Commission's decision to decline a categorical mitigation exemption for self-supplied and state-sponsored resources.").

[41] *See Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239, at P 5 (2019) (establishing an extended MOPR because "subsidized resources distort prices in a capacity market that relies on competitive auctions to set just and reasonable rates."); *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 72 (implementing Competitive Auctions with Sponsored Policy Resources (CASPR) rules that apply a MOPR to state-supported resources that "seeks to balance accommodating the entry of Sponsored Policy Resources in the FCM over time with maintaining competitively-based capacity auction prices."); *N.Y. Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,121 (2020) (limiting state-supported resources entitled to an exemption from MOPR).

rates."[42] Instead, the market-based prices derived from the RTO capacity markets are just and reasonable only when those prices are unaffected by the exercise of market power. That means that markets must not only include provisions to mitigate seller-side market power, but RTO capacity markets must be markets "where neither buyer *nor seller* has significant market power."[43] Otherwise, it would not be "rational to assume that the terms of their voluntary exchange are reasonable," or "to infer that the price is close to marginal cost."[44]

And, because state subsidies to generation owners constitute the exercise of buyer-side market power, RTO capacity markets must have provisions to mitigate the effects of such subsidies, as the Commission has held on numerous occasions. This is not a requirement the Commission has imposed only recently, based, as some have alleged, on political animosity toward renewable resources. Rather, as described in Part II, the Commission has consistently held—and the courts have consistently affirmed—that RTO capacity markets must have provisions mitigating state buyer-side market power. Without mitigation, the prices that result from those markets cannot be just and reasonable.

There is, of course, more than one approach to the mitigation of the states' exercise of buyer-side market power. The merit of any particular approach is beyond the scope of this white paper. The essential point is that RTO capacity markets must have provisions that adequately mitigate the states' exercise of buyer-side market power or the RTO capacity markets cannot be just and reasonable.

Three major arguments have been raised against the application of buyer-side market power mitigation measures to state subsidies: (1) such application is beyond the Commission's jurisdiction under the Federal Power Act (FPA); (2) such application unreasonably interferes with state policy choices; and (3) such application is unnecessary because RTO capacity markets are nothing more than administrative constructs that do not reflect competitive forces. Each of these arguments is briefly addressed below.

1. The Commission Has Jurisdiction to Mitigate State Buyer-Side Market Power

The argument that the Commission has no jurisdiction to impose buyer-side mitigation to state-supported resources has been considered and rejected by the Courts. For example, the D.C. Circuit held as follows in addressing this argument made on

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[42] *Texaco*, 417 U.S. at 397.

[43] *Tejas Power*, 908 F. 2d at 1004 (emphasis added).

[44] *Id.*

appeal of the Commission's approval of PJM's elimination of the state exemption from the MOPR:

> After reviewing the FERC Orders at issue here and the relevant case law, we conclude that FERC did not exceed its jurisdiction in eliminating the state-mandated provision. Under the FPA, FERC has jurisdiction over rules affecting the rates of the transmission or sale of energy in interstate commerce. *See* 16 U.S.C. § 824d. Here, it is undisputed that New Jersey and Maryland's plans to introduce thousands of megawatts of new capacity into the Base Residual Auction would have had an effect on the prices of wholesale electric capacity in interstate commerce. *See Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 374 (1988) (holding, among other things, that FERC had jurisdiction over power allocations that affect wholesale rates, and stating that "[s]tates may not regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates or to insure that agreements affecting wholesale rates are reasonable.") (emphasis added); *Municipalities of Groton v. FERC*, 587 F.2d 1296, 1302 (D.C. Cir.1978) (rejecting jurisdictional challenge to FERC's authority to levy deficiency charges on utilities that failed to procure generating capacity sufficient to meet its load requirements, and stating that, "[i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying that charge.").[45]

The D.C. Circuit then reiterated its holding later that same year in the appeal of ISO-New England's buyer-side mitigation provisions:

> FERC's rate-making authority confers broad power "to act in the public interest." *Miss. Indus. v. FERC*, 808 F.2d 1525, 1549 (D.C. Cir.1987) (internal quotations omitted), *vacated and remanded in part on other grounds*, 822 F.2d 1104 (D.C. Cir. 1987). We hold that FERC has jurisdiction to regulate the parameters comprising the Forward Capacity Market, and that applying offer-floor mitigation fits within the Commission's statutory rate-making power.[46]

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[45] *N.J. Bd. of Pub. Utils.*, 744 F.3d at 96.

[46] *New England Power Generators*, 757 F.3d at 291.

2. Deference to State Policy Does Not Justify the Approval of a Rate that is Not Just and Reasonable

The next argument asserts that, even if the Commission has the jurisdiction to require mitigation of state buyer-side market power, the Commission is not obligated to exercise that jurisdiction. Instead, unless state support for a generation resource is preempted under the standards of *Hughes v. Talen*,[47] the Commission should exercise its discretion to defer to the state policy and exempt it from RTO provisions protecting capacity markets against buyer-side market power.

It is of course appropriate for the Commission to take state policy choices into consideration in evaluating RTO capacity markets and it may be appropriate to accommodate those policies when doing so is consistent with the Commission's statutory obligations. But the Commission has the duty under the Federal Power Act to ensure that jurisdictional rates are just and reasonable. As explained above, market-based rates are not just and reasonable unless reached in a market "where neither buyer *nor seller* has significant market power."[48] The Commission cannot defer to a state policy when doing so would lead to a rate that is not just and reasonable, and failing to mitigate a state policy that exercises buyer-side market power to suppress RTO capacity prices would result in rates that are not just and reasonable.[49]

This holds true regardless of the whether the state articulates policy goals other than that of suppressing capacity prices. The Commission's evaluation of a seller's market power focuses on identifying whether a seller has market power and, if so, if that market power has been mitigated.[50] The Commission does not condition the requirement to mitigate a seller's market power on any consideration of whether a seller with market power has indicated any intent to actually exercise its market power to raise prices. Similarly, the question for buyer-side market power must be whether such market power

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[47] *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016)

[48] *Tejas Power*, 908 F. 2d at 1004 (emphasis added).

[49] *See N.J. Bd. of Pub. Utils.*, 744 F.3d at 101 ("FERC noted that while its 'intent [was] not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives,' the agency was 'forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's RPM is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity.'") (quoting *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,45 at P 3 (2011)).

[50] *See* Order No. 697 at P 3.

exists and, if so, whether it has been mitigated.[51] States clearly have the ability to affect RTO capacity market prices through subsidies, and therefore RTO markets must have provisions mitigating that market power in order for the prices resulting from RTO markets to be just and reasonable.[52]

This does not mean that the Commission is powerless to accommodate state policies (other than a state policy of price suppression) favoring certain types of generation resources. There are a number of RTO capacity market proposals that do just that. It does mean, however, that such accommodation must be achieved without artificially suppressing the RTO capacity market prices, which would result in capacity prices that are not just and reasonable.

3. RTO Capacity Markets Employ Administrative Constructs to Achieve Competitive Prices

The third argument is based on a criticism frequently raised against RTO capacity markets. It is based on the assertion that these markets are nothing more than an "administrative construct." The conclusion reached from this assertion is that prices determined in the RTO capacity markets are not the result of competitive forces. Therefore, so the logic goes, there is no reason to take action to protect those markets from distorted prices that do not reflect competitive outcomes.

This view improperly conflates two distinct concepts: market design which, by its very nature, must be based on an administrative construct, and market outcomes, which are driven by competitive forces. All central markets, by their nature, must be conducted pursuant to an administratively determined market design; whether that determination is made by a private market administrator or by a government regulator. There must be a standard definition, for example, of the product that is being traded in the market, there must be rules governing who may participate in the market as buyers and sellers, how trades must be executed, and rules designed to prevent market manipulation and the exercise of market power.

Securities markets, for example, are subject to detailed rules administered by market operators and overseen by the SEC that define the characteristics of the security and how is to be conducted. Commodities markets likewise have detailed rules as to

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[51] *See New England Power Generators*, 757 F.3d at 292 ("FERC specifically found that "[out-of-market] capacity suppresses prices *regardless of intent*," and this *necessitates action* by the Commission to correct for unjust and unreasonable outcomes.")(quoting *ISO New England Inc.*, 138 FERC ¶ 61,027 at P 170 (2011)) (emphasis added).

[52] *Cf. New England Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283 (2014)

what constitutes, for example, the "lean hogs" or "soybean meal" that are traded in the commodities markets. There also are detailed rules regarding the contracts used to trade commodities futures. These rules all affect the prices that result from the market. But, absent the exercise of market power or price manipulation, the prices that result from the administrative constructs governing these markets are established by competitive forces.

The same is true of RTO capacity markets. These markets are circumscribed by complex rules that address issues such as the definition of the product being sold, the entities entitled to participate as sellers, and the obligations associated with receiving a capacity award. There also are detailed rules designed to prevent the exercise of market power, both seller-side and buyer-side. But these rules—administrative constructs—simply set the boundaries within which competitive forces establish capacity prices "where neither buyer nor seller has significant market power."[53] Far from divorcing RTO capacity markets from competitive forces, the administrative constructs governing RTO capacity markets are what ensure that the results of those markets *are* competitive.[54] And the detailed rules protecting those results from the exercise of market power are necessary to ensure that those results continue to be competitive.

Moreover, to the extent to which the Commission were to determine that RTO capacity markets are based on an administrative construct that does not provide for competitive capacity prices, the consequence would have be that the prices from those markets could not be found to be just and reasonable. The Commission would be required either to develop an alternative administrative construct that permits the establishment of competitive prices free from seller-side and buyer-side market power or else to return to a cost-based regime for determining capacity prices. Continuing the use of the same administrative construct, modified only to eliminate mitigation of state buyer-side market power, would not lead to just and reasonable capacity prices being established in a market that did not produce competitive results in the first place.

IV. CONCLUSION

The states have buyer-side market power, and that market power cannot be ignored any more than the seller-side market power possessed by a number of companies that have amassed significant quantities of generation capacity. There are options for mitigating state buyer-side market power while at the same time accommodating state policies favoring certain types of generation resources. But state buyer-side market

[53] *Tejas Power*, 908 F.2d at 1004.

[54] To argue otherwise would be to conclude that, because tennis is played on a court of certain dimensions, over a net of a certain height, and that points are scored under particular conditions, tennis, as a game, is "uncompetitive." It is in fact the rules that permit competitive outcomes.

power must be mitigated in the RTO capacity markets. This is not a policy-driven position that can be changed by changing the Commission's policy. Rather it is a mandate dictated by the statutory requirement that the prices that result from RTO capacity markets must be just and reasonable.

Attachment D

DANLY OFFICE WHITE PAPER

THE REQUIREMENT THAT COMPETITIVE MARKETS BE PROTECTED FROM THE EXERCISE OF MARKET POWER APPLIED TO RTO CAPACITY MARKETS

SUPPLEMENT (June 17, 2021)

On May 20, 2021, our office issued a White Paper explaining why, under the law, RTO capacity markets cannot produce just and reasonable rates absent mechanisms that protect the market against the exercise of both seller-side and buyer-side market power, including buyer-side market power exercised by the states. We have received a great deal of feedback from many stakeholders and sincerely appreciate the engagement. One comment that we have received several times is that state action to subsidize resources cannot constitute the exercise of buyer-side market power because the states are not acting as buyers of power as their subsidies generally go to sellers, not buyers.

We are providing this supplement to our White Paper to address that comment. As explained below, it might perhaps be more accurate to describe state subsidies as providing incentives to owners of generation resources to exercise *seller-side* market power to reduce capacity market clearing prices. In any event, regardless of how one characterizes state subsidies: (1) the Commission and the courts have long found that it is appropriate to mitigate the price suppressive effects of state actions to subsidize generation; (2) it is necessary for RTO capacity markets to mitigate the price suppressive effects of state subsidies in order for capacity market prices to be just and reasonable; and (3) the intent of the states and the legitimacy of their reasons for offering subsidies is irrelevant to the question of whether the subsidies affect the justness and reasonableness of RTO capacity market prices.

We are interested in hearing reactions to this supplement. Please contact Matt Estes at matthew.estes@ferc.gov if you would like to discuss this further.

I. STATE SUBSIDIES PROVIDE INCENTIVES TO GENERATION OWNERS TO EXERCISE SELLER-SIDE MARKET POWER TO REDUCE CAPACITY MARKET CLEARING PRICES

It is of course true that states do not directly purchase power. Furthermore, the fixed demand curves used in RTO capacity auctions make it very difficult for any purchaser of capacity to directly influence capacity prices. That being the case, it is worth pausing to consider exactly how it is that state subsidies suppress RTO capacity market prices.

The answer is that the price suppression occurs through offers submitted into the auctions by subsidized *sellers* of capacity. As a general matter, an unsubsidized generation owner has an incentive to submit a capacity offer at a price close to its marginal cost. Otherwise, the owner would run the risk of receiving a capacity award at a clearing price below its marginal cost that would obligate the owner to operate its facility at a loss.[1]

By contrast, state subsidies make sellers indifferent as to whether they receive a capacity award priced below their marginal costs because the subsidy makes up any shortfall in market revenues earned by the seller. Therefore, owners of subsidized units have an incentive to offer below their marginal costs because their subsidy ensures that they will not operate at a loss even if the capacity market clears at a price below their marginal costs. Indeed, the entire objection to RTO minimum offer price rules (MOPRs) is that they prevent owners of subsidized generation resources from offering into capacity markets at prices below their marginal costs.

It is the price suppression caused by the submission of below-cost offers by *sellers* that has led RTOs, with the Commission's approval, to implement MOPRs that apply to offers by sellers of capacity from state-supported resources. In *New Jersey Board of Public Utilities v. FERC*, for instance, the Third Circuit accepted FERC's justification for such application of a MOPR by PJM:

> [T]he actual prospect of thousands of megawatts of new generation, developed under arrangements that would explicitly subsidize the resources regardless of Auction price, potentially being offered into the Reliability Market at a zero bid brought into focus the distortive effect—no longer "theoretical"—that the state exemption could have on market prices for all capacity.[2]

Whether state subsidies that create incentives for thousands of megawatts of below-cost capacity offers by sellers is properly characterized as the exercise of "buyer-side market power" is beside the point. If the price suppression is not caused by buyer-side market power, it is caused by seller-side market power. Either way, state subsidies artificially and unreasonably suppress capacity prices in an unduly preferential and

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[1] The calculus engaged in by owners of unsubsidized generation owners is more complicated than this. For example, the owner of an inexpensive resource might reasonably offer in below its marginal cost in the expectation that the market will clear at a level equal to the marginal costs of more expensive resources. There are other legitimate reasons for a generation owner to offer above or below its marginal costs based on its circumstances and its evaluation of the competitive conditions. However, as a general matter, owners of resources with marginal costs near the expected market clearing price can be expected to offer at or near their marginal costs.

[2] 744 F.3d 74, 100 (3d Cir. 2014) (citation omitted).

discriminatory manner that must be mitigated to protect the integrity of a capacity market premised on competition.

Currently, the capacity markets in PJM and ISO-NE are deemed to be uncompetitive, and therefore market power mitigation is applied to all offers by all generation resources into their capacity markets.[3] This mitigation must prevent both the exercise of market power to artificially increase capacity prices and the exercise of market power to artificially suppress capacity prices.

II. THE COMMISSION AND THE COURTS HAVE LONG FOUND IT NECESSARY TO MITIGATE THE PRICE SUPPRESSIVE EFFECTS OF STATE ACTIONS TO SUBSIDIZE GENERATION

Regardless of how state subsidies are characterized, both the Commission and the courts have consistently recognized that the price suppressive effects of such subsidies must be mitigated. And the Commission's orders to this effect have consistently been upheld on appeal.

For example, in 2008, the Commission upheld NYISO's application of a MOPR to state-supported resources, finding that "uneconomic entry can produce unjust and unreasonable prices by artificially depressing capacity prices and NYISO's proposal provides a reasonable means to deter that uneconomic entry."[4] The Commission concluded that, "at this time, the NYPSC has provided inadequate justification either for a general exemption [from the MOPR] or for a finding that the appropriate mechanism for supporting its goals is, in fact, an exemption from the price floor for new capacity."[5]

In 2011, the Commission approved PJM's proposal to eliminate the exclusion of state-supported resources from its MOPR.[6] The Commission explained that:

> *The mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules* that could allow uneconomic entry has caused

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[3] *See* ISO New England Inc. Internal Market Monitor, *2020 Annual Markets Report*, at 35-36 (June 9, 2021), 2020-annual-markets-report.pdf (iso-ne.com); PJM, *2022/2023 RPM Base Residual Auction Results*, at 4 (June 2, 2021), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx.

[4] *N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,301, at P 36 (2008) (citing *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211, at P 110 (2008)).

[5] *Id.* P 38.

[6] *See PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 (2011).

> us to reexamine our acceptance of the existing state exemption, which we approved as part of the 2006 RPM Settlement Order. For these reasons, we accept as just and reasonable PJM's proposal to eliminate the current state exemption.[7]

As noted above, on appeal to the Third Circuit, the court accepted the Commission's reasoning that application of the MOPR to state subsidies was reasonable because of "the distortive effect—no longer 'theoretical'—that the state exemption could have on market prices for all capacity."[8]

The Commission similarly refused to categorically exempt state sponsored resources from ISO-NE's MOPR, holding that "[w]e will accept [ISO-New England's] MOPR proposal that applies mitigation to all new resources offering into the FCM, including renewables that are procured pursuant to state policy initiatives to meet Renewable and Alternative Portfolio Standards."[9] This holding likewise was upheld on appeal by the D.C. Circuit in a section of its opinion titled "Buyer-Side Mitigation."[10] The court concluded that "FERC's considered conclusion that certain resources, by definition, depress capacity prices falls within its duty of ensuring that rates are just and reasonable."[11]

Since that time, the Commission has held on numerous occasions that it is appropriate to implement measures to mitigate price suppression resulting from state subsidies. Today, PJM, ISO-NE, and the NYISO all continue to apply mitigation in their capacity markets to state-supported resources whose subsidized offers otherwise would distort the competitiveness of the capacity auctions.[12]

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[7] *Id.* P 139 (footnote omitted) (emphasis added).

[8] *N.J. Bd. of Pub. Utils.*, 744 F.3d at 100.

[9] *ISO New England Inc.*, 142 FERC ¶ 61,107, at P 96 (2013).

[10] *New England Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 291-95 (D.C. Cir. 2014).

[11] *Id.* at 295.

[12] *See N.Y. Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,121, at P 65 (2020) (limiting state-supported resources entitled to an exemption from MOPR); *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239, at P 5 (2019) (establishing an extended MOPR because "subsidized resources distort prices in a capacity market that relies on competitive auctions to set just and reasonable rates"); *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 72 (2018) (implementing Competitive Auctions with Sponsored

It is not credible to assert that more than ten years of consistent Commission precedent requiring mitigation of price suppressive subsidies can now be ignored simply because the states themselves are not purchasers of power.

III. RTO CAPACITY MARKETS MUST MITIGATE THE PRICE SUPPRESSIVE EFFECTS OF STATE SUBSIDIES IN ORDER FOR CAPACITY MARKET PRICES TO BE JUST AND REASONABLE

In section III of the White Paper, we explained why, consistent with voluminous court precedent, competitive electric markets must be free from the exercise of both seller-side and buyer-side market power in order for the resulting prices to be just and reasonable. As we explained, the courts have held that market prices cannot be found to be just and reasonable without some mechanism to eliminate market power, but that "[i]n a competitive market, where *neither buyer nor seller has significant market power*, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment."[13]

This argument—that states are not purchasers—has been made in an attempt to distinguish the price suppressive effect of state subsidies from the situation described above by the D.C. Circuit. According to this argument, because states are not buyers of capacity in the RTO capacity markets, the provision of state subsidies to sellers cannot represent the exercise of buyer-side market power and the resulting capacity market prices are therefore free from buyer-side market power.

Although the term "buyer-side market power" may be arguably inapposite to the market-distorting effect of state subsidies, that terminology has come to be employed as a convenient shorthand. While language matters, the essential point is that state subsidies *distort* and suppress capacity market prices, as the Commission has repeatedly held.[14]

Policy Resources (CASPR) rules that apply a MOPR to state-supported resources that "seeks to balance accommodating the entry of Sponsored Policy Resources in the FCM over time with maintaining competitively-based capacity auction prices").

[13] *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990) (emphasis added).

[14] *See, e.g.*, *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 at P 5 ("subsidized resources distort prices in a capacity market that relies on competitive auctions to set just and reasonable rates"); *N.Y. Indep. Sys. Operator, Inc.*, 143 FERC ¶ 61,217, at P 3 (2013) ("NYISO's monthly spot ICAP market encompasses market power mitigation rules to prevent the exercise of both buyer and seller market power that would distort competitive outcomes"); *ISO New England Inc.*, 138 FERC ¶ 61,027, at P 75

And no court would ever conclude that the precedent on market-based rates could support a finding that state subsidies causing distorted, suppressed market prices are just and reasonable so long as the state does not purchase capacity and thus does not directly exercise buyer-side market power. Rather, as explained in section III of the White Paper, the Commission has the statutory duty to mitigate such price suppression—whatever term is applied to describe it—to ensure that capacity market prices are just and reasonable.[15]

IV. A LACK OF STATE INTENT TO SUPPRESS PRICES AND THE LEGITIMACY OF STATE POLICY CHOICES DO NOT EXCUSE THE COMMISSION FROM ENSURING THAT RTO CAPACITY MARKET PRICES ARE JUST AND REASONABLE

Finally, it is important to emphasize that the White Paper neither suggests that, nor examines whether, any state intends to suppress prices through the subsidies provided to its favored resources. Nor do we suggest that state policies to favor a particular type of generation resource are illegitimate, should be discouraged, or that the Commission has any jurisdiction over state generation resource choices. Fundamentally, the intent of a state in enacting its subsidy regimes, to the extent that there can be said to be such a thing and it can be discovered, is irrelevant to the obligations faced by the Commission in the face of the mandates of the Federal Power Act and unvarying court precedent.

Instead, the White Paper explains that, as part of the Commission's statutory obligation to ensure that RTO markets yield just and reasonable rates, the Commission must act to mitigate state actions that artificially suppress, or increase, RTO capacity market prices to any significant degree. State policy choices that have such effects on RTO capacity markets are not illegitimate, but the Commission is nevertheless obligated to mitigate those effects in order to ensure that markets subject to its exclusive jurisdiction are just and reasonable.[16] To the extent that the Commission determines that

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(2012) (mitigation required to prevent out of market resources "from distorting the market clearing price").

[15] *See New England Power Generators Ass'n*, 757 F.3d at 295 ("FERC's considered conclusion that certain resources, by definition, depress capacity prices falls within its duty of ensuring that rates are just and reasonable."); *see also PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 at P 143 ("Because below-cost entry suppresses capacity prices and because the Commission has exclusive jurisdiction over wholesale rates, the deterrence of uneconomic entry falls within the Commission's jurisdiction, and we are statutorily mandated to protect the RPM against the effects of such entry.").

[16] *See, e.g., Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481-82 (D.C. Cir. 2009) ("State and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new

it is appropriate to accommodate these policy choices, such accommodation must be arrived at by some means other than by permitting market price suppression in jurisdictional capacity markets.

construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission. Of course, those choices affect the pool of bidders in the Forward Market, which in turn affects the market clearing price for capacity. . . . But this is all quite natural: if consumer-constituents of state commissions prefer to forbid the construction of new power plants, they will appropriately bear the costs of that decision, including paying more for system reliability from older and less efficient units.").

Attachment E

DANLY OFFICE WHITE PAPER

THE REQUIREMENT THAT COMPETITIVE MARKETS BE PROTECTED FROM THE EXERCISE OF MARKET POWER APPLIED TO RTO CAPACITY MARKETS

SECOND SUPPLEMENT (July 15, 2021)

On May 20, 2021, our office issued a White Paper explaining why, under the law, RTO capacity markets cannot produce just and reasonable rates absent mechanisms that protect the market against the exercise of both seller-side and buyer-side market power, including buyer-side market power exercised by the states. We have received a great deal of feedback from many stakeholders and sincerely appreciate the engagement.

We issued a supplement to our White Paper on June 17, 2021 to address comments we received asserting that state action to subsidize resources cannot constitute the exercise of buyer-side market power because the states are not acting as buyers of power. As we explained, however state support of resources is characterized, when such support distorts capacity market prices, it must be mitigated in order for the capacity market price to be just and reasonable.

We issue this second supplement to address a different comment we have received: that the Commission is barred from mitigating the effects of state support for certain resources on RTO capacity markets under Federal Power Act (FPA) section 201(b)(1), which provides that the Commission has no jurisdiction over "facilities used for the generation of electric energy."[1] As we explain below, this statutory limit on the Commission's jurisdiction does not prevent the Commission from acting to mitigate market-distorting state support of generation resources to ensure that the rates produced by FERC-jurisdictional wholesale markets are just and reasonable.

We are interested in hearing reactions to this supplement. Please contact Matt Estes at matthew.estes@ferc.gov if you would like to discuss this further.

I. FPA SECTION 201(b)(1)

As an initial matter, it is important to consider FPA section 201(b)(1) in its entirety:

> The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce *and to the sale of electric energy at wholesale in interstate commerce*, but except as provided in paragraph (2)

[1] 16 U.S.C. § 824(b)(1).

> shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but *shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[2]

Although section 201(b)(1) does not give the Commission jurisdiction over *facilities* used for the generation of electricity, section 201(b)(1) does give the Commission jurisdiction—held by the courts to be exclusive[3]—over the wholesale *sale of electricity* generated by such facilities. And under FPA section 206(a), the Commission is charged with ensuring that "any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any . . . sale subject to the jurisdiction of the Commission, or . . . any rule, regulation, practice, or contract affecting such rate, charge, or classification" is just and reasonable.[4] The Commission's jurisdiction over rates, rules, regulations, and practices affecting wholesale sales of electricity gives the Commission extensive authority over the sales and operations of generation facilities even if it does not have jurisdiction over the facilities themselves.

In this regard, FPA section 201(a) provides that "*Federal regulation of matters relating to generation* to the extent provided in this subchapter and subchapter III of this chapter . . . *is necessary in the public interest*."[5] The Conference Report on the FPA explains that this language was "added to remove *any doubt as to the Commission's jurisdiction over facilities used for the generation* . . . of electric energy to the extent provided in other sections."[6] The statutory language and Conference Report confirm that

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[2] *Id.* (emphasis added).

[3] *See, e.g., Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1292 (2016) ("FERC has exclusive authority to regulate 'the sale of electric energy at wholesale in interstate commerce.'") (quoting 16 U.S.C. § 824(b)(1)).

[4] 16 U.S.C. § 824e(a).

[5] *Id.* § 824(a) (emphasis added).

[6] H.R. Rep. No. 74-1903 (1935) (emphasis added) (quoted in *Miss. Indus. v. FERC*, 808 F.2d 1525, 1543 (D.C. Cir. 1987), *vacated and remanded in part on other grounds*, 822 F.2d 1104 (D.C. Cir. 1987)).

Congress understood the jurisdiction it granted the Commission over wholesale rates necessarily would affect generation facilities and Congress nevertheless believed that the Commission's rate regulation affecting generation is in the public interest.

The case law addressing the division of jurisdiction between the Commission and the states likewise confirms that the Commission's lack of jurisdiction over generation facilities does not prevent the Commission from regulating rates in a way that affects state determinations as to the need for generation capacity and/or state choices regarding the generation capacity used to serve customers.

This is best illustrated by the litigation over the allocation of the costs of the Grand Gulf nuclear plant (Grand Gulf) among the various utilities in the Middle South Utilities (MSU) holding company system (now Entergy). Grand Gulf was subject to cost overruns that caused it to be the most expensive generation facility on the MSU system and, as Grand Gulf was being constructed, it became clear that MSU's demand growth was much lower than expected. Consequently, it was not clear that the Grand Gulf capacity was needed at the time it was placed in service. The Commission conducted two separate hearings to address how the costs of Grand Gulf should be allocated among the various states in which the MSU utilities are located and, at the conclusion of the hearings, the Commission issued an order allocating more of the costs of Grand Gulf to Arkansas and Mississippi than the utility commissions in those states asserted was warranted.[7]

On appeal, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) upheld the Commission's rulings against a number of attacks, including the argument that the Commission had no jurisdiction under FPA section 201(b)(1) to allocate the costs of Grand Gulf.[8] The D.C. Circuit held that "FERC has not exercised jurisdiction over generating facilities in any way that violates the FPA."[9] This was because "the Commission is acting pursuant to its exclusive rate authority over wholesale transactions and its remedial authority as set forth in sections 205 and 206."[10] As the court explained:

> *FERC has not regulated a facility, but rather the wholesale rates of interstate sales within the MSU system*. It is well-accepted that FERC must allow the recovery of the cost of generating facilities in setting wholesale

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[7] *See Middle S. Energy, Inc.*, 31 FERC ¶ 61,305, *reh'g denied*, 32 FERC ¶ 61,425 (1985).

[8] *See Miss. Indus.*, 808 F.2d at 1543-45.

[9] *Id.* at 1543.

[10] *Id.*

> rates. Here, FERC has simply exercised its undisputed authority over the wholesale rates of electric generating facilities in interstate commerce, which includes, under the facts presented, the authority to reallocate the costs of Grand Gulf across the system. As the statute quite plainly states, FERC's control here is exclusive. *The jurisdictional line drawn by Congress is bright, and FERC stands on the correct side of that line*.[11]

Subsequent to this decision, the Supreme Court ruled that the State of Mississippi could not defeat FERC's allocation by prohibiting the recovery in Mississippi retail rates of Grand Gulf costs allocated by the Commission to Mississippi pursuant to the Commission's jurisdiction over wholesale rates.[12] Earlier, the Supreme Court had rejected a similar effort by the state of North Carolina to allocate low-cost hydro power differently in retail rates than the Commission had allocated in a wholesale rate order.[13] These decisions did not directly rule on the question of the Commission's jurisdiction under FPA section 201(b)(1), but by holding that the Commission's wholesale allocations of generation capacity preempts contrary state retail allocations, the Supreme Court implicitly recognized that the Commission's allocation of generation capacity in a manner contrary to the directives of the states does not exceed the Commission's jurisdiction under section 201(b)(1).

In a more recent case, the D.C. Circuit rejected a challenge by the Connecticut Department of Public Utility Control ("Connecticut DPUC") to the Commission's jurisdiction to approve a requirement imposed by ISO-New England that utilities must obtain specific amounts of capacity and pay a deficiency charge when the amount of capacity obtained by the utilities fell below the required amount by a certain quantity.[14] The Connecticut DPUC argued that any increase in the capacity requirement mandated by ISO-New England amounted to a requirement that utilities install new capacity, and therefore the Commission's approval of this requirement violated the limitation on its jurisdiction imposed under FPA section 201(b)(1).[15]

The court rejected the Connecticut DPUC's claim that the Commission's approval of the capacity requirement imposed by ISO-New England amounted to direct regulation

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[11] *Id.* at 1544 (emphasis added).

[12] *See Miss. Power & Light Co. v. Mississippi*, 487 U.S. 354 (1988).

[13] *See Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986).

[14] *See Conn. Dep't of Util. Control v. FERC*, 569 F.3d 477, 480-85 (D.C. Cir. 2009).

[15] *See id*. at 481.

of generation facilities. First, ISO-New England's tariff did not require the installation of additional capacity at all. Instead, the tariff set a peak demand estimate, and employed market forces to locate a price at which market incentives were sufficient to meet that demand.[16] State and local authorities retained control over their power plants without interference from FERC. The tariff required only that states shoulder the economic consequences of their choices.[17] Consequently, the court found that the Commission was not attempting to impose a capacity requirement but was instead merely seeking to:

> [E]nsure that the capacity charges actually imposed by ISO-NE are fair to suppliers and consumers. That reasonable concerns about system adequacy might factor into the fairness of those charges is precisely what brings them within the heartland of [FERC's] . . . jurisdiction."[18]

These cases illustrate that the limitation on the Commission's jurisdiction in section 201(b)(1) does not prevent the Commission from regulating wholesale rates in a way that affects generation facilities, including effects on the amount and cost of generation acquired by a utility. Rather, section 201(b)(1) prohibits only the direct regulation of generation facilities by the Commission unrelated to the regulation of wholesale rates.

II. THE COURTS HAVE HELD THAT THE COMMISSION HAS JURISDICTION TO APPLY MITIGATION TO STATE-SUPPORTED GENERATION FACILITIES

Although the cases generally describing the bounds of the Commission's jurisdiction under FPA section 201(b)(1) are instructive, there is no need to extrapolate the holdings of those cases to the Commission's application of mitigation (such as imposition of a minimum offer price rule (MOPR)) to capacity market offers submitted by state-supported resources. The specific question of whether FPA section 201(b)(1) deprives the Commission of jurisdiction to impose such mitigation has been directly addressed by the courts. Their decisions unambiguously confirm that section 201(b)(1) does not prohibit the Commission from requiring such mitigation.

In 2014, the United States Court of Appeals for the Third Circuit (Third Circuit) rejected New Jersey's argument that the Commission was without jurisdiction to approve

[16] *Id.*

[17] *See id.*

[18] *Id.* at 483.

PJM's application of its MOPR to state-supported generation resources.[19] New Jersey argued that "by eliminating the state-mandated exemption, FERC effectively attempts to substitute its own power supply preferences for those of the states and LSEs in violation of § 201 of the FPA, which provides that states retain authority over 'facilities used for the generation of electric energy.'"[20] New Jersey further asserted that application of the MOPR to state-supported resources was different from the ISO-New England deficiency charge upheld by the D.C. Circuit in *Connecticut DPUC*. According to New Jersey, "in that case, FERC 'did not seek to dictate *which* resources LSEs used to fulfill their capacity obligations,' . . . while here, FERC is preventing New Jersey from using the resources it has chosen to promote."[21]

The Third Circuit rejected New Jersey's arguments, relying on FPA section 201(b)(1)'s grant of jurisdiction to the Commission to regulate wholesale rates, and on the cases discussed in Section I above.

> After reviewing the FERC Orders at issue here and the relevant case law, *we conclude that FERC did not exceed its jurisdiction in eliminating the state-mandated provision*. Under the FPA, FERC has jurisdiction over rules affecting the rates of the transmission or sale of energy in interstate commerce. *See* 16 U.S.C. § 824d. Here, it is undisputed that New Jersey and Maryland's plans to introduce thousands of megawatts of new capacity into the Base Residual Auction would have had an effect on the prices of wholesale electric capacity in interstate commerce. *See Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 374, 108 S. Ct. 2428, 101 L.Ed.2d 322 (1988) (holding, among other things, that FERC had jurisdiction over power allocations that affect wholesale rates, and stating that "[s]tates may not regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates or to insure that *agreements affecting wholesale rates* are reasonable.") (emphasis added); *Municipalities of Groton v. FERC*, 587 F.2d 1296, 1302 (D.C. Cir. 1978) (rejecting jurisdictional challenge to FERC's authority to levy deficiency charges on utilities that failed to procure generating capacity sufficient to meet its load requirements, and stating that, "[i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a

[19] *See N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 95-96 (3d Cir. 2014).

[20] *Id.* at 95 (quoting 16 U.S.C. § 824(b)(1)).

[21] *Id.* at 97 (quoting N.J. Br. 26 (emphasis in original)).

participant pays for power and reserve service, irrespective of the objective underlying that charge.").[22]

With respect to New Jersey's assertion that the Commission "is preventing New Jersey from using the resources it has chosen to promote," the Third Circuit held that "FERC is doing no such thing."[23] As the court explained:

> *The states may use any resource they wish to secure the capacity they need. The elimination of the state-mandated exemption means only that if the states wish to use a new generation resource to satisfy their capacity obligations required under the Reliability Pricing Model, the resource must clear the Base Residual Auction* at or near its net cost of new entry. Such a requirement ensures that the new resource is economical—*i.e.*, that it is needed by the market—and ensures that its sponsor cannot exercise market power by introducing a new resource into the auction at a price that does not reflect its costs and that has the effect of lowering the auction clearing price. Furthermore, even if the states' preferred generation resources fail to clear the auction, the states are free to use them anyway; the only caveat is that the states cannot use the resources to offset their capacity obligations in the RPM, as such obligations can only be satisfied by resources that are demanded by the capacity market at a price reflecting their cost. Thus, as in *Connecticut Department of Utility Control*, New Jersey and Maryland are *free to make their own decisions regarding how to satisfy their capacity needs, but they "will appropriately bear the costs of [those] decision[s]," . . . including possibly having to pay twice for capacity*.[24]

The D.C. Circuit reached the same conclusion later that same year in an appeal of ISO-New England's buyer-side mitigation provisions. The petitioners in that case similarly argued that "the orders serve to dictate which resources a utility must use to satisfy its capacity obligations, in violation of the FPA," and that "FERC's orders impermissibly determine the makeup of a state's resource portfolio."[25] In response, the court held:

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[22] *Id.* at 96 (emphasis added).

[23] *Id.* at 97.

[24] *Id.* (emphasis added) (quoting *Conn. DPUC*, 569 F.3d at 481).

[25] *New England Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 290 (D.C. Cir. 2014).

> Out-of-market resources—whether self-supplied, state-sponsored, or otherwise—directly impact the price at which the Forward Capacity Market auction clears. *As the price of capacity is indisputably a matter within the Commission's exclusive jurisdiction, FERC likewise has jurisdiction to mitigate buyer-side market power as to out-of-market entrants*. We agree with the Commission's finding that it has jurisdiction over mitigation matters "affecting or relating to wholesale rates" under FPA § 201 and 206. Third Order ¶ 220 (emphasis omitted) (citing *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 478, 481). We stress that FERC's mitigation measures here do not entail direct regulation of facilities, a matter within the exclusive control of the states. *See* 16 U.S.C. § 824(b)(1). The Commission also found that uneconomic entry, regardless of resource and regardless of intent, "can produce unjust and unreasonable prices by artificially depressing capacity prices." *Id*. ¶ 170. *As it is FERC's statutory obligation to ensure that rates are appropriate, we must respect its decision to maintain just and reasonable rates through curbing or mitigating buyer-side market power*.[26]

The D.C. Circuit also rejected the arguments that, in approving the MOPR, the Commission was impermissibly dictating the states' choice of generation resources on essentially the same grounds as the Third Circuit. The court explained that "states remain free to subsidize the construction of new generators, and load serving entities to build or contract for any self-supply they believe is necessary."[27] Further, "this Court has already rejected in *Connecticut Department of Public Utility Control* the argument that the type of regulation at issue here constitutes 'direct regulation of generation facilities.'"[28]

III. CONCLUSION

Under FPA section 201(b)(1), the Commission has no jurisdiction to directly regulate generation facilities. However, the Commission does have jurisdiction, indeed it has the duty, to regulate wholesale rates in a manner that can affect generation facilities.[29]

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[26] *Id*. at 290-91 (emphasis added).

[27] *Id.* at 291.

[28] *Id.* (quoting *Conn. DPUC*, 569 F.3d at 481-82).

[29] *See New England Power Generators Ass'n, Inc.*, 757 F.3d at 295 ("FERC's considered conclusion that certain resources, by definition, depress capacity prices falls within its duty of ensuring that rates are just and reasonable."); *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 143 (2011) ("Because below-cost entry suppresses capacity prices and because the Commission has exclusive jurisdiction over wholesale rates, the deterrence of uneconomic entry falls within the Commission's jurisdiction, and

And, as the courts have held, the Commission has jurisdiction to implement a MOPR or other mitigation to address the price distortive effects of state subsidies for certain types of generation resources.

we are statutorily mandated to protect the RPM against the effects of such entry.”).

Attachment F

DANLY OFFICE WHITE PAPER

RESULTS OF THE PJM CAPACITY AUCTION
(2022/2023 RPM Base Residual Auction)
June 17, 2021

On June 2, 2021, PJM announced the results of its 2022/2023 RPM Base Residual Auction, conducted in May. This was the first PJM capacity auction applying the extended minimum offer price rule (MOPR) established by the Commission in Docket Nos. EL16-49-000 and EL18-178-000.[1] As such, the results provide an important test of the effects of PJM's MOPR (and MOPRs in general). This white paper discusses the implications of the PJM results, based on public information provided by PJM.[2]

The most striking result of this auction is that the market clearing prices are significantly lower than those in previous auctions. The RTO-wide price of $50[3] is approximately 36% of the $140 RTO-wide price from the previous auction for the 2021/2022 delivery year.[4] This is the lowest RTO-wide price since the 2013/2014 auction, conducted more than ten years ago, and the fourth lowest RTO-wide price ever.[5] The constrained local delivery area (LDA) prices were higher than $50, but nevertheless lower than the constrained LDA prices in the 2021/2022 delivery-year auction and on the low side of constrained LDA prices in all previous auctions.[6]

One of the criticisms of the Commission's extended MOPR requirement for PJM (and of MOPRs in general) is that the MOPR was expected to prop up capacity prices to

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[1] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019).

[2] Specifically, the conclusions in this white paper are based on PJM, *2022/2023 RPM Base Residual Auction Results*, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx (PJM Report).

[3] The capacity prices reported by PJM, and used in this white paper, are expressed in dollars/MW-day. Each dollar of the capacity price reported by PJM results in an annual payment of $365, the $50 RTO-wide price reported by PJM would result in an annual payment of $18,250 for each MW of capacity awarded by PJM in the auction.

[4] PJM Report at 6, Tbl. 1—*RPM Base Residual Auction Resource Clearing Price Results in the RTO*.

[5] *Id.*

[6] *Id.* at 16, Fig. 2—*Base Residual Auction Resource Clearing Prices*.

benefit incumbent owners of fossil-fueled generation resources. This did not happen in the 2022/2023 delivery-year auction, as demonstrated by the low capacity prices.

PJM offered a number of explanations (unrelated to the extended MOPR) for the lower prices in this auction. These include a lower demand forecast, a shift to the left in the Variable Resource Requirement Curve, and a reduction in Net Cone.[7] PJM also noted that "[i]n general, offer prices from supply resources were lower in this auction compared to the prior auction."[8] With respect to this last point, there has been speculation that the lower offers were a consequence of the delay in conducting the auction. Suppliers may have entered into bilateral supply commitments for the 2022/2023 delivery year prior to the May 2021 auction and, once they made commitments requiring them to operate, offered in at low prices in order to ensure the receipt of a capacity award. If the auction had been conducted earlier, as is typically the case, suppliers would have entered into bilateral supply obligations only after learning whether they received a capacity award in the auction, rather than *vice versa*.

Regardless of the reason for the low auction prices, it is clear that the extended MOPR did not result in increased market clearing prices. A combined 3,239 MW of wind and solar resources cleared the auction, which represents 11,760 MW of installed wind and solar capacity.[9] This was a combined 62% increase (1,254 MW) over the wind and solar capacity awards in the previous auction for the 2021/2022 delivery year.[10] PJM has not released public data reflecting the number of such resources that failed to clear because of the application of the MOPR to their offers. However, we understand from PJM that only a minimal number of subsidized wind and solar resources that offered into

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[7] *Id.* at 26.

[8] *Id.* at 27.

[9] *Id.* at 13-14. Wind and solar resources are intermittent resources that cannot produce their full rated capacity at all times; therefore, PJM calculates Unforced Capacity (UCAP) values for these intermittent resources that are lower than the intermittent resources' installed capacity values and by different means than it does for conventional resources. The UCAP value for conventional resources' offers into PJM's capacity auction is based upon their net tested capacity times EFORD, the probability that a generator will not be available due to a forced outage or a forced derating when there is a demand on the unit to generate. In contrast, PJM calculates the value of intermittent resources based upon their average output during 368 summer peak hours. The intermittent resources can offer up to the lesser of either their qualified Capacity Interconnection Rights or summer peak average.

[10] *Id.*

the auction at their required minimum offer price failed to clear.[11] In other words, almost all renewable resources that offered into the auction at their minimum offer price received capacity awards.

It is important that PJM's MOPR had very little effect either on the capacity clearing price or on the ability of state supported renewable resources to clear the market. This means that PJM's administration of the extended MOPR approved by the Commission has not caused renewable resources (existing or new) to be unable to compete with conventional resources. This past auction shows that the extended MOPR, as presently implemented, allows renewable resources to be competitive even when capacity prices are at historic lows. Consequently, widely raised concerns that PJM's extended MOPR would increase capacity prices and unduly interfere with state policy choices were substantially unjustified and needlessly alarmist.

The eastern RTOs have indicated that they intend to revise their capacity market design in short order to eliminate their MOPRs. PJM has announced an intention to file a revised capacity market design proposal this summer to eliminate the expanded MOPR. ISO-NE likewise has stated an intent to make a filing in early 2022 that would eliminate its MOPR. Both RTOs have acknowledged, however, that to do so raises a number of difficult issues related to resource adequacy and would call into doubt the ability of the markets to ensure competitive results in the face of state subsidies. As I have previously written, and the Commission has previously held, that is a necessary prerequisite to finding that the capacity markets are just and reasonable.[12]

The results of PJM's auction suggest we reconsider the need to act so quickly. It is now apparent that, as presently implemented, the extended MOPR approved by the Commission did not exclude renewable resources, which in this auction proved to be cost competitive and were not priced out of the market by the application of a MOPR. There is little reason for RTOs to consider the elimination of their MOPRs before thoroughly and deliberately addressing the consequences attendant to their elimination. Nor do the RTOs face any urgent need, as some have suggested, to immediately eliminate their

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[11] In addition, it appears that Exelon's Quad City unit located in Illinois also failed to clear because of the MOPR. *See* Abbie Bennett, *3 Exelon Nuclear Plants Fail to Clear PJM Capacity Auction*, S&P GLOBAL (June 3, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/3-exelon-nuclear-plants-fail-to-clear-pjm-capacity-auction-64835071.

[12] *See Danly Office White Paper: The Requirement that Competitive Markets be Protected from the Exercise of Market Power Applied to RTO Capacity Markets*, (May 20, 2021), https://www.ferc.gov/news-events/news/danly-office-white-paper-requirement-competitive-markets-be-protected-exercise (May 20 White Paper). We have supplemented the May 20 White Paper with an additional posting today.

MOPRs, leaving it to later to address the resource adequacy and competitive consequences of their elimination. Indeed, the price competitiveness of renewable resources suggests that it may not be necessary to eliminate MOPRs at all in order to achieve state policy objectives. Instead, we should retain the use of MOPRs to mitigate the price-suppressive effects of state subsidies while finding alternative ways to accommodate state public policy choices.

Attachment G

2022/2023 RPM Base Residual Auction Results

Executive Summary

The 2022/2023 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 144,477.3 MW of unforced capacity in the RTO representing a 21.1% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2022/2023 Delivery Year as procured in the BRA is 19.9%, or 5.4% higher than the target reserve margin of 14.5%. This reserve margin was achieved at clearing prices that are between approximately 19% to 56% of Net CONE, depending upon the Locational Deliverability Area (LDA). The auction also attracted a diverse set of resources, including a significant increase in gas fired combined cycle generation, Energy Efficiency resources and new wind and solar resources.

The 2022/2023 BRA is the third where PJM has procured 100% Capacity Performance ("CP") Resources. CP Resources must be capable of sustained, predictable operation, and are expected to be available and capable of providing energy and reserves when needed throughout the entire Delivery Year. As was the case with the 2021/2022 BRA, the 2022/2023 BRA was conducted under the provisions of PJM's Enhanced Aggregation filing (Docket ER17-367-000 & 001) which was accepted by FERC on March 21, 2017. The 2022/2023 BRA is the first RPM auction conducted under the expanded application of the Minimum Offer Price Rule resulting from FERC's December 19, 2019 Order[1].

2022/2023 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2022/2023 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $50.00/MW-day. MAAC, EMAAC, BGE, COMED and DEOK were constrained LDAs in the 2022/2023 BRA with locational price adders, in regards to the immediate parent LDA, of $45.79/MW-day, $2.07/MW-day, $30.71/MW-day, $18.96/MW-day and $21.69/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2021/2022 BRA was $140.00/MW-day. Additionally, the EMAAC, PSEG, BGE, ATSI and COMED LDA were constrained LDAs in the 2021/2022 BRA with RCPs of $165.73/MW-day, $204.29/MW-day, $200.30/MW-day, $171.33/MW-day and $195.55/MW-day respectively.

2022/2023 BRA Resource Clearing Prices

Capacity Type	2022/23 BRA Resource Clearing Prices ($/MW-day)					
	Rest of RTO	MAAC	EMAAC	BGE	COMED	DEOK
Capacity Performance	$50.00	$95.79	$97.86	$126.50	$68.96	$71.69

[1] Docket Nos. EL16-49-000 EL18-178-000 (Consolidated)

2022/2023 RPM Base Residual Auction Results

2022/2023 BRA Cleared Capacity Resources

As seen in the table below, the 2022/2023 BRA procured 4,843.6 MW of capacity from new generation and 1,210.3 MW from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2022/2023 BRA is 1,558.0 MW which is a decrease of 2,493.8 MW from that procured in the 2021/2022 BRA. All external generation capacity that has cleared in the 2022/2023 BRA are Prior Capacity Import Limit (CIL) Exception External Resources[2] that qualify for an exception for the 2022/2023 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2022/2023 BRA is 8,811.9 MW which is a decrease of 2,313.9 MW from that procured in the 2021/2022 BRA; and, the total quantity of EE procured in the 2022/2023 BRA is 4,810.6 MW, which is an increase of 1,978.6 MW from that procured in the 2021/2022 BRA.

Megawatts of Unforced Capacity Procured by Type from the 2014/2015 BRA to the 2022/2023 BRA

BRA Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
2022/2023	4,843.6	1,210.3	1,558.0	8,811.9	4,810.6
2021/2022	893.0	508.3	4,051.8	11,125.8	2,832.0
2020/2021	2,389.3	434.5	3,997.2	7,820.4	1,710.2
2019/2020	5,373.6	155.6	3,875.9	10,348.0	1,515.1
2018/2019	2,954.3	587.6	4,687.9	11,084.4	1,246.5
2017/2018	5,927.4	339.9	4,525.5	10,974.8	1,338.9
2016/2017	4,281.6	1,181.3	7,482.7	12,408.1	1,117.3
2015/2016	4,898.9	447.4	3,935.3	14,832.8	922.5
2014/2015	415.5	341.1	3,016.5	14,118.4	822.1

*All MW Values are in UCAP Terms

[2] A Prior CIL Exception Resource is an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided to the definition of Capacity Import Limit.

2022/2023 RPM Base Residual Auction Results

Introduction
This document provides information for PJM stakeholders regarding the results of the 2022/2023 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2022/2023 BRA opened on May 19, 2021, and the results were posted on June 2, 2021.

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO to ensure that seasonal CP sell offers clear to form annual CP commitments.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

This document begins with a high-level summary of the BRA results followed by sections containing detailed descriptions of the 2022/2023 BRA results and a discussion of the results in the context of the previous BRAs.

Summary of Results
The 2022/2023 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 144,477.3 MW of unforced capacity in the RTO representing a 21.1% reserve margin. The reserve margin for the entire RTO is 19.9%, or 5.4% higher than the target reserve margin of 14.5%, when the Fixed Resource Requirement (FRR) load and resources are considered.

Resource Clearing Prices (RCPs) for the 2022/2023 BRA are shown in Table 1 below. MAAC, EMAAC, BGE, COMED and DEOK were constrained LDAs in the 2022/2023 BRA with locational price adders, in regards to the immediate parent LDA, of $45.79/MW-day, $2.07/MW-day, $30.71/MW-day, $18.96/MW-day and $21.69/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2021/2022 BRA was $140.00/MW-day. Additionally, the EMAAC, PSEG, BGE, ATSI and COMED LDA were constrained LDAs in the 2021/2022 BRA with RCPs of $165.73/MW-day, $204.29/MW-day, $200.30/MW-day, $171.33/MW-day and $195.55/MW-day respectively.

The quantity of Unforced Capacity procured from new Generation Capacity Resources cleared regardless of whether they had offered into a prior auction was 6,053.9 MW comprised of 4,843.6 MW from new generation units and 1,210.3 MW from uprates to existing or planned generation units.

The quantity of Unforced Capacity procured from external Generation Capacity Resources in the 2022/2023 BRA is 1,558.0 MW which is a decrease of 2,493.8 MW from that procured in the 2021/2022 BRA. All external generation capacity that has cleared in the 2022/2023 BRA are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2022/2023 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

The total Unforced Capacity of DR procured in the 2022/2023 BRA is 8,811.9 MW which is a decrease of 2,313.9 MW from that procured in the 2021/2022 BRA; and, the total quantity of EE procured in the 2022/2023 BRA is 4,810.6 MW which is an increase of 1,978.6 MW from that procured in the 2022/2023 BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all Existing Generation Capacity Resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

The Minimum Offer Price Rule (MOPR) of Section 5.14(h) of Attachment DD of the PJM OATT applies to sell offers of certain new Generation Capacity Resources that do not receive or are not entitled to receive a State Subsidy. Specifically, the provisions of Section 5.14(h) apply to the sell offers of such new Generation Capacity Resources (except those of nuclear, coal, integrated gasification combined cycle, hydroelectric, wind, or solar facilities) that are, located in an LDA for which a separate VRR Curve is established for the relevant Delivery Year, unless the resource has cleared an RPM Auction for the auction Delivery Year or prior Delivery Year. To the extent the new Generation Capacity Resource is a Capacity Resource with State Subsidy, then the provisions in Tariff, Attachment DD, section 5.14(h-1) apply. The MOPR of Section 5.14(h-1) of Attachment DD of the PJM OATT applies to the sell offers of any Capacity Resource with State Subsidy unless the Capacity Resource with State Subsidy qualifies for a Categorical Exemptions. The sell offer of a Capacity Resource with State Subsidy that qualifies for any one of the categorical exemptions is not subject to a MOPR Floor Offer Price. To avoid application of the MOPR, Capacity Market Sellers may request a unit-specific exception or elect the Competitive Exemption.

2022/2023 RPM Base Residual Auction Results

A further discussion of the 2022/2023 BRA results and additional information regarding the 2022/2023 RPM BRA are detailed in the body of this report. The discussion also provides a comparison of the 2022/2023 auction results to the results from the 2007/2008 through 2021/2022 RPM Auctions.

2022/2023 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins for the 2007/2008 through 2022/2023 RPM BRAs.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	Auction Results		
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	Reserve Margin
2007/2008	$ 40.80	129,409.2	19.1%
2008/2009	$ 111.92	129,597.6	17.4%
2009/2010	$ 102.04	132,231.8	17.6%
2010/2011	$ 174.29	132,190.4	16.4%
2011/2012[1]	$ 110.00	132,221.5	17.9%
2012/2013	$ 16.46	136,143.5	20.5%
2013/2014[2]	$ 27.73	152,743.3	19.7%
2014/2015[3]	$ 125.99	149,974.7	18.8%
2015/2016[4]	$ 136.00	164,561.2	19.3%
2016/2017[5]	$ 59.37	169,159.7	20.3%
2017/2018	$ 120.00	167,003.7	19.7%
2018/2019	$ 164.77	166,836.9	19.8%
2019/2020	$ 100.00	167,305.9	22.4%
2020/2021[6]	$ 76.53	165,109.2	23.3%
2021/2022	$ 140.00	163,627.3	21.5%
2022/2023	$ 50.00	144,477.3	19.9%

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers

The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the Fixed Resource Requirement alternative). The 2022/2023 RPM BRA cleared 144, 477.3 MW of unforced capacity in the RTO representing a 21.1% reserve margin. The reserve margin for the entire RTO is 19.9%, or 5.4% higher than the target reserve margin of 14.5%, when the Fixed Resource Requirement (FRR) load and resources are considered.

New Generation Resource Participation

The quantity of new Generation Capacity Resources cleared in this auction regardless of whether they had offered into a prior auction was 6,053.9 MW comprised of 4,843.6 MW from new generation units, and 1,210.3 MW from uprates to existing or planned generation units.

Table 2A shows the breakdown, by major LDA, of capacity in UCAP terms of new units and uprates at existing or planned units offered in the auction and capacity clearing in the auction.

Table 2A – Offered and Cleared New Generation Capacity by LDA (in UCAP MW)

	Offered			Cleared		
LDA	Uprate	New Unit	Total	Uprate	New Unit	Total
EMAAC	252.3	73.4	**325.7**	128.3	50.0	**178.3**
MAAC**	615.6	222.5	**838.1**	433.1	193.2	**626.3**
Total RTO	1,669.3	7,433.0	**9,102.3**	1,210.3	4,843.6	**6,053.9**

*All MW Values are in UCAP Terms

**MAAC includes EMAAC

***RTO includes MAAC

**** Cleared MW values may include new units that have offered in a prior BRA and not cleared

Capacity Import Participation

The quantity of capacity imports cleared in the 2022/2023 BRA were 1,558.0 MW (UCAP) which represents a decrease of 2,493.8 MW from the imports that cleared in the 2021/2022 BRA. The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared in the 2022/23 BRA are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2022/2023 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

Table 2B – Offered and Cleared Capacity Imports (in UCAP MW)

	External Source Zones					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)	248.3	0.0	809.4	240.9	259.4	**1,558.0**
Cleared MW (UCAP)	248.3	0.0	809.4	240.9	259.4	**1,558.0**
Resource Clearing Price ($/MW-day)	$50.00	$50.00	$50.00	$50.00	$50.00	

*Offered and Cleared MW quantities include resources that received CIL Exception and those associated with pre-OATT grandfathered transmission.
Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.

Demand Resource Participation

The total Unforced Capacity of DR offered into the 2022/2023 BRA was 10,513.0 MW, representing a decrease of 11.6% from the DR that offered into the 2021/2022 BRA. Of the 10,513.0 MW of total DR that offered in this auction, 8,811.9 MW cleared. The cleared DR is 2,313.9 MW less than that which cleared in the 2021/2022 BRA. Of the 8,811.9 MW of DR cleared in the 2022/2023 BRA, 8,369.9 MW were cleared as the annual Capacity Performance Product and 442.0 MW were cleared as the summer seasonal Capacity Performance product. Table 3A contains a comparison of the DR offered and cleared in 2021/2022 BRA & 2022/2023 BRA represented in UCAP.

Energy Efficiency Resource Participation

An EE resource is a project that involves the installation of more efficient devices/equipment or the implementation of more efficient processes/systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of installation as known at the time of commitment. The EE resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE performance hours) that is not reflected in the peak load forecast used for the BRA for the Delivery Year for which the EE resource is proposed. The EE resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention. Of the 5,056.8 MW of energy efficiency that offered into the 2022/2023 BRA, 4,810.6 MW cleared in the auction. Of the 4,810.6 MW of EE Resources cleared in the 2022/2023 BRA, 4,575.7 MW was cleared as the annual Capacity Performance Product and 234.9 MW were cleared as the summer seasonal Capacity Performance product.

Table 3B contains a summary of the DR and EE resources that offered and cleared by zone in the 2022/2023 BRA. Approximately 83.8% of the DR and 95.1% of the EE resources that were offered into the BRA cleared.

Figure 1 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2022/2023 Delivery Year. Demand side participation includes active load management (ALM) prior to 2007/2008 Delivery Year, Interruptible Load for Reliability (ILR) and DR offered into each BRA and nominated in FRR Plans, and EE resources starting with the 2012/2013 Delivery Year. The demand side participation in the capacity market has increased dramatically since the inception of RPM in the 2007/2008 Delivery Year through the 2015/2016 BRA, but as shown in Figure 1, total demand side participation and cleared resources for the 2022/2023 BRA have fallen below the levels seen in the 2015/2016 BRA.

2022/2023 RPM Base Residual Auction Results

Table 3A – Comparison of Demand Resources Offered and Cleared in 2021/2022 BRA & 2022/2023 BRA (in UCAP MW)

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	2021/2022*	2022/2023*	Increase in Offered MW	2021/2022*	2022/2023*	Increase in Cleared MW
EMAAC	AECO	83.6	73.7	**(9.9)**	83.4	62.2	**(21.2)**
EMAAC/DPL-S	DPL	320.3	279.1	**(41.2)**	265.1	269.3	**4.2**
EMAAC	JCPL	173.0	171.8	**(1.2)**	170.3	147.8	**(22.5)**
EMAAC	PECO	450.9	414.6	**(36.3)**	446.4	364.4	**(82.0)**
PSEG/PS-N	PSEG	423.3	393.0	**(30.3)**	407.9	294.6	**(113.3)**
EMAAC	RECO	6.0	2.3	**(3.7)**	5.8	1.6	**(4.2)**
EMAAC Sub Total		**1,457.1**	**1,334.5**	**(122.6)**	**1,378.9**	**1,139.9**	**(239.0)**
PEPCO	PEPCO	452.5	336.9	**(115.6)**	345.9	322.7	**(23.2)**
BGE	BGE	369.4	186.1	**(183.3)**	279.0	162.6	**(116.4)**
MAAC	METED	367.5	260.5	**(107.0)**	360.4	230.7	**(129.7)**
MAAC	PENELEC	373.5	333.1	**(40.4)**	364.5	299.8	**(64.7)**
PPL	PPL	744.5	715.1	**(29.4)**	684.7	661.7	**(23.0)**
MAAC Sub Total**		**3,764.5**	**3,166.2**	**(598.3)**	**3,413.4**	**2,817.4**	**(596.0)**
RTO	AEP	1,829.2	1,651.5	**(177.7)**	1,680.4	1,315.3	**(365.1)**
RTO	APS	1,049.7	878.3	**(171.4)**	1,019.4	669.0	**(350.4)**
ATSI/ATSI-C	ATSI	1,221.2	1,124.8	**(96.4)**	1,142.4	924.1	**(218.3)**
COMED	COMED	2,078.2	1,760.1	**(318.1)**	1,997.8	1,511.0	**(486.8)**
DAY	DAY	235.0	256.5	**21.5**	227.7	210.5	**(17.2)**
DEOK	DEOK	235.6	237.0	**1.4**	213.8	185.1	**(28.7)**
RTO	DOM	1,173.4	966.8	**(206.6)**	1,136.1	745.5	**(390.6)**
RTO	DUQ	140.6	181.6	**41.0**	135.4	148.6	**13.2**
RTO	EKPC	159.4	290.2	**130.8**	159.4	285.4	**126.0**
Grand Total		**11,886.8**	**10,513.0**	**(1,373.8)**	**11,125.8**	**8,811.9**	**(2,313.9)**

* MW values include both Annual and Summer-Period Capacity Performance DR

** MAAC sub-total includes all MAAC Zones

2022/2023 RPM Base Residual Auction Results

Table 3B – Comparison of Demand Resources and Energy Efficiency Resources Offered and Cleared in the 2022/2023 BRA (in UCAP MW)

		Offered MW (UCAP)*			Cleared MW (UCAP)*		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	73.7	76.2	149.9	62.2	76.2	138.4
EMAAC/DPL-S	DPL	279.1	120.1	399.2	269.3	119.9	389.2
EMAAC	JCPL	171.8	189.8	361.6	147.8	189.8	337.6
EMAAC	PECO	414.6	318.8	733.4	364.4	318.8	683.2
PSEG/PS-N	PSEG	393.0	387.2	780.2	294.6	384.4	679.0
EMAAC	RECO	2.3	1.7	4.0	1.6	1.7	3.3
EMAAC Sub Total		**1,334.5**	**1,093.8**	**2,428.3**	**1,139.9**	**1,090.8**	**2,230.7**
PEPCO	PEPCO	336.9	268.9	605.8	322.7	263.8	586.5
BGE	BGE	186.1	199.9	386.0	162.6	199.9	362.5
MAAC	METED	260.5	88.8	349.3	230.7	88.8	319.5
MAAC	PENELEC	333.1	89.0	422.1	299.8	89.0	388.8
PPL	PPL	715.1	242.1	957.2	661.7	242.1	903.8
MAAC Sub Total**		**3,166.2**	**1,982.5**	**5,148.7**	**2,817.4**	**1,974.4**	**4,791.8**
RTO	AEP	1,651.5	546.2	2,197.7	1,315.3	514.3	1,829.6
RTO	APS	878.3	231.5	1,109.8	669.0	220.0	889.0
ATSI/ATSI-C	ATSI	1,124.8	418.3	1,543.1	924.1	417.0	1,341.1
COMED	COMED	1,760.1	912.2	2,672.3	1,511.0	723.9	2,234.9
DAY	DAY	256.5	92.9	349.4	210.5	91.8	302.3
DEOK	DEOK	237.0	149.4	386.4	185.1	145.9	331.0
RTO	DOM	966.8	637.2	1,604.0	745.5	637.2	1,382.7
RTO	DUQ	181.6	86.6	268.2	148.6	86.1	234.7
RTO	EKPC	290.2	-	290.2	285.4	-	285.4
Grand Total		**10,513.0**	**5,056.8**	**15,569.8**	**8,811.9**	**4,810.6**	**13,622.5**

* MW values include both Annual and Summer-Period Capacity Performance DR and EE

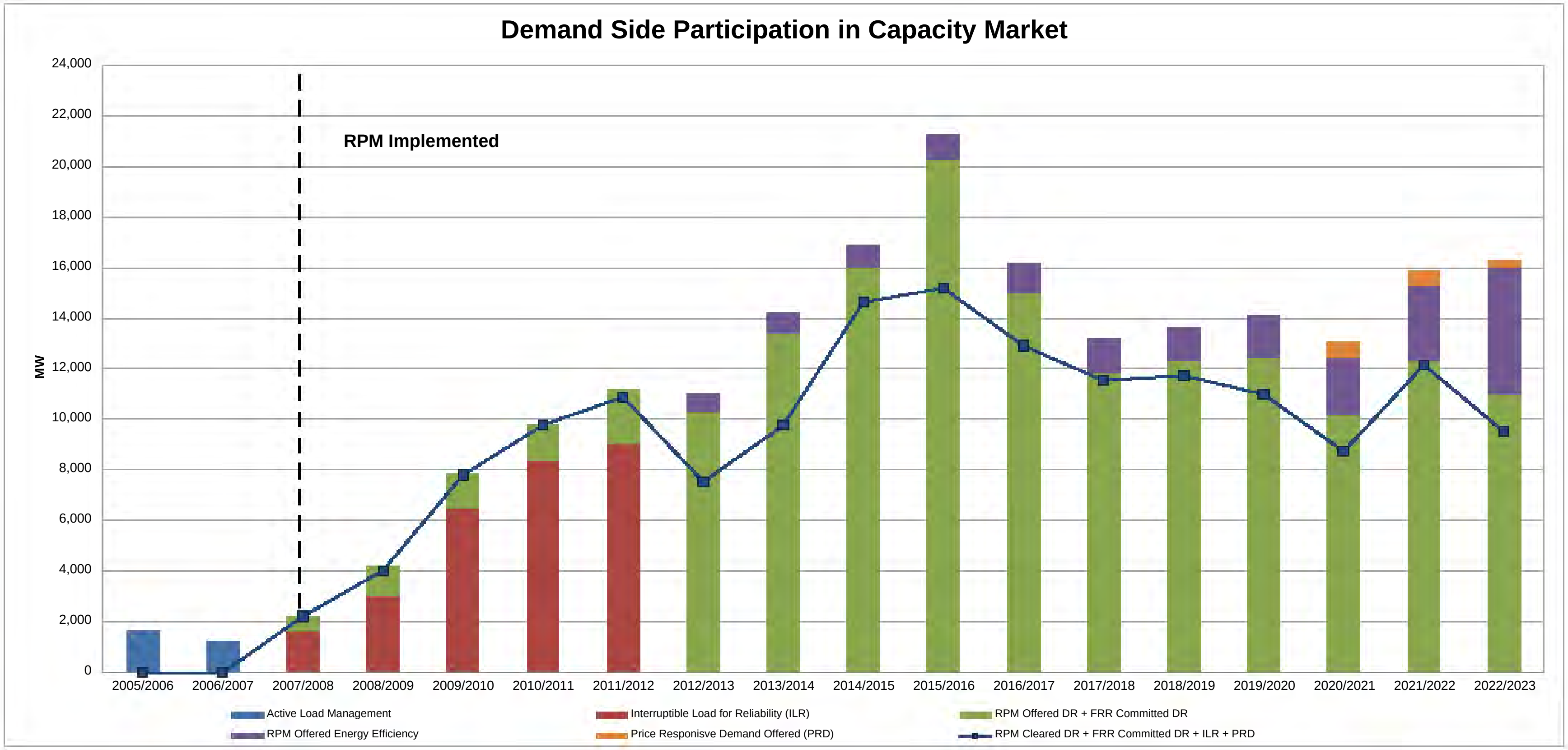
** MAAC sub-total includes all MAAC Zones

2022/2023 RPM Base Residual Auction Results

Table 3C – Breakdown of Annual and Seasonal Capacity Performance Resources by Resource Type and Season that Offered and Cleared in the 2022/2023 BRA (in UCAP MW)

	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	Annual Capacity Performance	Summer Capacity Performance	Winter Capacity Performance	Annual Capacity Performance	Summer Capacity Performance	Winter Capacity Performance
GEN	150,741.3	11.8	1,375.5	130,844.9	9.9	686.8
DR	10,071.0	442.0	-	8,369.9	442.0	-
EE	4,807.5	249.3	-	4,575.7	234.9	-
Grand Total	**165,619.8**	**703.1**	**1,375.5**	**143,790.5**	**686.8**	**686.8**

Figure 1 – Demand Side Participation in the PJM Capacity Market



Renewable Resource Participation

1,728.1 MW of wind resources cleared the 2022/2023 BRA as compared to 1,416.7 MW of wind resources that cleared the 2021/2022 BRA. Of the 1,728.1 MW of wind resources cleared in the 2022/2023 BRA, 1,057.5 MW were cleared as the annual Capacity Performance Product and 670.6 MW were cleared as the winter seasonal Capacity Performance product. The nameplate capability of wind resources that cleared in the 2022/2023 BRA as annual CP capacity and/or winter seasonal CP capacity is approximately 8,518.3 MW, which is 392.3 MW greater than the 8,126 MW of wind energy nameplate capability that cleared in the 2021/2022 BRA.

1,511.6 MW of solar resources cleared the 2022/2023 BRA as compared to 569.9 MW of solar resources that cleared the 2021/2022 BRA. Of the 1,511.6 MW of solar resources cleared in the 2022/2023 BRA, 1,501.7 MW were cleared as the annual Capacity Performance Product and 9.9 MW were cleared as the summer seasonal Capacity Performance product. The nameplate capability of solar resources that cleared in the 2022/2023 BRA as annual CP capacity and/or summer seasonal CP capacity is approximately 3,242.8 MW, which is 1,601.8 MW greater than the 1,641 MW of solar energy nameplate capability that cleared in the 2021/2022 BRA.

Price Responsive Demand Participation

A total Nominal PRD Value of 230 MW was elected and committed in the 2022/2023 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to changing wholesale prices. In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the Capacity Exchange system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. As shown in the 2022/2023 Planning Parameters, 230 MW of PRD across the RTO has elected to participate in the 2022/2023 BRA: 80 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 40 MW in the EMAAC LDA (with 19.6 MW located in the DPL-South LDA). The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the Delivery Year.

LDA Results

An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC, and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY and DEOK were modeled as LDAs in the 2022/2023 RPM Base Residual Auction. The MAAC, EMAAC,

2022/2023 RPM Base Residual Auction Results

BGE, COMED and DEOK LDAs were binding constraints in the auction resulting in a Locational Price Adder for these LDAs. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA. Table 4 contains a summary of the clearing results in the LDAs from the 2022/2023 RPM Base Residual Auction.

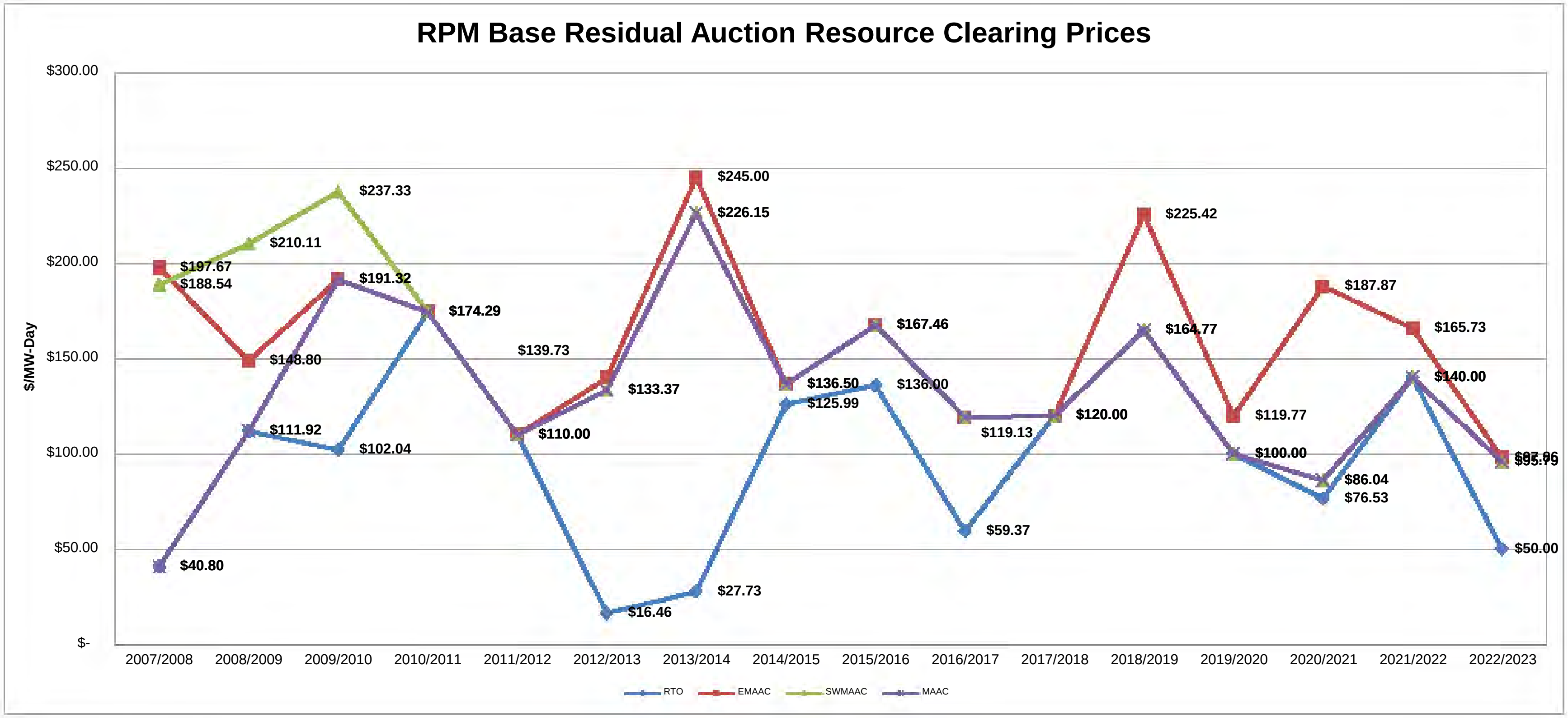
Table 4 –RPM Base Residual Auction Clearing Results in the LDAs

Auction Results	RTO	MAAC	SWMAAC	PEPCO	BGE	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND	PPL	COMED	DAY	DEOK
Offered MW (UCAP)*	167,698.4	71,080.8	10,185.0	4,870.7	2,866.2	32,773.8	1,726.5	6,169.0	3,547.4	11,752.6	2,590.1	10,702.2	29,500.2	1,310.6	3,236.7
Cleared MW (UCAP)**	144,477.3	64,614.2	8,284.1	3,533.6	2,494.5	29,333.8	1,305.3	4,436.5	2,527.2	10,543.9	1,912.5	10,144.7	19,197.5	1,253.0	2,114.8
System Marginal Price	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
Locactional Price Adder***	$0.00	$45.79	$0.00	$0.00	$30.71	$2.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$18.96	$0.00	$21.69
RCP for Capacity Performance Resources	$50.00	$95.79	$95.79	$95.79	$126.50	$97.86	$97.86	$97.86	$97.86	$50.00	$50.00	$95.79	$68.96	$50.00	$71.69

* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers
** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA
*** Locational Price Adder is with respect to the immediate parent LDA

Since the MAAC, EMAAC, BGE, COMED and DEOK LDAs were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2022/2023 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

Figure 2 – Base Residual Auction Resource Clearing Prices



* 2014/2015 through 2022/2023 Prices reflect the Annual Resource Clearing Prices.

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2022/2023 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 208,988.9 MW of installed capacity was eligible to be offered into the 2022/2023 Base Residual Auction, with 1,649.1 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2022/2023 auction increased slightly from that of the previous auction and FRR commitments increased by 19,639.7 MW from the 2021/2022 Delivery Year to 33,297.1 MW.

A total of 172,206.5 MW of capacity was offered into the Base Residual Auction. This is a decrease of 20,242.7 MW from that which was offered into the 2021/2022 BRA. A total of 36,782.4 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, or (3) having been excused from offering into the auction. Resources were excused from the must offer requirement are generally for the following reasons: approved retirement requests, resources categorically exempt from the Capacity Performance must-offer requirement, resources which received an exemption from the must-offer or Capacity Performance must-offer requirement and excess capacity owned by an FRR entity.

2022/2023 RPM Base Residual Auction Results

Table 5 –RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information in the RTO

	RTO[1]														
Auction Supply (all values in ICAP)	2008/2009	2009/2010	2010/2011	2011/2012[2]	2012/2013	2013/2014[3]	2014/2015[4]	2015/2016[5]	2016/2017[6]	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2	195,633.4	199,375.5	207,559.1	208,098.0	202,477.4	203,300.6	207,579.6	207,555.1	211,625.2	207,339.8
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4	4,766.1	7,620.2	4,649.7	8,412.2	6,300.9	5,724.6	4,821.4	5,440.5	4,725.0	1,649.1
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**	**200,399.5**	**206,995.7**	**212,208.8**	**216,510.2**	**208,778.3**	**209,025.2**	**212,401.0**	**212,995.6**	**216,350.2**	**208,988.9**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9	2,624.5	1,230.1	1,218.8	1,218.8	1,223.2	1,313.4	1,318.2	1,319.8	1,319.8	1,525.3
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1	25,793.1	33,612.7	15,997.9	15,576.6	15,776.1	15,793.0	15,385.3	13,931.6	13,657.4	33,297.1
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2	1,825.7	3,255.2	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5	7,826.4	8,923.8	1,960.0
Total Eligible RPM Capacity: Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**	**30,243.3**	**38,098.0**	**25,929.6**	**25,319.4**	**21,304.6**	**19,454.8**	**18,158.0**	**23,077.8**	**23,901.0**	**36,782.4**
Remaining Eligible RPM Capacity	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**	**192,449.2**	**172,206.5**
Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7	156,894.1	153,048.1	166,127.8	176,145.3	175,329.5	177,592.1	181,866.4	178,807.1	178,823.5	157,872.2
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4	12,528.7	15,043.1	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	9,047.8	10,911.9	9,677.9
EE Offered	0.0	0.0	0.0	0.0	632.3	733.4	806.5	907.8	1,112.6	1,289.0	1,205.5	1,517.4	2,062.9	2,713.8	4,656.4
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**	**192,449.2**	**172,206.5**
Total Eligible RPM Capacity Unoffered	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

[1]RTO numbers include all LDAs.
[2]All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.
[3]2013/2014 includes ATSI zone and generation
[4]2014/2015 includes Duke zone and generation
[5]2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
[6]2016/2017 includes EKPC zone

2022/2023 RPM Base Residual Auction Results

Table 6 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR) and Demand Resource Factor, when applicable, for the Delivery Year.

In UCAP terms, a total of 167,698.4 MW were offered into the 2022/2023 BRA, comprised of 152,128.6 MW of generation capacity, 10,513.0 MW of capacity from DR, and 5,056.8 MW of capacity from EE resources. Of those offered, a total of 144,477.3 MW of capacity was cleared in the BRA.

Of the 144,477.3 MW of capacity that cleared in the auction, a total of 131,541.6 MW cleared from Generation Capacity Resources, 8,811.9 MW cleared from DR, and 4,810.6 MW cleared from EE resources, of which, 686.8 MW cleared as matched seasonal CP resources. Capacity that was offered but not cleared in the BRA Auction will be eligible to offer into the Third Incremental Auction for the 2022/2023 Delivery Year.

Table 6 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in UCAP MW

	RTO*														
Auction Results	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0	147,188.6	144,108.8	157,691.1	168,716.0	166,204.8	166,909.6	172,071.2	171,262.3	171,663.2	152,128.6
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6	12,952.7	15,545.6	19,956.3	14,507.2	11,293.7	11,675.5	11,818.0	9,846.7	11,886.8	10,513.0
EE Offered	-	-	-	-	652.7	756.8	831.9	940.3	1,156.8	1,340.0	1,306.1	1,650.3	2,242.5	2,954.8	5,056.8
Total Offered	**131,880.6**	**133,551.0**	**133,092.7**	**137,720.3**	**145,373.3**	**160,898.1**	**160,486.3**	**178,587.7**	**184,380.0**	**178,838.5**	**179,891.2**	**185,539.5**	**183,351.5**	**186,504.8**	**167,698.4**
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4	142,782.0	135,034.2	148,805.9	155,634.3	154,690.0	154,506.0	155,442.8	155,976.5	150,385.0	131,541.6
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0	7,820.4	11,125.8	8,811.9
EE Cleared	0.0	0.0	0.0	0.0	568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5	1,515.1	1,710.2	2,832.0	4,810.6
Total Cleared	**129,597.6**	**132,231.8**	**132,190.5**	**132,221.5**	**136,143.5**	**152,743.3**	**149,974.7**	**164,561.2**	**169,159.7**	**167,003.7**	**166,836.9**	**167,305.9**	**165,109.2**	**163,627.3**	**144,477.3**
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.8	8,154.8	10,511.6	14,026.5	15,220.3	11,834.8	13,054.3	18,233.6	18,242.3	22,877.5	23,221.1

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

***Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performa

***Starting 2020/2021: Total RTO Cleared MW value includes Annual and matched Seasonal Capacity Performance sell offers

2022/2023 RPM Base Residual Auction Results

Table 7 contains a summary of capacity additions and reductions from the 2007/2008 BRA to the 2022/2023 BRA. A total of 10,578.5 MW of incrementally new generation capacity in PJM was available for the 2022/2023 BRA. This incrementally new generation capacity includes new Generation Capacity Resources and capacity upgrades to existing and planned Generation Capacity Resources. The increase is offset by generation capacity deratings on existing Generation Capacity Resources of 14,491.6 MW. The quantity of DR decreased by 1,234.0 MW and EE increased by 1,942.6 MW of installed capacity as compared to the 2021/2022 BRA.

Table 7 also illustrates the total amount of resource additions and reductions over fifteen Delivery Years since the implementation of the RPM construct. Over the period covering the first sixteen RPM BRAs, 62,567.4 MW of new generation capacity was added, which was partially offset by 55,822.8 MW of capacity de-ratings or retirements over the same period. Additionally, 10,115.7 MW of new DR and 4,656.4 MW of new EE resources were offered over the course of the sixteen Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last sixteen RPM auctions was 21,516.7 MW.

Table 7 – Incremental Capacity Resource Additions and Reductions to Date

	RTO*																
Capacity Changes (in ICAP)	**2007/2008**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014[1]**	**2014/2015[2]**	**2015/2016**	**2016/2017[3]**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**Total**
Increase in Generation Capacity	602.0	724.2	1,272.3	1,776.2	3,576.3	1,893.5	1,737.5	1,582.8	8,207.0	6,806.0	6,973.3	5,055.6	6,327.8	4,257.5	1,196.9	10,578.5	62,567.4
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301.8	-264.7	-3,253.9	-1,924.1	-1,550.1	-6,432.6	-4,992.0	-9,760.1	-3,620.8	-2,923.1	-3,016.1	-1,691.7	-14,491.6	-55,822.8
Net Increase in Demand Resource	555.0	574.7	215.0	28.7	661.7	7,938.1	2,993.3	2,514.4	4,200.5	-5,310.7	-3,077.7	-82.4	86.4	-1,811.4	1,864.1	-1,234.0	10,115.7
Net Increase in Energy Efficiency	0.0	0.0	0.0	0.0	0.0	632.3	101.1	73.1	101.3	204.8	176.4	-83.5	311.9	545.5	650.9	1,942.6	4,656.4
Net Increase in Installed Capacity	**482.4**	**923.5**	**937.1**	**1503.1**	**3973.3**	**7,210.0**	**2,907.8**	**2,620.2**	**6,076.2**	**-3,291.9**	**-5,688.1**	**1,268.9**	**3,803.0**	**-24.5**	**2,020.2**	**-3,204.5**	**21,516.7**

* RTO numbers include all LDAs

** Values are w ith respect to the quantity offered in the previous year's Base Residual Auction.

1) Does not include Existing Generation located in ATSI Zone

2) Does not include Existing Generation located in Duke Zone

3) Does not include Existing Generation located in EKPC Zone

Table 7A provides a further breakdown of the generation increases and decreases for the 2022/2023 Delivery Year on an LDA basis.

Table 7A – Generation Increases and Decreases by LDA Effective 2022/2023 Delivery Year

LDA Name	Increases	Decreases
EMAAC	360.7	(491.4)
MAAC*	1,065.6	(4,033.3)
Total RTO**	**10,578.5**	**(14,491.6)**

All Values in ICAP terms
*MAAC includes EMAAC
**RTO includes MAAC

Table 8 provides a breakdown of the new capacity offered into the each BRA into the categories of new resources, reactivated units, and uprates to existing capacity, and then further down into resource type. As shown in this table, there was a significant increase in generating capacity from combined cycle, wind and solar in the 2022/2023 BRA as compared to the 2021/2022 BRA. The capacity offered in the 2022/2023 BRA resulted from both new generating resources and uprates to existing resources including gas, nuclear, wind, and solar resources. As shown in Figure 3, the largest growth remains in combined cycle plants.

2022/2023 RPM Base Residual Auction Results

Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2022/2023

	Delivery Year	CT/GT	Combined Cycle	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Fuel Cell	Total
New Capacity Units (ICAP MW)	2007/2008			18.7	0.3						19.0
	2008/2009			27.0					66.1		93.1
	2009/2010	399.5		23.8		53.0					476.3
	2010/2011	283.3	580.0	23.0					141.4		1,027.7
	2011/2012	416.4	1,135.0			704.8		1.1	75.2		2,332.5
	2012/2013	403.8		7.8		621.3			75.1		1,108.0
	2013/2014	329.0	705.0	6.0		25.0		9.5	245.7		1,320.2
	2014/2015	108.0	650.0	35.1	132.9			28.0	146.6		1,100.6
	2015/2016	1,382.5	5,914.5	19.4	148.4	45.4		13.8	104.9	30.0	7,658.9
	2016/2017	171.1	4,994.5	38.3		24.0		32.1	54.3		5,314.3
	2017/2018	131.0	5,010.0	124.8	6.0	90.0		27.0			5,388.8
	2018/2019	1,032.5	2,352.3	29.9				82.8	127.1		3,624.6
	2019/2020	167.0	6,145.0	29.9				152.3	73.0		6,567.2
	2020/2021		2,410.0	26.3	4.0			94.3	30.2		2,564.8
	2021/2022			19.9				237.8	65.7		323.4
	2022/2023	14.0	5,626.8					1,440.8	345.1		7,426.7
Capacity from Reactivated Units (ICAP MW)	2007/2008					47.0					47.0
	2008/2009					131.0					131.0
	2009/2010										-
	2010/2011	160.0		10.7							170.7
	2011/2012	80.0				101.0					181.0
	2012/2013										-
	2013/2014										-
	2014/2015			9.0							9.0
	2015/2016										-
	2016/2017					21.0					21.0
	2017/2018					991.0					991.0
	2018/2019										-
	2019/2020										-
	2020/2021										-
	2021/2022										-
	2022/2023										-
Uprates to Existing Capacity Resources (ICAP MW)	2007/2008	114.5		13.9	80.0	235.6	92.0				536.0
	2008/2009	108.2	34.0	18.0	105.5	196.0	38.4				500.1
	2009/2010	152.2	206.0		162.5	61.4	197.4		16.5		796.0
	2010/2011	117.3	163.0		48.0	89.2	160.3				577.8
	2011/2012	369.2	148.6	57.4		186.8	292.1		8.7		1,062.8
	2012/2013	231.2	164.3	14.2		193.0	126.0		56.8		785.5
	2013/2014	56.4	59.0	0.3		215.0	47.0		39.6		417.3
	2014/2015	104.9		0.5	41.5	138.6	107.0	7.1	73.6		473.2
	2015/2016	216.8	72.0	4.7	15.7	63.4	149.2	2.2	24.1		548.1
	2016/2017	436.6	420.0	3.3	7.4	484.3	102.6	1.7	14.8		1,470.7
	2017/2018	71.9	212.5	5.1	105.9	64.8	11.0	0.4	2.1		473.7
	2018/2019	33.4	548.0	2.4	22.9	11.9	79.3	-	14.9	-	712.8
	2019/2020	29.3	72.5	3.9	5.2	65.3	-	-	46.8	-	223.0
	2020/2021	9.3	588.8	1.2	4.6	5.7		1.0	14.7		625.3
	2021/2022	100.2	549.9	7.1	3.6	91.9	-	24.2	18.4	-	795.3
	2022/2023	674.1	316.4	7.7		334.9	99.0	50.0	10.3		1,492.4
	Total	7,903.6	39,078.1	589.3	894.4	5,292.3	1,501.3	2,206.1	1,891.7	30.0	59,386.8

Figure 3: Cumulative Generation Capacity Increases by Fuel Type

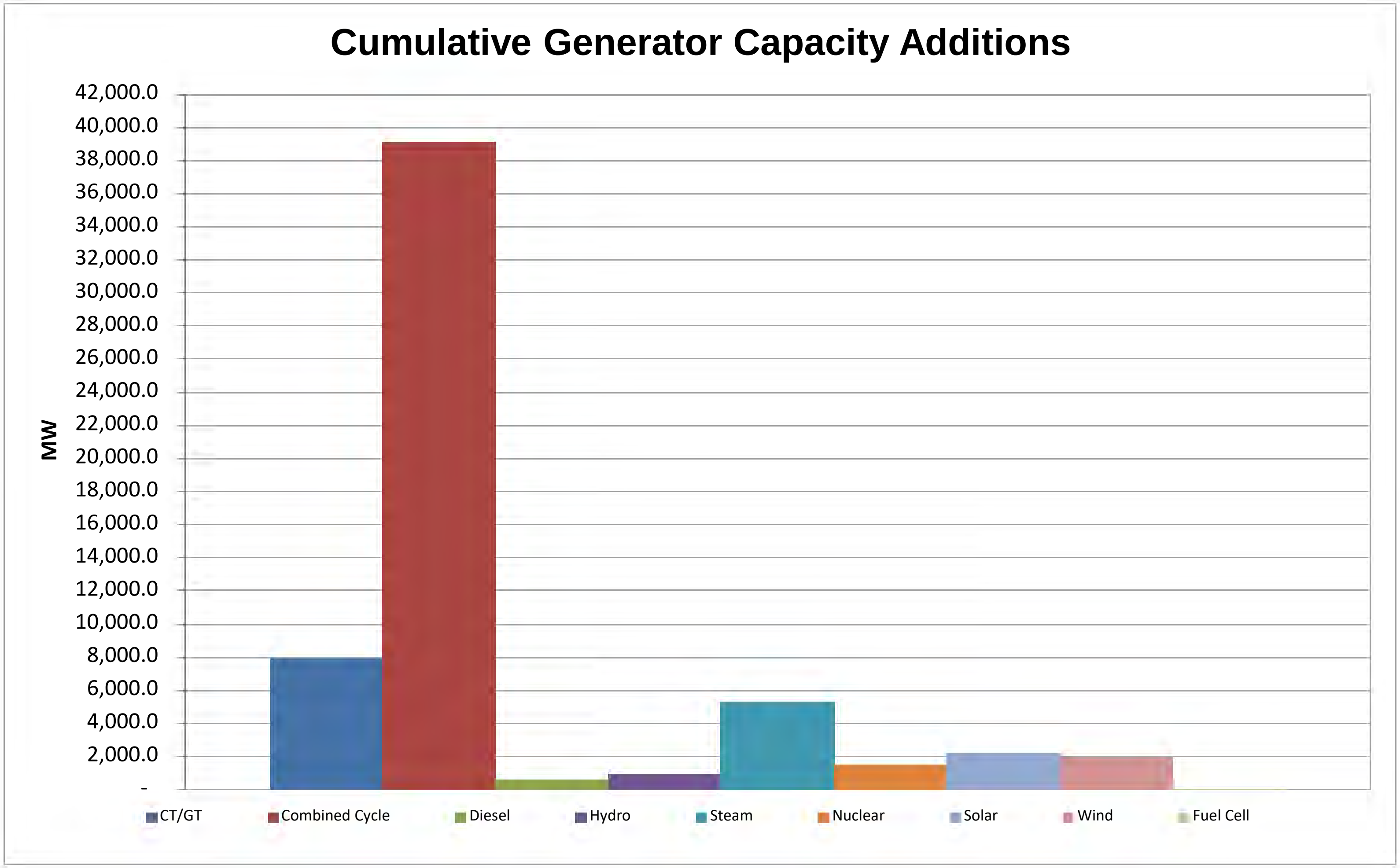


Table 9 shows the changes that have occurred regarding resource deactivation and retirement since the RPM was approved by FERC. The MW values shown in Table 9 represent the quantity of unforced capacity cleared in the 2022/2023 Base Residual Auction that came from resources that have either withdrawn their request to deactivate, postponed retirement, or been reactivated (i.e., came out of retirement or mothball state for the RPM auctions) since the inception of RPM. This total accounts for 13,706.2 MW of cleared UCAP in the 2022/2023 BRA which equates to 17,646.3 MW of ICAP Offered.

Table 9 – Changes to Generation Retirement Decisions since Commencement of RPM in 2007/2008

	RTO*	
Generation Resource Decision Changes	ICAP Offered	UCAP Cleared
Withdraw n Deactivation Requests	13,747.7	10,530.0
Postponed or Cancelled Retirement	3,165.2	2,465.0
Reactivation	733.4	711.2
Total	**17,646.3**	**13,706.2**

RPM Impact to Date

As illustrated in Table 5, for the 2022/2023 auction, the capacity exports were 1,525.3 MW and the offered capacity imports were 1,649.1 MW. The difference between the capacity imports and exports results is a net capacity import of 123.8 MW. In the planning year preceding the RPM auction implementation, 2006/2007, there was a net capacity export of 2,616.0 MW. In this auction, PJM is now a net importer of 123.8 MW. Therefore, RPM's impact on PJM capacity interchange is 2,739.8 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2022/2023 planning year can be estimated by adding the net change in capacity imports and exports over the period, the forward demand and energy efficiency resources, the increase in Installed Capacity over the RPM implementation period from Table 8 and the net change in generation retirements from Table 9. Therefore, as illustrated in Table 10, the minimum estimated net impact of the RPM implementation on the availability of capacity in the 2022/2023 compared to what would have happened absent this implementation is 90,718.7 MW.

Table 10 shows the details on RPM's impact to date in ICAP terms.

Table 10 – RPM's Impact to Date

Change in Capacity Availability	Installed Capacity MW
New Generation	46,346.1
Generation Upgrades (not including reactivations)	11,490.0
Generation Reactivation	1,550.7
Forward Demand and Energy Efficiency Resources	14,772.1
Cleared ICAP from Withdrawn or Cancelled Retirements	13,820.0
Net increase in Capacity Imports	2,739.8
Total Impact on Capacity Availability in 2022/2023 Delivery Year	**90,718.7**

Discussion of Factors Impacting the RPM Clearing Prices

The main factors impacting 2022/2023 RPM BRA clearing prices relative to 2021/2022 BRA clearing prices are provided below, separated out by changes to the demand-side and supply-side of the market.

Changes that impacted the Demand Curve:

- The forecast peak load for the PJM RTO for the 2022/2023 Delivery Year is 150,229.0 MW which is 2,418.4 MW or about 1.6% below the forecast peak load of 152,647.4 MW for the 2021/2022 BRA. This reduction, along with a lower Installed Reserve Margin and pool-wide EFORd, was manifested in a 3,086 MW decrease in the reliability requirement for the RTO as compared to the 2021/2022 BRA.
- 1% shift to the left of the downward-sloping Variable Resource Requirement Curve (proposed in PJM's Quadrennial Review filing (Docket No. ER19- 105))
- 230 MW of PRD across the RTO has elected to participate in the 2022/2023 BRA: 80 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 40 MW in the EMAAC LDA (with 19.6 MW located in the DPL-South LDA).
- The Net CONE decreased for the RTO and for all of the modeled LDAs. The Net CONE of the RTO decreased by 19.0% and the decrease in LDA Net CONE values ranged from 7.4% for the BGE LDA to 28.0% for the COMED LDA.

Changes that impacted the Supply Curve:

- The 2022/2023 BRA is the third BRA for which PJM has procured only Capacity Performance ("CP") Resources.
    - The nameplate capability of wind resources that cleared in the 2022/2023 BRA as annual CP capacity and/or winter seasonal CP capacity is approximately 8,518.3 MW, which is 392.3 MW greater than the 8,126 MW of wind energy nameplate capability that cleared in the 2021/2022 BRA.

- The nameplate capability of solar resources that cleared in the 2022/2023 BRA as annual CP capacity and/or summer seasonal CP capacity is approximately 3,242.8 MW, which is 1,601.8 MW greater than the 1,641 MW of solar energy nameplate capability that cleared in the 2021/2022 BRA.
- Capacity offered by DR in UCAP terms is 1,373.8 MW lower than in the 2021/2022 BRA.
- Capacity offered by EE in UCAP terms is 2,102.0 MW higher than in the 2021/2022 BRA.
- 686.8 MW of seasonal capacity resources cleared in an aggregated manner to form a year-round commitment. 686.8 MW of summer CP resources comprised of 442.0 MW of summer DR, 234.9 MW of summer EE and 9.9 MW of intermittent resources cleared along with 686.8 MW of winter CP resources comprised mainly of winter capability from wind resources.

- New generation capacity of 6,053.9 MW was offered into the BRA comprised of 4,843.6 of new generation and 1,210.3 MW of uprates.
- In general, offer prices from supply resources were lower in this auction compared to the prior auction
- The 2022/2023 BRA is the first RPM auction conducted under the expanded application of the Minimum Offer Price Rule resulting from FERC's December 19, 2019 Order[3].

[3] Docket Nos. EL16-49-000 EL18-178-000 (Consolidated)

Attachment H

NEWS RELEASE

FOR IMMEDIATE RELEASE

PJM Successfully Clears Capacity Auction to Ensure Reliable Electricity Supplies
Auction Attracts Diverse and Efficient Resources at Lower Wholesale Costs

(Valley Forge, PA – June 2, 2021) – PJM Interconnection announced today the successful procurement, through its annual capacity auction, of competitive and affordable power supplies for the 65 million people PJM serves.

Renewables, nuclear and new natural gas generators saw the greatest increases in cleared capacity, while coal units saw the largest decrease. Prices were significantly lower than in the previous auction.

The PJM capacity auction, called the Base Residual Auction, procures power supply resources in advance of the delivery year to meet electricity needs in the PJM service area, which includes all or part of 13 states and the District of Columbia.

Auctions are usually held three years in advance of the delivery year. The 2022/2023 auction was originally scheduled to be held in May 2019, but was postponed until this year as FERC considered approval of new capacity market rules, specifically the Minimum Offer Price Rule (MOPR).

"PJM's capacity market continues to support a competitive, diverse and reliable resource mix through the ongoing energy transition," said PJM President and CEO Manu Asthana. "We look forward to returning to a regular auction schedule while we continue work with our stakeholders to reform the capacity market to ensure its success into the future."

This year's auction procured 144,477 MW of resources for the period of June 1, 2022, through May 31, 2023, at a total cost of $3.9 billion. This total is $4.4 billion less than in the previous auction, for the 2021/2022 Delivery Year, when adjusted for changes in Fixed Resource Requirement (FRR) elections.

The auction produced a price of $50/MW-day for much of the PJM footprint, compared to $140/MW-day in the most recent auction in 2018. Prices are higher in some regions due to transmission limits.

Prices in this year's auction were significantly lower than prices in the previous auction for several reasons:

- A lower load forecast and reserve requirement, which in turn decreases the amount of capacity PJM needs to procure
- A 19% drop in the net Cost of New Entry, or CONE, which is a reference figure used to estimate the cost of a new generator to be built and enter the market
- Overall lower offer prices from resources participating in the auction

– MORE –

Renewable Resources Continue to Grow

The auction continues to attract more renewable resources into the capacity market, committing to meet PJM's strict performance standards. Solar and wind resources significantly increased their capacity contribution.

A total of 1,728 MW of wind cleared in the auction, representing an increase of 312 MW over the previous capacity auction. Solar increased by 942 MW over the previous capacity auction, with 1,512 MW clearing. These capacity values represent a total capability of these resources to provide as much as 11,761 MW (nameplate) into the PJM system.

Newer, more efficient combined-cycle natural gas plants also saw a significant increase, adding more than 3,414 MW of capacity. Energy Efficiency programs were up by 1,979 MW, or 70%, while demand response, at 8,812 MW, was down 2,314 MW, or 21%, from the previous auction.

Nuclear generators cleared an additional 4,460 MW when compared to the last auction, adjusting for FRR elections.

Coal generators, meanwhile, cleared 8,175 fewer megawatts than in the previous auction, when adjusted for coal units committed to FRR plans.

The total procured capacity in the auction represents a 19.9% reserve margin, compared to a 14.5% required reserve for the 2022/2023 Delivery Year. This accounts for load and resource commitments under FRR.

In five areas, ComEd, Duke Energy Ohio & Kentucky, the Mid-Atlantic Area Council (MAAC) region, Eastern MAAC region, and Baltimore Gas & Electric (BGE), capacity prices are higher than the overall PJM price. For ComEd, the price is $68.96/MW-day; for Duke Energy Ohio & Kentucky, the price is $71.69/MW-day; for MAAC, the price is $95.79/MW-day; for Eastern MAAC, the price is $97.86/MW-day; and for BGE, the price is $126.50/MW-day.

(The MAAC region consists of Atlantic City Electric, BGE, Delmarva Power, Jersey Central Power & Light, Met-Ed, PECO, Penelec, Pepco, PPL, PSE&G, PPL and Rockland Electric. BGE and the Eastern MAAC region have a different price than the rest of the MAAC region. The Eastern MAAC region is made up of Atlantic City Electric, Delmarva Power, Jersey Central Power & Light, PECO, PSE&G and Rockland Electric.)

PJM has compressed its auction calendar to gradually return to a three-year-forward basis. The next annual Base Residual Auction, for the 2023/2024 Delivery Year, will be held in December.

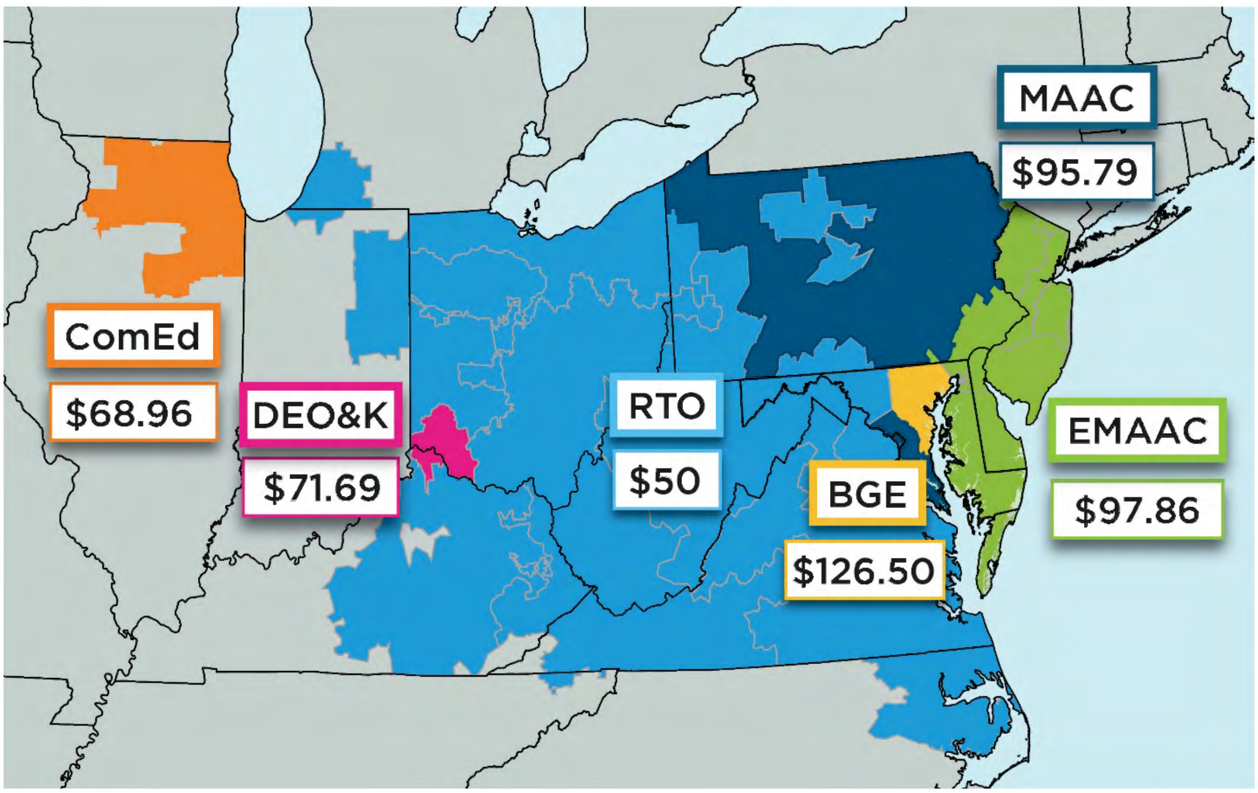
A detailed report of the results is available on PJM's capacity market web page.

– MORE –

2022/2023 Capacity Prices

Delivery Area	Capacity Price	Transmission Zone Affected
RTO	$50.00	
ComEd	$68.96	ComEd
DEOK	$71.69	Duke Energy Ohio & Kentucky
MAAC	$95.79	Met-Ed, Penelec, Pepco, PPL
Eastern MAAC	$97.86	Atlantic City Electric, Delmarva Power, Jersey Central Power & Light, PECO, PSE&G, and Rockland Electric
BGE	$126.50	Baltimore Gas & Electric

2022/2023 Capacity Prices



PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes over 85,103 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM's regional grid and market operations produce annual savings of $3.2 billion to $4 billion. For the latest news about PJM, visit PJM Inside Lines at insidelines.pjm.com.

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Attachment I

Table 1 - Offered and Cleared MW by MOPR Classification

MOPR Classification	Offered MW (UCAP) [5]	Cleared MW (UCAP) [5]
Exempt [1]	38,834	35,630
Non-Exempt MW not subject to MOPR [2]	116,835	100,618
New Entry MOPR (5.14(h)) [3]	1,810	513
State Subsidy MOPR (5.14(h-1)) [4]	10,220	8,404
Total MW	167,698	145,164

Notes:

(1) The "Exempt" MOPR classification includes Categorical Exemptions and Competitive Exemptions. Categorical Exemption includes Self-Supply Entity, Renewable Portfolio Standard, Demand Resource, Energy Efficiency Resource, and Capacity Storage Resource Exemptions.

(2) The "Non-Exempt MW not subject to MOPR" classification represents any Non-Exempt resources not subject to 5.14(h) or 5.14(h-1) MOPR.

(3) The MOPR of Section 5.14(h) of Attachment DD of the PJM OATT applies to sell offers of new Generation Capacity Resources that have not yet cleared in an RPM Auction (except those of nuclear, coal, integrated gasification combined cycle, hydroelectric, wind, or solar facilities) that are located in an LDA for which a separate VRR Curve has been established. If the Generation Capacity Resource is a Capacity Resource with State Subsidy, then the provisions in Tariff, Attachment DD, section 5.14(h-1) apply.

(4) The MOPR of Section 5.14(h-1) of Attachment DD of the PJM OATT applies to the sell offers of any Capacity Resource with State Subsidy unless the resource qualifies for a Categorical

(5) Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.

Table 2 - Offered and Cleared Results by MOPR Floor Price Type

MOPR Floor Price Type	Offered MW (UCAP) (1)	Cleared MW (UCAP) (1)
Default MOPR Price	6,977	5,153
Resource Specific MOPR Price	5,053	3,764
Total MW	12,030	8,917

Notes:
(1) Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.

Table 3 - Offered and Cleared Results by Resource Type

	Not Subject to MOPR				Subject to MOPR (3)	
	Exempt (1)		Non-Exempt (2)			
Resource Type	Offered MW (UCAP) (4)	Cleared MW (UCAP) (4)	Offered MW (UCAP) (4)	Cleared MW (UCAP) (4)	Offered MW (UCAP) (4)	Cleared MW (UCAP) (4)
CC / CT	8,289	8,246	62,875	58,319	2,009	788
Solar, Wind, & Hydro	8,224	6,920	-	-	633	477
Steam / Other Gen (5)	14,172	12,797	47,781	37,287	8,145	6,708
DR / EE	8,149	7,668	6,179	5,012	1,242	944
Total MW	38,834	35,630	116,835	100,618	12,030	8,917

Notes:

(1) The "Exempt" classification includes Categorical Exemptions and Competitive Exemptions. Categorical Exemption includes Self-Supply Entity, Renewable Portfolio Standard, Demand Resource, Energy Efficiency Resource, and Capacity Storage Resource Exemptions.
(2) The "Non-Exempt" classification represents any Non-Exempt resources not subject to 5.14(h) or 5.14(h-1) MOPR.
(3) Includes resources subject to MOPR of Section 5.14(h) or Section 5.14(h-1) of Attachment DD of the PJM OATT.
(4) Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.
(5) "Other Gen" includes diesel, fuel cell, and aggregate resources of different technology types

Attachment J

Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the last Base Residual Auction, for the 2021/2022 Delivery Year. The MMU has not completed its analysis of the 2022/2023 RPM Base Residual Auction.

Table 5-1 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. The MMU has not completed its analysis of the 2022/2023 RPM Base Residual Auction. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of 30 performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.
- Market performance was evaluated as not competitive based on the 2021/2022 RPM Base Residual Auction. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level. The MMU has not completed its analysis of the 2022/2023 RPM Base Residual Auction.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.
3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

parameters, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2020, the 2023/2024 Base Residual Auction is delayed and scheduled for December 2021, and first and second incremental auctions for the 2022/2023 through 2025/2026 Delivery Years are canceled if within 10 months of the revised BRA schedule.[4]

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[5]

Under RPM, capacity obligations are annual.[6] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[7] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[8] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[9]

4 174 FERC ¶ 61,036 (2021).
5 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
6 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either with commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
7 See 126 FERC ¶ 61,275 at P 86 (2009).
8 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
9 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.

The 2021/2022 RPM Third Incremental Auction and the 2022/2023 RPM Base Residual Auction were conducted in the first six months of 2021.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[10] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In the first six months of 2021, RPM installed capacity decreased 307.7 MW or 0.2 percent, from 184,245.0 MW on January 1 to 183,962.3 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on June 30, 2021, 46.0 percent was gas; 26.5 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.0 percent was oil; 0.8 percent was wind; 0.4 percent was solid waste; and 1.0 percent was solar.

10 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

- **Market Concentration.** In the 2022/2023 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[11] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[12] [13] [14]

- **Imports and Exports.** Of the 1,558.0 MW of imports in the 2022/2023 RPM Base Residual Auction, 1,558.0 MW cleared. Of the cleared imports, 954.9 MW (61.3 percent) were from MISO.

- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,115.9 MW for June 1, 2021, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2021/2022 Delivery Year (16,233.9 MW) less purchases of replacement capacity (4,118.0 MW).

Market Conduct

- **2022/2023 RPM Base Residual Auction.** Of the 1,083 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).

Market Performance

- The 2021/2022 RPM Third Incremental Auction and 2022/2023 RPM Base Residual Auction were conducted in the first six months of 2021.[15] The weighted average capacity price for the 2020/2021 Delivery Year is $111.07 per MW-day, including all RPM auctions for the 2020/2021 Delivery Year. The weighted average capacity price for the 2021/2022 Delivery Year is $147.33 per MW-day, including all RPM auctions for the 2021/2022 Delivery Year.

- For the 2021/2022 Delivery Year, RPM annual charges to load are $9.4 billion.

- In the 2021/2022 RPM Base Residual Auction, the market performance was determined to be not competitive as a result of noncompetitive offers that affected market results. The MMU has not completed its analysis of the 2022/2023 RPM Base Residual Auction.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first six months of 2021 was 6.8 percent, an increase from 5.9 percent in the first six months of 2020.[16]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first six months of 2021 was 82.5 percent, a decrease from 85.8 percent in the first six months of 2020.

Recommendations[17]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a

11 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

12 See OATT Attachment DD § 6.5.

13 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

14 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

15 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

16 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on July 21, 2021. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

17 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[18] [19] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[20] [21] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and

18 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
19 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
20 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
21 *See the 2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[22] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[23] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)

22 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

23 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the values in the CRF table in the tariff when the components change. (Priority: High. First reported 2020. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit which is not capable of supplying energy consistent with its day-ahead offer which should equal its ICAP, reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where

competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU has not completed its analysis of the

2022/2023 RPM Base Residual Auction. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of net CONE times B. But net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than net CONE times B.

The MMU filed a complaint with the Commission asserting that the market seller offer cap is overstated.[24] The result of an overstated market seller offer cap is to permit the exercise of market power, as occurred in the 2021/2022 BRA. The MMU has not completed its analysis of the 2022/2023 RPM Base Residual Auction. On March 18, 2021, the Commission issued an order determining that the current default market seller offer cap "is incorrectly calibrated such that it may unjustly and unreasonably prevent the appropriate review of offers, thereby allowing potential exercises of market power."[25] The Commission asked the parties to file briefs to address "whether an alternative method for market power mitigation in the PJM capacity market would better address the concern that the current methodology precludes the Market Monitor from reviewing offers that raise market power concerns and mitigating offers where appropriate." The MMU filed a brief on the market seller offer cap issue.[26]

24 In 2019, the MMU filed a complaint seeking an order directing PJM to update the assumptions regarding the expected number of performance assessment intervals (PAI) in calculating the default capacity market seller offer cap (MSOC). Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (February 21, 2019).
25 174 FERC ¶ 61,212.
26 Brief of the Independent Market Monitor for PJM, Docket No. EL19-47 and EL19-63, not consolidated (April 28, 2021).

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in the last BRA and in subsequent incremental auctions. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping. The MMU has not completed its analysis of the 2022/2023 RPM Base Residual Auction.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[27] [28] [29] [30] [31] [32] In 2020 and 2021, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The capacity performance modifications to the RPM construct significantly improved the capacity market and addressed a number of issues that had been identified by the MMU. But significant issues remain in the PJM capacity market design.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 7,828.5 ICAP MW on June 1, 2021, and will have excess reserves of 8,065.7 ICAP MW on June 1, 2022, based on

27 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).
28 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
29 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).
30 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
31 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
32 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

current positions.[33] A majority of capacity investments in PJM were financed by market sources.[34] Of the 42,969.5 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2021/2022 Delivery Years, 31,509.22 MW (73.3 percent) were based on market funding. Of the 6,675.0 MW of additional capacity that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years, 5,007.8 MW (75.0 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies, particularly for economic nuclear power plants, continued to evolve. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM Capacity Market as well as the competitiveness of PJM markets overall. These subsidy programs originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. Some subsidies were requested by the owners of economic resources. Some subsidies were requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced and is now being replaced by competition to receive subsidies. Competition to receive subsidies is now a reality and is accelerating in PJM.

33 The calculated reserve margin for June 1, 2022, does not account for cleared buy bids that have not been used in replacement capacity transactions.

34 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

Table 5-2 RPM related MMU reports: 2020 through 2021

Date	Name
January 16, 2020	Net Revenues for PJM RPM Base Residual Auctions in 2020 http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Net_Revenues_20232024_RPM_BRA_20200116.pdf
January 17, 2020	IMM Request for Clarification re MOPR Order Docket Nos. EL16-49 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Request_for_Clarification_Docket_Nos_EL16-49_EL18-178_20200117.pdf
January 21, 2020	CONE and ACR Values - Preliminary http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Special_Session_CONE_and_ACR_Values_20200128.pdf
February 5, 2020	IMM Answer to Requests for Rehearing's Docket No. EL14-69 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_To_RFRS_Docket_Nos_EL14-69_EL18-178_20200205.pdf
February 17, 2020	IMM MOPR Gross CONE Template http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MOPR_Gross_CONE_Template_20200217.xlsx
February 18, 2020	IMM Second Request for Clarification re MOPR Docket No. EL18-178, EL16-49 http://www.monitoringanalytics.com/filings/2020/IMM_Second_Request_for_Clarification_Docket_No_EL18-178_%20EL16-49_20200218.pdf
February 18, 2020	Unit Specific Nuclear ACR Information http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_MOPR_Unit_Specific_Nuclear_ACR_Information_20200219.pdf
February 21, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200221.pdf
February 28, 2020	Monitoring Analytics ACR Template http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_ACR_Template_20200228.pdf
March 20, 2020	Potential Impacts of the MOPR Order http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_MOPR_Order_20200320.pdf
April 16, 2020	Potential Impacts of the Creation of Maryland FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf
May 6, 2020	Potential Compliance with P386 of FERC Order on Rehearing http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_Potential_Compliance_with_P386_of_FERC_Order_on_Rehearing_20200506.pdf
May 13, 2020	Potential Impacts of the Creation of New Jersey FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf
May 15, 2020	IMM Request for Clarification re MOPR Ex Investigation Docket Nos. EL18-178-002 and EL16-49-002 http://www.monitoringanalytics.com/filings/2020/IMM_Request_for_Clarification_Docket_No_EL18-178-002_EL16-49-002_20200515.pdf
May 15, 2020	IMM Comments re MOPR-Ex Docket Nos. ER18-1314-00, EL16-49-000, EL18-178-000 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER18-1314-003_EL16-49_EL18-178_20200515.pdf
May 20, 2020	IMM Comments re NJBPU Investigation of Resource Adequacy Alternatives Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf
June 22, 2020	IMM Comments re MOPR-Ex Compliance Filing Docket Nos. ER18-1314, EL16-49 and ERL8-178 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER18-1314_EL16-49_ER18-178_20200622.pdf
June 24, 2020	IMM Reply Comments re NJ BPU Resource Adequacy Alternatives Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf
June 30, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200630.pdf
July 15, 2020	IMM Answer to PSEG and Exelon Reply re New Jersey FRR Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf
July 17, 2020	Potential Impacts of the Creation of Ohio FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf
July 20, 2020	IMM Comments re NJ BPU Nuclear Power Plant ZECs Docket No. EO18080899 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO18080899_20200720.pdf
July 23, 2020	IMM Answer re MOPR Ex Docket No. EL16-49, ER18-1314 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_EL16-49_ER18-1314_EL18-178_20200724.pdf
July 27, 2020	IMM Comments re ORDC Compliance Filing Docket No. EL19-58-002 and ER19-1486 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_EL19-58-002_ER19-1486-20200727.pdf
September 15, 2020	2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022 http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf
September 19, 2020	ELCC-IMM Comments https://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MRC_ELCC_IMM_Comments_20200919.pdf
September 30, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200930.pdf
October 19, 2020	Issues with HVDC as Capacity https://www.monitoringanalytics.com/reports/Presentations/2020/IMM_HVDCSTF_Issues_with_HVDC_as_Capacity_20201019.pdf
October 19, 2020	IMM Answer re EAS Docket No. EL19-58-003 https://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_EL19-58-003_20201019.pdf
November 5, 2020	PAI Settlement Issues https://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_PAI_Settlement_Issues_20201102.pdf
November 20, 2020	IMM Comments re ELCC Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-278_20201120.pdf
December 4, 2020	CRF Issues in the Capacity Market https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_CRF_Issues_in_the_Capacity_Market_20201204.pdf
December 14, 2020	IMM Answer and Motion for Consolidation re ELCC Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_ER21-278_20201214.pdf
December 17, 2020	IMM Comments re PAI Docket No. ER15-623, et al https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER15-623_et_al_20201217.pdf
December 18, 2020	IMM Answer re PJM ELCC Proposal Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_ER21-278_20201218.pdf
December 29, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20201229.pdf

Table 5-2 RPM related MMU reports: 2020 through 2021 (continued)

Date	Name
January 29, 2021	Analysis of NJ Zero Emissions Credit(ZEC)Applications https://www.monitoringanalytics.com/reports/Reports/2021/IMM_Public_Report_Analysis_of_NJ_ZEC_Applications_20210129.pdf
February 19, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20210219.pdf
March 4, 2021	Next Steps in Capacity Market Design https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_Capacity_Market_Workshop_Session_2_Next_Steps_in_Capacity_Market_Design_20210304.pdf
March 5, 2021	IMM Comment re New Jersey FRR Docket No. EO20030203 https://www.monitoringanalytics.com/filings/2021/IMM_Comment_Docket_No_EO20030203_20210305.pdf
March 22, 2021	IMM Comments re ELCC Docket No. ER21-278-001 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-278-001_20210322.pdf
March 31, 2021	IMM Answer re Jackson Complaint Docket No. EL21-62, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_Nos_EL21-62_EL21-63_20210331.pdf
April 7, 2021	RPM Capacity Transfer Rights: Education https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_RPM_Capacity_Transfer_Rights_Education_20210407.pdf
April 12, 2021	IMM Commentsr re Jackson Complaint Docket No. EL21-62, et al https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_Nos_EL21-62_EL21-63_20210412.pdf
April 19, 2021	IMM Answer to P3 re MSOC Docket Nos. EL19-47-001, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_et_al_20210419.pdf
April 26, 2021	IMM Comments re Modernizing Electricity Market Design Docket No. AD21-10 https://www.monitoringanalytics.com/filings/2021/IMM_Post_Technical_Conference_Comments_Docket_No_AD21-10_20210426.pdf
April 28, 2021	IMM Brief re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Brief_Docket_No_EL19-47_et_al_20210428.pdf
April 29, 2021	IMM Answer to PJM re ELCC Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_PJM_Docket_No_ER21-278_20210429.pdf
May 18, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_RPM_Must_Offer_Obligations_20210518.pdf
May 19, 2021	IMM Answer to Motion re ELCC Docket No. EL19-100 and ER20-584 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_Motion_Docket_No_EL19-100_20210519.pdf
May 25, 2021	IMM Comments re PJM Capacity Market CRF Docket No. ER21-1844 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1844_20210525.pdf
June 9, 2021	IMM Reply Brief re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Reply_Brief_Docket_No_EL19-47_EL19-63_20210609.pdf
June 15, 2021	IMM Response to Exelon re 10 Year Report Case No. 9271 https://www.monitoringanalytics.com/filings/2021/IMM_Response_to_Exelon_MDPSC_Case_No_%209271_20210615.pdf
June 16, 2021	IMM MOPR Matrix Entries https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MOPR_Matrix_Entries_20210616.pdf
June 22, 2021	IMM Comments re ELCC Docket No. ER21-2043 https://www.monitoringanalytics.com/filings/2021/IMM_Comment_Docket_No_ER21-2043_20210622.pdf
June 25, 2021	IMM Answer to Replies re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_20210625.pdf
June 28, 2021	Data Submission Window Opening: 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2023-2024_BRA_20210628.pdf
June 30, 2021	IMM MOPR Matrix Entries https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_CIFP_MOPR_MOPR_Matrix_Entries_20210630.pdf

Installed Capacity

On January 1, 2021, RPM installed capacity was 184,245.0 MW (Table 5-3).[35] Over the next six months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 183,962.3 MW on June 30, 2021, a decrease of 282.7 MW or 0.2 percent from the January 1 level.[36] [37] The 282.7 MW decrease was the result of an increase in exports (154.9 MW), derates (964.4 MW), and deactivations (2,736.5 MW), offset by new or reactivated generation (2,958.3 MW), capacity modifications (430.3 MW), and an increase in imports (184.5 MW).

At the beginning of the new delivery year on June 1, 2021, RPM installed capacity was 183,962.3 MW, an increase of 1,024.4 MW or 0.6 percent from the May 31, 2021, level of 182,937.9 MW.

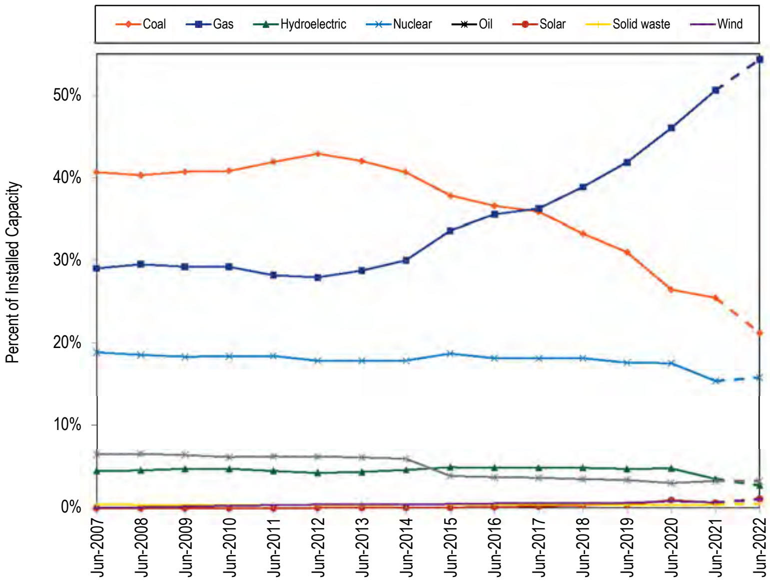
35 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
36 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.
37 Wind resources accounted for 1,522.9 MW, and solar resources accounted for 1,779.5 MW of installed capacity in PJM on June 30, 2021. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 15 (May 26, 2021).

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2021

	01-Jan-21		31-May-21		01-Jun-21		30-Jun-21	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	49,747.0	27.0%	49,340.2	27.0%	48,714.4	26.5%	48,714.4	26.5%
Gas	84,031.3	45.6%	83,914.1	45.9%	84,651.7	46.0%	84,651.7	46.0%
Hydroelectric	8,754.3	4.8%	8,753.5	4.8%	8,792.0	4.8%	8,792.0	4.8%
Nuclear	32,312.4	17.5%	32,301.2	17.7%	32,301.2	17.6%	32,301.2	17.6%
Oil	5,512.6	3.0%	5,507.1	3.0%	5,550.1	3.0%	5,550.1	3.0%
Solar	1,014.7	0.6%	1,051.1	0.6%	1,779.5	1.0%	1,779.5	1.0%
Solid waste	695.6	0.4%	650.5	0.4%	650.5	0.4%	650.5	0.4%
Wind	2,177.1	1.2%	1,420.2	0.8%	1,522.9	0.8%	1,522.9	0.8%
Total	184,245.0	100.0%	182,937.9	100.0%	183,962.3	100.0%	183,962.3	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2021, as well as the expected installed capacity for the 2022/2023 Delivery Year, based on the results of all auctions held through June 30, 2021.[38] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 25.5 percent on June 1, 2021, and is projected to decrease to 21.2 percent by June 1, 2022. The share of gas increased from 29.1 percent on June 1, 2007, to 50.6 percent on June 1, 2021, and is projected to increase to 54.3 percent on June 1, 2022.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 202



38 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2021, through June 30, 2021, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and June 30, 2021[39]

	01-Jan-21			31-May-21			01-Jun-21			30-Jun-21		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	20,843.6	12.2%	1	20,787.3	12.2%	1	20,747.0	12.2%	1	20,747.0	12.2%	1
Dominion Resources, Inc.	19,533.2	11.4%	2	19,505.1	11.5%	2	19,702.1	11.6%	2	19,702.1	11.6%	2
Vistra Energy Corp.	11,319.0	6.6%	3	11,319.0	6.7%	3	11,327.8	6.7%	3	11,327.8	6.7%	3
Riverstone Holdings LLC	10,941.4	6.4%	4	10,866.5	6.4%	5	10,914.8	6.4%	5	10,914.8	6.4%	5
LS Power Group	10,843.7	6.3%	5	11,053.7	6.5%	4	11,253.4	6.6%	4	11,253.4	6.6%	4

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2021, to June 30, 2021, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and June 30, 2021[40]

	01-Jan-21		31-May-21		01-Jun-21		30-Jun-21	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	137,312.5	74.5%	136,106.1	74.4%	136,807.7	74.4%	136,807.7	74.4%
Nonmarket	46,932.5	25.5%	46,831.8	25.6%	47,154.6	25.6%	47,154.6	25.6%
Total	184,245.0	100.0%	182,937.9	100.0%	183,962.3	100.0%	183,962.3	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[41] The FDI_c is defined as $1 - \sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[42] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[43] The average FDI_c for the first six months of 2021 decreased 0.3 percent compared to the

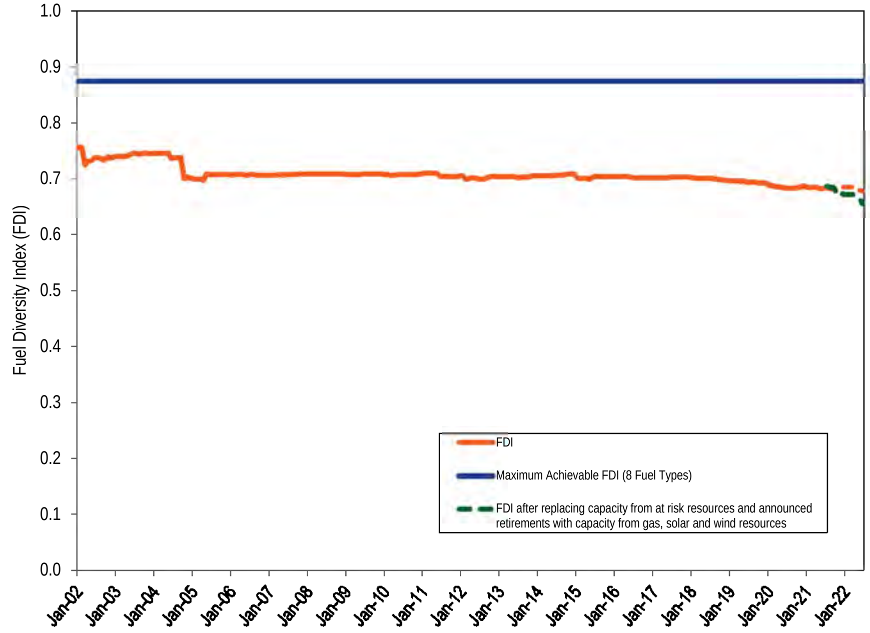
39 The calculated MW for January 1, 2021, were revised from the *2021 Quarterly State of the Market Report for PJM: January through March*.
40 The calculated MW for January 1, 2021, were revised from the *2021 Quarterly State of the Market Report for PJM: January through March*.
41 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.
42 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.
43 See the *2019 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.

first six months of 2020. Figure 5-2 also includes the expected FDI_c through June 2022 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 4,763 MW of coal, CT and other capacity were identified as being at risk of retirement.[44] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance of the retirement.[45] There are 10,161 MW of generation that have a requested retirement date after June 30, 2021.[46] The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity that cleared in an RPM auction from the at risk resources and other resources with deactivation notices is replaced by gas, wind and solar capacity.[47] [48] The FDI_c under these assumptions would decrease by 1.3 percent on average from the expected FDI_c for the period July 1, 2021, through June 1, 2022.

44 See Table 7-47 in the *2020 State of the Market Report for PJM*, Volume II, Section 7: Net Revenue.
45 See OATT Part V § 113.1.
46 See *2020 State of the Market Report for PJM: January through June*, Volume II, Section 12: Generation and Transmission Planning, Table 12-11.
47 It is assumed that 2,212.4 MW of replacement capacity is from solar units and 205.2 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 3,561.2 GWh of generation over a six month period assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-27 and Table 8-30. This level of GWh represents the increase in renewable generation required by RPS in the first six months of 2022 over the level of renewable generation that was required by RPS in the first six months of 2022. The split between solar and wind is based on queue data.
48 For this analysis resources for which PJM has received deactivation notifications were replaced with capacity beginning on the projected retirement date listed in the deactivation data. At risk resources that have not notified PJM regarding deactivation were replaced with capacity beginning on July 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2023



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[49]

49 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

In the first six months of 2021, the 2021/2022 RPM Third Incremental Auction and 2022/2023 RPM Base Residual Auction were conducted.[50]

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2020/2021 Delivery Year. The 19,278.5 MW increase was the result of new generation capacity resources (34,017.5 MW), reactivated generation capacity resources (1,374.4 MW), uprates (7,577.6 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (2,016.8 MW), offset by a net decrease in capacity imports (1,051.5 MW), deactivations (42,972.0 MW) and derates (3,651.8 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2016, through June 1, 2022, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2022, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Future Changes in Generation Capacity[51]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2020/2021 Delivery Year, internal installed capacity decreased by 3,654.3 MW after accounting for new capacity resources, reactivations, and uprates (42,969.5 MW) and capacity deactivations and derates (46,623.8 MW).

For the current and future delivery years (2021/2022 through 2022/2023), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified delivery year. Based on expected completion rates of cleared new generation capacity (4,841.2 MW) and pending deactivations (9,246.5 MW), PJM capacity is expected to decrease by 4,405.3 MW for the 2021/2022 through 2022/2023 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 through 2020/2021[52]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
Total	34,017.5	1,374.4	7,577.6	21,967.5	(1,051.5)	(2,016.8)	42,972.0	3,651.8	19,278.5

50 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

51 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

52 The capacity changes in this report are calculated based on June 1 through May 31.

Table 5-7 RPM reserve margin: June 1, 2016, to June 1, 2022[53 54]

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM		Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
										Percent	ICAP (MW)		
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	162,276.1	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	172,781.2	24.0%	8.0%	11,124.4	0.0	24.0%
01-Jun-20	159,560.4	148,355.3	11,488.3	558.0	136,309.0	15.5%	5.78%	169,348.8	24.2%	8.7%	11,911.9	0.0	24.2%
01-Jun-21	156,633.6	149,482.9	11,717.7	510.0	137,255.2	14.7%	5.22%	165,260.2	20.4%	5.7%	7,828.5	0.0	20.4%
01-Jun-22	139,666.7	150,229.0	28,535.5	230.0	121,463.5	14.5%	5.08%	147,141.5	21.1%	6.6%	8,065.7	0.0	21.1%

Sources of Funding[55]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2021/2022 Delivery Year totaled 35,391.9 MW (82.4 percent of all additions), with 26,320.6 MW from market funding and 9,071.3 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2021/2022 Delivery Year totaled 7,577.6 MW (17.6 percent of all additions), with 5,188.6 MW from market funding and 2,389.0 MW from nonmarket funding. In summary, of the 42,969.5 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2021/2022 Delivery Years, 31,509.2 MW (73.3 percent) were based on market funding.

Of the 6,675.0 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years, 5,680.5 MW are not yet in service. Of those 5,680.5 MW that have not yet gone into service, 4,215.7 MW have market funding and 1,464.8 MW have nonmarket funding. Applying the historical completion rates, 67.7 percent of all the projects in development are expected to go into service (2,870.4 MW of the 4,215.7 MW of in development market funded projects; 976.3 MW of the 1,464.8 MW of in development nonmarket funded projects). Together, 3,846.7 MW of the 5,680.5 MW of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2023/2024 Delivery Year.

Of the 994.5 MW of the additional generation capacity that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years and are already in service, 792.1 MW (79.6 percent) are based on market funding and 202.4 MW (20.4 percent) are based on nonmarket funding. In summary, 5,007.8 MW (75.0 percent) of the additional generation capacity (4,215.7 MW in service and 792.1 MW not yet in service) that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 1,667.2 MW (25.0 percent) of proposed generation that cleared at least one RPM auction for the 2022/2023 through 2023/2024 Delivery Years.

53 The calculated reserve margins in this table do not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.
54 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.
55 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

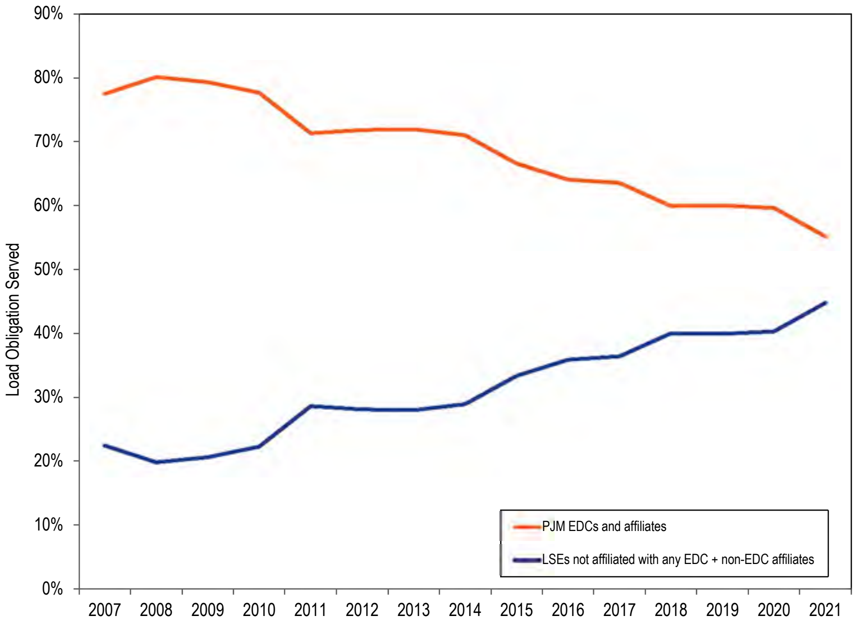
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2021, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 55.2 percent (Table 5-8), down from 59.7 percent on June 1, 2020. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 44.8 percent, up from 40.3 percent on June 1, 2020. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2021, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 55.2 percent on June 1, 2021. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 44.8 percent on June 1, 2021. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2020 and June 1, 2021

	1-Jun-20		1-Jun-21		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	104,849.4	59.7%	96,306.4	55.2%	(8,543.1)	(4.5%)
LSEs not affiliated with any EDC + non EDC Affiliates	70,838.3	40.3%	78,114.1	44.8%	7,275.8	4.5%
Total	175,687.7	100.0%	174,420.4	100.0%	(1,267.3)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2021



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. CTRs permit customers to receive the benefit of importing cheaper capacity using transmission capability. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights Eligible Required Transmission Enhancements.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2022/2023 RPM Base Residual Auction, EMAAC had 4,946.8 MW of CTRs with a total value of $3,737,529, COMED had 2,367.2 MW of CTRs with a total value of $16,381,936, BGE had 4,745.1 MW of CTRs with a total value of $53,188,332 and DEOK had 3,034.8 MW of CTRs with a total value of $24,026,133.

MAAC had 270.1 MW of customer funded ICTRs with a total value of $4,513,768, EMAAC had 40.0 MW of customer funded ICTRs with a total value of $30,222, BGE had 65.7 MW of customer funded ICTRs with a total value of $736,441, COMED had 1,376.0 MW of customer funded ICTRs with a total value of $9,522,470 and DEOK had 155.0 MW of customer funded ICTRs with a total value of $1,227,112.

MAAC had 128.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $2,139,474, EMAAC had 948.0

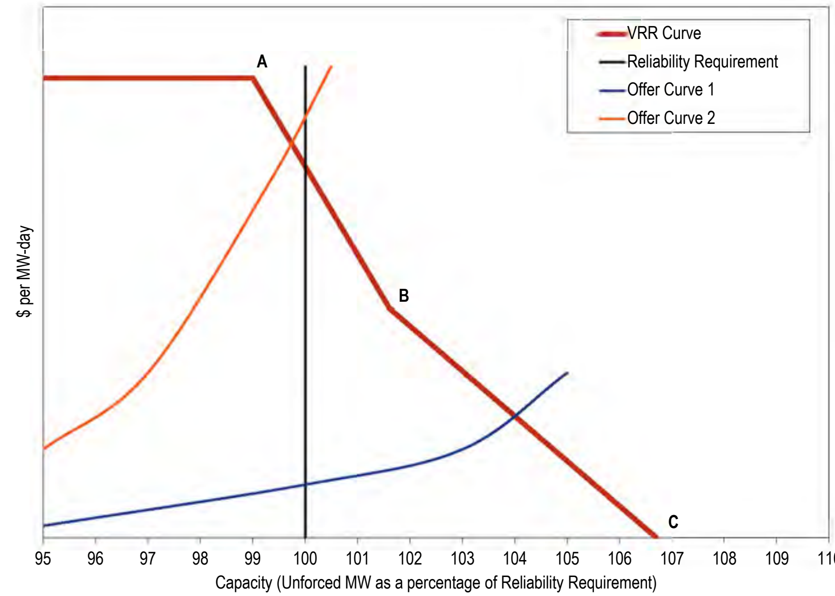
MW with a value of $716,261 and BGE had 306.0 MW with a value of $3,430,000.

Demand Curve

Effective for the 2018/2019 and subsequent delivery years, PJM revised the variable resource requirement (VRR) curve. The starting MW point of the downward sloping demand curve is set at 99.0 percent of the reliability requirement. The highest MW point is set at 106.7 percent of the reliability requirement. Almost all of the downward sloping part of the VRR curve lies to the right side of the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2022/2023 RPM BRA. The clearing price and cleared quantity would be lower if a vertical VRR curve set at the reliability requirement were used in place of the existing VRR curve. This is the case if the supply curve intersects the VRR curve to the right side of the reliability requirement (Offer Curve 1). The only exception would be if the supply curve intersects the VRR curve to the left of the reliability requirement (Offer Curve 2). In that case, the clearing price and cleared quantity would be higher with the vertical demand curve than with the existing VRR curve. In almost all RPM auctions, the offer curve intersected the VRR curve to the right side of the vertical demand curve.

Figure 5-4 VRR curve relative to the reliability requirement: 2022/2023 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2022/2023 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[56] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[57] [58] [59]

56 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

57 See OATT Attachment DD § 6.5.

58 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

59 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-9 RSI results: 2019/2020 through 2022/2023 RPM Auctions[60]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1
2019/2020 First Incremental Auction				
RTO	0.63	0.50	53	53
EMAAC	0.00	0.00	5	5
2019/2020 Second Incremental Auction				
RTO	0.61	0.48	38	38
BGE	0.00	0.00	1	1
2019/2020 Third Incremental Auction				
RTO	0.70	0.59	72	72
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2020/2021 Second Incremental Auction				
RTO	0.40	0.56	34	34
2020/2021 Third Incremental Auction				
RTO	0.54	0.72	59	59
MAAC	0.25	0.18	14	14
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3

60 The RSI shown is the lowest RSI in the market.

Table 5-9 RSI results: 2019/2020 through 2022/2023 RPM Auctions (continued)

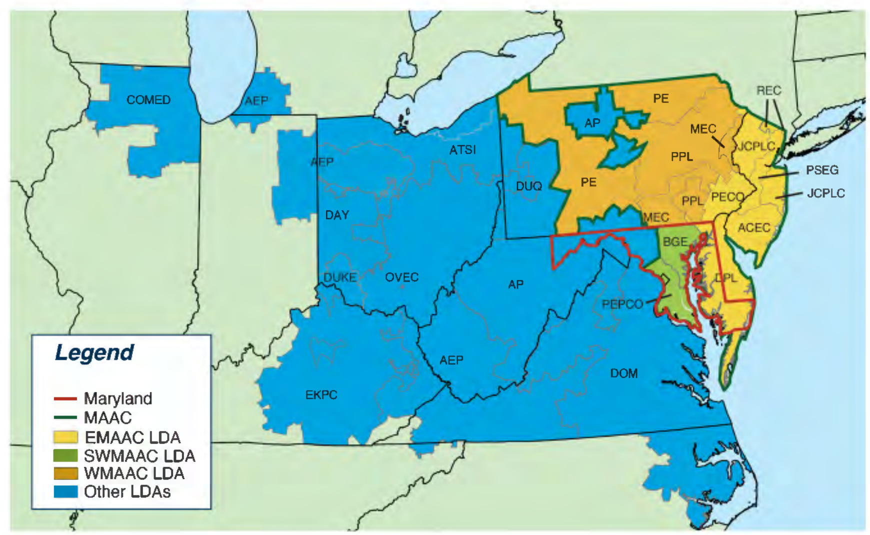
RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0
2021/2022 Third Incremental Auction				
RTO	0.57	0.41	59	59
EMAAC	1.00	0.19	6	6
PSEG	0.00	0.00	1	1
BGE	0.00	-0.00	2	2
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[61] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[62] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[63] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-5, Figure 5-6 and Figure 5-7.

Figure 5-5 Map of locational deliverability areas



61 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
62 OATT Attachment DD § 5.10 (a) (ii).
63 146 FERC ¶ 61,052 (2014).

Figure 5-6 Map of RPM EMAAC subzonal LDAs

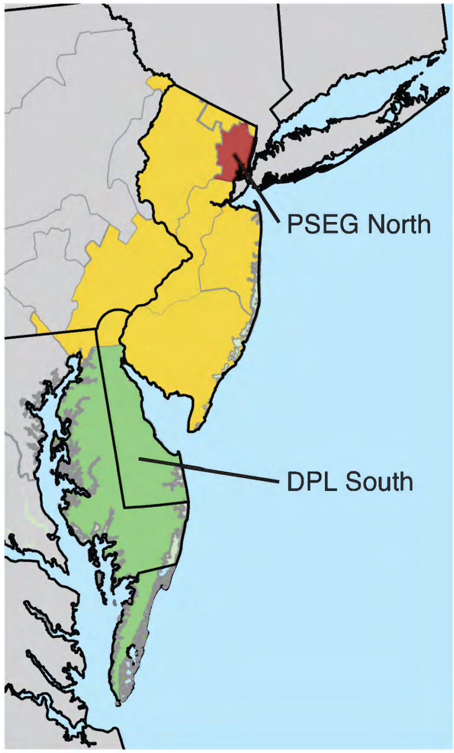
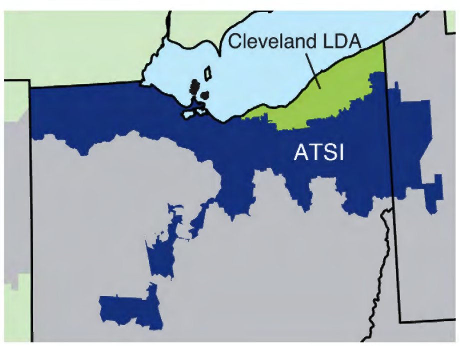


Figure 5-7 Map of RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[64]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources.

For the 2017/2018 through the 2019/2020 Delivery Years, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[65] Capacity market sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the

64 OATT Attachment DD § 5.6.6(b).
65 147 FERC ¶ 61,060 (2014).

resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external generation capacity resource must obtain an exception to the CILs to be eligible to offer as a Capacity Performance Resource, which means that effective with the 2020/2021 Delivery Year, CILs are no longer defined as an RPM parameter.[66]

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that have previously cleared an RPM auction.[67] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

As shown in Table 5-10, of the 1,558.0 MW of imports offered in the 2022/2023 RPM Base Residual Auction, 1,558.0 MW cleared. Of the cleared imports, 954.9 MW (61.3 percent) were from MISO.

66 151 FERC ¶ 61,208 (2015).
67 161 FERC ¶ 61,197 (2017), *order denying reh'g*, 170 FERC ¶ 61,217 (2020).

Table 5-10 RPM imports: 2007/2008 through 2022/2023 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0

Demand Resources

There are two basic demand products incorporated in the RPM market design:[68]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM auction as capacity and receive the relevant LDA or RTO resource clearing price. The EE resource type was eligible to be offered in RPM auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[69]

68 Effective June 1, 2007, the PJM active load management (ALM) program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM auctions as capacity resources and receive the clearing price.
69 Letter Order, Docket No. ER10-366-000 (January 22, 2010).

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of demand resource and energy efficiency resource products included in the RPM market design:[70] [71]

- **Base Capacity Resources**
  - **Base Capacity Demand Resources.** A demand resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base capacity DR is required to be capable of maintaining each interruption for at least 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the base capacity energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the base capacity energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.
- **Capacity Performance Resources**
  - **Annual Demand Resources.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
  - **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the annual energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

Effective with the 2020/2021 Delivery Year, the Capacity Performance Product will be the only capacity product type, with two possible season types, annual and summer.

- **Annual Capacity Performance Resources**
  - Annual Demand Resources
  - Annual Energy Efficiency Resources
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A demand resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the summer-period efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

70 151 FERC ¶ 61,208.
71 PJM Reliability Assurance Agreement Article 1.

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 12,115.9 MW for June 1, 2021, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2021/2022 Delivery Year (16,233.9 MW) less replacement capacity (4,118.0 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2018 to June 1, 2022[72 73 74]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-18	DR cleared	11,435.4	4,361.9	1,707.2	1,226.4	86.8	389.9	139.2	559.3	1,034.3	287.2	1,895.2	667.1	716.2		
	EE cleared	2,296.3	706.8	315.9	317.6	9.2	102.0	45.2	186.1	184.4	33.2	807.4	131.5	43.1		
	DR net replacements	(3,182.4)	(1,268.4)	(584.3)	(199.5)	(52.4)	(150.9)	(43.6)	(25.6)	(261.0)	(136.7)	(430.0)	(173.9)	(220.0)		
	EE net replacements	248.8	163.0	45.5	107.6	1.1	22.4	9.1	(8.9)	14.7	4.7	29.0	116.5	5.4		
	RPM load management	10,798.1	3,963.3	1,484.3	1,452.1	44.7	363.4	149.9	710.9	972.4	188.4	2,301.6	741.2	544.7		
01-Jun-19	DR cleared	10,703.1	3,878.9	1,659.2	817.0	91.3	381.2	176.5	554.6	1,047.0	333.9	1,759.9	262.4	741.4		
	EE cleared	2,528.5	821.4	395.3	301.7	7.8	134.5	52.8	170.0	204.8	41.7	792.9	131.7	72.7		
	DR net replacements	(2,138.8)	(1,004.2)	(468.8)	(129.0)	(40.9)	(141.5)	(86.6)	(74.8)	(130.3)	(123.1)	(143.0)	(54.2)	(208.9)		
	EE net replacements	(50.0)	(24.1)	4.7	3.3	(0.2)	2.7	9.1	2.2	3.4	0.0	0.0	1.1	(20.4)		
	RPM load management	11,042.8	3,672.0	1,590.4	993.0	58.0	376.9	151.8	652.0	1,124.9	252.5	2,409.8	341.0	584.8		
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,427.7	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,806.2	1,810.5	979.1	501.1	42.0	353.1	136.0	275.9	420.5	95.7	982.7	225.2	186.7	111.0	135.5
	DR net replacements	(4,111.0)	(1,302.8)	(568.4)	(160.8)	(28.1)	(195.8)	(100.2)	(106.5)	(483.2)	(137.4)	(609.5)	(54.3)	(235.1)	(50.9)	(90.2)
	EE net replacements	(7.0)	0.0	0.0	(1.1)	0.1	0.0	34.9	(2.6)	80.0	7.0	10.6	1.5	(1.7)	8.0	(17.5)
	RPM load management	12,115.9	3,961.8	1,792.2	964.1	80.3	567.8	259.3	512.7	1,214.1	238.1	2,457.5	451.4	647.6	295.8	248.3
01-Jun-22	DR cleared	8,811.9	2,817.4	1,139.9	485.3	48.4	294.6	93.8	322.7	924.1	166.5	1,511.0	162.6	661.7	210.5	185.1
	EE cleared	4,810.6	1,974.4	1,090.8	463.7	49.6	384.4	182.6	263.8	417.0	41.8	723.9	199.9	242.1	91.8	145.9
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	13,622.5	4,791.8	2,230.7	949.0	98.0	679.0	276.4	586.5	1,341.1	208.3	2,234.9	362.5	903.8	302.3	331.0

72 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
73 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
74 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2022[75 76 77]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0		8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,766.5	1.087	8,443.0
01-Jun-22	8,811.9	0.0	0.0	8,811.9	0.0	8,811.9	0.0	1.087	0.0

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2022[78 79]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,806.2	0.0	(7.0)	4,799.2	0.0	4,799.2
01-Jun-22	4,810.6	0.0	0.0	4,810.6	0.0	4,810.6

75 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
76 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
77 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.
78 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.
79 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE add back rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[80] [81] [82] For Base Capacity, offer caps are defined in the PJM Tariff as avoidable costs less PJM market revenues, or opportunity costs based on the potential sale of capacity in an external market. For Capacity Performance Resources, offer caps are defined in the PJM Tariff as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. For RPM Third Incremental Auctions, capacity market sellers may elect, for Base Capacity offers, an offer cap equal to 1.1 times the BRA clearing price for the relevant LDA and delivery year or, for Capacity Performance offers, an offer cap equal to the greater of the net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[83] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a generation capacity resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/nonperformance charges.[84] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[85]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[86] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Calculation of Offer Caps

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's

80 See OATT Attachment DD § 6.5.
81 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
82 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
83 OATT Attachment DD § 6.8 (b).
84 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2021/2022 RPM Base Residual Auction—Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
85 OATT Attachment DD § 6.8(a).
86 151 FERC ¶ 61,208.

performance during performance assessment intervals (A) in the delivery year.[87]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The level of bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[88]

The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A})$$

2. The expected number of performance assessment intervals equals 360. (H = 360 intervals, or 12 hours)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment hours ($\bar{A}$)

87 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.

88 OATT Attachment DD § 10A (d).

The competitive offer of such a resource is:

$$p = \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A}))$$

In other words, the competitive offer of such a resource is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned $(CPBR \times H \times \bar{A})/12$ and the net nonperformance charges it would incur by taking on the capacity obligation $(PPR \times H \times (\bar{B} - \bar{A})/12)$. Both the components are proportional to the expected number of performance assessment intervals. If the expected number of performance assessment intervals (*H*) is significantly lower than the value used to determine the nonperformance charge rate (PPR), the opportunity of earning bonuses as an energy only resource, as well as the net nonperformance charges incurred by taking on a capacity obligation are lower. Under such a scenario, the likelihood that that the resource's Net ACR is lower than the expected energy only bonuses is reduced. For resources whose Net ACR is greater than the expected energy only bonuses, the competitive offer is the Net ACR adjusted with any capacity performance bonuses or nonperformance charges they expect to incur during the delivery year.

This means that when the expected number of performance assessment intervals are lower than the value used to determine the nonperformance charge rate (360 intervals, or 30 hours), the current default offer cap of Net CONE times B overstates the competitive offer and the market seller offer cap.

The recent history of a low number of emergency actions in PJM reflect the improvements to generator performance with the capacity performance design, the reduction in actual and expected pool wide outage rates as a result of new units added to the system and the retirement of old units, the upward biased peak load forecasts used in RPM, and the high reserve margins in capacity.[89] [90] Given these developments, the assumption that there would be 30 hours of emergency actions in a year that would trigger performance assessment intervals is unsupported. Since the nonperformance charge rate

89 PJM experienced only one emergency event since April 2014 that triggered a PAI in an area that at least encompasses a PJM transmission zone. On October 2, 2019, PJM declared a pre-emergency load management action that triggered PAIs in four zones for a period of two hours or 24 five minute intervals.

90 See Table 5-7.

is defined in the tariff as net CONE divided by 30 hours, the adjusted default offer cap to reflect a lower estimate for the number of PAIs is much lower than net CONE times B.

In the 2021/2022 RPM Base Residual Auction, net CONE times B exceeded the actual competitive offer level of a Low ACR resource that the default offer cap is based on.[91] While most participants offered in the 2021/2022 RPM Base Residual Auction at competitive levels based on their expectation of the number of performance assessment hours and projected net revenues, some market participants did not offer competitively and affected the market clearing prices.

MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[92] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for Combined Cycle (CC) and Combustion Turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[93]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[94] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exception process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from modeled LDAs only.

Effective December 8, 2017, FERC issued an order on remand rejecting PJM's MOPR proposal in Docket No. ER13-535, and as a result, the rules that were in effect prior to PJM's December 7, 2012, MOPR filing were reinstated. These changes include eliminating the Competitive Entry and Self Supply Exemptions and retaining only the Unit Specific Exception request; narrowing the region subject to MOPR from the entire RTO to only modeled LDAs; eliminating the 20.0 MW threshold for applicability; decreasing the screen from 90 percent to 100 percent of the applicable net CONE values; redefining the applicability criteria to exclude nuclear, coal, IGCC, hydroelectric, wind and solar facilities; modifying the duration of mitigation criteria from clearing in a prior delivery year to clearing in any delivery year; and changing the procedural deadlines.[95]

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[96] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes include expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable net CONE or net

91 See Monitoring Analytics, LLC "Analysis of the 2021/2022 RPM Base Residual Auction—Revised," at Attachment B <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
92 135 FERC ¶ 61,022 (2011).
93 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).
94 143 FERC ¶ 61,090 (2013).
95 161 FERC ¶ 61,252 (2017).
96 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

ACR values. The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[97] The MMU has recommended such an approach. The change in the offset will affect MOPR floor prices and the results of unit specific reviews under MOPR. The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative approaches.[98] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[99]

Issues addressed during the MOPR unit specific review process in 2021 for the 2022/2023 BRA included documentation of asset life greater than 20 years, degradation of resource performance, operating and maintenance expenses, required capital expenditures, tax assumptions, documentation of forward net revenues, and the use of retail savings as a source of net revenue offset to EE gross CONE. The MMU did not agree with PJM's judgments about parameters and calculations of MOPR floors in a significant number of cases (Table 5-15).

2022/2023 RPM Base Residual Auction

As shown in Table 5-14, 1,083 generation resources submitted Capacity Performance offers in the 2022/2023 RPM Base Residual Auction. Unit specific offer caps were not calculated for any generation resources (0.0 percent). Of the 1,083 generation resources, 872 generation resources had the net CONE times B offer cap (80.5 percent), 35 Planned Generation Capacity Resources had uncapped offers (3.2 percent), 40 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units (3.7 percent), four generation resources had uncapped planned uprates and were price takers for the existing portion of the unit (0.4 percent), and the remaining 132 generation resources were price takers (12.2 percent). Market power mitigation was not applied to any Capacity Performance sell offers.

97 173 FERC ¶ 61,134 (2020).
98 Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).
99 Modernizing Electricity Market Design, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).

MOPR Statistics

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-15, of the 13,149.2 ICAP MW of MOPR Unit-Specific Exception and Resource-Specific Exception requests for the 2022/2023 RPM Base Residual Auction, the MMU agreed with requests for 6,794.7 MW.

Table 5-14 ACR statistics: 2022/2023 RPM auction

	2022/2023 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	0	0.0%
Unit specific ACR (APIR and CPQR)	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost input	0	0.0%
Default ACR and opportunity cost	NA	NA
Net CONE times B	872	80.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	40	3.7%
Uncapped planned uprate and price taker	4	0.4%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	35	3.2%
Existing generation resources as price takers	132	12.2%
Total Generation Capacity Resources offered	1,083	100.0%

Table 5-15 MOPR statistics: 2022/2023 RPM auction[100]

MOPR Type	Calculation Type	Number of Requests	ICAP (MW) Requested	ICAP (MW) MMU Agreed	ICAP (MW) Offered	UCAP (MW) Offered	UCAP (MW) Cleared
Capacity Resources with No State Subsidy	Unit Specific Exception	148	8,849.0	4,882.7	1,720.0	1,702.4	490.3
Capacity Resources with State Subsidy - Cleared	Resource Specific Exception	2	2,134.0	1,240.0	2,134.0	2,126.1	2,126.1
Capacity Resources with State Subsidy - New	Resource Specific Exception	109	2,166.2	672.0	1,207.1	1,248.5	1,104.4
Capacity Resources with No State Subsidy	Default	NA	NA	NA	116.7	98.9	0.0
Capacity Resources with State Subsidy - Cleared	Default	NA	NA	NA	6,590.9	6,332.9	4,954.7
Capacity Resources with State Subsidy - New	Default	NA	NA	NA	459.8	493.0	153.1
Total		259	13,149.2	6,794.7	12,228.5	12,001.7	8,828.6

Replacement Capacity[101]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2022. The 2022 numbers are not final.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition

100 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers are not reported as a result of PJM confidentiality rules.

101 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.[102]

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2022

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	144,477.3	0.0	0.0	144,477.3	0.0	144,477.3

102 See Monitoring Analytics, LLC, "Analysis of the 2021/2022 RPM Base Residual Auction – Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for all RPM auctions held through the first six months of 2021, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through the first six months of 2021.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA from the 2018/2019 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through the first six months of 2021. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through the first six months of 2021 based on the unforced MW cleared and the resource clearing prices. In the 2019/2020 Delivery Year RPM revenue was $7.1 billion. In the 2020/2021 Delivery Year, RPM revenue was $7.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first six months of 2021. In 2019, RPM revenue was $8.7 billion. In 2020, RPM revenue was $7.1 billion.

Table 5-22 shows the RPM annual charges to load. For the 2019/2020 Delivery Year, RPM annual charges to load were $7.0 billion. For the 2020/2021 Delivery Year, annual charges to load are $7.0 billion.

Table 5-17 Capacity market clearing prices: 2019/2020 through 2022/2023 RPM Auctions[103]

		RPM Clearing Price ($ per MW-day)													
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30	$80.00
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30	$80.00
2019/2020 BRA	Capacity Performance	$100.00	$100.00	$100.00	$100.00	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$202.77	$100.30	$100.00
2019/2020 First Incremental Auction	Base Capacity	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Capacity Performance	$51.33	$51.33	$51.33	$51.33	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33	$51.33
2019/2020 Second Incremental Auction	Base Capacity	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14	$10.01
2019/2020 Second Incremental Auction	Base Capacity DR/EE	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14	$10.01
2019/2020 Second Incremental Auction	Capacity Performance	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00	$32.87
2019/2020 Third Incremental Auction	Base Capacity	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Base Capacity DR/EE	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$20.00	$21.35	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Capacity Performance	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35
2020/2021 BRA	Capacity Performance	$76.53	$86.04	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$188.12	$86.04	$76.53
2020/2021 First Incremental Auction	Capacity Performance	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90
2020/2021 Second Incremental Auction	Capacity Performance	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25
2020/2021 Third Incremental Auction	Capacity Performance	$10.00	$15.25	$10.00	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$10.00	$10.00	$15.25	$10.00
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55
2022/2023 BRA	Capacity Performance	$50.00	$95.79	$50.00	$95.79	$97.86	$95.79	$97.86	$97.86	$97.86	$95.79	$50.00	$68.96	$126.50	$71.69

Table 5-18 Capacity market cleared MW: 2019/2020 through 2022/2023 RPM Auctions[104]

		UCAP (MW)													
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	TOTAL
2019/2020	BASE	57,090.2	9,996.2	9,066.6	12,754.9	20,382.4	1,598.5	5,583.1	3,228.9	6,971.7	10,291.1	22,971.4	4,422.9	2,971.6	167,329.5
2019/2020	FIRST	774.9	249.4	39.3	157.7	78.7	11.7	10.6	28.8	43.6	147.5	711.4	31.9	9.6	2,295.1
2019/2020	SECOND	435.6	160.4	30.1	146.2	210.1	21.2	38.1	44.8	41.9	263.6	105.8	107.5	7.3	1,612.6
2019/2020	THIRD	1,531.9	440.9	429.4	1,216.6	265.7	2.4	180.4	23.2	83.6	454.2	867.4	255.2	76.1	5,827.0
2020/2021	BASE	53,574.6	11,413.2	8,990.6	14,398.2	19,978.5	1,647.2	5,041.2	2,975.4	6,410.0	9,925.9	23,960.3	4,021.1	2,437.8	164,773.9
2020/2021	FIRST	1,245.3	331.0	144.2	83.4	76.2	38.9	105.8	32.0	97.8	666.9	644.4	38.7	20.3	3,524.8
2020/2021	SECOND	415.7	206.9	53.0	30.7	302.9	28.4	29.5	48.8	35.4	366.2	194.6	160.3	31.5	1,903.8
2020/2021	THIRD	961.2	569.7	118.7	89.0	194.1	33.1	423.0	137.0	93.1	554.3	127.7	39.8	145.4	3,486.0
2021/2022	BASE	52,896.5	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	2,746.1	163,627.3
2021/2022	FIRST	194.1	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	2,143.2
2021/2022	SECOND	1,242.5	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	3,707.5
2021/2022	THIRD	1,638.4	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	5,235.0
2022/2023	BASE	37,732.2	12,804.7	10,147.4	14,118.7	23,658.8	1,305.3	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	144,477.3

103 See the *2019 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market
104 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-19 Weighted average clearing prices by zone: 2019/2020 through 2022/2023

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2019/2020	2020/2021	2021/2022	2022/2023
RTO				
AEP	$93.63	$74.42	$133.84	$50.00
APS	$93.63	$74.42	$133.84	$50.00
ATSI	$92.97	$69.75	$142.59	$50.00
Cleveland	$89.17	$68.93	$90.81	$50.00
COMED	$188.90	$182.15	$189.54	$69.02
DAY	$93.63	$72.42	$132.69	$50.00
DUKE	$93.63	$121.24	$127.66	$71.66
DUQ	$93.63	$74.42	$133.84	$50.00
DOM	$93.63	$74.42	$133.84	$50.00
EKPC	$93.63	$74.42	$133.84	$50.00
MAAC				
EMAAC				
ACEC	$112.48	$182.04	$158.72	$97.79
DPL	$112.48	$182.04	$158.72	$97.79
DPL South	$115.95	$178.65	$159.65	$97.86
JCPLC	$112.48	$182.04	$158.72	$97.79
PECO	$112.48	$182.04	$158.72	$97.79
PSEG	$110.56	$165.74	$184.82	$97.77
PSEG North	$116.03	$176.45	$190.48	$97.82
REC	$112.48	$182.04	$158.72	$97.79
SWMAAC				
BGE	$88.20	$80.71	$174.43	$126.49
PEPCO	$90.59	$84.24	$133.37	$95.19
WMAAC				
MEC	$93.81	$81.85	$134.56	$95.79
PE	$93.81	$81.85	$134.56	$95.79
PPL	$88.53	$85.07	$138.51	$95.77

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2022/2023[105]

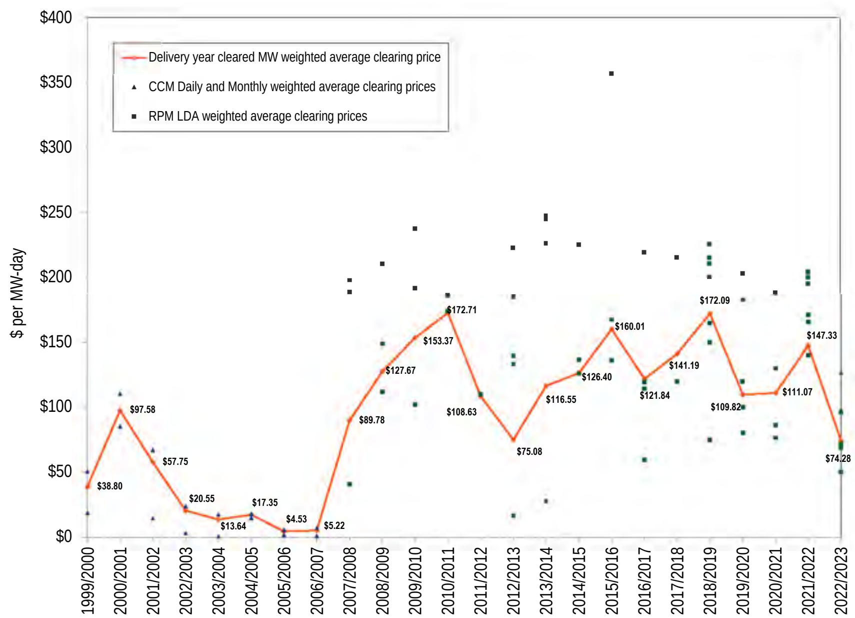
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$74.28	144,477.3	365	$3,916,953,841

Table 5-21 RPM revenue by calendar year: 2007 through 2023[106]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$104.50	156,985.8	365	$6,183,448,991
2023	$74.28	59,770.1	151	$1,620,438,438

105 The results for the ATSI Integration Auctions are not included in this table.
106 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-8 History of capacity prices: 1999/2000 through 2022/2023[107]



107 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2021/2022 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-9 Map of RPM capacity prices: 2018/2019 through 2021/2022

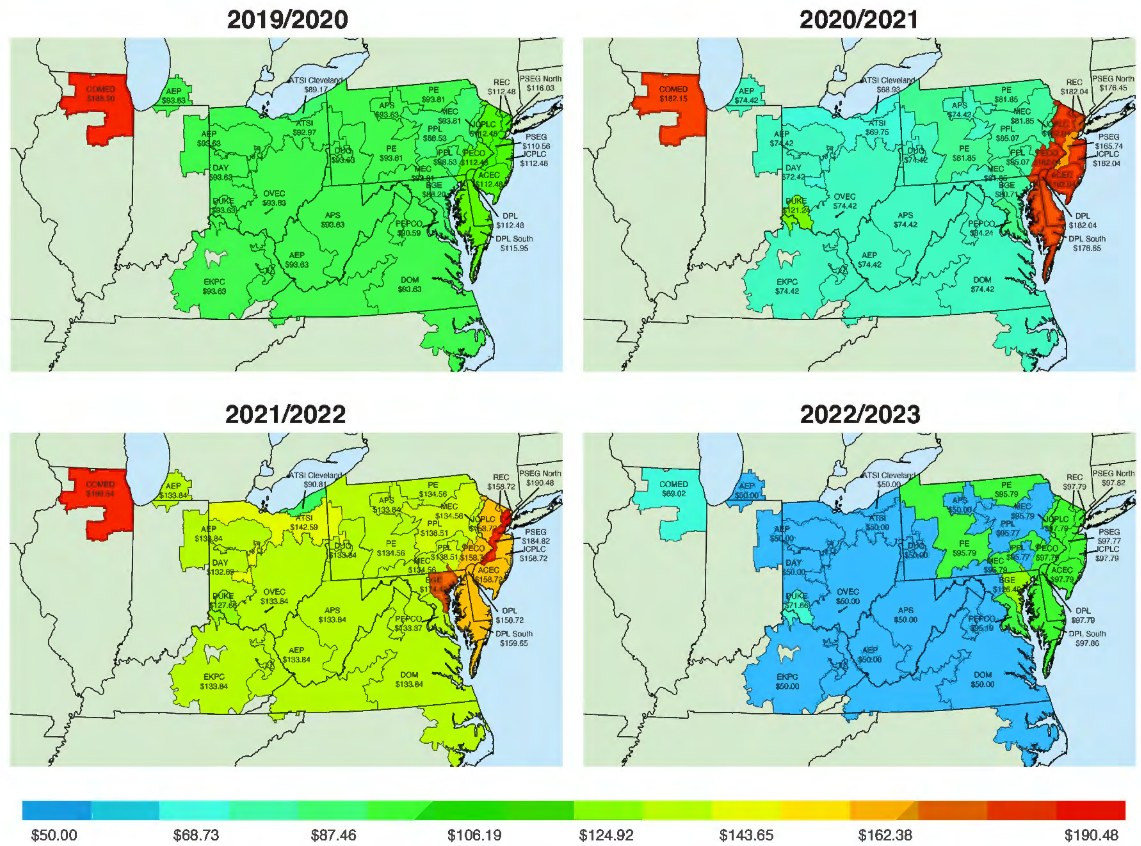


Table 5-22 RPM cost to load: 2019/2020 through 2022/2023 RPM Auctions[108] [109] [110]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2019/2020			
Rest of RTO	$98.07	89,185.9	$3,201,364,940
Rest of EMAAC	$115.58	24,415.1	$1,032,810,556
BGE	$97.79	7,595.2	$271,828,430
COMED	$192.56	24,985.1	$1,760,892,086
PEPCO	$92.90	7,330.3	$249,230,694
PSEG	$115.83	11,281.1	$478,247,326
Total		164,792.8	$6,994,374,033
2020/2021			
Rest of RTO	$77.31	69,073.7	$1,949,098,489
Rest of MAAC	$87.06	29,555.9	$939,246,366
EMAAC	$174.32	35,740.4	$2,274,098,760
COMED	$189.92	23,744.7	$1,645,988,210
DUKE	$104.50	5,072.0	$193,459,838
Total		163,186.7	$7,001,891,663
2021/2022			
Rest of RTO	$142.16	82,768.3	$4,294,838,410
Rest of EMAAC	$164.73	23,719.9	$1,426,178,211
ATSI	$160.21	13,995.4	$818,411,597
BGE	$163.50	7,491.2	$447,049,048
COMED	$198.43	22,721.2	$1,645,630,168
PSEG	$188.46	10,987.4	$755,803,998
Total		161,683.4	$9,387,911,433
2022/2023			
Rest of RTO	$50.09	51,125.9	$934,814,759
EMAAC	$97.75	35,300.9	$1,259,545,677
WMAAC	$96.42	15,495.6	$545,317,684
BGE	$107.92	7,611.3	$299,826,001
COMED	$67.17	22,940.7	$562,472,028
DUKE	$59.38	5,304.6	$114,962,107
PEPCO	$95.97	6,698.3	$234,639,139
Total		144,477.3	$3,951,577,394

108 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.
109 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.
110 The net load prices and obligation MW for 2021/2022 are not finalized.

MOPR and FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. As made clear in recent analyses of FRR options in Illinois, Maryland, New Jersey, Ohio, and the District of Columbia, the FRR approach is likely to lead to significant increases in payments by customers when it replaces participation in the PJM markets.[111] The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market.

FRR proposals in Illinois for the COMED Zone and in New Jersey are primarily nuclear subsidy programs that would increase nuclear subsidies well beyond the ZECs rules currently in place in both states while also providing for payments to some renewable resources at above market prices.[112] The MMU has prepared reports with analysis on the potential impacts of states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service

111 The MMU has posted several reports regarding the creation of FRRs. "Potential Impacts of the Creation of a ComEd FRR," (December 18, 2019). <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf>. "Potential Impacts of the Creation of Maryland FRRs," (April 16, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf>. "Potential Impacts of the Creation of New Jersey FRRs," (May 13, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf>. "Potential Impacts of the Creation of Ohio FRRs," (July 17, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf>. "Potential Impacts of the Creation of District of Columbia FRR," (May 7, 2021) <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_Potential_Impact_of_the_Creation_of_District_of_Columbia_FRR_20210507.pdf>.
112 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

area.[113] [114] [115] [116] [117] The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC market would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the expected elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable or clean resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a demand curve for clean resources based on the quantity of such resources identified by one or more states and clear a market for clean resources as part of the capacity market clearing process.

The MMU's proposed modifications to the MOPR rules would retain the fundamentals of the current capacity market design and result in a de minimis impact on competitive market outcomes while recognizing defined state authority. The MMU's proposed modifications to the MOPR rules would retain a clear MOPR rule while recognizing state authority over the generation facilities in each state. The MMU's proposed modifications would permit exemptions from MOPR for state programs designed to support specific emerging technologies that would not otherwise be competitive. All other technologies are competitive and are expected to clear in capacity auctions, even with the application of MOPR. The MMU's proposed modifications would not impede or interfere with authorized state policies, regardless of the targeted technology. The MMU's proposed modifications also recognize that the definition of a competitive offer, the MOPR floor, is net ACR and not net CONE. Even when the MOPR rules are applied, the MOPR floors are defined to be competitive offers and expected to clear when consistent with market fundamentals. A competitive offer is a competitive offer. The MOPR offer floor is the same as the market seller offer cap (MSOC).

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly.

PJM has proposed a flawed Effective Load Carrying Capability (ELCC) approach to defining the capacity contribution of intermittent resources.[118] Implementing PJM's flawed ELCC approach, based on static average rather than dynamic, market defined marginal values, and locking in values for old technology for long periods regardless of market realities, and basing the results on incorrect assumptions about the dispatch of some resource types,

113 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

114 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

115 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).

116 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

117 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

118 *PJM Interconnection L.L.C.*, Docket No. ER21-278 *Effective Load Carrying Capability Construct* (October 30, 2020).

would be a significant mistake and create new issues for the PJM capacity markets. The results could degrade reliability, impede innovation and the introduction of new technologies, and inefficiently displace thermal resources. It is essential to not build in a bad market design from the beginning as such designs gain momentum and gain entrenched supporters among the beneficiaries. If done correctly, ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources, but only if done correctly and only if all the required assumptions are made explicit and decided explicitly.[119]

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution.

119 Comments and Motions of the Independent Market Monitor for PJM, Docket No. ER21-278 and EL19-100 (November 20, 2020). Answer and Motion for Leave to Answer and Alternative Motion for Consolidation of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 10, 2020). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 18, 2020). Comments and Motions of the Independent Market Monitor for PJM, ER21-278-001 (March 22, 2021). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (April 28, 2021).

Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO/ISO to help ensure reliability. PJM should require firm fuel as a condition of being a capacity resource.

CRF Issue[120]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A are not correct. These tables should have been updated in 2018 and should be updated prior to the next capacity market auction. Correct CRFs will ensure that offer caps and offer floors in the capacity market are correct. The required changes are clear and unambiguous. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[121] In the filing PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[122] [123]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1-\frac{sB}{\sqrt{1+r}}-s(1-B)\sqrt{1+r}\sum_{\mathrm{j}=1}^{\mathrm{L}}\frac{\mathrm{m_j}}{(1+\mathrm{r})^{\mathrm{j}}}\right]}{(1-s)\sqrt{1+\mathrm{r}}\left[(1+r)^N-1\right]}$$

120 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).
121 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement", PJM Interconnection L.L.C., Docket ER21-1844-000 (May 4, 2021).
122 See "Comments of the Independent Market Monitor for PJM", ER21-1844-000 (May 25, 2021).
123 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket ER21-1635-000.

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the CRF formula be included in the tariff.[124] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-24 shows the CRFs that are currently posted. The values in Table 5-24 were calculated using the formula above and the financial assumptions in Table 5-25. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-23 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
m_j	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

The MMU supports the changes to the tariff to correct the application of CRF to the capacity market but there are still unresolved issues. The tariff revisions lack clarity about how CRF values will be determined in the future and to which projects they apply, and lack clarity about how CRF values would be applied to APIR for project costs that are currently being recovered. For example, Table 5-24, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.[125] For example, a project that can use the depreciation provisions relevant for the 2023/2024 Delivery Year uses the depreciation provisions once and those provisions affect the project's CRF for its entire life, regardless of the CRF values in the table for subsequent delivery years. However, changes in the tax rate apply each year and if the tax rate changes the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-24 for delivery years after 2022/2023 would not apply to the calculation of APIR values for projects that go into service for the 2022/2023 Delivery Year. A similar issue exist for projects that were assigned a CRF under the previous tariff rules. The change in the tax rate should be reflected in the CRF going forward. PJM does not plan to do this and the Commission indicated that the issue is "beyond the scope" of the PJM filing.[126]

Table 5-24 Levelized CRF values: Delivery Year 2022/2023 through Delivery Year 2025/2026

Age of Existing Units (Years)	Remaining Life of Plant	Levelized CRF 2022/2023	Levelized CRF 2023/2024	Levelized CRF 2024/2025	Levelized CRF 2025/2026
1 to 5	30	0.088	0.091	0.094	0.096
6 to 10	25	0.093	0.096	0.098	0.101
11 to 15	20	0.101	0.104	0.107	0.110
16 to 20	15	0.116	0.119	0.122	0.126
21 to 25	10	0.147	0.152	0.158	0.164
25 Plus	5	0.246	0.258	0.271	0.283
Mandatory CapEx	4	0.296	0.312	0.328	0.345
40 Plus Alternative	1	1.100	1.100	1.100	1.100

Table 5-25 Financial assumptions for CRF calculations

Financial Parameter	Parameter Value
Equity Funding Percent	45.000%
Debt Funding Percent	55.000%
Equity Rate	13.000%
Debt Interest Rate	6.000%
Federal Tax Rate	21.000%
State Tax Rate	9.300%
Effective Tax Rate	28.347%
After tax Weighted Average Cost of Capital	8.215%

124 Order 176 FERC ¶61,003 (July 2, 2021).
125 See "Capital Recovery Factors ("CRF") for Avoidable Project Investment Cost ("APIR") Determinations <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/crf-values-for-apir-determination.ashx>.
126 Order 176 FERC ¶61,003 (July 2, 2021) at 28.

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU at least 90 days prior to the proposed deactivation date. Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[127] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[128]

Table 5-26 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through June 2021. Of the 89 deactivation requests submitted, 18 units (20.2 percent) deactivated an average of 220 days earlier than their initially requested date; 12 units (13.5 percent) deactivated an average of 95 days later than the originally requested deactivation date; and 30 units (33.7 percent) deactivated on their initially requested date. Twelve (13.5 percent) of the unit deactivations were cancelled an average of 435 days before their scheduled deactivation date, and 17 (19.1 percent) of the unit deactivations have not yet reached their target retirement date.

Table 5-26 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through June 2021

	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	18	20.2%	(220)
Late	12	13.5%	95
On time	30	33.7%	0
Cancelled	12	13.5%	(435)
Pending	17	19.1%	-
Total	89	100.0%	-

127 OATT Attachment DD § 6.6(g).
128 OATT Part V §113

Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.[129] The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[130]

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[131] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[132] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.[133] The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.[134] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[135] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[136]

129 OATT Part V §114
130 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").
131 OATT § 113.2; OATT Attachment M § IV.1.
132 OATT § 113.2.
133 *Id.*
134 OATT § 113.1.
135 OATT Attachment DD § 6.6(g).
136 *Id.*

Under the current rules, a unit providing RMR service can recover its costs under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[137] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[138] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[139] The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.[140] Project investment is capped at $2 million, above which FERC approval is required.[141] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[142]

Table 5-27 shows units that have provided RMR service to PJM.

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

In each of the cost of service recovery rate filings for RMR service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive

Table 5-27 RMR service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

137 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
138 OATT § 115.
139 *Id.*
140 OATT § 118.
141 OATT §§ 115, 117.
142 OATT § 119.

depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate and costs associated with closing the unit that would have been incurred regardless of the RMR service period.[143] In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.[144] Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual incremental costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V.

143 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
144 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual incremental costs associated with the RMR service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-28 shows the capacity factors by unit type for January through June, 2020 through 2021. In the first six months of 2021, nuclear units had a capacity factor of 90.6 percent, compared to 92.1 percent in the first six months of 2020; combined cycle units had a capacity factor of 48.6 percent in the first six months of

2021, compared to a capacity factor of 52.0 percent in the first six months of 2020; all steam units had a capacity factor of 28.4 percent in the first six months of 2021, compared to 20.1 percent in the first six months of 2020; coal units had a capacity factor of 31.6 percent in the first six months of 2021, compared to 22.2 percent in the first six months of 2020.

Table 5-28 Capacity factor (By unit type (GWh)): January through June, 2020 and 2021[145][146]

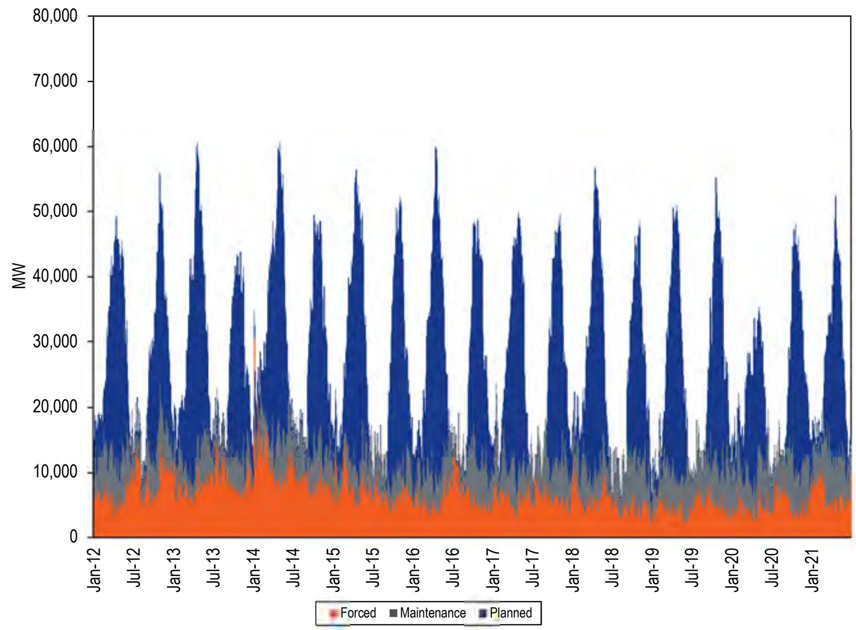
	2020 (Jan-Jun)		2021 (Jan-Jun)		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2021 from 2020
Battery	17.1	1.1%	19.9	1.3%	0.2%
Combined Cycle	143,222.5	52.0%	135,855.4	48.6%	(3.3%)
Single Fuel	122,567.8	53.6%	120,092.5	52.0%	(1.6%)
Dual Fuel	20,654.7	43.9%	15,762.9	32.6%	(11.3%)
Combustion Turbine	5,742.5	3.8%	6,960.0	4.7%	0.8%
Single Fuel	4,357.3	4.1%	5,105.9	4.9%	0.7%
Dual Fuel	1,385.2	3.2%	1,854.1	4.3%	1.1%
Diesel	90.3	4.0%	150.3	6.7%	2.7%
Single Fuel	89.1	4.8%	143.7	7.7%	3.0%
Dual Fuel	1.2	0.3%	6.5	1.7%	1.4%
Diesel (Landfill gas)	822.2	44.2%	740.5	41.9%	(2.3%)
Fuel Cell	114.2	81.8%	110.2	79.4%	(2.5%)
Nuclear	136,376.3	92.1%	133,383.6	90.6%	(1.5%)
Pumped Storage Hydro	2,624.5	9.0%	2,627.8	9.1%	0.1%
Run of River Hydro	6,531.3	37.5%	5,763.2	33.3%	(4.2%)
Solar	1,855.4	20.5%	3,440.2	19.7%	(0.8%)
Steam	73,587.8	20.1%	99,686.8	28.4%	8.4%
Biomass	2,731.8	51.9%	2,866.7	55.8%	3.9%
Coal	69,065.8	22.2%	94,813.1	31.6%	9.5%
Single Fuel	68,024.6	22.9%	91,955.6	32.0%	9.0%
Dual Fuel	1,041.2	7.0%	2,857.5	23.9%	16.9%
Natural Gas	1,772.6	33.7%	2,006.8	32.2%	(1.5%)
Single Fuel	192.9	39.6%	260.6	38.9%	(0.7%)
Dual Fuel	1,579.7	18.7%	1,746.2	15.2%	(3.5%)
Oil	17.6	0.1%	0.3	0.0%	(0.1%)
Wind	14,496.4	31.4%	14,967.0	29.9%	(1.5%)
Total	385,483.8	36.8%	403,708.0	38.6%	1.8%

145 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
146 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.

Generator Performance Factors

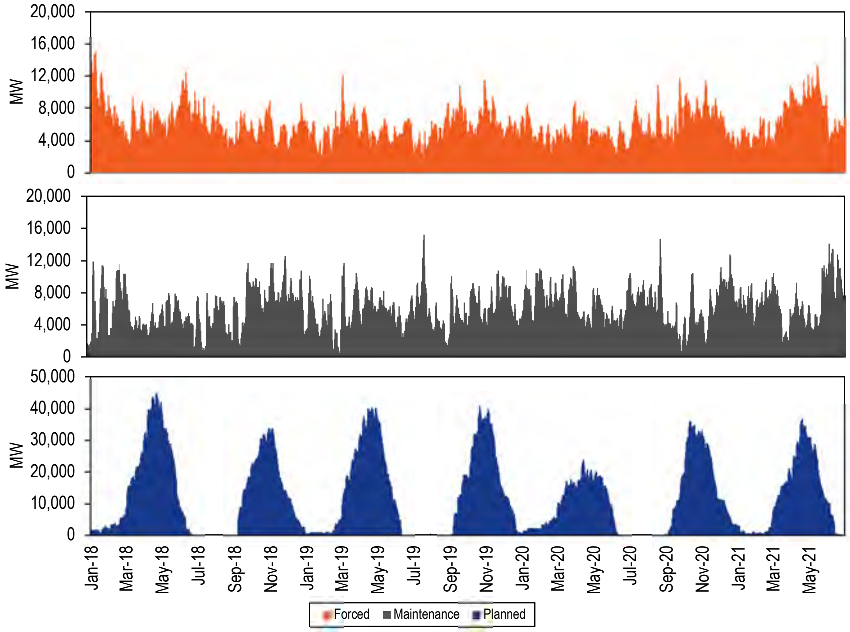
Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-10, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-14.

Figure 5-10 Outages (MW): 2012 through June 2021



In 2020, planned, maintenance and forced outages were lower than in 2019 (Figure 5-11). The MWh of planned outages were 26 percent lower than in 2019. The MWh of maintenance outages were 7 percent lower than in 2019. The MWh of forced outages were 20 percent lower than in 2019. In 2021, planned outages were 15 percent lower, maintenance outages were 9 percent higher, and forced outages were 57 percent higher in the first six months of 2021 than in the first six months of 2020.

Figure 5-11 Outages (MW): Forced, maintenance and planned outages 2018 through June 2021



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-12. Metrics by unit type are shown in Table 5-29.

Figure 5-12 Equivalent outage and availability factors: January through June, 2007 to 2021

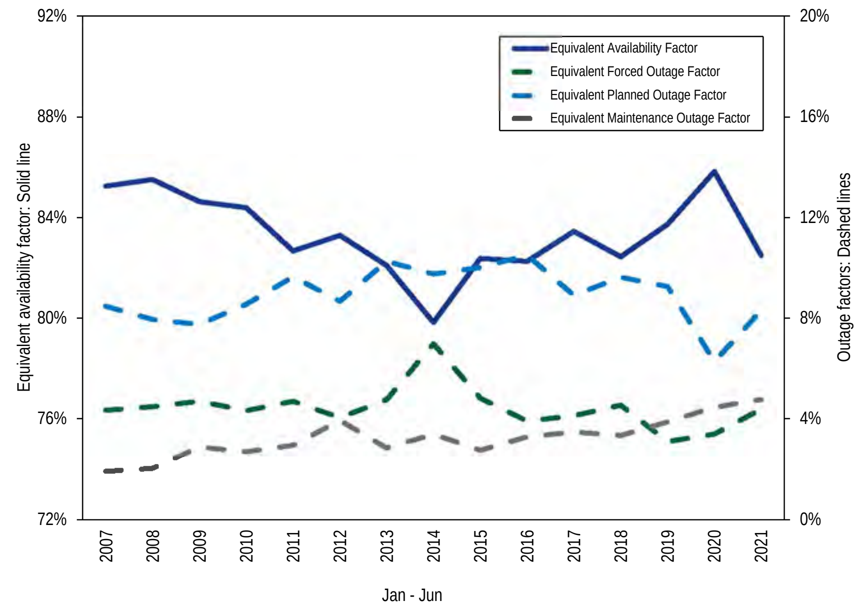


Table 5-29 EFOF, EPOF, EMOF and EAF by unit type: January through June, 2007 through 2021

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other			
Jan-Jun	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	6.3%	12.1%	2.4%	79.2%	1.8%	7.8%	1.6%	88.8%	5.0%	3.2%	2.6%	89.2%	9.1%	0.8%	2.3%	87.8%	1.6%	5.9%	2.1%	90.4%	1.2%	5.0%	0.2%	93.5%	6.0%	10.8%	2.4%	80.8%
2008	7.7%	8.7%	2.5%	81.1%	1.7%	7.3%	1.6%	89.4%	3.4%	5.6%	2.4%	88.6%	9.2%	1.8%	1.4%	87.7%	1.5%	6.9%	2.4%	89.3%	1.0%	6.9%	0.5%	91.6%	3.9%	11.9%	3.2%	81.0%
2009	7.1%	9.4%	3.1%	80.4%	3.1%	7.1%	3.6%	86.2%	1.5%	3.7%	2.6%	92.3%	6.8%	0.4%	1.5%	91.4%	2.1%	10.3%	3.1%	84.5%	4.0%	5.6%	0.8%	89.6%	3.9%	11.2%	5.9%	79.0%
2010	7.5%	10.9%	3.7%	77.9%	2.8%	9.5%	4.1%	83.6%	2.1%	2.7%	1.8%	93.4%	4.1%	0.7%	1.0%	94.1%	0.6%	10.5%	2.2%	86.7%	1.3%	6.4%	0.6%	91.7%	3.8%	10.3%	3.1%	82.7%
2011	8.2%	12.1%	4.0%	75.7%	2.5%	10.2%	2.8%	84.5%	1.5%	4.0%	1.9%	92.6%	2.4%	0.0%	2.7%	94.9%	1.1%	13.7%	1.6%	83.6%	2.0%	6.7%	2.0%	89.3%	4.5%	11.4%	2.9%	81.2%
2012	6.8%	11.0%	7.1%	75.1%	2.2%	8.7%	2.1%	87.0%	1.9%	3.2%	1.8%	93.1%	3.9%	0.1%	1.9%	94.1%	3.7%	4.2%	1.6%	90.6%	1.1%	8.2%	0.7%	90.0%	4.5%	11.0%	3.8%	80.8%
2013	7.2%	13.9%	4.5%	74.3%	1.9%	11.5%	3.1%	83.4%	5.2%	4.0%	1.5%	89.4%	4.2%	0.4%	1.7%	93.7%	0.5%	7.5%	2.1%	89.9%	1.1%	6.7%	0.4%	91.8%	7.2%	12.8%	3.6%	76.4%
2014	10.1%	11.3%	5.2%	73.4%	3.2%	12.3%	2.4%	82.1%	10.0%	4.5%	1.8%	83.8%	14.8%	0.8%	2.4%	82.0%	1.9%	11.1%	3.7%	83.3%	1.8%	7.0%	0.8%	90.5%	7.9%	14.7%	5.7%	71.7%
2015	8.2%	10.9%	3.9%	77.1%	2.4%	11.5%	2.0%	84.0%	3.3%	5.5%	2.1%	89.2%	9.5%	0.6%	2.7%	87.2%	2.1%	10.4%	1.6%	86.0%	1.1%	6.0%	1.2%	91.7%	7.2%	20.4%	4.7%	67.7%
2016	7.5%	11.5%	5.5%	75.5%	3.2%	11.7%	1.9%	83.2%	2.0%	5.8%	2.3%	89.9%	5.8%	0.3%	3.5%	90.4%	2.2%	8.0%	3.8%	86.0%	0.9%	6.3%	1.2%	91.6%	3.2%	23.4%	4.0%	69.4%
2017	9.6%	10.9%	6.5%	73.0%	2.1%	11.2%	1.6%	85.1%	1.1%	5.3%	2.2%	91.4%	5.5%	0.3%	2.0%	92.2%	2.3%	6.9%	3.2%	87.7%	0.4%	6.3%	0.7%	92.7%	3.1%	10.6%	4.7%	81.6%
2018	10.3%	12.9%	5.9%	70.9%	1.6%	10.9%	1.3%	86.2%	2.0%	5.9%	1.8%	90.4%	5.9%	1.2%	2.8%	90.1%	2.7%	5.6%	3.4%	88.4%	0.5%	6.5%	0.3%	92.8%	4.0%	11.4%	7.6%	77.0%
2019	6.8%	10.6%	7.3%	75.2%	1.8%	11.0%	1.7%	85.5%	1.2%	7.1%	1.9%	89.8%	7.2%	1.3%	2.7%	88.8%	1.1%	4.7%	4.0%	90.2%	0.5%	6.5%	0.9%	92.2%	3.0%	14.1%	6.8%	76.2%
2020	4.2%	7.7%	10.1%	77.9%	5.5%	7.5%	2.3%	84.7%	5.5%	4.0%	1.8%	88.7%	8.4%	0.2%	2.6%	88.8%	6.1%	2.3%	2.6%	89.0%	2.0%	5.0%	0.7%	92.3%	11.7%	8.4%	4.1%	75.8%
2021	8.2%	11.0%	9.3%	71.5%	2.1%	9.8%	2.6%	85.5%	1.7%	6.3%	3.6%	88.4%	7.3%	0.8%	4.3%	87.6%	10.2%	3.7%	3.3%	82.8%	0.8%	5.8%	1.2%	92.2%	8.4%	8.2%	6.3%	77.1%

Generator Forced Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[147] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first six months of 2021 was 6.8 percent, an increase from 5.9 percent in the first six months of 2020. Figure 5-13 shows the average EFORd since 1999 for all units in PJM.[148]

147 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.
148 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2020 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Figure 5-13 Trends in the equivalent demand forced outage rate (EFORd): January through June, 1999 through 2021

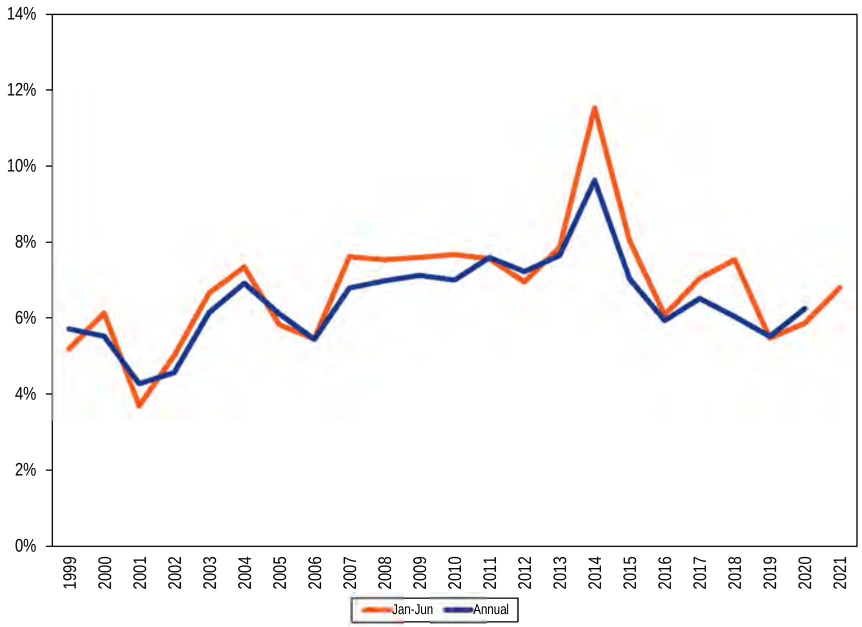


Table 5-30 shows the class average EFORd by unit type.

Table 5-30 EFORd by unit type: January through June, 2007 through 2021

	Jan-Jun														
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	7.7%	8.9%	8.8%	9.3%	10.5%	10.0%	9.7%	13.0%	10.0%	9.4%	12.2%	13.4%	9.7%	7.2%	11.5%
Combined Cycle	4.0%	3.6%	5.3%	4.5%	3.6%	2.9%	2.8%	5.6%	3.3%	4.5%	2.8%	2.8%	2.6%	5.5%	2.9%
Combustion Turbine	17.9%	15.0%	10.5%	15.6%	9.3%	8.8%	14.6%	23.9%	14.0%	7.5%	6.8%	8.9%	6.3%	5.5%	4.9%
Diesel	10.6%	10.0%	8.5%	5.8%	6.2%	5.1%	4.4%	15.9%	10.8%	7.6%	6.3%	6.2%	8.0%	8.4%	8.4%
Hydroelectric	2.2%	2.2%	2.5%	1.0%	1.5%	5.2%	0.8%	3.2%	2.6%	3.2%	3.2%	3.6%	1.4%	6.1%	11.6%
Nuclear	1.3%	1.1%	4.0%	1.5%	2.3%	1.3%	1.3%	2.2%	1.2%	1.1%	0.4%	0.6%	0.6%	2.0%	0.9%
Other	11.4%	10.5%	10.1%	7.4%	10.5%	8.5%	13.0%	16.3%	14.5%	7.2%	13.9%	11.1%	8.4%	11.7%	16.7%
Total	7.6%	7.5%	7.6%	7.7%	7.6%	7.0%	7.9%	11.5%	8.0%	6.1%	7.1%	7.5%	5.5%	5.9%	6.8%

Other Forced Outage Rate Metrics

Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, neither XEFORd nor EFORp are relevant.

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[149] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).

PJM EFOF was 4.4 percent in the first six months of 2021. This means there was 4.4 percent lost availability because of forced outages. Table 5-31 shows that forced outages for boiler tube leaks, at 13.2 percent of the systemwide EFOF, were the second largest single contributor to EFOF.

Table 5-31 Contribution to EFOF by unit type by cause: January through June, 2021

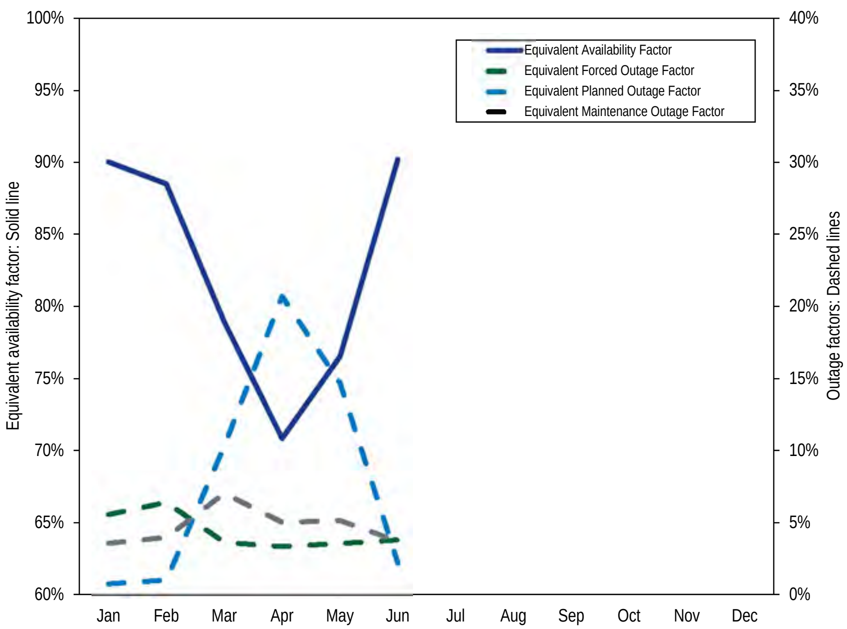
	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Generator	19.0%	34.8%	4.6%	9.4%	1.7%	0.0%	0.2%	15.1%
Boiler Tube Leaks	20.0%	5.2%	0.0%	0.0%	0.0%	0.0%	3.4%	13.2%
Turbine	0.0%	1.6%	16.9%	0.0%	90.7%	0.0%	0.0%	8.6%
Feedwater System	12.6%	1.5%	0.0%	0.0%	0.0%	8.7%	0.2%	8.2%
Controls	0.5%	3.6%	1.2%	6.4%	0.1%	0.0%	50.8%	7.1%
Electrical	8.0%	1.6%	15.5%	2.6%	0.2%	0.0%	0.3%	6.0%
Miscellaneous (Steam Turbine)	4.2%	12.7%	0.0%	0.0%	0.0%	0.0%	2.5%	3.9%
Boiler Air and Gas Systems	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	3.2%
Condensing System	3.1%	2.1%	0.0%	0.0%	0.0%	30.7%	0.3%	3.2%
Economic	0.2%	2.7%	3.3%	2.3%	1.6%	0.0%	18.7%	3.0%
Unit Testing	0.9%	1.3%	20.8%	24.8%	3.5%	0.0%	1.7%	2.4%
High Pressure Turbine	3.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%
Auxiliary Systems	1.0%	8.6%	10.9%	0.0%	0.3%	0.0%	0.3%	2.0%
Valves	2.8%	0.5%	0.0%	0.0%	0.0%	0.8%	0.4%	1.8%
Miscellaneous (Generator)	2.1%	0.1%	1.0%	1.2%	0.0%	5.3%	0.1%	1.6%
Fuel Quality	2.3%	0.2%	0.0%	10.4%	0.0%	0.0%	0.3%	1.5%
Boiler Piping System	1.9%	1.9%	0.0%	0.0%	0.0%	0.0%	0.2%	1.3%
Boiler Fuel Supply from Bunkers to Boiler	1.7%	0.2%	0.0%	0.0%	0.0%	0.0%	0.7%	1.2%
Slag and Ash Removal	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	1.0%
All Other Causes	10.4%	21.1%	26.0%	42.8%	1.8%	54.5%	14.8%	13.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

149 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Performance by Month

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-14.

Figure 5-14 Monthly generator performance factors: January through June, 2021



Attachment K

Attachment E

Affidavit of Adam J. Keech
on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER18-___-000**
	)	

AFFIDAVIT OF ADAM J. KEECH
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Adam J. Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as the Executive Director, Market Operations for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its proposed market reforms to address the impacts of state resource decisions on PJM's Reliability Pricing Model.

2. I have served in my current position since 2016 but have served as Director or Senior Director of Market Operations since 2013 where I had very similar responsibilities. The Market Operations Departments at PJM are responsible for technical design, implementation, and clearing of all PJM electricity markets and include the Day-ahead Market Operations Department, the Real-time Market Operations Department, the Market Simulation Department, the Capacity Market Operations Department, and the Interregional Market Operations Department. The responsibilities of these departments includes the Day-ahead and Real-time Energy Markets, Day-ahead Scheduling Reserve Market, Regulation, Synchronized Reserve and Non-Synchronized Reserve Markets, Financial Transmission Rights and Reliability Pricing Model auctions and Market-to-Market coordination between PJM and the Midcontinent Independent System Operator, Inc. and between PJM and the New York Independent System Operator.

3. In my capacity as Executive Director of the Market Operations Departments, I am directly responsible for the development of market rule changes through PJM's stakeholder process, oversight of the technical implementation of rule changes, and ensuring that PJM's market operations processes and market clearing results adhere to the requirements detailed in the PJM Open Access Transmission Tariff ("Tariff") and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.. As Executive Director of the Market Operations Departments, my basic responsibility is to make sure that PJM's markets are designed in a manner that leads to efficient, intuitive market outcomes that minimize the cost of procurement, meet system reliability needs, and incentivize market participants to act in a manner that promotes system reliability. Prior to assuming my leadership role in Market Operations, I served as Director of Dispatch for PJM where I was responsible for real-time system operations in the control room and compliance with North American Electric Reliability Corporation ("NERC") standards. Before that, I served as manager of PJM's Real-time Market Operations Department for three years, where I was directly responsible for PJM's real-time markets including the Real-Time Energy Market, Regulation, Synchronized Reserve

and Non-Synchronized Reserve Markets in addition to the Real-Time Security Constrained Economic Dispatch tool used by PJM's system operators.

4. I have worked at PJM since January 2003. I hold a Bachelor's of Science degree in Electrical Engineering from Rutgers University in New Brunswick, NJ and a Master's of Science degree in Applied Statistics from West Chester University in West Chester, PA.

5. My affidavit supports PJM's filing of Tariff revisions to fill a gap in the current capacity market rules, which have no mechanism to address the price suppressive effects of below-cost offers from a number of resource types that receive substantial subsidies under various state programs. PJM's Senior Market Strategist, Dr. Anthony Giacomoni in his affidavit provides an overview of the type of state subsidy programs to which PJM's filing responds, and provides estimates of the current and projected megawatts of state-subsidized capacity resource in the PJM Region, and the dollar value of the subsidies. In my affidavit, I discuss when offer behavior is (or is not) competitive, and provide analyses and data showing the likely PJM capacity market impact of the state subsidies. I also support the 5,000 MW transition threshold in the Capacity Repricing proposal by providing an estimate of the megawatt quantity of subsidized resources currently in the PJM Region that would be within the definition of subsidies subject to repricing.

A. Subsidized, Below-Cost Capacity Offers Significantly Reduce Clearing Prices Received by Unsubsidized Competitive Sellers

6. Subsidized, below-cost capacity offers can result in significant and widespread clearing price reductions that are attributable to the subsidies. PJM prepares sensitivity analyses following the Base Residual Auction ("BRA") each year illustrating how additional zero-price offers would have changed the clearing results. Specifically, PJM runs two sensitivities adding first 3,000 MW, and then 6,000 MW, of zero-priced supply to the region outside of MAAC. PJM also runs two sensitivities adding first 3,000 MW, and then 6,000 MW, of zero-priced supply in MAAC. Adding such zero-priced supply is not intended to represent new entry, but rather to illustrate what would happen if supply that originally offered at too high a price to clear the auction instead, relying on a subsidy to help cover its uncompetitive costs, offered at zero price. The injection of this low-priced supply results in a shift to the right of the supply curves by the specified MW amounts. The results from running these four sensitivities for the past three Base Residual Auctions are shown in Attachment 1 focusing on the Locational Deliverability Areas ("LDAs") that show price reductions.

7. As can be seen, adding comparatively small quantities of subsidized offers disproportionately reduces the clearing prices paid to all resources. For example, for the 2020/2021 Delivery Year, the "3000 MW Outside MAAC" scenario adds zero-priced supply of less than 2%, but decreases clearing prices in the RTO unconstrained pricing area by roughly 10%. The "6000 MW Outside MAAC" adds zero-priced supply of less than 4%, but decreases clearing prices in the RTO by 21%. *See* Attachment 1 at 3.

8. For the same Delivery Year, the "3000 MW Inside MAAC" scenario, which assumes about 1,000 MW of the added zero-priced supply is offered in the EMAAC LDA (which represents about 4% of supply in EMAAC), reduces clearing prices in that LDA by nearly 20%. EMAAC clearing prices are reduced *by about one-third* in the second MAAC scenario, which assumes about 2,000 MW of the 6,000 MW of added zero-priced supply (representing about 7% of supply in EMAAC) is offered in EMAAC. *See* Attachment 1 at 3.

9. Notably, these post-BRA sensitivity analyses do not test for how the clearing results would change if *the subsidized offers that actually cleared* in the subject BRA had submitted offers reflecting their competitive net costs. The sensitivities show only what would happen if *additional* subsidized offers were submitted in the BRA. Therefore, the clearing price reductions—relative to what would happen if sellers with subsidies that offered below cost instead offered at a level sufficient to cover the net costs they need from the capacity market—would be even greater than shown here.

B. Subsidized Offers from Specific Resources that Cannot Clear with Cost-Based Offers Would Have Significant Price Suppressive Effects

10. PJM also has simulated capacity auctions that reprice—to zero—only two plants that cannot currently clear at competitive offers that recover their costs. As stated by Exelon in a public announcement, both the Quad Cities plant and Three Mile Island nuclear generating stations failed to clear PJM's May 2017 BRA.[1] As shown in Attachment 2, allowing just these two plants to offer into the capacity auction at a subsidized price of zero would reduce the capacity revenues received *by every seller in the unconstrained portion of the RTO* by 2%. That 2% revenue reduction, experienced by every cleared seller in the unconstrained part of the RTO, is more significant than it sounds. A seller that clears a resource with 1,000 MW of unforced capacity, for example, would see a $547,500 reduction in its annual capacity market revenues for a that Delivery Year—due solely to the subsidy.

11. Sellers in the ComEd LDA would see their capacity revenues cut by nearly 10% due solely to allowing the subsidized offer. This would result in a reduction in annual capacity market revenues of $6.75 million for that same 1,000 MW resource.

12. In the MAAC LDA, the clearing price would drop by $1/MW-day, as a result of the zero offer from Three Mile Island in that LDA. While this too does not sound very significant, it represents a reduction of $365,000 in annual capacity market revenues for a resource with 1,000 MW of unforced capacity, and a reduction in total capacity market revenues for the MAAC region of approximately $24 million.

13. This analysis highlights an important point. Sellers are rational. Sellers that need to cover their costs submit offers at the level necessary to cover their costs.

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1 *Exelon Announces Outcome of 2020-2021 PJM Capacity Auction*, Exelon Corp (May 24, 2017), http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017.

Cost-recovery offers for Quad Cities and Three Mile Island were submitted in the 2017 BRA—as we know because their offers proved too high to clear. Simply because these resources are operated at a high capacity factor, or are existing resources, does not mean that they have zero costs of committing as capacity or that all of their costs are recovered through energy market revenues. This example is instructive as a reminder of the fundamental economic principles that govern whether or not a rational, unsubsidized seller will submit a zero-price offer.

14. Many sellers submit zero-price offers in PJM's capacity market. But this does not prove that many sellers are irrational. Sellers estimate whether they will recover their resource's costs in PJM's markets. If they anticipate that, for a given Delivery Year, they might not fully recover their resource costs in PJM's energy and ancillary service markets—*and they are not receiving a subsidy*—then they will offer into the capacity market at a price they consider the minimum needed to continue the operation of their resource through that Delivery Year. Conversely, if a seller anticipates that it will recover its resource costs fully in PJM's energy and ancillary service markets, then it can safely offer into the capacity market at zero price, because any revenues it receives will be surplus to its revenue requirement. Some sellers may fall in between these two alternatives. If an unsubsidized seller only has limited revenue needs from the PJM capacity market, and it reasonably expects, based on capacity clearing price trends for its LDA, that capacity prices will more than cover its net costs, then the seller might offer at zero price. All three of these scenarios represent rational competitive behavior.

15. By contrast, a zero-priced offer *that is made possible only because a seller receives an out-of-market subsidy* is not competitive behavior. The seller is relying on a state subsidy available only to select resources to submit an offer in the PJM capacity market that is well below what it needs if one looks only at its resource costs and the revenues available to it from PJM's other markets. The simulation of zero-price offers from Quad Cities and Three Mile Island exemplifies such below-cost subsidized offers. Consequently, the clearing price reductions shown in the simulation are entirely due to uneconomic price suppression.

C. Threshold for Application of Capacity Repricing

16. The Capacity Repricing proposal sets certain threshold levels of subsidized offers that must be passed before subsidized offers will be repriced. For the entire PJM Region, the threshold is 5,000 MW. For individual LDAs, the threshold level is 3.5% of the Reliability Requirement for the LDA. If either threshold is exceeded, all units in that region will be repriced.

17. The threshold, which is necessarily a matter of judgment, provides assurance that subsidies are affecting a significant portion of Capacity Resources before PJM implements this significant rule change. As a further means to assure that repricing will be applied only where subsidies are a significant concern, Capacity Repricing applies only to resources with capacity of at least 20 MW; it only applies if the subsidy is at least 1% of the resource's expected PJM market revenues; and it does not apply to a process or

installation (such as municipal solid waste or landfill gas) where electrical generation is ancillary to the facility's primary purpose.

18. For reference, PJM has estimated the market penetration of resources with subsidies that would be subject to repricing. PJM reviewed resources across its footprint that could have offered into the 2017 BRA, were eligible to receive a payment from a state-based RPS/REC programs, and would have been repriced based on PJM's proposal. PJM identified 698 MW from resources that could potentially be benefiting from state RPS/REC programs and whose primary commercial function is electricity generation. PJM also identified a total of 981 MW of demand resources and price-responsive demand benefiting from certain specific state programs that subsidize, through general ratepayer revenues, the costs of providing demand curtailment. Last, while it did not clear the 2017 BRA, the Quad Cities plant was subsequently found entitled to a ZEC subsidy in Illinois for its approximately 1,400 MW of PJM Region capacity.

19. In total, based on the last BRA, 3,079 MWs of unforced capacity eligible to receive subsidies would trigger repricing. Since that is short of the 5,000 MW threshold, RTO-wide repricing would not be applied in the May 2019 BRA (i.e., the earliest BRA to which repricing could apply) if the same quantity of unforced capacity persisted. However, 1,674 MW were identified within the ComEd LDA. This exceeds 3.5% of the reliability requirement for that LDA, and thus would trigger repricing.

20. This concludes my affidavit.

Attachment 1
to
Affidavit of Adam J. Keech

2018-2021 BRA Scenario Analysis

2018-2019															
Scenario #	**Scenario Description**	**Auction Results**	**RTO**	**MAAC**	**EMAAC**	**SWMAAC**	**PSEG**	**PS-NORTH**	**DPL-SOUTH**	**PEPCO**	**ATSI**	**ATSI-C**	**COMED**	**BGE**	**PPL**
BASE	Actual 2018/19 results	CP RCP	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$164.77	$215.00	$164.77	$164.77
3	Add 3000 MW of CP supply to bottom of supply curve in region outside of MAAC (1806 MW in rest of RTO, 760 MW in ComEd, 285 MW in rest of ATSI, 149 MW in ATSI-Cleveland)	CP RCP	$148.50	$149.27	$225.36	$149.27	$225.36	$225.36	$225.36	$149.27	$148.50	$148.50	$174.42	$149.27	$149.27
Price reduction compared to BASE			-$16.27	-$15.50	-$0.06	-$15.50	-$0.06	-$0.06	-$0.06	-$15.50	-$16.27	-$16.27	-$40.58	-$15.50	-$15.50
5	Add 6000 MW of CP supply to bottom of supply curve in region outside of MAAC (3612 MW in rest of RTO, 1520 MW in ComEd, 570 MW in rest of ATSI, 298 MW in ATSI-Cleveland)	CP RCP	$120.51	$149.19	$225.38	$149.19	$225.38	$225.38	$225.38	$149.19	$120.51	$120.51	$160.00	$149.19	$149.19
Price reduction compared to BASE			-$44.26	-$15.58	-$0.04	-$15.58	-$0.04	-$0.04	-$0.04	-$15.58	-$44.26	-$44.26	-$55.00	-$15.58	-$15.58
7	Add 3000 MW of CP supply to bottom of supply curve in MAAC (300 MW in rest of MAAC, 1001 MW in rest of EMAAC, 264 MW in rest of PS, 252 MW in PS-North, 122 MW in DPL-South, 331 MW in PEPCO, 359 MW in BGE, 371 MW in PL)	CP RCP	$150.00	$150.00	$185.34	$150.00	$185.34	$185.34	$185.34	$150.00	$150.00	$150.00	$215.00	$150.00	$150.00
Price reduction compared to BASE			-$14.77	-$14.77	-$40.08	-$14.77	-$40.08	-$40.08	-$40.08	-$14.77	-$14.77	-$14.77	$0.00	-$14.77	-$14.77
9	Add 6000 MW of CP supply to bottom of supply curve in MAAC (600 MW in rest of MAAC, 2002 MW in rest of EMAAC, 528 MW in rest of PS, 504 MW in PS-North, 244 MW in DPL-South, 662 MW in PEPCO, 718 MW in BGE, 742 MW in PL)	CP RCP	$143.22	$143.22	$168.74	$143.22	$168.74	$168.74	$168.74	$143.22	$143.22	$143.22	$215.00	$143.22	$143.22
Price reduction compared to BASE			-$21.55	-$21.55	-$56.68	-$21.55	-$56.68	-$56.68	-$56.68	-$21.55	-$21.55	-$21.55	$0.00	-$21.55	-$21.55

Notes:

(1) Incremental supply additions and removals have been allocated to LDAs based on LDA pro-rata share of the peak-load of the region to which supply is being added or removed.

(2) In scenarios 2 through 5, the rest of RTO area includes the AEP, APS, DAY, DEOK, DUQ, DOM and EKPC zones; and the rest of ATSI area includes the ATSI zone outside of the ATSI-Cleveland LDA.

(3) In scenarios 6 through 9, the rest of MAAC area includes the Penelec and MetEd zones; the rest of EMAAC area includes the AECO, JCPL, PECO zones and the DPL zone outside of the DPL-South LDA; and the rest of PS area includes the PS zone outside of the PS-North LDA.

2019-2020															
Scenario #	**Scenario Description**	**Auction Results**	**RTO**	**MAAC**	**EMAAC**	**SWMAAC**	**PSEG**	**PS-NORTH**	**DPL-SOUTH**	**PEPCO**	**ATSI**	**ATSI-CLEVELAND**	**COMED**	**BGE**	**PPL**
BASE	Actual 2019/20 results	CP RCP	$100.00	$100.00	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$100.00	$202.77	$100.30	$100.00
3	Add 3000 MW of CP supply to bottom of supply curve in region outside of MAAC (1966.4 MW in rest of RTO, 655.3 MW in ComEd, 251.7 MW in rest of ATSI, 126.6 MW in ATSI-Cleveland)	CP RCP	$87.50	$100.17	$119.77	$100.17	$119.77	$119.77	$119.77	$100.17	$87.50	$87.50	$197.96	$100.30	$100.17
Price reduction/increase compared to BASE			-$12.50	$0.17	$0.00	$0.17	$0.00	$0.00	$0.00	$0.17	-$12.50	-$12.50	-$4.81	$0.00	$0.17
5	Add 6000 MW of CP supply to bottom of supply curve in region outside of MAAC (3932.7 MW in rest of RTO, 1310.6 MW in ComEd, 503.5 MW in rest of ATSI, 253.2 MW in ATSI-Cleveland)	CP RCP	$75.00	$99.77	$119.77	$99.77	$119.77	$119.77	$119.77	$99.77	$75.00	$75.00	$186.15	$100.00	$99.77
Price reduction compared to BASE			-$25.00	-$0.23	$0.00	-$0.23	$0.00	$0.00	$0.00	-$0.23	-$25.00	-$25.00	-$16.62	-$0.30	-$0.23
7	Add 3000 MW of CP supply to bottom of supply curve in MAAC (300.1 MW in rest of MAAC, 990.4 MW in rest of EMAAC, 259.7 MW in rest of PS, 258.4 MW in PS-North, 119.7 MW in DPL-South, 335.4 MW in PEPCO, 354.8 MW in BGE, 381.5 MW in PL)	CP RCP	$99.97	$99.97	$99.97	$99.97	$99.97	$99.97	$99.97	$99.97	$99.97	$99.97	$202.77	$100.70	$99.97
Price reduction/increase compared to BASE			-$0.03	-$0.03	-$19.80	-$0.03	-$19.80	-$19.80	-$19.80	-$0.03	-$0.03	-$0.03	$0.00	$0.40	-$0.03
9	Add 6000 MW of CP supply to bottom of supply curve in MAAC (600.2 MW in rest of MAAC, 1980.8 MW in rest of EMAAC, 519.4 MW in rest of PS, 516.8 MW in PS-North, 239.4 MW in DPL-South,670.8 MW in PEPCO, 709.6 MW in BGE, 763.0 MW in PL)	CP RCP	$95.00	$95.00	$95.00	$95.00	$95.00	$95.00	$95.00	$95.00	$95.00	$95.00	$202.77	$112.17	$95.00
Price reduction/increase compared to BASE			-$5.00	-$5.00	-$24.77	-$5.00	-$24.77	-$24.77	-$24.77	-$5.00	-$5.00	-$5.00	$0.00	$11.87	-$5.00

Notes:

(1) Incremental supply additions and removals have been allocated to LDAs based on LDA pro-rata share of the peak-load of the region to which supply is being added or removed.

(2) The Rest of RTO area includes the AEP, APS, DAY, DEOK, DUQ, DOM and EKPC zones; and the Rest of ATSI area includes the ATSI zone outside of the ATSI-Cleveland LDA.

(3) The Rest of MAAC area includes the Penelec and MetEd zones; the Rest of EMAAC area includes the AECO, JCPL, PECO zones and the DPL zone outside of the DPL-South LDA; and the Rest of PS area includes the PS zone outside of the PS-North LDA.

2020-2021																	
Scenario #	Scenario Description	Auction Results	RTO	MAAC	EMAAC	SWMAAC	PSEG	PS-NORTH	DPL-SOUTH	PEPCO	ATSI	ATSI-C	COMED	BGE	PPL	DAY	DEOK
BASE	Actual 2020/21 results	CP RCP	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$76.53	$188.12	$86.04	$86.04	$76.53	$130.00
3	Add 3000 MW of CP supply to bottom of supply curve in region outside of MAAC (1536.1 MW in rest of RTO, 754.8 MW in ComEd, 291 MW in rest of ATSI, 146.3 MW in ATSI-Cleveland, 115.6 MW in DAY, 156.2 MW in DEOK)	CP RCP	$69.32	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$69.32	$69.32	$185.00	$86.04	$86.04	$69.32	$122.50
Price reduction compared to BASE			-$7.21	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$7.21	-$7.21	-$3.12	$0.00	$0.00	-$7.21	-$7.50
5	Add 6000 MW of CP supply to bottom of supply curve in region outside of MAAC (3072.2 MW in rest of RTO, 1509.6 MW in ComEd, 582 MW in rest of ATSI, 292.7 MW in ATSI-Cleveland, 231.1 MW in DAY, 312.4 MW in DEOK)	CP RCP	$60.00	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$60.00	$60.00	$174.36	$86.04	$86.04	$60.00	$115.00
Price reduction compared to BASE			-$16.53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$16.53	-$16.53	-$13.76	$0.00	$0.00	-$16.53	-$15.00
7	Add 3000 MW of CP supply to bottom of supply curve in MAAC (302.4 MW in rest of MAAC, 991.6 MW in rest of EMAAC, 259.3 MW in rest of PS, 258 MW in PS-North, 120.1 MW in DPL-South, 336.9 MW in PEPCO, 352.3 MW in BGE, 379.4 MW in PL)	CP RCP	$74.50	$85.00	$149.92	$85.00	$149.92	$149.92	$149.92	$85.00	$74.50	$74.50	$188.12	$85.00	$85.00	$74.50	$130.00
Price reduction compared to BASE			-$2.03	-$1.04	-$37.95	-$1.04	-$37.95	-$37.95	-$37.95	-$1.04	-$2.03	-$2.03	$0.00	-$1.04	-$1.04	-$2.03	$0.00
9	Add 6000 MW of CP supply to bottom of supply curve in MAAC (604.9 MW in rest of MAAC, 1983.2 MW in rest of EMAAC, 518.7 MW in rest of PS, 516 MW in PS-North, 240.1 MW in DPL-South, 673.7 MW in PEPCO, 704.6 MW in BGE, 758.8 MW in PL)	CP RCP	$75.00	$75.00	$124.70	$75.00	$124.70	$124.70	$124.70	$75.00	$75.00	$75.00	$188.12	$75.00	$75.00	$75.00	$130.00
Price reduction compared to BASE			-$1.53	-$11.04	-$63.17	-$11.04	-$63.17	-$63.17	-$63.17	-$11.04	-$1.53	-$1.53	$0.00	-$11.04	-$11.04	-$1.53	$0.00

Notes:
(1) Incremental supply additions and removals have been allocated to LDAs based on LDA pro-rata share of the peak-load of the region to which supply is being added or removed.
(2) The Rest of RTO area includes the AEP, APS, DUQ, DOM and EKPC zones; and the Rest of ATSI area includes the ATSI zone outside of the ATSI-Cleveland LDA.
(3) The Rest of MAAC area includes the Penelec and MetEd zones; the Rest of EMAAC area includes the AECO, JCPL, PECO zones and the DPL zone outside of the DPL-South LDA; and the Rest of PS area includes the PS zone outside of the PS-North LDA.

Attachment 2
to
Affidavit of Adam J. Keech

2020-2021 BRA Scenario Analysis

Scenario #	Scenario Description	Auction Results	RTO	MAAC	EMAAC	SWMAAC	PSEG	PS-NORTH	DPL-SOUTH	PEPCO	ATSI	ATSI-C	COMED	BGE	PPL	DAY	DEOK
BASE	Actual 2020/21 results	CP RCP	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$76.53	$188.12	$86.04	$86.04	$76.53	$130.00
	Change offers of Quad Cities and Three Mile Island (TMI) nuclear facilities to $0/MW-day	CP RCP	$75.00	$85.00	$187.87	$85.00	$187.87	$187.87	$187.87	$85.00	$75.00	$75.00	$170.01	$85.00	$85.00	$75.00	$130.00
Price reduction compared to BASE			-$1.53	-$1.04	$0.00	-$1.04	$0.00	$0.00	$0.00	-$1.04	-$1.53	-$1.53	-$18.11	-$1.04	-$1.04	-$1.53	$0.00

Notes:

(1) The Rest of RTO area includes the AEP, APS, DUQ, DOM and EKPC zones; and the Rest of ATSI area includes the ATSI zone outside of the ATSI-Cleveland LDA.

(2) The Rest of MAAC area includes the Penelec and MetEd zones; the Rest of EMAAC area includes the AECO, JCPL, PECO zones and the DPL zone outside of the DPL-South LDA; and the Rest of PS area includes the PS zone outside of the PS-North LDA.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER18-__-000**

Adam J. Keech, being first duly sworn, deposes and states that he is the Adam J. Keech referred to in the foregoing document entitled "Affidavit of Adam J. Keech," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

____

Subscribed and sworn to before me, the undersigned notary public, this 6th day of April, 2018.

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Linda Spreeman, Notary Public
Lower Providence Twp., Montgomery County
My Commi. sion Expires Nov. 17, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Linda Spreeman
Notary Public

My Commission expires: Nov 17, 2019