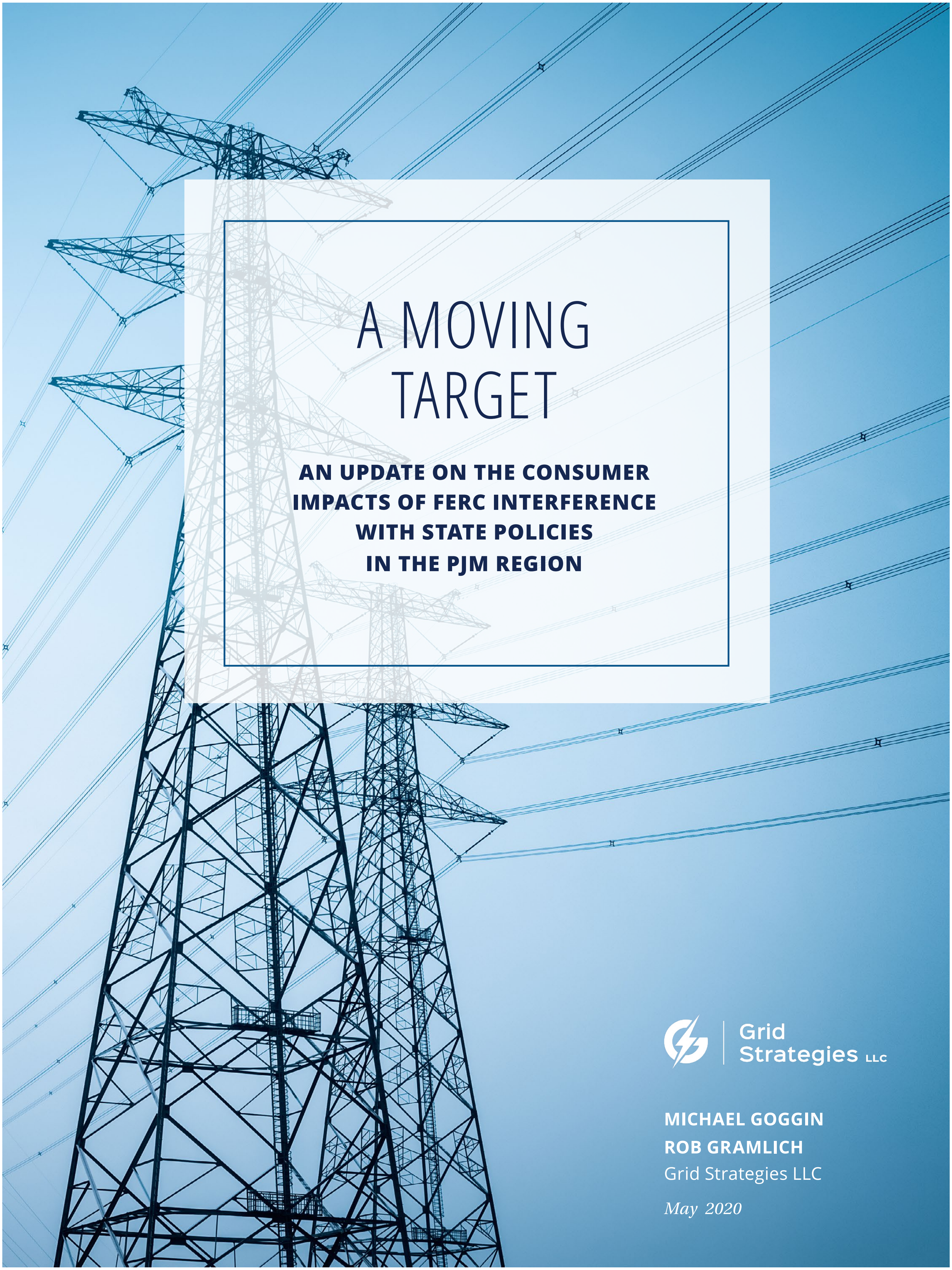

A MOVING TARGET

AN UPDATE ON THE CONSUMER IMPACTS OF FERC INTERFERENCE WITH STATE POLICIES IN THE PJM REGION

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INTRODUCTION

In December 2019 the US Federal Energy Regulatory Commission (FERC) ruled that, for the nation's biggest electricity market, PJM, bids in the capacity market auction from resources that benefit from state clean energy policies must be submitted only above certain minimum levels.[1] This broadly applied "Minimum Offer Price Rule" (MOPR) has been the subject of heated debate in the PJM region, which covers all or part of 13 Mid-Atlantic and Great Lakes states, as well as in New York and New England. While PJM had offered two versions of MOPR and the Independent Market Monitor and various stakeholders had proposed others, what FERC chose was a different one altogether. PJM declared that the FERC version "may have paradoxically unintended consequences over time and may result in less economic efficiency."[2] Now that FERC has finalized its process by rejecting most of PJM and others' rehearing requests,[3] the courts need to determine whether FERC's new version of broad MOPR should be rejected because it is arbitrary and capricious, and states and PJM need to decide how to make state policies and wholesale markets fit together given this new policy.

Cost impacts for electricity consumers are relevant to many parties' next steps. In response to at least fifteen parties who raised cost concerns with FERC,[4] the Commission agreed that "costs are an important

1 FERC, "FERC Directs PJM to Expand Minimum Offer Price Rule," December 19, 2019.
2 PJM, *Request for Rehearing and Request for Clarification of PJM Interconnection, L.L.C., January 21, 2020.*
3 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at P. 139-140, April 16, 2020.*
4 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at fn 330, April 16, 2020.*

consideration in decision-making, and we do not take lightly the concern that these revisions to the PJM capacity market may increase the capacity market costs customers will bear."[5] Yet FERC went ahead and finalized the decision without providing any estimate of the costs of its action, stating "the actual cost impacts of the replacement rate are speculative at this point, however, because—among other unknown factors—the MOPR's default offer price floors are not yet determined."[6] While FERC may not have paid appropriate attention to the costs of its order, states and consumers require some estimate of the costs to forecast their own costs and policy designs.

Our previous analysis put the consumer cost of earlier proposed versions of broad MOPR in PJM at up to $5.7 billion per year, relative to the current $10 billion/year PJM capacity market.[7] FERC's December order and the recent PJM compliance filing[8] each change the likely impacts of MOPR in PJM. This paper updates the assessment of MOPR impacts based on the current version of MOPR and scenarios for potential MOPR bid levels. There are so many versions of MOPR and factors such as bid levels that vary between versions and over time that it is not possible to definitively conclude, as some have, that MOPR will have limited cost impacts. Under most scenarios, MOPR will result in billions or tens of billions of dollars in excess costs to electricity consumers across PJM.

FERC'S NEW GENERAL MOPR POLICY

FERC's current MOPR policy is different than what was proposed by PJM and other parties, and includes significant changes from recent Commission positions. Courts will have plenty of material to review regarding whether these changes are arbitrary or capricious. In our August 2019 paper on the cost impacts of MOPR, we explained that "The U.S. Federal Energy Regulatory Commission (FERC) has begun a major policy shift that it says is necessary to protect wholesale electricity markets from the impacts of state policies."[9] We described the shift this way: "A major policy shift underway at FERC expanded MOPR from a surgical fix for specific potential exercises of market power, towards a role in which the MOPR applies across the entire market to any state policy that incentivizes generation from resources that could have an impact on the market."[10] Previously MOPR had been a tool to address monopsony, or buyer-side market power. In that previous policy, exemptions for renewable energy sources were allowed because they were not being used as means of exercising buyer-sider market power.

In December, FERC explicitly adopted the shift we had described: "the expanded MOPR does not focus on buyer-side market power mitigation."[11] FERC made this same decision in the New York ISO where the policy of "Buyer Side Mitigation," despite the name, no longer applies to buyer-side market power or its mitigation.[12] By no longer focusing on buyer side market power, many resources become subject to MOPR and renewable energy exemptions are eliminated.

FERC's December order was also a major shift from the policy of the Commission led by Chairman Kevin McIntyre at the beginning of the Trump administration. The new policy removed the main mechanism of

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5 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at P. 139, April 16, 2020.*

6 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at P. 139, April 16, 2020.*

7 Goggin and Gramlich, *Consumer Impacts of FERC Interference with State Policies: An Analysis of the PJM Region,* August 2019.

8 PJM, *Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RMP Auction Deadlines, and Request for and Extended Comment Period of at Least 35 Days, March 18, 2020.*

9 Goggin and Gramlich, *Consumer Impacts of FERC Interference with State Policies: An Analysis of the PJM Region,* p. 1, August 2019.

10 Goggin and Gramlich, *Consumer Impacts of FERC Interference with State Policies: An Analysis of the PJM Region,* p. 4, August 2019.

11 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at P. 45, April 16, 2020.*

12 FERC, "FERC Approves Market Rules to Protect Competition, Supplies in NYISO," February 20, 2020.

accommodating state policy the McIntyre Commission had proposed in June 2018. The “Resource-Specific Fixed Resource Requirement” was suggested by that Commission as a way to accommodate state policy via bilateral capacity contracting for utility self-supply. In December, with little explanation,[13] the current Commission terminated the McIntyre Commission’s approach.

In an unprecedented move, the new FERC policy also makes new utility self-supply subject to MOPR. A large part of the electric industry is made up of public- and consumer-owned utilities, and the new policy targets their market segment in ways that will require fundamental changes to how they do business.[14]

The new FERC policy also applies to state energy and capacity procurements. Over PJM and state objections, and despite the fact that suppliers to state procurements such as the New Jersey Basic Generation Service generally do not own their own generation or physically contract with specific generators, the policy is now considered a state subsidy by FERC. As discussed further below, our analysis is likely to be conservative as it does not include the impact of applying the MOPR to self-supply, default service auctions, demand response, and energy efficiency resources.

One FERC decision does potentially reduce MOPR impacts on clean energy and consumers in the short run. The December order exempts somewhat more existing renewable energy than prior proposals, by stating that renewable resources under development that signed a Construction Service Agreement (CSA) to interconnect to the PJM system before the date of the Order are exempt from the MOPR.

More background on FERC MOPR policy and its evolution is provided in Appendix A.

CONSUMER COST IMPACTS OF FERC’S CURRENT MOPR POLICY

The consumer cost of FERC’s current MOPR approach depends on a number of factors, many of which are still undetermined. In the sections below we evaluate how these undetermined factors affect consumer costs, including two quantitative scenarios of FERC’s new MOPR approach.

Price floors are moving targets

The cost of MOPR significantly depends on what price floors FERC applies to various state-supported resources that are found to be subject to the MOPR—i.e., the minimum level those resources are permitted to bid into the auction. If the allowed bids are low enough that resources can “clear the market,” the resources receive a capacity payment and consumers need not pay for redundant capacity to replace those resources, though capacity market prices may increase due to the price floor. If resources do not clear, capacity market prices increase and redundant replacement capacity must be purchased and paid for by consumers, further increasing their bills.

MOPR’s impacts can be dialed up or down based on dozens of assumed cost and performance inputs that are used to calculate minimum allowed bids. Appropriate bid levels are in the eye of the beholder. Over the course of the process at PJM and FERC, there have been many approaches to calculating bid levels.

The table below shows the variation in allowed bid levels for different resource types as proposed at

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13 FERC, *Order Establishing Just and Reasonable Rate, 169 FERC ¶ 61,239 at P. 6, December 19, 2019.*

14 See, eg, *Request for Clarification and Rehearing of the National Rural Electric Cooperative Association and East Kentucky Power Cooperative, Inc., January 21, 2020.*

different times. For example, the allowed bids for onshore wind range from the mid-400s to over 1000 $/MW-day. Proposed solar bids have ranged from over $500 to $175.

TABLE 1. *Changing proposed default bid levels for relevant resources*

RESOURCE TYPE	PRELIMINARY IMM-RECOMMENDED DEFAULT BID LEVEL $/MW-DAY[15]	PJM 2018 FILING DEFAULT BID LEVEL $/MW-DAY[16]	PJM MARCH 2020 COMPLIANCE FILING DEFAULT BID LEVEL $/MW-DAY[17]
Existing Nuclear - Single Unit	$179.79	$631	$210
Existing Nuclear - Dual Unit	$0	$593	$0
New Hydro	NA	$1,066	NA
New Pumped Hydro	NA	NA	NA
New Solar PV (Tracking)	$532.07	$387	$175
New Solar PV (Fixed)			$367
New Onshore Wind	443.89	$2,489	$1,023
New Offshore Wind	$1,741.83	$4,327	$3,146

For reference, the capacity market clearing price for the most recent PJM auction was $140/MW-day, with some zones within PJM clearing at higher prices between $165.73/MW-day and $204.29/MW-day.[18] With very few exceptions, the allowed renewable bids are above these clearing prices.

It is unknown whether FERC will accept the numbers in PJM's recent compliance filing, some other proposal, or if FERC will impose its own numbers. As discussed in more detail below, it is also unclear to what extent FERC will allow resources to provide resource-specific information that demonstrates their bid level should be lower than the default value, which may allow some low-cost and high-performance resources to clear the market. Given that uncertainty, we evaluate the consumer costs under two scenarios below, first with the new PJM bid proposal, and second with the original PJM proposal. The latter scenario indicates the potential impacts if FERC were to not accept the somewhat lower price floors PJM is now proposing. These costs are calculated relative to the current consumer cost of the PJM capacity market, which for reference totaled $8.7 billion in 2019.[19] The methodology for this analysis is explained in detail in the next section.

Consumer cost case with nuclear plants clearing the market (New PJM proposal)

Under PJM's new proposal, the multi-unit nuclear resources are certain to clear the market, and the single-unit nuclear resources likely will. This scenario assumes new renewable sources do not clear, as they either use the default bid levels proposed by PJM or are unable to obtain resource-specific offer floors that are low enough to clear. Under this scenario, MOPR could increase consumer costs for capacity in the PJM region by nearly $10 billion total over its first nine years, or an average of over $1 billion per year, as shown below.

15 Monitoring Analytics, "CONE and ACR Values - Preliminary," p. 2, January 21, 2020.

16 PJM, *Initial Submission of PJM Interconnection,* pp. 6 & 46, October 2, 2018.

17 PJM, *Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RMP Auction Deadlines, and Request for and Extended Comment Period of at Least 35 Days,* pp. 64, March 18, 2020, and *Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C.*, p. 16, March 18, 2020.

18 PJM, "2021/2022 RPM Base Residual Auction Results," p. 15, n.d.

19 Monitoring Analytics, "2019 State of the Market Report for PJM: Volume 1,"p. 16, March 12, 2020.

TABLE 2. *MOPR consumer cost by auction year* ***with*** *nuclear units clearing*

($ millions)

AUCTION YEAR	TOTAL COST	PARTS OF NJ, DE, MD, AND PA (EMAAC)	PART OF IL (COMED)	PART OF OH (ATSI)	REST OF PJM
22/23	**$722**	$472	$9	$40	$201
23/24	**$1,255**	$764	$15	$74	$402
24/25	**$1,790**	$1,057	$21	$108	$603
25/26	**$638**	$233	$39	$14	$352
26/27	**$779**	$277	$46	$17	$441
27/28	**$917**	$318	$52	$19	$529
28/29	**$1,052**	$356	$57	$21	$617
29/30	**$1,186**	$395	$63	$23	$705
30/31	**$1,314**	$429	$67	$25	$793
TOTAL	**$9,652**	**$4,301**	**$368**	**$340**	**$4,643**
AVERAGE PER YEAR	**$1,072**	**$478**	**$41**	**$38**	**$516**

Even if FERC adopts PJM's recently-filed bid levels for existing nuclear plants, it is possible that the single-unit nuclear plants in New Jersey (Hope Creek) and Ohio (Davis-Besse and Perry) will not clear the market, as PJM's proposed default bid floor of $179/MW-day is slightly higher than the most recent auction's $165.73/MW-day clearing price for much of New Jersey (EMAAC) and the $171.33/MW-day clearing price for northern Ohio (ATSI). This would significantly increase the cost of MOPR for consumers in those zones.

An additional source of uncertainty regarding the cost of MOPR is the pace of future renewable energy deployment. The estimate above assumes that renewable deployment occurs gradually as state RPS requirements ramp up over time. The cost of MOPR would be higher if renewable deployment is front-loaded into the next few years to benefit from federal renewable tax credits that are phasing down for projects completed through the mid-2020s. This would result in a larger cost being attributable to MOPR, as those resources are subject to MOPR for a longer period of time and there is a larger price impact in the near-term, but likely lower total cost to consumers because the renewable projects benefits from larger tax credits. Our study in August 2019 reached a consumer cost estimate of up to $5.7 billion per year based on the assumptions that states and utilities will front-load renewable deployment to take advantage of the federal tax credits, and that nuclear units will be subject to the MOPR.

As mentioned above, another significant source of uncertainty is whether renewable resources will be able to clear the capacity market using unit-specific bids that are significantly lower than what PJM recently filed as the default bid levels. Under the unit-specific option, a resource can provide PJM with documentation of its actual costs and performance to demonstrate that it should have a different bid floor. For new renewable resources, PJM filed average default bid levels of $175/MW-day for solar PV with tracking, $367/MW-day for solar PV without tracking, $1,023/MW-day for land-based wind, and $3,146/MW-day for offshore wind, with solar and land-based wind default bid levels varying by PJM zone. While all of those are significantly higher than the most recent PJM-wide capacity market clearing price of $140/MW-day, it is likely that some solar, and potentially some land-based wind projects, could demonstrate evidence for unit-specific bid levels that are low enough to clear the capacity market.

Even if the vast majority of solar and land-based wind resources are able to use unit-specific bid floors to clear the market, it is unlikely that offshore wind resources will be able to clear the market. State policies in New Jersey, Virginia, and Maryland call for around 7,247 MW of offshore wind (representing around 1,884 MW of unforced capacity, per Appendix B below) that would be subject to the MOPR by 2030.[20] As a result, even this scenario would impose significant costs on PJM consumers by driving prices markedly higher in a zone that is already congested and experiences high capacity market prices. These cost impacts will occur in near-term auctions though possibly not the first one for 2022-23.

More likely is that some solar and land-based wind projects will be able to use unit-specific bids that are low enough to clear the market, while others will not. Even if projects are able to successfully use unit-specific bids, the process of demonstrating sufficient evidence to justify that bid introduces additional regulatory uncertainty into renewable project development in PJM, which is costly and may distort development decisions regarding project siting, technology, and financing towards options for which it is easier to qualify for a lower bid level. This uncertainty is compounded by the fact that PJM is currently revising the method for calculating the capacity value for wind and solar projects – a key determinant of the bid level under the unit-specific process – and that that capacity value accreditation will likely change over time.

Consumer costs without nuclear plants clearing the market (PJM's original proposal)

Another scenario is one in which the FERC sets nuclear bid levels closer to the higher levels that PJM previously filed with FERC, which are much higher than those in PJM's current compliance filing. We do not know what FERC will accept, but it seems plausible that FERC could impose higher default floors than PJM currently proposes based on FERC's apparent view that the state policies it targets with the MOPR have suppressed capacity market clearing prices. We assume that new renewable resources are still unable to clear the market in this scenario.

20 NJ Department of Environmental Protection, "Offshore Wind In New Jersey," n.d., and Morehouse, "Maryland 50% RPS Bill Doubles Offshore Wind Target, Expands Solar-Carve Out," Updated May 22, 2019.

If FERC adopts minimum bid levels that are closer to what PJM had initially proposed instead of the PJM's more recent filing, it is unlikely that subsidized nuclear units in Illinois, New Jersey, and Ohio will be able to clear the capacity market. If this occurs, the MOPR would impose a much larger cost on consumers, particularly in the near term as capacity market prices spike in already congested zones in Illinois, New Jersey, and Ohio, as shown in the tables below. Due to the higher costs in those zones, total consumer costs in this scenario would be more than double those in the scenario in which the nuclear plants cleared the market, reaching a total of almost $24 billion over the next nine years, averaging over $2.6 billion per year.

TABLE 3. *MOPR consumer cost by auction year without nuclear units clearing ($ millions)*

AUCTION YEAR	TOTAL	PARTS OF NJ, DE, MD, PA (EMAAC)	PART OF IL (COMED)	PART OF OH (ATSI)	REST OF PJM
22/23	**$4,124**	$2,303	$125	$1,495	$201
23/24	**$4,650**	$2,594	$132	$1,522	$402
24/25	**$5,177**	$2,887	$138	$1,548	$603
25/26	**$1,315**	$554	$205	$204	$352
26/27	**$1,456**	$597	$212	$207	$441
27/28	**$1,594**	$639	$218	$209	$529
28/29	**$1,728**	$677	$223	$211	$617
29/30	**$1,863**	$716	$229	$213	$705
30/31	**$1,990**	**$750**	**$233**	**$215**	**$793**
TOTAL	**$23,898**	**$11,717**	**$1,715**	**$5,823**	**$4,643**
AVERAGE PER YEAR	**$2,655**	**$1,302**	**$191**	**$647**	**$516**

Other factors that could increase the cost of MOPR

The costs may be higher than the scenarios above because they do not account for greater opportunities for exercise of supplier market power, application to utility self-supply, potential impacts on voluntary Renewable Energy Credit purchases, or impacts on energy efficiency and demand response.

SELLER MARKET POWER: Seller market power can raise the cost of MOPR. It is widely acknowledged that RPM is structurally noncompetitive and therefore vulnerable to the exercise of market power. As explained in the dissent of Commissioner Richard Glick, citing the NYU Institute of Policy Integrity, "the MOPR will decrease the competitiveness of the market, both by reducing the number of resources offering below the MOPR price floor and by changing the opportunity cost of withholding capacity."[21] These factors raise and steepen the supply curve such that a small amount of capacity subject to MOPR can have a large impact on price. In addition, mandating bid price floors for resources subject to the MOPR can facilitate anti-competitive bidding behavior by providing market participants with more information about what other resources are bidding.

SELF-SUPPLY: The cost estimates here and in other analyses cited below do not include the effects of applying the MOPR to new resources owned or contracted for by vertically integrated utilities and public power, known as self-supply. This additional cost is uncertain because the bid floor determinations for all

21 Glick dissent to *Order Establishing Just and Reasonable Rate*, *169 FERC ¶ 61,239 at P. 56, December 19, 2019.*

resources have not yet been finalized as explained above, and because new capacity additions planned by vertically integrated utilities and public power over the next 10 years have not yet been determined. Most of the self-supplied resources are owned by public power utilities. Public power's tax-exempt financing can lower the cost of generation, so presumably the bid levels would need to be higher than they are presently to reflect the higher market cost of capital, which has the potential to raise clearing prices even further.

STATE PROCUREMENTS: The cost estimates here and in other analyses cited below do not include the effects on state procurements. The New Jersey Basic Generation Service and similar approaches in other PJM states are now subject to FERC's new MOPR policy, yet almost no work has been done to determine which resources would be affected by this extension of the MOPR, or what the effects will be for these programs. If FERC deems the prices received in such auctions to be above competitive levels, and those premiums flow through to generators, it may require higher bids for generators. It is not clear this policy is even possible to implement because state procurement is typically for capacity and energy that have been unbundled from the associated generation.

DEMAND RESPONSE AND ENERGY EFFICIENCY: Demand response and energy efficiency resources will be affected by the MOPR order, raising costs to consumers beyond what we have estimated here. The Commission stated "We acknowledge that the requirements of the replacement rate, including the application of the default offer price floor, may require aggregators and [Curtailment Service Providers] to know all of their demand response resource end-users prior to the capacity auction."[22] However, the demand response and energy efficiency business often lines up participating customers after winning the capacity auction. Design factors such as zonal aggregation and whether certain payments to these sources are considered state subsidies will change under the new FERC approach, reducing the amount of capacity from these sources. As the Advanced Energy Management Alliance stated, "Ignoring such value streams, available to customers physically able and willing to contract for them, would unnecessarily prevent generation-backed DR from competing in the PJM capacity market, or force artificial increases in offer prices that would be harmful to consumers.[23]

FERC noted the IMM's analysis showing that energy efficiency and demand response have reduced prices between 13 and 65 percent over the last seven auctions.[24] It only stands to reason that if participation of new energy efficiency and demand response resources is significantly reduced, prices would rise. Further, the Commission invited a fundamental question of whether energy efficiency and demand response should even participate at all in the capacity market: "If parties believe that these resources should no longer qualify as capacity resources or be eligible to participate in PJM's capacity market, such a determination would be more appropriate in a new proceeding."[25] For reference 11,126 MW of demand response and 2,832 MW of energy efficiency cleared in PJM's last capacity market auction, and default bid floors for demand response resources are high, $254/MW-day, well above clearing prices. As a result, the removal of new demand response and energy efficiency resources could have a costly impact on the capacity market.

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22 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at P. 266, April 16, 2020.*

23 See, eg, Advanced Energy Management Alliance, *Request for Clarification, January 24, 2020.*

24 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at fn 563, April 16, 2020.*

25 FERC, Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at P. 255, April 16, 2020. Note also Commissioner Danly's statement upon issuance of this order intending to review the participation of "non-energy producing resources."

Cost Assessment Methodology

First, we estimated the amount of generating capacity that would be subject to the MOPR. Table 4 below identifies the nameplate capacity of these resources, as well as the capacity credit PJM gives to those resources in its capacity market.

In the case using the new lower PJM-filed nuclear bid levels, we assume that nuclear plants will still be able to clear the market despite being subject to the MOPR, in part because the nuclear resources that receive state incentives are located in capacity market zones with high prices that will further increase under the MOPR, making it easier for those resources to clear. As a result, in this case, renewable resources account for the vast majority of the generating capacity subject to the MOPR. If PJM's earlier filed bid levels are used, we assume that none of the subsidized nuclear plants in Illinois, New Jersey, and Ohio are able to clear the market, which results in significantly higher costs for consumers, as shown in the results presented above.

PJM states have a large amount of unmet demand to comply with state RPS and storage requirements. We estimate that meeting those targets will require 46,630 MW of nameplate renewable and storage capacity through the year 2030.[26] The nameplate capacity of those renewable and storage resources was converted to unforced capacity (UCAP) using the average capacity value for each resource type for projects with signed Construction Service Agreements (CSAs) in the PJM interconnection queue. We calculated that the average capacity value was 11.1% of nameplate capacity for land-based wind, 26% for offshore wind, and 49.6% for solar,[27] resulting in a total UCAP of PJM's remaining RPS and storage requirement demand of around 17,775 MW.

FERC's MOPR Order states that renewable resources under development that signed a CSA before the date of the Order are exempt from the MOPR. We identified 3,833 MW of nameplate wind capacity and 5,404 MW of nameplate solar capacity that has not yet been placed in service but had a signed CSA by the date of FERC's Order. We assumed that all of those resources are completed and will not be subject to the MOPR. The unforced capacity equivalent of that nameplate capacity is around 3100 MW. That leaves around 14,600 MW (UCAP) of PJM RPS and storage mandate capacity subject to the MOPR in the conservative case with all PJM nuclear plants clearing the capacity market. In a case in which minimum bid levels for existing nuclear plants are closer to the higher levels that PJM had previously proposed, the additional unforced capacity of 2,116 MW in Ohio, 3,573 MW in New Jersey, and 1,850 MW in Ohio from those states' nuclear plants would bring the total PJM unforced capacity subject to the MOPR to 22,170 MW.

26 New Jersey's offshore wind and storage requirements, DC's RPS, and Virginia's renewable and storage requirements extend beyond 2030, though only capacity required through 2030 is included in this analysis. For Virginia renewable and storage targets that specify a requirement for a utility to contract for a certain amount of capacity by 2035, it was assumed that 7/15 of the total capacity would be placed in service by 2030. This is based on an assumed 3-year lag between contracting and placing a resource in service, so that resources will be placed in service between 2023 and 2038, with 7/15 of the total capacity being placed in service by 2030. For the Virginia targets, see Kirkland & Ellis, "Clean Energy Legislation Arrives in Virginia - Will It Become Law This Week?" April 7, 2020.

27 Battery storage was given a 98% capacity value to reflect an assumed 2% forced outage rate. While PJM currently requires storage resources to provide 10-hour duration to receive credit in the capacity market, PJM has initiated a process to replace that requirement with a calculation of the actual capacity value of battery storage, which is likely to be nearly 100% for the battery penetrations required by Virginia and New Jersey.

TABLE 4. *Resources likely subject to MOPR with nuclear plants clearing market*

RESOURCE	MW NAMEPLATE	CAPACITY VALUE	UCAP MW EXCLUDED BY MOPR
OVEC coal	2300	91.1%	Clears market
Ohio nuclear units	2150	98.397%	Clears market
NJ nuclear units	3631	98.397%	Clears market
IL PJM nuclear units	1880	98.397%	Clears market
NJ Tier 1 RPS, wind	1428	11.1%	158
NJ Tier 1 RPS, solar	1062	49.6%	527
NJ solar carveout	2465	49.6%	1223
NJ offshore wind	3500	26%	910
NJ storage	2000	98%	1960
VA storage	1260	98%	1235
VA offshore wind	2427	26%	631
VA solar	3022	49.6%	1499
VA wind	4771	11.1%	530
Incremental Illinois RPS demand 2019-2030, wind	533	11.1%	59
Incremental Illinois RPS demand 2019-2030, solar	1384	49.6%	686
Other PJM state RPS demand, wind	1877	11.1%	208
Other PJM state RPS demand, solar	5916	49.6%	2934
MD wind	1219	11.1%	135
MD solar	3212	49.6%	1593
MD offshore	1320	26%	343
ACCREDITED CAPACITY SUM			**14,632 MW**

Next, we allocated the capacity subject to MOPR to PJM zones covering southern New Jersey and portions of northern Delaware, northeast Maryland, and southeast Pennsylvania (EMAAC), the PJM portion of Illinois (ComEd), and northern Ohio (ATSI), as well as the rest of PJM. 132.1 MW of solar nameplate capacity in New Jersey with a signed CSA was counted towards meeting the solar carve-out portion of the New Jersey RPS and reduced the remaining RPS demand in EMAAC, as was 247.8 MW of offshore capacity in Maryland. All other unmet RPS demand was allocated based on the expected RPS compliance resource mix for each state, as tallied in the table above. That yields the following amounts of capacity subject to MOPR by the year 2030. Details by state and resource type are provided in Appendix B.

TABLE 5. *2030 MW not clearing due to MOPR, by zone*

	MW UCAP WITH NUCLEAR PLANTS CLEARING	MW UCAP WITHOUT NUCLEAR PLANTS CLEARING
EMAAC	4,778	8,351
ComEd	746	2,595
ATSI	275	2,391
Rest of PJM	8,834	8,834

FIGURE 1. *2021/2022 Base Residential Auction EMAAC Supply Curve*

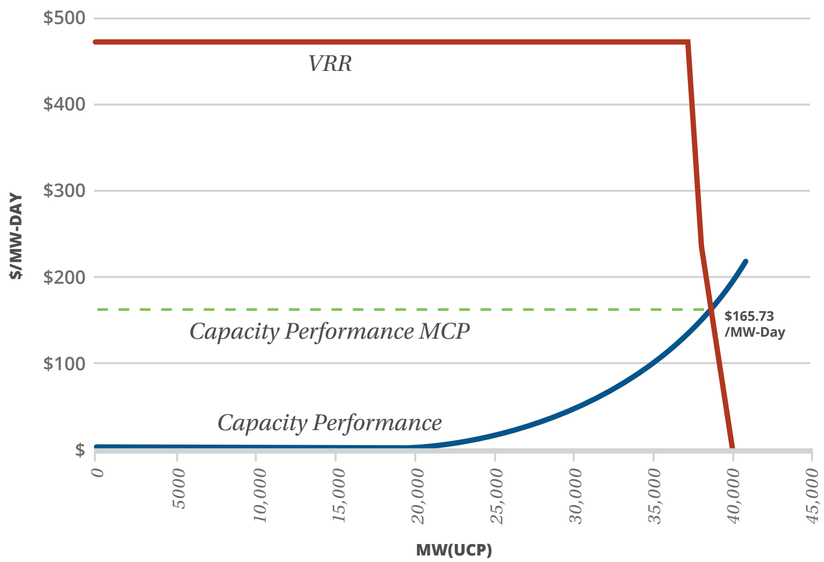
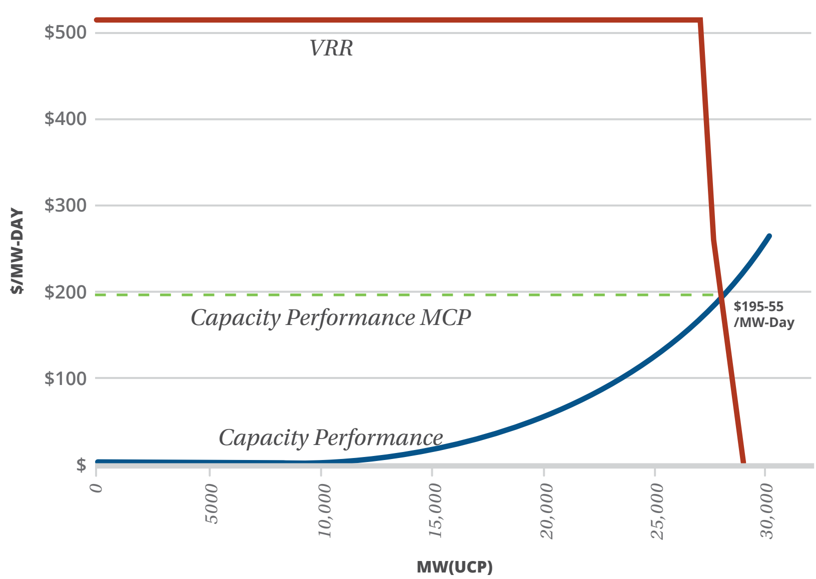


FIGURE 2. *2021/2022 Base Residential Auction COMED Supply Curve*



For the first three auction years, consumer costs were calculated by removing the capacity subject to MOPR from the zonal supply curve to calculate the new market clearing price, which was then multiplied by the total capacity demand in that zone. This method is intended to estimate the cost of imposing the MOPR in the near-term, when capacity supply is inelastic (unable to increase in response to higher prices) so the primary impact of reducing capacity supply is to increase capacity market prices. This tends to impose a larger cost on consumers, as the higher price applies to all MW of capacity procured in the capacity market. It was conservatively assumed that all projects with signed CSAs were built first to meet remaining RPS demand, which significantly delays and reduces the total cost impact of MOPR.

The price impact was calculated by linearly extrapolating from scenario analysis conducted by PJM that examines the impact of adding or removing 3,000-6,000 MW of unforced capacity in different zones.[28] The impact of MOPR on prices in PJM zones that already cleared at higher capacity market prices is particularly pronounced, as the market clearing price is already on a steep part of the zonal supply curve, as shown in Figures 1 and 2 below.[29] Consumers in southern New Jersey and portions of northern Delaware, northeast Maryland, and southeast Pennsylvania (EMAAC) and the PJM portion of Illinois (ComEd) are the most negatively affected by MOPR because they already had high capacity prices and also have the most renewable and potentially nuclear capacity subject to MOPR due to their strong state clean energy policies.

Over the longer-term, supply will likely increase in response to the higher prices and prices will return to their equilibrium level. This additional investment reflects the inefficiency of MOPR, as costly investment in redundant capacity is required. Consumers must still bear the cost of building redundant capacity to

28 See PJM 2021/2022 Base Residual Auction Scenario Analysis.
29 See PJM 2021/2022 Base Residual Auction supply curves, pp. 2 & 6, n.d.

replace the capacity that was unable to clear the market due to the MOPR. Most likely, new gas generators will provide a large share of that replacement capacity, which will be less valuable in a carbon-constrained future.

This new market equilibrium will be reached after market participants have enough time to build new generating capacity, which typically requires at least several years for most large-scale resources. We assume that prices will not return to a long-run equilibrium until 2025, based on NERC's estimate that it typically requires up to 5 years to complete the planning, permitting, and construction of a new gas generator.[30] The consumer cost of MOPR in the first three auctions (22/23, 23/24, and 24/25) was estimated using the capacity price impact method described above.

For the remaining six auction years through 2030, we calculated the cost of building redundant gas combined cycle capacity to replace capacity subject to the MOPR to estimate the long-run cost of MOPR, based on a net CONE of $235/MW-day[31] and a forced outage rate of 4.4%.[32] We conservatively assume that combined cycle gas generators provide the replacement capacity; assuming the use of combustion turbine gas generators would have resulted in a 14% higher calculated MOPR cost for replacement resources due to their higher net CONE. Consumers must ultimately pay the cost of building and maintaining this redundant fossil generating capacity to replace the capacity removed from the market by the MOPR, while they are also paying for the clean energy resources incentivized by state policy.

MOPR could have the indirect effect of lowering energy market prices, somewhat offsetting its direct impact of increasing capacity market prices. This could occur because the MOPR drives retention of

30 NERC, *Potential Reliability Impacts of EPA's Clean Power Plan: Phase II, p. 54, May 2016.*

31 PJM, "Preliminary Default MOPR Floor Offer Prices for New Generation Capacity Resources," slide 8, February 28, 2020; Net CONE and not gross CONE was used to reflect that capacity resources also provide energy and ancillary services.

32 PJM, *2019 PJM Reserve Requirement Study,* October 8, 2019.

excess generating capacity that reduces the frequency and magnitude of scarcity hours that tend to drive high energy market prices. That is of no comfort to renewable energy suppliers, which generally earn most of their revenues selling energy. Any beneficial impact to consumers from a reduction in energy market prices is likely to be limited, given that PJM's energy market supply curve is fairly flat due to the relatively low cost of the region's gas generators and the relatively high cost of the region's coal generators, and the fact that PJM already has a large excess of generation. Moreover, low energy prices can dull the price signals needed at times of day and season when flexible resources are needed to keep the system in balance. Generally it is beneficial for low carbon grids to have more revenue flowing through the energy market.[33]

Other estimates of the cost of broad MOPR in PJM

Our results are generally consistent with other analyses that suggest MOPR will drive increases in capacity market prices. ICF stated that the FERC order "sends a positive signal for PJM capacity prices."[34] They estimate that prices would increase by $25 to $35/MW-day for the upcoming 2022-2023 auction and $50 to $70/MW-day in the long term.[35]

Similarly, Charles River Associates found "Resulting market rules are likely to drive up capacity prices in upcoming Base Residual Auctions (BRA), though potentially duplicative capacity procurement and the resulting high reserve margins may drive down prices in the energy and ancillary services markets."[36]

Even if one looks only at replacing the capacity that is excluded due to MOPR, the costs exceed $1 billion per year. In one of the author's affidavits in the PJM proceeding it was stated "PJM's MOPR-Ex proposal would result in the procurement of roughly $14 billion to $24.6 billion of redundant capacity over roughly the next 10 years. These costs would be borne by PJM customers, translating to a cost of between $216 and $379 for each of the 65 million people in the PJM footprint."[37]

Recently the Independent Market Monitor (IMM), Monitoring Analytics, issued a report on the cost of the new form of MOPR. Monitoring Analytics claims, "the IMM concludes that the December 19th Order is not expected to have an impact on the clearing prices and auction revenues in the 2022/2023 RPM BRA."[38] This analysis seems to assume that FERC will approve the nuclear price floors proposed by PJM, which is not certain as we describe above. The IMM report also did not evaluate cost impacts in subsequent auctions when offshore wind policies take effect, and increasing amounts of RPS-supported resources come online.

The IMM also did not evaluate the effects on self-supply, energy efficiency, demand response, and state resource procurements which were impacted in FERC's rehearing order, issued after the Monitoring Analytics report. The IMM encouraged FERC to limit demand response to those with a verified location and identity, and energy efficiency to verified rather than estimated quantities.[39] The Commission's decision to apply MOPR to energy efficiency and demand response was based in part on the IMM's position: "the Market Monitor has found that both energy efficiency and demand response resources

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33 See, eg, Goggin, Gramlich, Shparber, and Silverstein, Customer-Focused and Clean: Power Markets for the Future, November 2018.

34 Kovanen, Rose, Pande, and Katsigiannakis, *FERC's MOPR Order Will Reshape PJM and Northeast Capacity Markets,* 2020.

35 Hale, "Analysis Finds MOPR Could Cause Collapse in PJM Capacity Market Pricing," February 5, 2020.

36 Charles River Associates, "FERC Directs PJM Capacity Mark Reforms: Progress but Not Certainty," December 2019.

37 Goggin, *Affidavit of Michael Goggin, Grid Strategies LLC on Behalf of the Sustainable FERC Project, Natural Resources Defense Council, and Sierra Club, May 7, 2018*.

38 Monitoring Analytics, *Potential Impacts of the MOPR Order, March 20, 2020.*

39 Monitoring Analytics, *Request for Clarification of the Independent Market Monitor for PJM, January 17, 2020.*

have substantially affected revenues in the PJM capacity market."[40] Right or wrong, these limitations will reduce the quantity of these resources able to participate. The IMM notes that "The IMM does not include detailed Locational Deliverability Area (LDA) prices or cleared quantities in this report for confidentiality reasons." Monitoring Analytics does not fully explain its methods or provide quantitative information about its data and assumptions. Its recommended bid levels have been publicly shared, but it is not clear what FERC will put in place as discussed above.

Potential costs to purchasers of voluntary RECs

FERC's rehearing order agreed with PJM and other protesters that voluntary purchases by consumers were not state subsidies and that resources receiving revenues as a result of voluntary REC purchases should not be subject to MOPR. However the Commission obfuscated this point in two places by saying "The treatment of voluntary RECs in this order is not a determination regarding whether the revenue from voluntary REC transactions results or could result in capacity market distortions."[41] Thus, the Commission appears willing to consider further action to raise the bids for resources earning revenues as a result of voluntary transactions.

Increasingly, large corporate entities are buying renewable energy directly, either unbundled Renewable Energy Credits (RECs), or bundled power purchase agreements (PPAs) that transfer rights to energy and RECs together. The following analysis in Table 6 illustrates, for the given performance assumptions, the approximate increase in the $/MWh price for wind and solar PPAs that would be necessary to compensate for the MOPR preventing a new renewable generator from receiving PJM capacity market revenue. With some recent solar PPAs in the region being signed at around $30/MWh, the MOPR could impose a 50% increase in the cost of purchasing solar energy.

40 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at P. 266, April 16, 2020.*

41 FERC, *Order on Rehearing and Clarification, 171 FERC ¶ 61,035 at fns 807 & 808, April 16, 2020.*

TABLE 6. *Cost impacts on voluntary wind and solar power sales*

SOLAR	WIND	
100	100	*Project size MW*
140	140	*$/MW-day*
20%	40%	*Capacity factor*
50%	13%	*Capacity value*
175,200	350,400	*MWh per year*
$2,555,000	$664,300	*Current capacity market revenue*
$14.58	$1.90	*$/MWh impact on revenue*

CONCLUSION

The consumer costs of MOPR are significant, likely in the billions of dollars. Two factors may reduce the consumer cost estimate in PJM relative to previous estimates: the possibility that FERC will accept lower nuclear and renewable bid levels than what was originally proposed, and FERC's expanded exemption of existing renewable energy projects. Both factors increase the amount of supply in the capacity market that is not subject to MOPR or is able to clear notwithstanding the MOPR, likely reducing the consumer cost relative to previous estimates in the near term. However, MOPR is likely to fully affect offshore wind, and other factors could keep MOPR prices high, such as accelerated renewable energy purchasing to capture expiring tax credits, the potential removal of a significant amount of demand response and energy efficiency, the potential future application to voluntary RECs, application of MOPR to self-supply by vertically integrated utilities, and last but not least, what FERC ultimately decides about bid levels in response to PJM's proposed levels. Bid levels and general MOPR design are moving targets. These factors, especially the offshore wind impact, could impact prices in the near term if not in the next auction. MOPR will impose significant costs on PJM consumers since reversing alleged "price suppression" is the Commission's explicit objective. These costs will only grow over time if states continue to pursue clean energy objectives and FERC does not change its MOPR policy.

APPENDIX A
LACK OF ECONOMIC POLICY BASIS FOR FERC'S MOPR

MOPR reflects a major policy shift that FERC justified on the basis of protecting wholesale electricity markets from the impacts of state policies. More states are enacting policies with increasingly ambitious targets for carbon-free resources, in part due to the lack of federal action on greenhouse gas emissions. FERC has no jurisdiction over these state policies, so it has resorted to a price penalty for states that pursue them. What MOPR does is raise the electricity capacity bids of resources that are deemed to benefit from state policies, increasing costs for consumers and hindering states from achieving their energy policy objectives.

MOPR began as a policy to mitigate "buyer-side market power," and had nothing to do with state environmental policy. Buyer-side market power, or "monopsony power" as it is known in economics, can arise when a large buyer in a market withholds purchasing, or supports entry into the market, in order to suppress prices below competitive levels. In practice, this has been extremely rare. FERC decisions going back 5-10 years found, and the courts agreed, that certain state policies were attempting to do that, and action was required to prevent wholesale market impacts.[42] MOPR replaces the bids of the generating unit tied to the state policy with a minimum bid level that is deemed by FERC to be competitive (an estimate of what the unsubsidized level would have been).

With FERC's recent orders, the Commission has expanded MOPR from a surgical fix for specific potential exercises of market power to applying across the entire market to any state policy that incentivizes generation. FERC Commissioner Glick has dissented from this view from the start, saying "Broad application of the MOPR usurps the authority over generation resource decisions that Congress left to the states when it enacted the Federal Power Act (FPA). The better course of action would be for the Commission and the RTOs/ISOs to stop using the MOPR to interfere with state public policies and, instead, apply the MOPR in only the limited circumstance for which it was originally intended: to prevent the exercise of buyer-side market power."[43]

Renewable energy resources incentivized by state policies had been exempt from MOPR until this recent change in FERC policy. FERC typically found that state renewable energy policies were not plausible means of exercising buyer market power, because support of renewable energy resources would be an ineffective means for states to lower capacity prices, given their relatively small capacity value.[44] However, FERC recently eliminated such exemptions in ISO New England, New York ISO, and PJM.[45]

The effect of broad MOPR application to state-supported resources is to significantly hinder their participation in the capacity market and raise capacity prices. By artificially raising suppliers' bids, MOPR tends to raise market-clearing prices and causes consumers to pay for redundant capacity—customers first pay for the construction of resources through state policy, but when those resources are unable to clear the capacity market due to the MOPR, customers are forced to buy an equivalent amount of capacity that does clear in the capacity market. FERC itself has acknowledged this harm, but has downplayed its significance in recent decisions.[46] This extra capacity is unnecessary because the state-supported resources continue to exist and provide physical capacity, despite being subject to the MOPR. As the market monitor for New York and New England has stated, "[t]he MOPR in this case is likely to significantly increase costs for New England's consumers. It can also cause conventional new resources to clear the [Forward Capacity Auction] inefficiently by preventing higher-cost renewables from clearing (even though they are committed to entering)."[47]

Broad MOPR application to state policies does not recognize that many state policies are themselves designed to correct market failures. A state may consider environmental impacts from fossil fuel electricity generation to be an externality cost to society that should be internalized, consistent

42 *Hughes v. Talen Energy Marketing LLC*, 136 S. Ct. 1288 (2016).

43 Glick dissent to *Order on Tariff Filing*, 162 FERC ¶ 61,205, p. 1, March 9, 2018.

44 "We find that the Complainants have demonstrated that NYISO's Services Tariff is unjust, unreasonable, or unduly discriminatory or preferential, pursuant to section 206 of the FPA, because it applies buyer-side market power mitigation to certain renewable and self-supply resources that have limited or no incentive and ability to artificially suppress ICAP market prices. This finding is consistent with the Commission's generally-applied minimum offer price rule policy; specifically, that buyer-side market power mitigation rules are intended to address market power exhibited by certain entities seeking to lower capacity market prices." See FERC, *Order on Complaint and Directing Compliance Filing*, 153 FERC ¶ 61,022 at P. 10, October 9, 2015, citing ConEd Complaint Order, 150 FERC ¶ 61,139 at P. 2: "we find that intermittent renewable resources with low capacity factors and high development costs, including many wind and solar resources, narrowly defined, provide their developer with limited or no incentive and ability to exercise buyer-side market power to artificially suppress ICAP market prices." (Par. 47)

45 FERC June 2018 Order on PJM Capacity market: "We find it unjust and unreasonable, and unduly discriminatory or preferential, for a resource receiving out-of-market payments to benefit from its participation in the PJM capacity market, by not competing on a comparable basis with competitive resources." FERC, *Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act*, 163 FERC ¶ 61,236 at P. 66, June 29, 2018, FERC, *Order on Tariff Filing*, 162 FERC ¶ 61,205, March 9, 2018, and FERC, "FERC Approves Market Rules to Protect Competition, Supplies in NYISO," February 20, 2020.

46 PJM, *Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act*, 163 FERC ¶ 61,236 at P. 159, June 29, 2018.

47 Patton, *Comments of David B. Patton, Ph.D Regarding State Policies Affecting Eastern RTOs*, p. 4, April 24, 2017.

with standard economic theory. In this case, policies compensating resources for clean attributes enhance rather than detract from market efficiency, as explained by scholars at the Institute for Policy Integrity.[48]

FERC did not and has not explained how a broad MOPR is consistent with decades of regulatory policy regarding what is a "just and reasonable" rate in a market. FERC policy has been clear that a just and reasonable rate in a market is the price where demand and supply intersect, as long as market power is absent or mitigated. This has been the general framework established by FERC and the courts since electricity competition began in the early 1990s.[49,50,51] This standard calls for careful identification of market power, and tailored mitigation to address it. FERC's order is not based on a finding of market power, and there was no information in the record on which to base such a finding.

FERC mitigation of state policy also violates its obligation to avoid over-mitigation.[52] The courts have reined in the Commission when it fails to carefully identify market power and tailor mitigation to the action constituting an exercise of market power. Market power analysis requires a demonstration of an incentive and ability to exercise market power. Such demonstrations of market power are not present in the recent FERC proceedings where broad MOPR has been applied. While it is widely accepted that RTOs have an appropriate role in mitigating generation (seller) market power, these programs are based on well-defined structural market failures such as pivotal supplier situations. Correctly or incorrectly, extensive market power analysis and regulatory proceedings were undertaken to balance over- and under-mitigation. No such effort has been made for broadly applying mitigation to buyer-side market power.

FERC's recent orders abandoned its previous attempts to accommodate state policy. In 2018 FERC had proposed a potential workaround to the adverse impacts of a broad MOPR, in the form of a carve-out for state-supported resources called a "Fixed Resource Requirement-Resource-Specific" (FRR-RS). In the FRR-RS, a load-serving entity could undertake direct bilateral purchases of capacity from state-supported resources subject to MOPR, and correspondingly reduce the amount of capacity it needs to buy through PJM's centralized market. The Commission instituted this approach to accommodate state policy and allow state-supported resources a means of selling capacity. Similarly, in approving ISO-New England's CASPR approach, the Commission was trying to accommodate state policy and provide capacity compensation for resources that provide it. However in the December 2019 order, FERC abandoned all attempts to accommodate state policy.

These issues of over-mitigation, absence of any demonstrated market power, arbitrary and capricious departure from court- and FERC- policy of just and reasonable rates, targeting FERC intervention directly at state policies that are not in FERC's jurisdiction, and lack of accommodation of state policy will all be reviewed by the courts in coming months and years.

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48 Bialek and Unel, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms*, April 2018.

49 *Elizabeth Gas Co. v. F.E.R.C.*, 10 F. 3d. at 870 (DC Cir. 1993),

50 "[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." See *Tejas Power Corp. v. F.E.R.C*, 908 F.2d 998, 1004 (D.C. Cir. 1990).

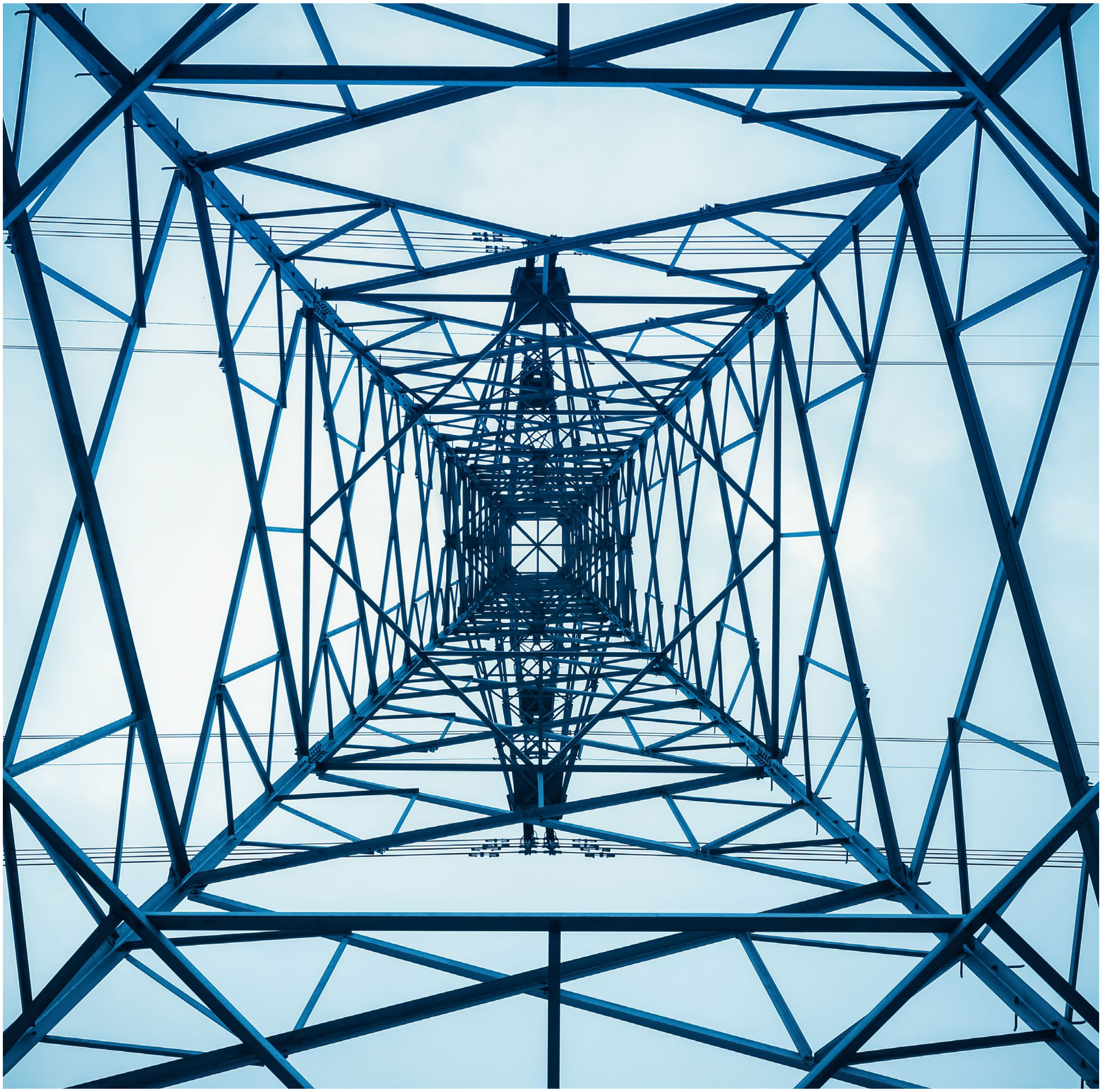
51 Gramlich, "The Role of Energy Regulation in Addressing Generation Market Power," Environmental & Energy Law & Policy Journal, Volume 1, No. 1, March 31, 2006.

52 *Edison Mission Energy INC v. Consolidated Edison Company of New York, Inc., et al., Intervenors*, 394 F.3d 964 (D.C. Cir. 2005): "[Mitigation] may well do some good by protecting consumers and utilities against... the exercise of market power. But the Commission gave no reason to suppose that it does not also wreak substantial harm."

APPENDIX B

RENEWABLE RESOURCES EXEMPTED BASED ON THE EXISTING RPS EXEMPTION

	UNMET RPS DEMAND THROUGH 2030		CAPACITY WITH SIGNED CSA		NET REMAINING (RPS DEMAND - CSA SUPPLY)	
	MW NAMEPLATE	MW UCAP	MW NAMEPLATE	MW UCAP	MW NAMEPLATE	MW UCAP
NJ generic RPS, wind	2440	271	1012	112	1428	158
NJ generic RPS, solar	1545	766	484	240	1062	527
NJ solar carveout	2598	1288	132	66	2465	1223
NJ offshore wind	3500	910	0	0	3500	910
VA offshore wind	2427	631	0	0	2427	631
VA solar	3022	1499	0	0	3022	1499
VA wind	4771	530	0	0	4771	530
Incremental IL RPS demand 2019-2030, wind	911	101	378	42	533	59
Incremental IL RPS demand 2019-2030, solar	2015	999	630	313	1384	686
Other PJM state RPS demand, wind	3208	356	1331	148	1877	208
Other PJM state RPS demand, solar	8612	4271	2695	1337	5916	2934
MD wind	2082	231	864	96	1219	135
MD solar	4675	2319	1463	726	3212	1593
MD offshore	1568	408	248	64	1320	343
TOTAL	**43373**	**14580**	**9237**	**3143**	**34136**	**11437**



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