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FERC directs PJM capacity market reforms: Progress but not certainty

On December 19, 2019, the Federal Energy Regulatory Commission (FERC) directed PJM to expand the Minimum Offer Pricing Rules (MOPR) to a broad range of subsidized resources, both new and existing. The Commission reasoned that this will protect the PJM capacity market from the effect of state subsidies for preferred generation. Key takeaways include the following:

- FERC directed PJM to implement a MOPR to both new and existing resources, with exemptions for certain existing subsidized resources, though not extending to conventional, non-self-supply resources (e.g., coal and nuclear units benefitting from state action in Illinois, Ohio, and New Jersey).
- 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.
- Expected legal challenges and state responses make the long-term outlook highly uncertain. The legal substance of FERC's Order will likely be reviewed on appeal, particularly the sensitive topic of the interplay between state decisions and FERC jurisdictional wholesale rates. Conflict on this issue may also drive states to further action, which could include requiring load service entities (LSEs) to withdraw from the reliability pricing model (RPM) or leaving the PJM market altogether.
- FERC, PJM, and its stakeholders will now begin to interpret and implement the Commission's directives, a process that may be contentious and result in further delay. In the most optimistic of scenarios, capacity market operations could restart as soon as late 2020.

Background and directives

After considerable controversy and delay, FERC has directed a path forward for PJM with respect to reforming its capacity market, the Reliability Pricing Model (RPM). The underlying issue, which has been festering in the PJM market since at least 2016, is the interplay between state policies affecting favored generation resources and the FERC-jurisdictional RPM market. Following a series of complaints related to the effect of subsidized resources on capacity market prices and several proposals put forth by PJM to address said concerns, in June 2018 FERC found that PJM's

capacity market rules needed to be revised. In doing so, FERC initiated a process by which it would gather input from stakeholders and then, itself, determine the appropriate remedy that PJM would then be required to implement. All input was received by early November 2018. However, owing to a shifting Commission makeup, to issues with quorum and recusal, and to the challenging economic, political, and legal substance of the proceeding, no final decision was made until the end of 2019.

What's in the Order

In its Order,[1] the Commission directed PJM to remedy the issues identified by expanding the MOPR mechanism to include a broader range of resources, similar to the "MOPR-Ex" proposal that was initially presented by PJM. Originally a tool to fend against the exercise of buyer-side market power, the MOPR has long been suggested as the tool by which state subsidies can be addressed. The new, expanded MOPR will now apply to all subsidized resources, new and existing. The idea is that, by constraining the ability of capacity resources to include subsidies in their bid formulation, the capacity market will ostensibly produce prices that would have prevailed in the absence of any state action. Resources that are subject to the MOPR – or, colloquially, those that are "MOPR'ed" – will not be allowed to offer capacity into an RPM auction at a price level below the applicable, administratively-determined reference prices, or "default offer price floor." Reference prices are to be developed on a technology-specific basis, with floor prices for existing resources based off of a Net Avoidable Cost Rate (Net ACR) and floor prices for new resources based off of the Net Cost of New Entry (Net CONE). There are no mechanical changes required to the RPM auction mechanics.

In addition to exempting Federal subsidies entirely, FERC directs PJM to also implement three new categorical exemptions to resource types to which the MOPR will not apply:

1. Existing self-supply resources;
2. Existing demand response, energy efficiency, and storage resources; and
3. Existing renewable resources participating in RPS programs.

These new categorical exemptions will live alongside the existing Competitive Exemption, which allows any new resources that are not subsidized to avoid MOPR treatment. There will also be a unit-specific exemption process, by which any resource subject to the MOPR may justify a competitive offer below the relevant MOPR price floor by demonstrating justified, non-subsidy-adjusted going forward costs. Notably absent from the list of exemptions, and the resource types most likely to be impacted by the changes are:

- Existing coal and nuclear resources currently receiving subsidies (particularly in Illinois, New Jersey, and Ohio) or vying to receive state subsidies in the future;
- New or future self-supply resources, like those developed by vertically integrated utilities, municipal utilities, or electric cooperatives; and
- New or future renewable resources participating in RPS programs, as well as any new or future demand response, energy efficiency, or storage resources that are deemed to receive a subsidy.[2]

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1 https://ferc.gov/whats-new/comm-meet/2019/121919/E-1.pdf

2 Note that new vs. existing subsidies are delineated as of the date of the Commission's Order.

What's not in the Order

Given the broad range of possible outcomes and reforms considered in this docket to date, it is also worth considering what the Commission did *not* order:

- **No materiality threshold:** There is no exception for resources below a certain size, nor for subsidies below a certain amount. FERC reasons that even small subsidies can, in aggregate, have a significant impact on the market. Also, the Commission reasons that the unit-specific exemption process should provide flexibility such that resources receiving small subsidies will still clear if they are able to perform economically without the subsidy.
- **No repricing:** Various proposals considered as part of this docket included a repricing step of one form or another, generally creating a second auction run wherein subsidized resources would be entered at a mitigated offer level, therefore resulting in a higher price for the "pricing run" of the auction. No such step is required here. Repricing would likely have added complexity to the market, making price forecast efforts less reliable, while also requiring the development of legal and economic reasoning to support an auction format that establishes the quantity procured at one step and the prevailing price at another.[3]
- **No resource-specific carve outs:** Several options available to the Commission, including one suggested in the June 2018 Commission order, included the expansion of the Fixed Resource Requirement (FRR)[4] rule set to include resource-specific arrangements. Setting aside the merit of such rules, they would have created new and multifaceted concerns around state-jurisdictional contracts that would have needed to be established to facilitate matching of load and generation on a relatively granular basis. The pre-existing LSE-wide "all-or-nothing" FRR rules will persist.

A broad definition of "subsidy"

A lot is likely to hinge on how FERC has defined "subsidy" for the purpose at hand. In its December 19 Order, FERC defines subsidies as follows:

> *A direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) 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 (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction.*[5]

To observe that this is a very broad definition of subsidy would probably be accurate. As an initial

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[3] Substantively distinct from repricing, some intervenors had suggested implementing a secondary auction by which existing resources could sell out of their capacity market positions to make way for new, subsidized resources. This would have been similar to ISO-NE's structure of Competitive Auctions with Sponsored Resources (CASPR). FERC required no such change in PJM.

[4] PJM's Fixed Resource Requirement rules allow an LSE to effectively self-schedule for their resource adequacy needs, provided the LSE identifies sufficient generation to fulfill the *entire* resource adequacy requirements of all of its load. The all-or-nothing aspect of the current FRR rules is a major differentiator between the status quo and the unit-specific rules that were proposed during this proceeding.

[5] Order, 169 FERC ¶ 61,239 at P 65.

matter, PJM will be required to interpret FERC's words and determine how to apply them in practice. This will be an ongoing source of uncertainty. However, a more inclusive reading could include all of the following, as pointed out by FERC Commissioner Glick in his dissent:

- Generation of the types identified above, including existing subsidized coal and nuclear units, all future generation developed by vertically integrated utilities and public power entities, and any future subsidized renewables, demand response, energy efficiency, and storage
- All new or incremental resources that sell renewable energy certificates (RECs), whether they are tied to voluntary programs (e.g., those associated with corporate carbon reduction targets) or mandatory compliance (e.g., RPS)
- Any resources that receive state and local tax benefits, like property tax exemptions, tax breaks for preferred fuel types, or other preferred tax treatment
- Any resource that benefits, however indirectly, from state participation in a carbon pricing program like the Regional Greenhouse Gas Initiative (RGGI). Affected states would include Maryland, Delaware, and New Jersey, and with Virginia and Pennsylvania as potential future participants. Not only could this sweep up all generators in those states (or beyond, given that PJM is a regional market), quantifying the specific impact on each resource would be complex
- Any generation that participates in state-mandated processes, like New Jersey's Basic Generation Service Electricity Supply Auction or any other provider-of-last-resort auctions
- Not only resources that receive an incentive, but those that are *eligible* to receive incentives but opt not to

On compliance, we expect that not all of these resource classes are ultimately swept up in the definition of subsidy, but predicting which ones PJM will succeed in including or excluding is premature.[6] And not all included resources will necessarily be mitigated to a level that will lead them to not clear in the RPM auctions. If the resource-specific showing process is structured effectively, a broad range of resources may be able to justify capacity offers very similar to those allowed before the instant reforms. However, the administrative burden is likely to be high, both for market participants and for PJM and its market monitor.[7] Relatedly, the level of administrative intervention in the market is likely to rise considerably, as the above resource types effectively constitute what is likely a significant fraction of the overall resources available in the market. PJM and its market monitor will therefore have a hand in determining what constitutes an acceptable bid for a much larger group of market participants. To the extent that these market participants are unhappy with this outcome – either the administrative burden or the possibility that they will fail to clear due to mitigation – the Commission has also, by defining "subsidy" so broadly, effectively created a very large and diverse constituency of aggrieved parties, who may pressure the Commission in the written record, in the courts, and via political channels, to change course in their approach.

Expected market impacts and possible state response

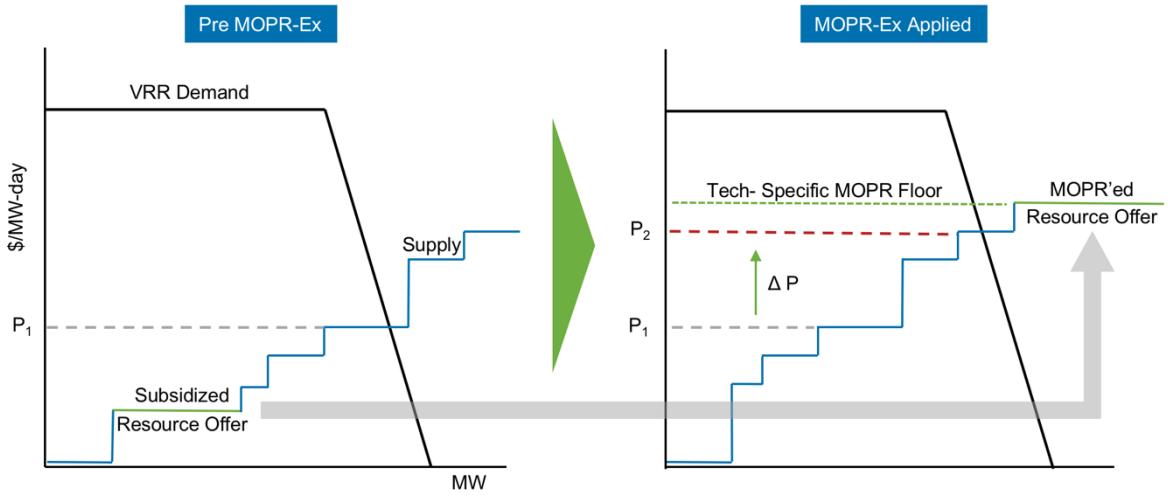
Consistent with the overarching concerns of addressing the "price suppressive" impacts of state subsidies in the PJM capacity market, we expect the immediate, near-term impact of the ordered reforms to be upward pressure on RPM prices (setting aside any state responses, discussed later). This will occur as a result of two primary dynamics. First, several thousand MW of existing

6 Even after compliance is complete, it is foreseeable that the Commission will receive regular FPA Section 206 complaints requesting adjudication of whether certain state and local government programs, new or ongoing, should be classified as a subsidy.

7 To the extent the market monitor is involved in reviewing exemption requests.

subsidized coal and nuclear generation in Illinois, New Jersey, and Ohio is likely to be MOPR'ed such that their mitigated prices lead them not to clear the auction. This reduction in available capacity that previously cleared the auction will drive up market prices across the PJM footprint. This dynamic is illustrated in Figure 1. Second, to the extent that new self-supply resources, subsidized renewables, or subsidized demand response, energy efficiency, or storage resources would have entered the market, their entry may be now be delayed owing to limitations of submitting offers low enough to clear the auction. Again, such resources that would have entered low on the supply curve will not do so, which will reduce future downward pressure on prices.

Figure 1: Stylized illustration of the application of the MOPR-Ex rules to an existing, subsidized, infra-marginal resource. In this case, the application of the MOPR is sufficient to move the resource to a position in the supply stack where it fails to clear the auction. The clearing prices shifts from P_1 to P_2 and the market clears a smaller volume of capacity.



Source: CRA analysis

Secondary effects and potential oversupply

The proposed reforms are likely to have a range of secondary economic effects. Potentially the most significant result is that the PJM footprint will now have a bifurcated system of resource procurement. RPM will continue to exist for all resources to ensure resource adequacy for the market as a whole, but it will primarily procure resources that are not subject to the MOPR, as many of those resources – particularly those receiving significant subsidies – are likely to be effectively priced out of the auction. Alongside RPM will operate a range of state-subsidized resources – including renewables and self-supply resources – that do not clear in the auction but are developed nonetheless to serve state policy and utility planning objectives.

From a consumer standpoint, we would expect that the result is duplicative procurement, and therefore duplicative costs that need to be recovered. This specter of double payment was raised by multiple intervenors in this FERC proceeding. The more existing, subsidized coal and nuclear generation remains in service, the more acute this problem will be.

From a market standpoint, the result is that the PJM footprint is likely to be oversupplied in aggregate, with reserve margins well in excess of those targeted by RPM auctions. This capacity oversupply will lead to a glut of generation available to the energy and ancillary services markets,

which will drive down prices in those markets. In a possibly perverse result, these lower energy and ancillary service revenues are likely to drive down expected margins, which in turn will drive up the amount of missing money in the PJM marketplace, thereby placing further upward pressure on capacity market prices and increasing the region's reliance on the capacity market in general.[8] Reduced expected margins will also drive up Net CONE estimates, driving up the variable resource requirement (VRR) curve and again leading to higher expected RPM prices.

Possible state reactions

It is also likely that there will be state legislative responses to the FERC-mandated reform. An already well-developed example is in Illinois, where the state legislature is poised to direct utilities operating in its state and in PJM (ComEd) to employ the "full" FRR option in its service territory, effectively carving the ComEd zone out of PJM for the purposes of the capacity market. As proposed, the Illinois Power Authority would then run its own procurement(s) for resource adequacy in the relevant portions of the state. This would allow Illinois to continue to support the at-risk nuclear units in the state – as it has been via its existing zero emission credit (ZEC) program – while also ensuring that Illinois ratepayers are not required to procure duplicative capacity. Interestingly, because of the nature of the ComEd zone as an importer of capacity under the prior market design, this would likely drive down prices across the rest of PJM as "export demand" to ComEd declines.[9] Other states could follow suit, particularly those with significant clean energy targets, existing or planned coal and nuclear subsidies, or those with vertically integrated utilities operating in the state. It is also possible that FERC's proposal will be considered sufficiently offensive to some states and their interests in exercising influence over generation decisions in their state that they could leave PJM altogether.

The path from here

As several Commissioners noted at the December FERC open meeting, this order was issued more than 500 days from when it was first promised, and nearly a year has elapsed since the Commission's target issue date. Unfortunately, the timeline going forward is far from evident. In the best case scenario, PJM is able to file, without requesting an extension, a compliance filing on the Commission's proposed 90-day clock. This filing will then initiate what is likely a 60-day action clock for the Commission to receive comments – and there will be many of them – and act to approve or reject PJM's proposed tariff changes on compliance. If PJM threads the needle and its compliance filing is consistent with what the Commission expected, FERC could conceivably act by late May to approve the revised RPM rules. Given the complexity of implementing the Commission's mandate, the need to elaborate on unclear ordering provisions, and the delays that have been experienced at every turn in this process, such expedience seems unlikely.

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8 We consistently advise clients to emphasize the importance of continually improving and increasing reliance on energy and ancillary services markets. Capacity markets are fundamentally supplemental, administrative constructs. They are prone to political and regulatory capture and have proven both controversial and difficult to administer. Thus, it should be a constant goal of market operators, market oversight entities, and market regulators to improve the efficiency of price signals from the energy and ancillary service markets to minimize the quantity of missing money, thus shrinking necessary capacity payments and limiting reliance on the capacity market. The smaller the payments available, the less time and energy will be spent debating the effects of arcane market rules, and the less effort will be expended in rent seeking efforts and regulatory responses thereto.

9 Monitoring Analytics, "Potential Impacts of the Creation of a ComEd," December 18, 2019. FRRwww.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf.

Possible auction timelines

Once the Commission gives PJM the green light on a complete set of tariff provisions, PJM will then need to implement those provisions. PJM will likely submit a proposed implementation schedule, which could range in duration. Using PJM's recent filings as a guide, in its initial "jump ball" filing in this proceeding, PJM requested at least 150 days between the tariff effective date and the auction date. This time is necessary to allow preparation for the auction by both the market operator and market participants, and is likely to be particularly essential in order to process the potentially considerable volume of unit-specific exemptions that could result from the new market rules, as ordered. Altogether, under a most optimistic of timelines, the 2022/23 BRA would likely be delayed until the very end of 2020.[10]

As PJM proposes the timeline for the 2022/2023 BRA, the 2023/24 is certain to be affected, and the 2024/25 auction may be as well. The 2023/24 BRA, under normal circumstances, would have been held in May 2020. It cannot now be held until after the revised RPM rules are finalized and the 2022/23 BRA is complete. Thus, that auction will almost certainly need to be delayed until early 2021. The Commission, PJM, and its stakeholders will need to grapple with the implications of holding multiple BRAs in quick succession, and the economic and potential market manipulation ramifications thereof. If it is determined that holding three BRAs in as few as six months is problematic, there may also be need to push back the 2024/25 BRA from its May 2021 scheduled date to some later time.

Destined for appeal

Finally, all of the above assumes no intervention by the courts on appeal. If there is one thing that is certain about FERC's recent order, it is that it is destined for appeal. Without wading into the legal substance, the subject matter of this proceeding straddles the complex and porous relationship between state and federal jurisdiction over appropriate regulation around electric generation, and the interplay between state decisions and FERC jurisdictional wholesale rates. The Commission's findings are likely to test the application of at least three recent Supreme Court cases: *Hughes v. Talen*, *FERC v. EPSA*, and *Oneok, Inc. v. Learjet, Inc.* Moreover, as described above, by virtue of how the Commission has made its finding here, it has likely created a broad and influential coalition of aggrieved parties who may challenge the Commission's determination. Surely, this reality will not accelerate the process towards wrapping up the docket.

[10] At some point during this timeline, PJM will also need to develop, and have reviewed and approved, technology-specific reference levels for Net CONE and Net ACR for a range of resources that had not formerly been considered for MOPR-style mitigation.

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