

ATTACHMENT A

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FRR Obligation, Internal Requirements and Capacity of Resources Subject to MOPR

In an effort to understand how well the FRR could enable a resource adequacy structure aligned with state policy, we quantified the existing and incremental (by 2030) resources subject to the minimum offer price rule, by New Jersey zone, and compared these to the FRR obligations and internal resource requirements of different potential FRR service areas.

FRR Obligation and Internal Requirement vs. UCAP of Resources Subject to MOPR

	PSEG	JCPL	AECO	RECO	Notes
FRR Obligation (UCAP MW)	10,225.1	6,134.8	2,509.5	415.9	[1]
Within Zone (UCAP MW)	4,110.5	-	-	-	[1]
Within EMAAC (UCAP MW)	8,333.5	4,999.9	2,045.2	338.9	[1]
Existing Nuclear (UCAP MW)	3,397.8				[2]
Incremental Solar (UCAP MW)	332.4	699.8	717.3	-	[3]
Incremental Offshore Wind (UCAP MW)	-	473.2	436.8	-	[4]
Incremental Storage (UCAP MW)	882.0	313.6	764.4	-	[5]
<i>RPS wind assumed to be out of state</i>					
Total Internal Resources by 2030 Subject to MOPR (UCAP MW)	4,612.1	1,486.6	1,918.5	-	
Capacity Share by Zone from PJM Interconnection Queue					[6]
<i>Solar (inc. Solar + Storage)</i>	19%	40%	41%		[6]
<i>Storage (Standalone)</i>	45%	16%	39%		[6]
<i>Offshore Wind</i>		52%	48%		[6]

Notes

[1] Based on 2022/23 Planning Parameters

[2] Hope Creek 1, Salem 1-2 from 2022/23 planning model, assumed 98% capacity value.

[3] Assumes 3527 MW of incremental solar to meet RPS Tier 1 and Solar Carve Out (based on Gramlich, "A Moving Target," May 2020) , with 49.6% capacity value

[4] Assumes 3500 MW of offshore wind (NJ Offshore Wind Target), with 26% capacity value

[5] Assumes 2000 MW storage (NJ Storage Target) with 98% capacity value

[6] Calculated share of MW of Active, Engineering and Procurement, In Service and Under Construction interconnection requests in NJ.

The FRR obligation and internal resource requirements were developed based on 2022/23 planning parameters published by PJM, while the resources subject to MOPR were estimated as follows.

For existing nuclear units, we applied a 98% capacity value to the ICAP listed in PJM's 2022/23 RPM resource model. For solar, we used an estimate for incremental solar capacity in NJ of 3527 by 2030,¹ and assumed that solar resources were distributed across the state in proportion to the capacity in the PJM interconnection queue for solar and solar plus storage resources. For offshore wind and storage, we assumed the state targets of 3500 MW offshore wind and 2000 MW of storage were distributed in proportion to capacity of those resources in the PJM interconnection queue (storage was assumed to be in proportion to stand-alone storage interconnection requests). A 49.6% capacity value was applied to solar, 26% to offshore wind, and 98% to storage.² Onshore wind used to meet New Jersey's RPS goals was assumed to be out of state, consistent with assumptions in the 2019 Energy Master Plan.

This analysis shows that by 2030, it's possible that resources subject to MOPR are able to meet the entire internal capacity requirement in the PSEG zone. The other zones are not constrained to meeting their FRR obligation with within-zone resources, but a substantial portion of the total requirements in JCPL and AECO may also be met with incremental renewable energy.

¹ Michael Goggin and Rob Gramlich, *A Moving Target: An Update on the Consumer Impacts of FERC Interference with State Policies in the PJM Region* (May 2020), <https://gridprogress.files.wordpress.com/2020/05/a-moving-target-paper.pdf>.

² *Id.*

ATTACHMENT B

WHETHER TO FRREXIT:

INFORMATION STATES NEED ON THE COSTS AND BENEFITS OF DEPARTING THE PJM CAPACITY CONSTRUCT

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MAY 2020

ACKNOWLEDGMENTS

The authors thank the Sustainable FERC Project for support in this work, Jesse Schneider of Grid Strategies for research support, and Jim Wilson and Casey Roberts for helpful review and comments.¹

FERC'S MOPR IS CAUSING STATES TO CONSIDER ALTERNATIVES TO THE PJM CAPACITY CONSTRUCT

In a series of recent orders, the Federal Energy Regulatory Commission has sought to insulate the PJM capacity market from the effects of certain state policies it has deemed “subsidies.”² The orders expand the use of the Minimum Offer Price Rule (MOPR), applying an administratively set offer floor to any resource that receives or is entitled to receive a state subsidy. The order extends MOPR to a wide range of resources, including new energy efficiency, demand response, wind, solar, offshore wind, and nuclear resources supported by state programs, resources procured by public power entities, and resources that secure contracts to sell to end-use customers pursuant to state-sanctioned basic generation service auctions.³

Applying MOPR to such a wide range of resources will raise costs for customers in PJM to the extent it raises market clearing prices by causing higher priced supply offers to meet demand, and to the extent it forces customers to support the construction or retention of redundant capacity by causing “state subsidized” resources to fail to clear in the capacity market. MOPR also threatens the achievement of state policy goals, and complicates the administration of state processes such as basic generation service auctions. The precise impacts to the market are not yet clear, as they depend both on market dynamics, and on how FERC rules on PJM’s pending compliance filing.⁴ However, it is clear that some resources such

1 The information contained in this publication should not be construed as legal advice. Should further analysis or explanation of the subject matter be required, please contact the lawyer with whom you normally consult.

2 FERC, *Order Rejecting Proposed Tariff Provisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act*, 163 FERC ¶ 61,236, June 29, 2018; FERC, *Order Establishing Just and Reasonable Rate*, 169 FERC ¶ 61,239, December 19, 2019; and FERC, *Order on Rehearing and Clarification*, 171 FERC ¶ 61,035, April 16, 2020.

3 FERC, *Order on Rehearing and Clarification*, 171 FERC ¶ 61,035, at P. 54, April 16, 2020.

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

as offshore wind and energy storage will be impacted by the rule, and that costs will grow over time as the amount of state-supported resources that are effectively blocked from selling in the PJM capacity market increases.⁵

Given these impacts, states are seeking to better understand the magnitude of the likely cost consequences for customers, and considering alternatives to full participation in PJM's centralized capacity auction, the Reliability Pricing Model (RPM), including use of the Fixed Resource Requirement (FRR) option provided for in PJM's tariff.⁶ This report seeks to help states assess the consequences of adopting FRR, reviews recent cost estimates of FRR produced by Monitoring Analytics, PJM's Independent Market Monitor, and discusses FRR design choices states may make.

Monitoring Analytics provides data and a framework for states to use in considering the consequences of FRR. But we caution stakeholders in placing any confidence in the price estimates arrived at by Monitoring Analytics. As explained below, Monitoring Analytics' scenarios are based on an erroneous assumption that utilities would pay generators located inside and outside constrained capacity zones the same price, despite the fact that the external generators would be willing to receive a lower price as they do in PJM's RPM. While it is difficult to predict prices of FRR given the many unknown market dynamics and design features of FRR, we believe a different set of assumptions would be more reasonable in estimating prices, and we urge states to request modeling of additional scenarios so as to paint a more complete picture of future market results that may be driven by FRR. While there are challenges in implementing FRR that deserve careful consideration, FRR also brings several benefits that offer the potential to lower costs for customers.

BACKGROUND

FRR Provides an Option to Opt Out of PJM's Centralized Capacity Market Auction

The PJM tariff provides an opportunity for a utility to opt out of PJM's RPM, and instead handle procurement for its own resource adequacy needs. This opt out option is called the Fixed Resource Requirement Alternative (FRR), and rules for invoking and implementing it are set forth in the PJM Reliability Assurance Agreement (RAA).⁷ Other regions do not have FRR-like provisions; it is unique to PJM. Given state concerns with how state-supported resources are treated in the RPM, naturally they are considering the pros and cons of FRR.

FRR does not modify the resource adequacy requirements or the reserve sharing efficiencies that underlie the RPM. Under FRR, reserve margins based on technical reliability assessments as assessed across the full region are still in place on all entities. Likewise, the capacity value of specific resource types, and the performance requirements associated with a capacity obligation are the same in RPM and FRR.

5 Together, state policies in the PJM region call for the construction of approximately 7,127 megawatts of offshore wind by 2030 and an additional 6,773 megawatts by 2035. See NJ Department of Environmental Protection, "Offshore Wind In New Jersey," n.d., Morehouse, "Maryland 50% RPS Bill Doubles Offshore Wind Target, Expands Solar-Carve Out," Updated May 22, 2019, and Kirkland & Ellis, "Clean Energy Legislation Arrives in Virginia - Will It Become Law This Week?" April 7, 2020. (We assume 7/15 of Virginia's 2035 offshore wind targets will be met by 2030).

6 See Morehouse, "Maryland Taking a 'Serious Look' at Exiting PJM Capacity Market Through FRR, Says PSC Chair," April 29, 2020, Walton, "New Jersey Looks to Exit PJM Capacity Market, Worried MOPR Will Impede 100% Carbon-Free Goals," March 31, 2020, and Beattie, "Five PJM States Suggest FERC Order Could Prompt Exit from Regional Market," January 30, 2020. Non-PJM states are also considering capacity market exit, for the same reasons. See Letter to Gordon van Weillie, President and CEO, ISO New England, from Katie S. Dykes, Commissioner Connecticut Department of Energy and Environmental Protection, January 15, 2020, and comments in the New York Department of Public Service's *Proceeding on Motion of the Commission to Consider Resource Adequacy Matters*.

7 PJM, *Reliability Assurance Agreement Among Load Service Entities in the PJM Region (RAA)*, Schedule 8.1, September 17, 2010.

The FRR change is limited to the means of procuring the requisite capacity and the prices paid. Entities can exit the RPM and utilize the FRR, while remaining part of PJM for its energy market and transmission planning benefits.⁸

Contrary to Monitoring Analytics' claim that PJM's RPM is a "market" and FRR is a "non-market" approach, the RPM is a single-buyer structure properly considered a competitive procurement rather than a market where wholesale buyers are able to make their own choices as they do in SPP, MISO, ERCOT, and CAISO. Markets have many buyers as well as many sellers. An FRR could be designed as a single buyer competitive procurement or a many buyer structure that would be closer to a market as discussed below.

FRR Requires Capacity Procurement Plans to Be Developed for Applicable Service Areas

A utility that elects to implement FRR is generally responsible for developing a capacity plan that satisfies the resource adequacy obligations of all load in its service area,⁹ but PJM's tariff also provides some flexibility for states to establish rules for broader statewide capacity procurement plans.¹⁰

Unlike the PJM centralized RPM auction process, which procures capacity according to a sloping demand curve and tends to yield an amount in excess of the minimum reserve margin, FRR quantities are set at the fixed capacity reserve margins for applicable utilities.¹¹ While RPM typically clears capacity that results in around 22% reserve margin, FRR plans must only meet the Installed Reserve Margin target of 15 to 16%.¹²

FERC's Minimum Offer Price Rule does not apply to capacity sales offers to entities that have elected to use the FRR. Thus, an offshore wind resource supported by a state policy, for example, would be free to sell low-cost capacity to an FRR entity.

EVALUATING MONITORING ANALYTICS' ANALYSIS OF FRR COSTS

Whether consumers benefit or lose money with an FRR has been the subject of studies by Monitoring Analytics.¹³ These reports provide useful information to states as they evaluate FRR by, for example, explaining the mechanics of FRR and detailing how much capacity must be purchased for different possible FRR service areas and what percentage must be sourced internally. The reports also provide cost estimates of FRR under different price scenarios. Monitoring Analytics has publicly argued that these studies provide a basis for concluding that FRR would be more expensive than continued reliance on RPM.¹⁴ But as explained below, the reports' cost estimates risk confusing or even misleading states to the extent they suggest confidence that FRR will yield higher prices than continued reliance on PJM's RPM. While it is difficult to predict capacity prices that would result from implementation of FRR in one or more

8 Operating and planning systems across wide areas significantly increases reliability and lowers cost, especially when the system has a large amount of renewable resources. See Goggin, Gramlich, Shparber, and Silverstein, *Customer Focused and Clean: Power Markets for the Future*.

9 PJM, *RAA*, Schedule 8.1.D, September 17, 2010.

10 An FRR service area may be designated as the service territory of the applicable utility, or according to boundaries set by state law or regulation. See PJM, *RAA*, Article 1 & Schedule 8.1.I, September 17, 2010.

11 In other words, FRR uses a vertical demand curve. While RPM has recently cleared at a 22%, FRR entities would be required to meet a roughly 15% reserve margin.

12 PJM's capacity market design virtually guarantees that the market will procure capacity in excess of the required reserve margin. Even at prices as high as net CONE * B, the market would clear more than the required reserves.

13 Monitoring Analytics, *Potential Impacts of the Creation of New Jersey FRRs*, May 13, 2020, Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, April 16, 2020, and Monitoring Analytics, *Potential Impacts of the Creation of a ComEd FRR*, December 18, 2019.

14 See Morehouse, "Maryland Taking a 'Serious Look' at Exiting PJM Capacity Market Through FRR, Says PSC Chair," April 29, 2020.

service areas, a reasonable set of assumptions yields lower price estimates for FRR than for continued reliance on RPM.

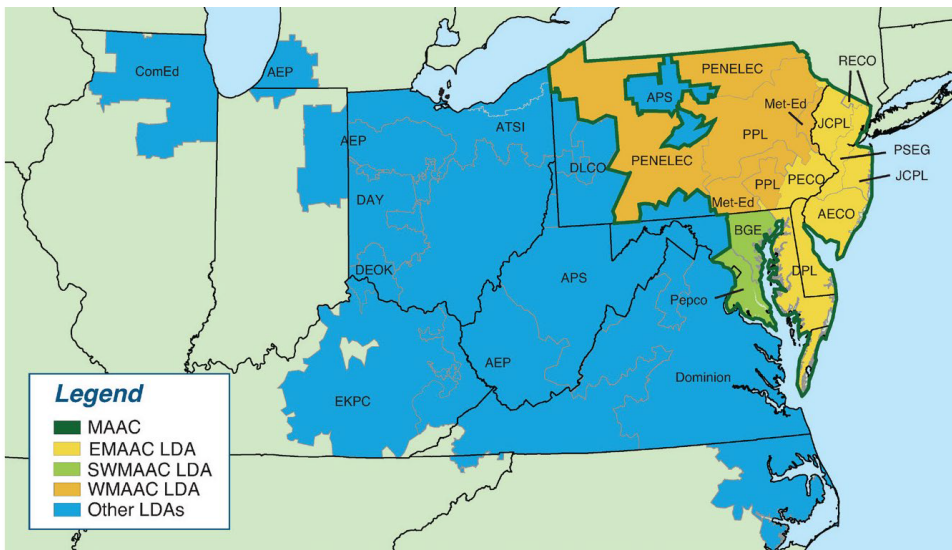
What a Reasonable Cost Framework Looks Like

The most natural baseline assumption in evaluating future prices in an FRR would be to assume that an FRR entity will procure capacity at market prices. Capacity prices depend on the Locational Deliverability Area (LDA) in which generation sources are located. Prices are higher to the extent that constraints in the transmission system prevent capacity from flowing to areas where there is not sufficient lower-cost capacity to serve all of the local demand. Such locationally varying prices are standard features of electricity markets, for energy (called Locational Marginal Prices, or LMP), capacity, and other products in PJM and other markets around the world.

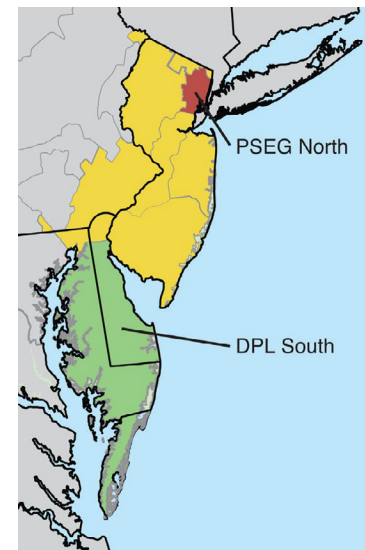
In PJM’s most recent BRA, for example, prices were as follows: ¹⁵

	21/22 BRA RESOURCE CLEARING PRICES (\$/MW-DAY)					
	REST OF RTO	EMAAC	PSEG	BGE	ATSI	OMED
Capacity Performance	\$140.00	\$165.73	\$204.29	\$200.30	\$171.33	\$195.55

MAP OF THE LOCATIONAL DELIVERABILITY AREAS



MAP OF RPM EMAAC SUBZONAL LDAS



Source: Monitoring Analytics, PJM Q1 2020 State of the Market Report, at p. 269, May 14, 2020.

LDAs for which transmission constraints create a higher price are colloquially known as “constrained zones.”

An FRR Entity is required to purchase capacity in a manner that respects constraints in the transmission system, sourcing external capacity only to the extent it can be reliably imported.¹⁶ An FRR entity would be required to purchase a certain amount of its capacity from suppliers located within the FRR Service area.

¹⁵ See [2021/2022 RPM Base Residual Auction Results](#).

¹⁶ The amount of transmission import capability to a given area is known as the Capacity Emergency Transfer Limit (CETL).

Because absent a reason to the contrary an FRR entity should be expected to seek to procure capacity at least cost consistent with transmission system constraints, a reasonable FRR analysis of an FRR service area located partially or fully within a constrained LDA would begin with the assumption of purchasing as much of an internal FRR load as can be met at lower prices outside the applicable LDA, and then meeting the rest of internal load with internal generation. Unfortunately the Monitoring Analytics reports do not provide the critical information of what is the maximum import capability into constrained zones or, equivalently, the Minimum Internal Resource Requirement that must be met with internal resources. This information is not provided presumably because of Monitoring Analytics' assumption that load is first met with all available internal generation, and then supplementing with external sources (i.e., the reverse of the method above).¹⁷ We recommend that states request that this key data on Minimum Internal Resource Requirements be provided and used in scenario modeling with the assumption that an FRR entity imports capacity up to the transmission limit. An adjustment can be made if the inflexibility of local capacity or another similar factor dictates that internal resources would have yielded lower costs, based on the offers made in the most recent BRA.

Monitoring Analytics Assumes Artificially High Payments to Generators Outside Constrained Capacity Zones

Monitoring Analytics reports all suffer from a central flaw: they assume that FRR entities would purchase as much capacity as possible from internal resources, importing capacity only to the extent "needed to cover any shortfall in meeting the FRR obligation", even where the FRR entity is located within a transmission-constrained area where local capacity prices are higher than those of the importing region(s).¹⁸ Monitoring Analytics never justifies this assumption, which leads to higher prices across all scenarios that modeled an FRR entity located entirely or partially within a transmission-constrained LDA.

This feature of Monitoring Analytics' analysis threatens to mislead readers who are not intimately familiar with PJM's complex rules, because half of the scenarios it examines assume capacity prices from the most recent BRA. While this framing suggests an apples-to-apples cost comparison, in fact it yields skewed results that in effect presume an irrational capacity purchasing strategy by the FRR entity.

In PJM's centralized RPM, suppliers located outside of constrained capacity zones who have not specifically paid for import rights into constrained zones are paid the lower price of the external zone. Even though they import some capacity from such external resources, capacity customers located within constrained zones pay a higher capacity price for all of the capacity they purchase, corresponding to the higher clearing price that is necessary to attract sufficient in-zone suppliers. The RPM accounts for this difference between what customers pay and what suppliers earn through Capacity Transfer Rights (CTRs). As Monitoring Analytics explains, CTR "revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers."¹⁹ Load is charged the applicable RPM clearing price *net* CTRs, which reduce the total cost.²⁰

17 It might be reasonable for the entity not to fully utilize the import limit to the extent that internal capacity is sourced from large, inflexible units, and the full amount of external capacity required to replace that internal capacity costs more.

18 Monitoring Analytics, *Potential Impacts of the Creation of New Jersey FRRs*, p. 7, May 13, 2020, and Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, p. 7, April 16, 2020. See also Monitoring Analytics, *Potential Impacts of the Creation of a ComEd FRR*, p. 4, December 18, 2019 ("There would be no capacity transfers from the rest of RTO to the ComEd LDA, or the price of imports to the ComEd LDA from the RTO would be the same as the LDA price.")

19 Monitoring Analytics, *Potential Impacts of the Creation of a ComEd FRR*, p. 9, December 18, 2019.

20 As Monitoring Analytics explains, "The MW of CTRs available for allocation to LSEs in an LDA is equal to the unforced capacity imported into the LDA determined based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants which include Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs)." See Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, at fn. 37, April 16, 2020.

Under FRR, the value of transmission import capability would be reflected differently because the applicable sales would not be administered through the RPM. Rather than first paying a higher constrained-zone price for capacity and then subtracting from that price the value of CTRs, load can directly pay the external suppliers a lower amount reflecting the lower value of capacity outside the constrained zone. No adjustment is needed for CTRs.

Monitoring Analytics suggests that the loss of CTRs is a cost of FRR. Its reports state that “[c]redits for CTRs do not exist with an FRR because the CTR credits are based on the operation of integrated capacity market with locational pricing.”²¹ But the value is not lost to the consumer since, as we explain in the New Jersey FRR example above, the applicable load-serving entity can directly pay a lower price for external capacity. This lower price paid to external suppliers times the quantity imported approximates CTR value.²² There is no actual loss of transmission rights held by load when a utility elects FRR, nor would that be consistent with open access principles or FERC policy on transmission rights.

Where Monitoring Analytics estimated FRR costs in an area that was not constrained by a binding transmission import limits, the scenario it examined that assumed capacity prices equal to those of the most recent BRA yielded cost savings of 5.4 percent for the applicable FRR service area.²³ We would expect similar levels of savings for the other scenarios were Monitoring Analytics to apply a new assumption that the FRR entity would import lower-cost capacity where possible.

Higher Prices in Half of Monitoring Analytics’ Scenarios Result from Assumed High Prices

Above and beyond Monitoring Analytics’ assumption that FRR entities source capacity from internal resources to the greatest extent possible, half of Monitoring Analytics’ scenarios yield significantly higher prices because they assume that prices would equal net CONE*b, the offer cap in PJM’s RPM auction.²⁴ Net CONE * b is net Cost of New Entry adjusted by a factor based on the number of Performance Assessment Intervals (when the system falls short on reserves), a level that is much higher than prices yielded by recent RPM auctions. This assumption automatically drives the result that prices are higher.

Monitoring Analytics does not explain this price assumption in its Maryland or New Jersey analyses.²⁵ The reader may infer, however, that net CONE * B is used because Monitoring Analytics anticipates that some FRR suppliers will exercise market power.²⁶ Monitoring Analytics asserts that “FRR creates market power for the small number of local generation owners” and concludes that because of this, even its price

21 Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, p. 19, April 16, 2020.

22 Monitoring Analytics’ Maryland report, for instance, states that “[t]he price of imports to Maryland from capacity resources outside Maryland is assumed to be the same as the price paid to the capacity resources in Maryland meeting the FRR obligation.” See Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, p. 7, April 16, 2020. This assumption runs contrary to standard economic analysis, which absent justification would presume a competitive price paid to generators rather than an arbitrarily inflated price. Monitoring Analytics does not explain why load participating in an FRR would have to pay constrained-zone prices to generators located outside of constrained zones, despite the fact that in the RPM those generators would only receive the base BRA price and not a higher constrained zone price.

23 Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, p. 36, April 16, 2020.

24 Monitoring Analytics, *Potential Impacts of the Creation of New Jersey FRRs*, p. 6 (scenarios 1, 3 & 5), May 13, 2020, Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, p. 6 (scenarios 1, 3, & 5), April 16, 2020, and Monitoring Analytics, *Potential Impacts of the Creation of a ComEd FRR*, p. 3 (scenario 1), December 18, 2019.

25 Monitoring Analytics’ New Jersey analysis does suggest that the net CONE * B priced scenarios are “likely to be conservatively low”, but does not explain why net CONE * B was chosen. See Monitoring Analytics, *Potential Impacts of the Creation of New Jersey FRRs*, p. 4, May 13, 2020. Monitoring Analytics bases this conclusion on its assertion that under FRR “there are no market rules requiring competitive behavior,” ignoring FERC’s responsibility under the Federal Power Act to ensure rates are just and reasonable by scrutinizing anti-competitive conduct.

26 In its ComEd analysis, Monitoring Analytics justifies its net CONE * B assumption on different grounds, stating that it is reasonable because Exelon has asserted “that the current total revenue from energy, ancillary and capacity markets is not adequate for its nuclear plants.” See Monitoring Analytics, *Potential Impacts of the Creation of a ComEd FRR*, pp. 8-9, December 18, 2019. But this ignores both the fact that Exelon would not be the sole capacity supplier to a ComEd FRR service area, and the fact that Exelon could offer capacity at prices that reflect the revenues its generators earn pursuant to Illinois’ Zero Emission Credit program.

estimates that utilize net CONE * B as an input assumption “are likely to be conservatively low.”²⁷

Even still, Monitoring Analytics does not explain why it assumes prices of net CONE * B for *all* suppliers, rather than only for those pivotal suppliers that possess market power. Further, empirical evidence in the BRA demonstrates that despite the presence of market power in several LDAs, prices have still cleared well below net CONE * B. As we explain below, market power is a significant challenge that states, PJM, and FERC should carefully address in designing and implementing FRR. But it is important to recognize that FRR does not “create” market power, which flows from the underlying dynamics of market suppliers’ generation ownership and relevant transmission system constraints. The Market Monitor’s conclusion that it does so is based on the reports’ underlying arbitrary assumption that FRR entities will not seek to purchase external capacity unless forced to do so for reliability reasons. And regardless of the presence or absence of specific tariff rules, FERC has a responsibility to ensure just and reasonable rates by preventing anti-competitive conduct, prohibiting pivotal suppliers from making extortionary capacity sales offers.

Monitoring Analytics Ignores the Costs of MOPR

The Monitoring Analytics studies of FRR costs do not discuss the cost of MOPR.²⁸ But MOPR will raise RPM costs to the extent it raises market clearing prices by causing higher priced supply offers, and to the extent it forces customers to support the construction or retention of redundant capacity. MOPR also could increase the cost of state programs because state-supported resources that do not clear the capacity market may require more revenue from Renewable Energy Credits (RECs) and other payments in order to cover their costs and be developed as the states desire.

Over time, we expect the cost of MOPR to rise. Some state policies such as New Jersey and Maryland offshore wind procurements support resources that will offer capacity soon if not the next auction, and it is nearly certain that MOPR will cause offshore wind energy not to clear in the RPM, raising costs to consumers. As the amount of such “state subsidized” resources that are able to offer capacity but cannot clear in the RPM increases, so will the costs of MOPR.²⁹

FRR avoids any costs associated with MOPR because state-supported resources would not be subject to a price floor under FRR. FRR entities could procure capacity from state-supported resources at competitive rates that reflect the value of revenues earned pursuant to state programs. The costs of state clean energy policies would also be reduced as compared to BRA with MOPR, because state-supported resources could more confidently rely on capacity revenues.

²⁷ Monitoring Analytics, *Potential Impacts of the Creation of New Jersey FRRs*, p. 4, May 13, 2020.

²⁸ This lack of discussion of MOPR costs may stem from the fact that Monitoring Analytics has published a study predicting that the MOPR will not affect prices in the upcoming BRA. This study only evaluates the upcoming auction and not future years in which it is clear there will be a cost of MOPR.

²⁹ MOPR will also raise capacity market to the extent a resource subject to an administratively set offer floor ends up being the marginal price-setting resource in any given auction.

BENEFITS OF FRR

As we explain below, beyond its ability to prevent the costs associated with MOPR, there are several factors that could push prices lower in an FRR plan relative to RPM:

Lower reserve margin requirements tend to cause lower total costs under FRR

The one certain part of any analysis of FRR is that the quantity of reserves needed is lower. As stated by Monitoring Analytics, “the zonal FRR [Unforced capacity, or] UCAP obligations are lower than the UCAP obligations in the capacity market. The reduced obligations are a result of the fact that the RPM auction clearing uses sloped demand curves (Variable Resource Requirement or VRR curves) while the FRR Entities use vertical demand curves based on a fixed MW requirement.”³⁰ The required reserve margin for FRR entities is currently approximately 15 percent, significantly lower than the approximately 22 percent reserve margin that has resulted from recent auctions with the VRR curve in place.³¹

The lower reserve margin under FRR would allow consumers of the applicable utility to not pay for the excess capacity currently being procured by PJM based on the stakeholder- and PJM-determined VRR curve. Because the load in an FRR plan is required to buy less capacity, it could pay a small premium to sellers participating in the FRR plan and still pay less in aggregate than through RPM.

Costs are reduced outside of FRR areas

As Monitoring Analytics found, with an FRR, prices would also fall across other zones and the rest of the pool. This happens because with the smaller amount of capacity needed for an FRR, significant demand is removed from the full regional market. For example, for the scenario where it examined the PEPCO zone assuming capacity prices equal to those yielded by the most recent BRA, Monitoring Analytics found that net load charges for the rest of PJM would decrease by roughly \$90 million, or 1 percent.³²

These cost savings have been identified by other analysts. ICF estimates the general impact of the lower reserve margin procured under FRR to be a reduction in price of \$15 to \$25 per MW-day in the near term and \$30 to \$50/MW-day in the long term if only two states opt for FRR.

ICF COST ESTIMATE FOR RTO WIDE CAPACITY MARKET³³

\$/MW-DAY	NEAR TERM	MID TERM	LONG TERM
CASE 1 <i>Previous market construct</i>	100 to 120	150 to 160	180 to 200
CASE 2 <i>MOPR with no additional FRR</i>	125 to 155 (25 to 35)	180 to 210 (30-50)	230 to 270 (50 to 70)
CASE 3 <i>MOPR with MD and NJ FRR</i>	115 to 145 (15 to 25)	170 to 200 (20 to 40)	210 to 250 (30 to 50)
CASE 4 <i>MOPR with IL, MD, NJ, and VA FRR</i>	65 to 95 (-35 to -25)	120 to 140 (-30 to -20)	140 to 180 (-40 to -20)

30 Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, p. 7, April 16, 2020.

31 The VRR curve procures much more capacity than reliability metrics would suggest is needed. PJM’s own analysis shows that higher reserve margins yield diminishing marginal returns for reliability. See *PJM, 2019 PJM Reserve Requirement Study*, p. 37, October 8, 2019.

32 Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, p. 36, April 16, 2020.

33 ICF, “*The Potential Impacts of FERC’s PJM Minimum Offer Price Rule Order*,” slide presentation used for a public webinar, February 2020.

Greater flexibility in FRR can reduce costs relative to RPM

FRR provides greater flexibility to utilities and states in how they meet their capacity obligations. The PJM capacity construct includes penalties for non-performance in order to encourage actual delivery of energy since “capacity” itself is merely the ability to provide energy when needed. The details of performance assessment and penalties matter a great deal in terms of costs to consumers and incentives for market participants. In an FRR, performance rules remain in effect. However, there is more flexibility under the FRR. Non-performance penalties in an FRR could be assessed on a physical and portfolio-wide basis rather than an economic penalty applied to individual units reducing the risk on individual unit owners.³⁴ The unit-specific financial penalties which provide asymmetric risks from under-performance relative to rewards for over-performance have served as a disincentive to capacity market participation for renewable energy.³⁵ The physical option simply requires the FRR entity (e.g., the utility) to add more physical resources to the FRR capacity plan in the next year to account for underperformance by rather than economic penalties, and is a portfolio-wide option rather than a unit-specific assessment.

Because of this greater flexibility, FRR better facilitates the use of seasonal resources as compared to RPM. RPM’s current annual commitment duration penalizes seasonal resources.,³⁶ An NREL report on capacity market design found that “given the seasonality of both load and generation, shorter obligation periods will likely improve the efficiency of capacity markets... When bidding into a market, resources are often allowed to offer only their lowest effective capacity value for the obligation period. For example, in PJM, where only an annual capacity product is traded, combustion turbines get assigned their summer capacity factor even though their effective capacity in the winter is much higher.”³⁷ The Brattle Group found that separating summer and winter capacity markets in PJM would save consumers \$100 to \$600 million per year on a continuing basis.³⁸

PJM’s current rules allowing individual resources with different output profiles to pair to meet its annual performance requirements provide some flexibility, though at a suboptimal level compared with what could be achieved with a larger portfolio. Because the FRR option inherently involves the FRR entity assembling a portfolio of resources, FRR provides an easier means for assembling a more efficient portfolio.

FRR also gives suppliers and purchasers more flexibility in the types of transactions they arrange. For example, a purchaser may be able to secure lower prices by offering multi-year price lock. Price formulas could partially or fully index to RPM. And the purchase could also be combined with energy, ancillary services, or environmental attributes providing the purchaser and seller more certainty as to their total costs and revenues.

34 See PJM, *RAA*, Schedule 8.1.C, September 17, 2010; “the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources, Seasonal Capacity Performance Resources, and Base Capacity Resources, as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.” Schedule 8.1.G at P. 2 states “For any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources.”

35 Goggin, Gramlich, Shparber, and Silverstein, *Customer-Focused and Clean: Power Markets for the Future*, p. 29, November 2018.

36 As observed by Slywia Bialek and Burcin Unel observe, “[s]horter commitment duration is also favorable to generators characterized by seasonal generation capabilities because capacity products with long durations, e.g. annual capacity products, limit what those generators can offer.” Bialek and Unel, “*Will You Be There for Me the Whole Time? On the Importance of Obligation Periods in Design of Capacity Markets*,” *The Electricity Journal* 32, pp. 21–26, March 2019.

37 Jenkin, Beiter, and Margolis, *Capacity Payments in Restructured Markets Under Low and High Penetration Levels of Renewable Energy*, pp. 23 & 26, February 2016.

38 Newell, Spees, Yang, Metzler, and Pedtke, *Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM*, April 12, 2018.

CHALLENGES WITH FRR

While there are some consumer benefits to FRR, there are also challenges in implementing FRR that if left unaddressed could result in higher prices or cause difficulties in FRR administration.

Building transparency and stability takes time

An advantage of a central auction sometimes cited by small energy developers is the transparency and predictability it provides relative to having to deal with many procurement entities. FRR relies upon bilateral transactions that would not necessarily provide market transparency to the same extent as a centrally cleared auction. However, transparency can be created by private entities such as Level10 and ICE, by brokers and intermediaries, or by the utility or state procurement entities. These institutions and practices take time to develop.

Monopsony power and affiliate preferences

Some utilities are not only distribution companies but also owners of generation. There would be an incentive under a distribution company-based FRR to favor their own generation. FERC applies greater scrutiny to affiliate transactions,³⁹ but state policy should also consider and address the potential for affiliate abuse.

Lock-in

Once a utility leaves PJM's centralized RPM, it must stay out of the BRA for five years. This might be considered a risk by states given the uncertainty of how an FRR might turn out, or whether RPM might become less hostile to state policy. However, the five-year requirement applies *except* "in the event of a State Regulatory Structural Change."⁴⁰ A State Regulatory Structural change is defined, with respect to a given Party, as:

a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

39 FERC's "affiliate restrictions include a provision prohibiting power sales between a franchised public utility with captive customers and any market-regulated power sales affiliates without first receiving Commission authorization for the transaction under section 205 of the FPA." FERC, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295, at P. 23, June 21, 2007; clarified in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 121 FERC ¶ 61,260, December 14, 2007; *Order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, April 21, 2008, clarified in *Order on Rehearing and Clarification*, 124 FERC ¶ 61,055, July 17, 2008; *Order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326, December 18, 2008; *Order on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284, June 1, 2009; *Order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206, March 18, 2020; *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied, sub nom. Public Citizen, Inc. v. FERC*, 567 U.S. 934 (2012); see also 18 C.F.R. § 35.59 (setting forth the Commission's affiliate restrictions).

40 PJM, RAA, Schedule 8.1.C, September 17, 2010.

Under this rule, states have the power to make regulatory changes that would trigger an FRR entity's ability to re-enter the BRA. Thus, the five-year requirement may not be such a concern for states fearing locking in to an unknown approach.

Seller market power

Supplier market power is when a power supplier has both the incentive and ability to raise prices above competitive level. It is present when a load-serving entity needs supply from a given generator in order to meet demand or regulatory obligations—i.e. there are limited alternatives to a given power supplier. Market power tends to be higher inside transmission constrained areas where the ability of external resources to compete is limited. Supplier market power is widely recognized to be a chronic problem in PJM capacity markets. Monitoring Analytics has found that it exists in certain zones in New Jersey, Maryland, and Illinois.⁴¹ In a Complaint filed with the Commission on February 21, 2019, Monitoring Analytics states that “structural market power is endemic” in PJM.⁴²

Notably, however, market power exists with or without FRR. It stems from transmission system limitations and concentration of supply ownership that exist regardless of how the capacity market is structured. Monitoring Analytics suggests that market power increases in FRR relative to RPM. However, that assertion is based on the flawed assumption that internal resources will receive a preference over external resources in an FRR plan. Each Monitoring Analytics report includes pivotal supplier analysis that presumes FRR entities will not freely purchase external capacity, yielding results suggesting greater market power than would truly be present in an FRR.⁴³ Monitoring Analytics' Maryland analysis, for instance, says “There would be capacity imports into Maryland FRRs only from capacity resources needed to cover any shortfall in meeting the FRR obligation.”⁴⁴

If it were true that only internal resources would be used, then it could be the case that those generators would have more market power than they do in the RPM. But states and utilities need not design an FRR that confers market power to local generation, or exacerbates existing market power. It is unlikely that state regulators would allow such a design given possible adverse effects on consumers. Thus, the question is not whether or not market power is increased in FRR, but rather whether market power mitigation tools are as strong in an FRR context as they are in RPM.⁴⁵

FRR does raise a challenge with regard to market power insofar as the rules of the road are less established for FRR than for BRA. States and other stakeholders should work with FERC and PJM to address market power in the FRR context. But as explained below, FERC has a statutory obligation to mitigate market power, and tools it may use to address market power in FRR service areas. FERC has determined that in the absence of market power, market-based rates (i.e., those reflecting arms-length negotiation between buyer and seller) are just and reasonable.⁴⁶ But where the seller has market power that has not been mitigated, FERC may not rely on market competition alone to satisfy its duty to ensure

41 Monitoring Analytics, *State of the Market Report for PJM*, p. 8, March 12, 2020.

42 *Complaint of the Independent Market Monitor for PJM*, at p. 2, Docket No. EL19-47, Feb. 21, 2019.

43 Monitoring Analytics, *Potential Impacts of the Creation of New Jersey FRRs*, pp. 10-11, May 13, 2020, and Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, pp. 9-10, April 16, 2020.

44 Monitoring Analytics, *Potential Impacts of the Creation of Maryland FRRs*, p. 7, April 16, 2020.

45 Notably, Monitoring Analytics has found that PJM currently lacks “effective market power mitigation in the capacity market” due to its methodology for calculating its offer cap. See *Complaint of the Independent Market Monitor for PJM*, at p. 2, Docket No. EL19-47, Feb. 21, 2019.

46 FERC, *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, Order No. 697, 119 FERC ¶ 61,295, at PP. 2-5, June 21, 2007.

just and reasonable rates.⁴⁷ As the U.S. Court of Appeals for the Ninth Circuit stated in *California ex rel. Harris v. FERC*, “[t]he FPA cannot be construed to immunize those who overcharge and manipulate markets in violation of the FPA.”⁴⁸

In protecting FRR markets from price manipulation, FERC can draw upon long-established tools. FERC has many decades of history in bringing enforcement actions for anti-competitive conduct, requiring sellers to submit indicative market screens where appropriate,⁴⁹ and in setting cost-based rate caps and bid caps. As FERC explains in Order No. 697, the Commission may, for example, “investigate a specific utility or anomalous market circumstances to determine whether there has been any conduct in violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations.”⁵⁰ And as Order No. 861 makes clear, “sellers engaged in . . . bilateral sales remain subject to EQR reporting requirements.”⁵¹ “[T]he Commission conducts ongoing analysis of *ex post* transactional EQR and other market data to detect indications of market power” and “in the event someone is aware of a situation where a Seller is exercising market power in a bilateral transaction in an RTO/ISO geographic area, evidence of that exercise of market power, for example an analysis of EQR data, could serve as the basis of a complaint or a protest.”⁵²

For long term products such as capacity, setting such caps is a relatively straightforward exercise (compared to energy market bidding protocols where there are separate markets every hour at every system node). Cost caps have been instituted in similar market settings, including as part of CAISO’s resource adequacy backstop mechanism, where caps are set going forward costs plus a 20 percent adder for the Capacity Procurement Mechanism,⁵³ and at full cost-of-service for Reliability Must Run.⁵⁴ Just as PJM sets offer caps in RPM, states and FERC could work together to establish a process for similar offer caps to be used in the FRR.⁵⁵ A lower, unit- and technology-specific, cost cap could also be used consistent with traditional FERC cost-based rate policy.

47 See *California ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013-18 (9th Cir. 2004) (holding that FERC’s reporting requirements are integral to its process of ensuring that market-based rates are just and reasonable under the FPA); *review granted, cause remanded sub nom. California ex rel. Harris v. FERC*, 784 F.3d 1267 (9th Cir. 2015); FERC, *Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy*, 107 FERC ¶ 61,018, 61,055, Apr. 14, 2004 (“The Commission does not believe it has the legal basis to approve market-based rates if the applicant has not mitigated market power.”)

48 *California ex rel. Harris v. FERC*, 784 F.3d 1267 (9th Cir. 2015).

49 In Order No. 861, FERC eliminated the requirement for sellers to submit indicative market screens for capacity sales in RTOs with centralized capacity markets, but it retained the requirement to submit indicative screens in regions without such markets (CAISO and SPP) and eliminated the rebuttable presumption in those markets that Commission-approved RTO/ISO market monitoring and mitigation is sufficient to address horizontal market power concerns. FERC, *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040, at PP. 17, 38, 46 & 59, July 18, 2019; *Order on reh’g*, Order No. 861-A, 170 FERC ¶ 61,106, Feb. 20, 2020.

50 FERC, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295, at P. 5, June 21, 2007.

51 FERC, *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040, at P. 62, July 18, 2019.

52 FERC, *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040, at P. 62, July 18, 2019. One challenge in mitigating market power through enforcement based on EQR data in the FRR setting is the absence of a reference price from clearing in the centralized capacity market. Nevertheless, as FERC discussed in Order No. 861, the Commission may utilize a variety of data in establishing benchmarks to judge conduct, such as “energy prices and other liquid and frequently traded products, such as standardized forward contracts.” Order No. 861, at P. 60. States considering FRR may seek to work with FERC in designing FRR procurement mechanisms so as to facilitate establishment of market reference prices.

53 FERC, *Order on Tariff Revisions*, 153 FERC ¶ 61,001, at PP. 13 & 29, October 1, 2015.

54 FERC, *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040, at P. 34, July 18, 2019.

55 For the same reasons that Monitoring Analytics has challenged the current offer cap methodology in the PJM capacity market, we recommend developing a different offer cap methodology than the one currently used in PJM for RPM. To the extent states or PJM view the current offer cap as appropriate, however, there is nothing that would prevent a similar offer cap from being implemented in the FRR context.

States may also be able to mitigate market power through rules evaluating the prudence of utility capacity purchases.⁵⁶

Another means of designing FRR with market power in mind is the choice of FRR zones. A state need not have all its utilities elect FRR simultaneously. For example, in Maryland, the PEPCO zone is less constrained than Maryland's other distinct electrical zones. The PEPCO zone requires only 7% in-zone generation, facilitating robust competition from external resources. To the extent states are concerned with how market power may affect FRR prices, they can choose to apply FRR in less constrained zones such as PEPCO. Further, state clean energy policies may be designed to account for the presence of some but not all utilities in FRR.

Physical Delivery of Environmental Attributes

State policies direct the purchase of Renewable Energy Credits (RECs), and those RECs currently can come from outside the state and as far away as systems in the Midwest that are connected to PJM but not inside PJM and not inside the constrained capacity zones where load is situated. For resources to be exempt from MOPR under an FRR, they must be physically deliverable such that the resources needed to meet an LSE's capacity obligation do not exceed capacity import limits. An FRR essentially forces physical delivery of renewable energy which is not the case today. States will need to consider how to meet both their physical capacity and renewable energy needs under an FRR regime.

EXACT FRR COSTS DEPEND ON FRR DESIGN

FRR can be designed in a variety of ways. A thorough comparison of FRR and RPM depends on what type of FRR would be used.

PJM's RAA provides that the applicable FRR entity bearing resource adequacy responsibilities could be a utility, or distribution company.⁵⁷ Further, the procurement entity(ies) could be whoever the state chooses and need not be the FRR entity. The FRR Entity could serve a limited administrative reporting functions while other entities handle actual procurements. The PJM RAA provides that "[n]othing herein shall obligate or preclude a state, acting either by law or through a regulatory body acting within its authority, from designating the Load Serving Entity or Load Serving Entities that shall be responsible for the capacity obligation for all load in one or more FRR Service Areas."⁵⁸ States may design the procurement structure to prevent the risk of affiliate abuse, or to preserve or establish retail competition structures they desire.

56 As FERC explains in Order No. 861, states commissions review capacity sales in the SPP region because in that region "capacity costs are recovered in the rate bases of franchised public utilities." FERC, *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040, at P. 47 n. 67, July 18, 2019. While states cannot regulate sales prices for electricity for resale in interstate commerce (which is exclusively FERC jurisdictional), they can regulate the prudence of purchases by buyers. Further, FERC's jurisdiction over capacity sales stems from its jurisdiction over practices affecting rates, not from its authority over interstate wholesale electricity rates themselves. See *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009) (holding that FERC has jurisdiction to review an Installed Capacity Requirement pursuant to the "Commission's jurisdiction over practices affecting wholesale rates").

57 PJM, *RAA*, Article 1, September 17, 2010.

58 PJM, *RAA*, Schedule 8.1.1 - Savings Clause for State-Wide FRR Program, September 17, 2010.

De-centralized market FRR design

One model would be a de-centralized approach where competitive retail suppliers handle the procurement. In this case states would need to make sure retail suppliers are equipped to handle this responsibility.⁵⁹ The state would also need to make sure the FRR entity fairly administers the interaction with PJM. In this de-centralized model, the market would be expected to work more like ERCOT where many buyers and many sellers interact to trade contracts of different terms, conditions, and durations.

Distribution company based FRR

Another option for states under FRR would be for a distribution company to handle the procurement for all retail suppliers. A state could establish rules for this procurement and allocation process including the rules for recovering prudent capacity contracting costs in retail rates. PJM's Reliability Assurance Agreement specifically allows states to determine a mechanism for retail suppliers to compensate the utility, and envisions that retail suppliers could contribute capacity to the plan instead of paying for capacity.⁶⁰

State agency based FRR

A third option under FRR would be for a state agency to handle procurement of capacity for all users. For example, the Illinois Power Agency could be assigned the resources and responsibility for the procurement in that state.

CONCLUSION

At this stage, given uncertain market dynamics and questions surrounding how states and utilities may implement FRR, it is difficult for anyone to render a confident and accurate prediction of FRR prices. While Monitoring Analytics provides useful data and a structure to evaluate FRR costs, we recommend that it provide a more complete picture of the potential costs of FRR by conducting additional scenarios applying the reasonable assumption that FRR entities would competitively procure externally-located capacity. Given the potential benefits of FRR, including its ability to prevent MOPR costs that could become very large over time for states with ambitious clean energy programs, it makes sense for these states and their utilities to closely examine the FRR option. In doing so, we recommend they evaluate design options that offer the potential to maximize the benefits of FRR while addressing the challenges it raises, including the critical challenge of market power.

⁵⁹ See, e.g., Gramlich and Lacey, *Who's the Buyer? Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment*, March 2020.

⁶⁰ PJM, *RAA*, Schedule 8.1.D.8 & 8.1.D.9, September 17, 2010.