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May 20, 2020

VIA ELECTRONIC MAIL
Honorable Aida Camacho-Welch, Secretary
NJ Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: In the Matter of the BPU Investigation of Resource Adequacy Alternatives-- Rate Counsel's Response to Staff Request for Written Comments BPU Docket No.: EO20030203

Dear Secretary Camacho-Welch:

Please accept for filing the enclosed comments being submitted on behalf of the New Jersey Division of Rate Counsel ("Rate Counsel") in response to the Request for Written Comments issued by the Staff of the Board of Public Utilities for comment on March 27, 2020 with subsequent Public Notice extending the deadline for comments to May 20, 2020. In accordance with the Notice, these comments are being filed electronically with the Board's Secretary at board.secretary@bpu.nj.gov.

Please acknowledge receipt of these comments.

Thank you for your consideration and attention to this matter.

Respectfully submitted,

By: */s/ Stefanie A. Brand*
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Director, Division of Rate Counsel

Enclosure

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In the Matter of the BPU Investigation of Resource Adequacy Alternatives

Rate Counsel's Response to Staff Request for Written Comments

BPU Docket No.: EO20030203

Introduction

Rate Counsel appreciates the opportunity to comment on the important issues the Board is investigating in this matter. There is no doubt that the series of orders issued by the Federal Energy Regulatory Commission (FERC) regarding "state subsidized resources" and their participation in the PJM Capacity market have complicated the desire of New Jersey and other states to move to more sustainable generation resources while maintaining stable and affordable sources of energy. Rate Counsel, like the Board, has appealed those orders, and intends to pursue those appeals to protect the State's role under the Federal Power Act and its important goals of promoting clean energy while maintaining safe, adequate and proper service at just and reasonable rates.

However, we urge the Board to proceed with caution. As discussed in much greater detail below, many of the options that may alleviate one aspect of the problems created by FERCs orders could lead to other problems that are as, if not more, dangerous. We need to carefully think through the consequences of any actions taken and any changes made.

With respect to the Fixed Resource Requirement (FRR) option at PJM, while at first glance it may appear to be a means for avoiding some of the negative impacts of recent FERC actions, Rate Counsel notes that this option likely brings with it many unwanted and expensive consequences. The PJM Independent Market Monitor, Marketing Analytics (MA), has issued a study exploring the possible costs if New Jersey pursues FRR. The MA Study estimates that a statewide FRR could increase capacity costs for New Jersey ratepayers by 29%, and that this estimate may be low. In addition, and of equal concern, there appears to be no feasible route to a New Jersey FRR that does not implicate significant market power issues. If we allow this level of market power, these increases will likely be just the beginning. There will be no competition or market oversight to prevent the exercise of that market power later to increase prices to the detriment of New Jersey's citizens.

With respect to the establishment of a State Power Authority to assist either with an FRR or re-regulation of generation, this option will no doubt need substantial study before any determination could be made on whether it will be helpful. Creation of a new state agency always entails costs and complications. It would certainly take time to implement, which may be too late to address the immediate problems created by FERC's orders. No matter what, whether New Jersey decides to explore FRR, a State Power Authority or re-regulation of generation, Legislative action would be required. This, too, takes time and will be complicated.

Finally, Rate Counsel strongly urges the Board not to attempt to transform the Basic Generation Service (BGS) auction into something it is not. The BGS auction was created to ensure a stable and affordable supply of energy for residential and small commercial customers who do not wish to or cannot shop for their electricity from Third Party Suppliers. It has been a success. It has brought to these customers the benefits of competition and protection from volatility. While the recent FERC Orders have cast some doubt as to whether these auctions provide "subsidies," there are far less extreme measures being discussed at PJM to address this aspect of the FERC Orders that could preserve the important protections the BGS auctions provide to residential and small commercial ratepayers. Especially now, these customers need to be able to count on those protections. Discussions of altering the purpose of the BGS auction to further other goals, such as the promotion of clean energy, will serve to <u>ensure</u> that our BGS auction is seen as a means to provide subsidies to certain favored generation resources. In fact, just the discussion alone could have the damaging effect of discouraging bidders to participate, thus diminishing competition and threatening the effectiveness of this important State program. Moreover, if we alter the purpose of the BGS auction in a manner that increases prices, customers will flee the auction for Third Party Suppliers, thus diminishing the effectiveness of the auction overall, including as a tool to promote clean energy.

In sum, we urge the Board to proceed slowly and carefully. Our aims should be to foster competition, avoid enhancing market power, and protect New Jersey ratepayers from excessive rates. While the FERC orders have certainly created roadblocks for the state to achieve its goals, we must make sure that our citizens continue to have safe, adequate and affordable service and that any action we take does not undermine that important, fundamental principle.

Rate Counsel's Responses to Staff's Questions

Initially, Rate Counsel is concerned about the scope of the questions provided by Board Staff in this investigation. The questions focus on the issue of whether the Fixed Resource Requirement, or some other mechanism can be utilized to meet New Jersey's clean energy goal. Focusing on whether a mechanism can meet a goal without review of its costs is inappropriate. It is undisputed that meeting New Jersey's clean energy goals will be expensive. Board Staff should not only be concerned with how to meet these goals, but how to do so in a cost effective manner. Rate Counsel intends to address this significant issue while answering the questions below.

1. **Can New Jersey Utilize the Fixed Resource Requirement ("FRR") Alternative to Satisfy the State's Resource Adequacy Needs?**

   a. **Discussion of the FRR requirements under the PJM Tariff and how they may be applied to a restructured state, New Jersey specifically.**

The PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA")[1] defines the capacity requirements[2] that each PJM Load Serving Entity ("LSE") must satisfy. RAA Article 1, Definitions, defines Load Serving Entity to include all entities with state or local authority to serve end users; this will include investor-owned utilities, electric cooperatives, and public power entities, and also load aggregators, power marketers, and qualified end-use customers. RAA Schedule 17 lists the LSEs who are parties to the RAA.[3]

Most LSEs satisfy their capacity obligations passively through PJM's administration of its RPM capacity market. The RAA also provides an alternative approach for LSEs to satisfy these capacity obligations, the Fixed Resource Requirement ("FRR") Alternative.[4] RAA Schedule 8.1.B defines the eligibility provisions for FRR. Investor-owned utilities, electric cooperatives, and public power entities (that is, not all LSEs) are eligible to elect FRR.[5] The RAA also includes a "Savings Clause for State-Wide FRR Programs",[6] making it clear that a state is not precluded by any provisions of the RAA from determining, through legislative or

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[1] Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, PJM Interconnection, L.L.C. Rate Schedule FERC No. 44, available at https://www.pjm.com/directory/merged-tariffs/raa.pdf.
[2] See RAA ARTICLE 7 -- RESERVE REQUIREMENTS AND OBLIGATIONS, section 7.1, Forecast Pool Requirement and Unforced Capacity Obligations, SCHEDULE 4, GUIDELINES FOR DETERMINING THE FORECAST POOL REQUIREMENT, and SCHEDULE 8, DETERMINATION OF UNFORCED CAPACITY OBLIGATIONS.
[3] RAA Schedule 17 identifies as parties to the RAA the following entities, among many others: Atlantic City Electric Company, Jersey Central Power & Light Company, Public Service Electric & Gas Company, South Jersey Energy Company, Borough of Lavallette, New Jersey, Borough of Milltown, Borough of Park Ridge, New Jersey, Borough of Seaside Heights, New Jersey, Borough of South River, New Jersey, Vineland Municipal Electric Utility (City of Vineland), Stream Energy New Jersey, LLC.
[4] RAA Section 7.4 Fixed Resource Requirement Alternative, and SCHEDULE 8.1.A-The Fixed Resource Requirement.
[5] RAA Schedule 8.1.B.2 specifies that an eligible entity can elect FRR for only part of its PJM load if it elects FRR for all of its load within an FRR service territory.
[6] RAA Schedule 8.1.I Savings Clause for State-Wide FRR Programs.

regulatory action, that all LSEs in the state shall meet their capacity obligations as FRR entities under a state-wide FRR program.

An entity electing FRR commits to meeting the capacity obligation of <u>all</u> of the load in its service territory through FRR (FRR cannot be used to meet only a portion of a FRR entity's service area load[7]), including load that may be served by other LSEs under retail choice programs,[8] for a minimum of five years.[9] The entity electing FRR must submit an initial FRR Capacity Plan before the RPM Base Residual Auction for the first delivery year to which the FRR plan will be applicable (generally, over three years in advance[10]), showing commitments of resources that meet RPM Capacity Performance requirements sufficient to satisfy the capacity obligations (reflecting forecast load growth) for the term of the FRR election (initially, the five year minimum term). The resources included in the FRR Capacity Plan must also satisfy certain restrictions on the locations of the resources having to do with the capacity zones that PJM has established for the delivery year.[11] The FRR Capacity Plan is subject to review and approval by PJM.[12]

Where an FRR entity acquires capacity for LSEs that serve load under a state retail choice program (as would be the case in New Jersey), the LSEs would compensate the FRR

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[7] It is worth noting that in a 2018 order, FERC had floated the idea of allowing resource-specific FRR plans, which would have allowed much more flexibility as to the resources and loads that are outside of RPM. However, while PJM and stakeholders made several proposals along those lines, no such rules were approved. 163 FERC ¶ 61,236 (June 29, 2018)
[8] RAA Schedule 8.1.D.8.
[9] RAA Schedule 8.1.C.1.
[10] The schedule will likely be different (more compressed) for the next few RPM base residual auctions in light of the delay of these auctions.
[11] RAA Section 8.1.D.5. These restrictions reflect the transmission constraints applicable to each zone (Locational Delivery Area, or "LDA"), and ensure that the FRR entity is permitted to use only its fair share of each applicable zone's capacity to import lower-cost resources from outside the zone. For example, if the Eastern MAAC zone in which New Jersey is located is only able to import 20% of its capacity need from outside Eastern MAAC due to transmission constraints, a New Jersey FRR entity would have to source at least 80% of its capacity from inside Eastern MAAC.
[12] RAA Schedule 8.1.D.7.

entity for this capacity according to a state-approved compensation mechanism.[13] If the applicable state has not established such a mechanism, the RAA calls for using the RPM price applicable to the unconstrained region of the PJM RTO for the allocation. LSEs within an FRR entity service territory may also self-supply resources (that is, meet capacity needs with Capacity Performance resources that the LSE owns or has under contract).[14]

The RAA includes various other, perhaps less important provisions applicable to FRR entities, such as provisions for FRR entities whose service territories overlap LDA boundaries,[15] limits on excess capacity sales into RPM,[16] penalty provisions,[17] termination provisions,[18] and treatment of commitments for transmission upgrades.[19]

RPM typically clears capacity quantities well in excess of the Reliability Requirement,[20] while an FRR Entity is only required to meet the Reliability Requirement in its FRR Plan. This might seem to be an advantage for FRR, however, this is not necessarily the case. Due to RPM's sloped demand curve, the larger the excess cleared in RPM, the lower the auction clearing price; and the total RPM capacity cost allocated to loads actually declines as more and more excess is cleared.[21]

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[13] RAA Schedule 8.1.D.8.
[14] RAA Schedule 8.1.D.9.
[15] RAA Schedule 8.1.B.2.
[16] RAA Schedule 8.1.E.
[17] RAA Schedule 8.1.G.
[18] RAA Schedule 8.1.C.
[19] RAA Schedule 8.1.D.6.
[20] See, for instance, 2021/2022 RPM Base Residual Auction Results p. 1 (stating that the reserve margin resulting from the auction was 21.5%, or 5.7% higher than the target reserve margin of 15.8%), available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.
[21] For instance, using the 2020/2021 parameters for EMAAC, if RPM clears at "Point B" on the RPM demand curve at 104% of the Reliability Requirement, the price is 75% of Net CONE, and the total capacity cost is $8.1 billion; if instead RPM clears halfway between Points B and C at 106% of the Reliability Requirement, the price falls to about 40% of Net CONE and the total cost is $4.1 billion. See 2020/2021 RPM Base Residual Auction Planning Parameters.

b. Discussion of any practical limits presented as a result of New Jersey's geographic location along the Atlantic Ocean and along the NYISO Seam.

In RPM base residual auctions, various capacity zones (LDAs) are typically defined, to ensure that the auction selects sufficient capacity located inside each zone to respect transmission limits and satisfy locational reliability requirements. As a result, the RPM auctions can result in higher capacity prices in constrained zones. In recent auctions PJM has defined the following LDAs applicable to New Jersey:[22] Eastern MAAC, which includes all of New Jersey and parts of Pennsylvania and Delaware; PS, the PSE&G service territory; and PS North, the northern portion of the PSE&G service territory. FRR Capacity Plans are subject to limits on reliance on capacity from outside applicable LDAs based on the same PJM reliability analyses that determine the limits used in the RPM auctions.

Additionally, there are capacity sales from New Jersey into New York.[23] This capacity is not eligible to satisfy RPM capacity requirements, and it would also not be available for use in an FRR Capacity Plan.

Discussion of the pricing and/or rate implications associated with FRR

PJM's Independent Market Monitor, Monitoring Analytics, recently completed an analysis of the potential impacts of statewide or zonal FRR in New Jersey ("MA Report").[24] Beginning with the results of the most recent RPM base residual auction (for 2021/2022), the

[22] See, for instance, 2021/2022 RPM Base Residual Auction Planning Period Parameters, pp. 2-4 (describing the LDAs defined for the auction, and noting EMAAC, PS, and PS North), available https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-rpm-bra-planning-parameters-report.ashx?la=en, and 2021/2022 RPM Base Residual Auction Results, p. 1 (showing the capacity prices resulting from the auction applicable to EMAAC, PS, and other LDAs), available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.
[23] Table III-2 Existing Generating Facilities from NYISO 2019 Load and Capacity Data available at https://www.nyiso.com/documents/20142/2226333/2019-Gold-Book-Final-Public.pdf/
[24] Monitoring Analytics, Potential Impacts of the Creation of New Jersey FRRs, May 13, 2020.

MA Report estimated the total capacity cost for a New Jersey state-wide FRR entity, compared to the actual cost in auction. While there are many details to these calculations,[25] the key assumption is the price an FRR entity would pay for capacity for an FRR Plan. The MA Report noted that the prices an FRR entity would pay would result from bilateral negotiations to which no market power mitigation would apply, and as a result, the actual prices "could substantially exceed" both of the price assumptions used in the analysis,[26] which were as follows:

- The New Jersey FRR entity would pay prices based on the applicable RPM market seller offer caps (Scenario 1). The offer caps are based on the Net Cost of New Entry times a Balancing Ratio, and vary by zone; the weighted average was used.
- The New Jersey FRR entity would pay prices similar to recent RPM prices; the weighted average of clearing prices applicable to New Jersey from the 2021/2022 Base Residual Auction was used.

The results of the analysis are summarized in Table 1. Under the assumption that sellers would be paid based on the market seller offer caps (Net CONE x B) to participate in the FRR Plan (Scenario 1), New Jersey's capacity cost would increase by $386 million (29.6%) compared to the cost of obtaining capacity through RPM.[27] Under the assumption that sellers would be paid prices as in the most recent RPM auction, the cost increase would be $32 million, 2.4%.

[25] As examples, the analysis documented in the MA Report addresses the fixed amount of capacity required in an FRR Plan, energy efficiency addbacks, price-responsive demand, seasonal capacity offers (both matched and unmatched), Capacity Transfer Rights credits, and make-whole payments, among other details.

[26] MA Report p. 4.

[27] Arguably, a New Jersey FRR entity would be able to acquire the allowed small portion of capacity from outside the zone under more competitive circumstances than the capacity that must be acquired within the Eastern MAAC zone. Assuming the recent Rest of RTO auction price for these purchases would lower the cost increase in Scenario 1 from 29.6% to 19.6% (by 100% - 83.2% = 16.8% x ($140/$235.42)= 10%).

Table 1: Estimated Cost Impacts of a New Jersey-Wide FRR						
	FRR Price Assumption		Annual Cost ($ mil.)		Cost Increase	
Scenario	Assumption	$/MW-day	FRR	RPM	$ mil.	Percent
1	Offer Cap: Net CONE x B	$235.42	$1,694	$1,308	$386	29.6%
2	Recent Auction	$186.16	$1,340	$1,308	$32	2.4%
Source: MA Report Tables 12 and 14.						

This analysis did not reflect in any way the payments that some resources receive under state policies to encourage renewable and zero carbon resources (which might be an offset to capacity costs, whether under RPM or FRR), or that some resources that might be excluded from receiving RPM capacity payments due to the MOPR might be eligible for inclusion in an FRR Plan.

The MA Report also applied these two pricing assumptions to evaluate the cost impact of FRR for just the PSEG zone (Scenarios 3 and 4) and for just the JCPL zone (Scenarios 5 and 6). These analyses produced results similar to the state-wide FRR analysis: large cost increases under the offer cap price assumption, and a small price increase (a small decrease in scenario 6) under the recent auction price assumption.[28]

The MA Report also evaluated the likelihood of market power issue in some detail and presented relevant facts, discussed in section [h] below.

c. Discussion of whether and how the State could pursue an FRR construct under existing legislative and regulatory provisions.

Legislation would be required for New Jersey to implement the FRR alternative, unless the BPU is willing to re-regulate electric generation service and can make the findings required

[28] MA Report Tables 1, 17, 21, 26, 31.

to do so under EDECA. Additionally, re-regulation would require overcoming significant practical and legal obstacles.

As explained above, implementation of the FRR option would require the State's electric distribution entities to utilize this option. However, this option appears inconsistent with the industry structure and regulatory model envisioned by EDECA and implemented by the Board in the restructuring proceedings it conducted for the New Jersey' four electric utilities. Under the provisions of EDECA, the electric utilities, formerly responsible for generating electricity, transporting it through their electric distribution systems, and delivering it to customers, retained their regulated monopolies only over electricity transmission and distribution. The utilities divested most of their generation assets to unregulated entities, while their customers were given the option to choose to purchase electric generation service from competitive suppliers. N.J.S.A. 48:3-52; N.J.S.A. 48:3-53, N.J.S.A. 48:3-59.[29] The utilities retained only limited responsibility for electric supply. Under EDECA, they are required to provide default service, known as basic generation service ("BGS") to those customers who choose not to purchase generation service from competitive suppliers, until such time as the Board determines this is no longer in the public interest. N.J.S.A. 48:3-57(a)(1). However, they are not permitted to provide generation service directly. Instead, EDECA provides that BGS "shall be purchased" by the utilities at "prices consistent with market conditions." Id.

[29] EDECA was implemented for the State's four electric utilities in summary Orders issued by the Board in 1999, later confirmed in the following Final Decisions and Orders: In Re Public Service Electric and Gas Company's Rate Unbundling, Stranded Costs and Restructuring Filings, 1999 N.J. PUC Lexis 11 (1999), aff'd 330 N.J. Super. 112 (App. Div. 2000), aff'd 167 N.J. 377, cert. denied 534 U.S. 813 (2001); In re Jersey Central Power and Light Company d/b/a GPU Energy – Rate Unbundling, Stranded Cost and Restructuring Filings, BPU Docket Nos. EO97070458, EO97070459, and EO97070460 (March 7, 2001); ln re Atlantic City Electric – Rate Unbundling. Stranded Costs and Restructuring Filings, BPU Docket Nos. EO97070455, EO97070456, and EO97070457 (March 30, 2001); In re Rockland Electric Company's Rate Unbundling, Stranded Cost and Restructuring Filings, BPU Dkt. Nos. EO97070464, EO97070465, and EO97070466 (July 22, 2002).

Consistent with this altered role for New Jersey's electric utilities, EDECA made a fundamental change in the Board's regulatory authority. Under N.J.S.A. Title 48, the Board has jurisdiction over "public utilities," as that term is defined in N.J.S.A. 48:2-13 (a). EDECA amended this definition, which formerly included companies engaged in providing "electric light, heat [or] power" service, to include only those engaged in "transmit[ting] and distribut[ing] electricity to end users within this State." L. 1999 c. 23, sec. 52 (emphasis supplied); N.J.S.A. 48:3-51 (definition of "electric public utility") (emphasis supplied). Further, with the exception of authority specifically provided elsewhere in EDECA, N.J.S.A. 48:3-56(a) provides that the Board "shall not regulate, fix, or prescribe the rates, tolls, charges, rate structures, rate base, or cost of service of competitive services." Under N.J.S.A. 48:3-56(b) "electric generation service is deemed to be a competitive service."

Implementation of the FRR option for New Jersey would require the State's electric utilities to assume responsibility for meeting the unforced capacity obligations of all electricity suppliers serving customers within their respective service territories, including both competitive suppliers and those providing BGS. It is questionable whether the Board would have the authority to mandate implementation of the FRR option for New Jersey under the current regulatory structure. Retail choice has been implemented for all of the State's electric distribution utilities. At the present time, their obligations as utilities under N.J.S.A. Title 48 do not include participation in the competitive electric supply market. Thus, an attempt by the Board to require the utilities to assume the capacity obligations of the competitive suppliers could be subject to legal challenge. The Board's authority to oversee the FRR process and assure the reasonableness of the costs of capacity would be subject to challenge for the same reasons.

In addition, competitive suppliers could argue that implementation of the FRR alternative would be contrary to EDECA. The FRR structure would effectively require them to cede responsibility to the utilities for meeting their unforced capacity obligations. Arguably, this would violate EDECA's prohibition on BPU regulation of the "rates, tolls, charges, rate structures, rate base, or cost of service of competitive services" including competitive electric supply. N.J.S.A. 48:3-56(a) & (b).

EDECA contains provisions allowing the Board, in consultation with the Legislature, to re-regulate competitive services, including electric generation service. However, this would involve both procedural and substantive hurdles. The Board would have to find after notice and a hearing, the competitive service should be "reclassif[ied] as regulated" because "sufficient competition is no longer present" for that service. N.J.S.A. 48:3-56(d). Based on that finding, the Board would submit recommendations to the Legislature. N.J.S.A. 48:3-56(k). The Legislature would then have 90 days to issue a concurrent resolution expressing any disagreements with the Board's recommendations. In the absence of action by the Legislature, the Board's recommendations would be deemed approved. In the event of a concurrent resolution, the Board would have 45 days to submit revised recommendations to the Legislature. Id. Even assuming the BPU is willing to undertake the statutory process for re-regulation, it would likely be a lengthy process, with no guarantee that the record would support the necessary findings, or that the Legislature would concur.

Further, re-regulating electric generation would not be a simple process. The State's electric utilities no longer own the assets that are required to provide electric generation service. The utilities would have to either procure generation service in the competitive market, as they do now for their BGS customers, or re-acquire their former generation assets. The former would continue to leave the Board with no ability to engage in cost-of-service regulation of electric supply. The latter would require the utilities to re-acquire generation from entities with market power, some of which are affiliated with the utilities, and would require the unwinding of existing contractual commitments. It is unclear whether this could be accomplished at a reasonable cost, while recognizing the constitutionally protected property rights of generation owners and other participants in the electric supply market.

d. Discussion of any New Jersey legislative and regulatory limitations or potential amendments necessary to pursue FRR.

See d above.

e. **Discussion of which entity would procure capacity under an FRR construct and whether capacity would be procured state-wide**.

The EDCs are the members of PJM, and they would be responsible for procuring capacity under an FRR construct. As noted above, state-wide FRR procurement is also allowed, and a new entity could be formed for that purpose.

f. Discuss the pros and cons of a State Power Authority ("SPA"), looking at examples from across the country, including discussion of any legislative and regulatory limitations and potential amendments necessary to pursue an SPA.

With respect to the establishment of a State Power Authority to assist either with an FRR or re-regulation of generation, this option will require substantial study before any determination can be made on whether it will be practical. The creation of a new state agency will entail costs and complications. It would certainly take time to implement, which may be too late to address the immediate problems created by FERC's orders.

At a high level there may be advantages and disadvantages to the creation of state power authority for New Jersey.

Creation of a New Jersey Power Authority could in theory provide New Jersey residents with certain benefits. The advantages of the state power authority are outlined below. One, a state power authority can lower the cost of electricity or at least minimize cost increases over time in several ways. If a state power authority purchases an existing facility or constructs a new power plant, the power authority can sell the plant's power output on an average-cost basis rather than at the higher market clearing price.[30] In addition, the state power authority could sell power without having to earn a profit for shareholders. Second, a state power authority would enjoy a lower cost of capital than private firms and could thus finance the construction of new generation less expensively. A state power authority could less expensively finance a project if the authority can issue bonds, if allowable, backed by the full faith and credit of the state and/or tax-exempt bonds. The State's ability to create a power authority with the authority to issue bonds, however, is severely curtailed by the New Jersey Constitution. Art. III, Sec. 2, Para. 3b. Third, a state power authority can make price stability one of its goals. Strategies for achieving this goal include procuring electricity via a portfolio of contracts of varying length agreed at different points in time. Fourth, a state power authority could help ensure adequate, reliable electricity supply via long-term planning, diversification of supply sources, and procurement of new capacity when the private market fails to deliver needed supply. This could facilitate the promotion of renewable energy projects by offering project financing and long-term contracts. Fifth, a state power authority that owns its own power generation could supply electricity at below-market rates to targeted groups such as certain firms that pledge to retain jobs in New Jersey or to economically disadvantaged households or communities. NYPA administers multiple economic development programs.[31]

[30] The Supreme Court ruling in the Hughes v. Talen Energy Mktg., LLC, 136 S.Ct. 1288, 194 L. Ed. 2d 414 (2016), effectively limits the ability of a state contracted facility from participating in the wholesale market.
[31] NY Power Authority, "Economic Development." *NYPA.gov*. <http://www.nypa.gov/economic.htm>Available at: http://www.nypa.gov/economic.

There are also a number of disadvantages to the creation of a state power authority that must be considered as well. First, the state should consider the full impact of recent Supreme Court Rulings on the ability of a state power authority to participate in wholesale markets. It is not clear how the state power authority would exercise control regarding retirements needed to meet the state's 100 percent clean energy requirements over existing generation that it does not own. Second, as at least a quasi-public entity, a state power authority shifts financial risk from private firms and investors to electricity consumers and state taxpayers. When a state power authority issues bonds to finance construction of a new power plant, state taxpayers bear the risk of default if the bonds are backed by the full faith and credit of the state. In addition, if a new power plant construction project financed by the state power authority experiences cost overruns, electricity consumers and state taxpayers may have to cover the unexpected costs. If a state power authority enters into long-term contracts for electricity supply, it shifts onto consumers and taxpayers the risk that short-term electricity prices will fall below the prices agreed in the long-term contract. Third, if a state power authority can exercise eminent domain or preempt local regulations in order to facilitate siting and construction of new power generation, there is a potential for abuse of this ability.

g. Discussion of any affiliate relations or market power concerns related to implementation of FRR in New Jersey.

New Jersey FRR entities (whether the electric distribution companies, or a state entity) would have to attempt to construct their FRR Capacity portfolios through bilateral negotiations with suppliers that own eligible capacity. As the MA Report notes, no market power mitigation, or even market monitoring, would apply to the voluntary bilateral negotiations between a potential New Jersey FRR entity and capacity sellers, nor are there any competitive benchmarks for what a competitive price would be:

> In the FRR approach, there is no PJM market monitoring of offer behavior by generation owners, there are no market rules governing offers, and there are no market rules requiring competitive behavior. In the absence of a competitive market that includes the FRR area(s), there is no competitive market reference point to define what a competitive offer would be from the FRR generation owners in a bilateral negotiation or what the competitive market price would be. Prior market results do not define a competitive outcome in subsequent periods because market dynamics and market outcomes may change significantly. As a result, even the higher estimates of the cost impact to the customers of New Jersey from the creation of an FRR are likely to be conservatively low.[32]

As explained above, New Jersey FRR entities would have to construct FRR Capacity Plans that meet the locational requirements established by PJM. The most recent FRR Minimum Internal Resource Requirement would require at least 83.2% of a New Jersey FRR entity's capacity to be located in the Eastern MAAC zone. However, the ownership of the capacity in the Eastern MAAC zone is limited since the zone includes New Jersey, Delaware, parts of southwestern Pennsylvania, and the eastern shore of Maryland. Accordingly, a New Jersey FRR entity would face substantial market power in attempting to construct an FRR Capacity Plan as described below. The MA Report recognized this, and concluded that to construct a New Jersey FRR Plan, "the price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap,"[33] that is, the prices assumed in the MA Report's FRR scenarios discussed above. The MA Report provided standard measures of the concentration of generation ownership that indicate the presence of market power.

Under FERC's merger policy, a Herfindahl-Hirschman Index (HHI) over 1800 indicates a highly concentrated market; the MA Report calculated the HHI to be 2445 for New Jersey, and even higher in the PSEG zone.[34]

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[32] MA Report, p, 4
[33] MA Report p 4.
[34] MA Report p. 10.

The MA Report also applied a "more precise measure of structural market power," the pivotal supplier test, describing it as follows:

> A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the pivotal supplier test are measured by the residual supply index (RSIx). [35]

The MA Report found that "All participants in the New Jersey, JCPL, and PSEG FRRs fail the one and three pivotal supplier test (RSI is less than 1.0)."[36]

The MA Report also compared the FRR capacity needs of New Jersey and zones to the capacity available in New Jersey, and quantified the shortfalls,[37] concluding that "[Load Serving Entities] in New Jersey would need to secure capacity both from resource owners in New Jersey and capacity resources outside New Jersey to meet the FRR UCAP obligation for the New Jersey FRR service area."[38]

This is not the first time the notion that New Jersey might use the FRR alternative has arisen. In an order issued April 12, 2011, FERC accepted changes to the RPM MOPR that were opposed by New Jersey, and suggested New Jersey could pursue state policy initiatives while satisfying the state's capacity obligations through the FRR alternative. At that time, the Division of Rate Counsel explained that the FRR alternative was not in fact a viable option for New Jersey, primarily due to the substantial market power that a New Jersey FRR entity would face in attempting to build an FRR Capacity Plan, among other barriers. See May 12, 2011 Affidavit of James F. Wilson, attached as Exhibit 1. Nothing has substantially changed since that time – New Jersey remains in the same constrained zone (Eastern MAAC), and the capacity serving the state remains highly concentrated and largely owned by affiliates of the electric

[35] MA Report p. 10.
[36] MA Report p. 11.
[37] MA Report p. 14 Table 8.
[38] MA Report p. 13.

distribution companies. The high concentration of capacity ownership in Eastern MAAC was quantified recently in a filing by PSE&G at FERC.[39] According to the filing, (specifically PSE&G and affiliates control over 20% of the capacity in Eastern MAAC; together with Exelon and affiliates, the two entities control a third of the capacity.[40]

The most recent New Jersey specific state summary is based on 2018 data and available at the PJM website.[41] According to PJM, New Jersey's actual 2018 peak load was 15,000 MW.[42] PJM's forecasted summer load, which is used for planning purposes, is projected to be 18,672 MW for 2019 and 18,455 MW for 2029.[43] For capacity market purposes, PJM indicated that New Jersey located resources offered 15,018 MW into the most recent PJM capacity auction (2021/2022), and that 13,230 MW cleared the PJM auction that encompassed 164,343 MW overall.[44] PJM typically matches its capacity requirements by zones that do not necessarily match to state boundaries. However, the 2019 load forecast represents a rough approximation of the amount of capacity PJM considered to be required for New Jersey. In that sense, the difference of approximately 5,442 MW (18,672 MW – 13,230 MW) represents total -out-of-state capacity needs to meet current loads.

h. Discussion of any related topics.

As a restructured state, New Jersey faces additional challenges to implementing FRR. The state and the participating load-serving entities would face additional costs and risks, primarily due to the inflexibility of the FRR provisions, the complexity of the FRR and RPM

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[39] PSEG Fossil LLC and Yards Creek Energy, LLC, Joint Application for Approval under Section 203 of the Federal Power Act, Docket No. EC20-49-000, March 30, 2020 "PSEG-Yards Application").
[40] PSEG-Yards Application Attachment 1, Affidavit of Julie R. Solomon, Table 2 p. 5, and workpapers.
[41] https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2018/2018-new-jersey-state-data.ashx?la=en
[42] Ibid. Slide 38.
[43] Ibid. Slide 31.
[44] Ibid. Slide 36.

rules, and the uncertain market and regulatory environment in which FRR Entities would be obligated to build and manage FRR Capacity Plans. This section identifies several such challenges; a more detailed review would likely identify quite a few more.

1. **Five Year FRR Capacity Plans Submitted Three Years in Advance**. The FRR alternative is elected for a minimum five-year period, and the FRR Capacity Plan submitted each **year** must identify resources for a five-year period beginning three years into the future (meaning that an FRR Capacity Plan submitted in April 2021 would have to identify sufficient resources to satisfy capacity obligations for the 2024/2025 through 2028/2029 Delivery Years). While an FRR Entity is permitted to update its FRR Capacity Plan each year and to identify replacement resources, there are likely to be costs incurred to obtain the rights to include resources in the FRR Capacity Plan and to adjust the plan from year to year The only exception from this minimum commitment is in the event of a "State Regulatory Structural Change" that substantially changes the state's retail access or default service rules.

2. **Changing Load Forecasts**. As stated above, the FRR Capacity Plan must identify resources to meet forecast obligations eight years into the future (for a five-year plan, three years forward). Load forecasting that far in advance is of course highly uncertain, and this requirement can lead to contracting a substantial quantity of resources that ultimately will not be needed. For example, PJM's forecast of Eastern MAAC peak loads resulted in a Reliability Requirement of 39,371 MW for the 2017/2018 Base Residual Auction, but for 2021/2022, the forecast was much lower and the requirement was 35,994.[45]

3. **Changing Internal Resource Requirements**. New Jersey FRR Service Areas would be located within defined LDAs and, therefore, subject to a requirement that a high

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[45] PJM, 2021/2022 RPM Base Residual Auction Planning Parameters, p. 5 Table 2.

percentage of the resources for the FRR Capacity Plan must be located within the LDA. The internal resource requirement is a function of the peak load forecast and also the estimated transmission capacity available to the LDA (Capacity Emergency Transfer Limit, or "CETL"). Both the load forecast and the CETL values change from year to year, causing swings in the minimum internal resource values.

4. **Changing LDAs and New LDA Internal Resource Requirements**. PJM has authority to define additional LDAs that could include portions or all of the New Jersey zones, based on tests reflecting transmission constraints or "if warranted by other reliability concerns consistent with the Reliability Principles and Standards." RAA Schedule 10.1. PJM has authority to include LDAs in RPM auctions if "such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels", or if PJM finds that including the LDA "is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards." PJM Tariff Attachment DD section 5.10.ii.C. The fact that a zone was entirely served by an FRR Entity would presumably not change this authority. If PJM chooses to model an additional LDA in RPM, it must notify the market of the new LDA and of the corresponding FRR minimum internal resource requirement by March 31 before the base residual auction. This would give an FRR Entity only a few weeks to adjust its FRR Capacity Plan, due one month before the base residual auction, to conform to the new minimum internal resource requirements.

5. **Restrictions on Sale of Excess Capacity**. An FRR Entity must either carry a "threshold amount" of excess capacity above the obligation based on forecast peak load, or commit to not selling any excess capacity into RPM auctions. This may not be a problem under the circumstances contemplated here, because the FRR Entity would likely simply release any

excess resources from contractual obligations, although arranging and exercising this flexibility would likely entail additional cost.

6. **Possible Rejection of FRR Plan**. The RAA states that PJM can reject an FRR Plan if it is found to not satisfy the FRR Entity's capacity obligations, and the FRR Entity would be given five business days to cure the insufficiency. If the FRR Entity is unable to address the insufficiency, it would be subject to an FRR Commitment Insufficiency Charge equal to two times the Cost of New Entry for the relevant location (two times $133,144/MW-year, for 2021/2022[46]), times the shortfall in MW, "for the remaining term of such plan." RAA Schedule 8.1, section D.7.

7. **Various Penalties for Non-Compliance or Resource Non-Performance**. The RAA specifies various penalties for non-compliance with the FRR requirements or non-performance of the resources used to meet the FRR obligations, rendering any failure to accurately manage the portfolio of resources used to fulfill the FRR capacity obligations costly. FRR Entities might choose to carry excess capacity (at additional cost) to mitigate the risk of the various penalties.

These and other provisions of the FRR rules impose highly inflexible capacity procurement requirements and substantial penalties for any non-compliance that are not founded on or required by the resource adequacy needs of the system. Many of these provisions reflect the consensus achieved among the parties to the RPM settlement to make the FRR alternative unattractive, and are not necessary to ensure that an FRR Entity bears its share of the capacity needs of the system. No capacity-short load-serving entity would acquire commitments to meet 100% of forecast needs eight years in advance, as required by the FRR rules, nor would any state

[46] PJM, 2022/2023 RPM Base Residual Auction Planning Parameters, p. 7 Table 3.

require its load-serving entities to do so. This requirement is especially inefficient under current circumstances, characterized by slower and increasingly uncertain peak load growth and an abundance of short lead-time new resources, most notably demand response

Furthermore, if New Jersey tried to use FRR, there is substantial regulatory risk that the rules would be changed. The complexity of the FRR and RPM rules, the fact that FRR has never been elected for loads in a large, capacity-importing region, and the fact that the only intersection of FRR and retail access has led to protracted litigation, provide additional reasons for concern that FRR election by New Jersey entities would reveal additional shortcomings in the rules or consequences considered unintended or undesirable by some interested parties.

As one example of FRR provisions that could be changed to make it less attractive, there has long been grumbling about the "Fixed" aspect of the Fixed Resource Requirement ("FRR") alternative. As noted above, under the current rules, an FRR entity need only procure the required RTO-wide reserve margin, based on a "one day in ten years" resource adequacy criterion. RPM typically clears a substantially larger reserve margin,[47] and this has led parties to argue that FRR entities "lean on the rest of the RTO for reliability support in excess of the level they are procuring."[48] These parties propose that FRR entities be required to procure the larger reserve margin clearing in RPM. Taking a different angle of attack, the MA Report notes that zonal reliability requirements are determined based on a more stringent "one day in 25 years"

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[47] See, for instance, PJM, 2021/2022 Base Residual Auction Results, Table 1 (showing recent RPM cleared reserve margins over 21%, compared to a target reserve margin of 15.8% for 2021/2022); see also Wilson, James F., Over-Procurement of Generating Capacity in PJM: Causes and Consequences, prepared for Sierra Club and Natural Resources Defense Council, February 2020, p. 1. https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/Wilson%20Overprocurement%20of%20Capacity%20in%20PJM.PDF

[48] See, for instance, Affidavit of Roy J. Shanker, Ph.D. on Behalf of the PJM Power Providers Group, attachment to the Initial Brief of the PJM Power Providers Group, October 2, 2018 in FERC Docket Nos. EL16-49 et al., p. 16.

standard, and suggests that the higher standard and resulting larger requirement should apply to FRR entities located in zones.[49]

As another potential example, the percentage of internal resources required for each LDA in a FRR Plan is based on a calculation that likely would receive additional attention, which could lead to these percentages increasing. The Minimum Internal Resource Requirement depends upon the LDA's Capacity Emergency Transfer Objective ("CETO"), among other parameters. The CETO methodology is described in PJM Manual 20 and, accordingly, it can be changed without FERC approval.[50] The current rules allowing FRR entities to purchase and sell bilaterally with other PJM entities has also come under attack.[51]

While pursuing the FRR alternative would likely entail substantial administrative cost due to its many requirements and inflexibility, and substantial market costs due primarily to market power, there is also considerable risk that the rules would be changed to impose additional onerous requirements or costs just before or even after an FRR Entity has elected FRR and become committed to its minimum five-year term. If that happens, there is a substantial risk that pursuing the FRR option would not solve the problems the state is seeking to solve, but will just lead to additional different problems since under the FRR option, New Jersey would still be subject to PJM oversight and rules.

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[49] MA Report p. 13 ("However, if a New Jersey FRR service area were created, the FRR UCAP obligation reflects only the 1 day in 10 years loss of load expectation, which is a less stringent reliability standard than the 1 day in 25 years that would apply if New Jersey remained in the PJM Capacity Market (note 30): This result, which has been part of the RPM design from its inception, should be reviewed to ensure its consistency with the design of FRRs and the capacity market. In the future, this rule could be changed to ensure consistency."

[50] See PJM Manual 20: PJM Resource Adequacy Analysis Revision: 10, Effective Date: March 21, 2019, Section 4: PJM Capacity Emergency Transfer Objective Analysis, Section 4.3, Modeling Specifics (describing inputs to the calculation, including monthly load profiles, assumptions about retirements and planned generation, and the "one day in 25 years" LDA risk level, among others), and page 35, Revision History (noting ten revisions, and four since 2015).

[51] Affidavit of Roy J. Shanker, Ph.D. on Behalf of the PJM Power Providers Group, attachment to the Initial Brief of the PJM Power Providers Group, October 2, 2018 in FERC Docket Nos. EL16-49 et al., p. 16.

2. Can New Jersey Utilize the FRR to Accelerate Achievement of New Jersey Clean Energy Goals?

a. Discuss whether FRR is a viable construct to assist New Jersey in achieving its clean energy goals.

FRR by itself is not a construct that will assist New Jersey in achieving its clean energy goals. Rather, New Jersey would need to put further requirements on the FRR plan, such as mandatory clean energy resource requirements to achieve the state's clean energy goals. It is unclear whether the FRR mechanism is necessary to do this. The FRR extends over a period of five years, the state's clean energy goals extend over a period of thirty years. In theory, New Jersey could structure successive FRR plans to meet its clean energy objectives, but the five year period may be insufficient to impact long-term generation and retirement decisions to get New Jersey to 100% clean energy by 2050. The FRR construct is limited to the PJM capacity market. Large scale renewable projects would still need to participate in the wholesale energy market, unless New Jersey returns to a cost of service mechanism like vertically integrated utilities. As noted previously, the five year period for FRR capacity obligation does not address the required energy revenues for a developer of large scale renewables. Also, as discussed below, this could impact pricing and reliability.

b. Discuss whether any FRR could be structured to ensure procurement of clean energy resources to meet resource adequacy needs in line with the 2019 EMP objectives.

(i) How would procuring greater numbers of clean energy resources affect pricing outcomes?

In general, clean energy resources are more costly than other resources on the market. For example, the Board's recent approval of the first 1,100 MW of offshore wind for the state was set a levelized Ocean Renewable Certificate (OREC) price of $116.82/MWh over the 20 year period.[52] However, as Governor Murphy has expressed in the release of the 2019 NJ Energy Master Plan, use of clean energy resources versus traditional fossil fuels is the preferred state policy.[53] As stated in Rate Counsel's comment on the EMP, the rate impact on NJ ratepayers must be carefully considered before the adoption of any revision of the state's energy procurement processes.[54] Further, as of this date, the analysis of the modelling of the EMP on NJ rates is still not known. Rate Counsel would caution that the Board consider the rate impacts of incorporating clean energy goals in conjunction with any consideration of an alternative capacity procurement approach. To the extent clean energy resources are required; New Jersey should try to meet its policy goals in the most cost efficient way possible.

(ii) Could the State require that procurements "internalize" the value of anticipated carbon emissions during the delivery year, subject to a true-up?

As a potential FRR entity approaches resource owners and attempts to negotiate their commitments to an FRR Capacity Plan, the FRR entity can propose provisions that would call for any future revenues associated with carbon attributes to be reflected in the pricing. However, there would not seem to be a mechanism for the state to require any resource owners to accept such provisions.

As noted above, the state can establish a mechanism for how the cost of an FRR Capacity Plan is allocated to LSEs.[55] The compensation mechanism can also take into account that some resources included in a FRR Capacity Plan are likely to be receiving revenues through a state program that compensates zero emissions resources, and these revenues may be partly or wholly

[52] See the BPU Order dated June 21, 2019 in BPU Docket No, QO18121289 at page 19. The BPU's consultant estimated that the net OREC levelized price to be $46.46/MWh. Available at https://www.bpu.state.nj.us/bpu/pdf/boardorders/2019/20190621/6-21-19-8D.pdf
[53] https://www.2020 NJBPU EMP.pdf,
[54] See, Rate Counsel Comments on draft Energy Master Plan 9-16-19.pdf; pp. 6-7.
[55] RAA Schedule 8.1.D.8.

reflected in the cost of the FRR Capacity Plan. The entity or entities responsible for managing the could recover the costs, net of revenues, from the LSEs

(iii) How could New Jersey determine what such a reference carbon value could be, addressing both price and environmental considerations?

New Jersey is about to re-enter the Regional Greenhouse Gas Initiative (RGGI) after leaving RGGI in 2011. The nine states (ten, once New Jersey re-enters) participate in a regional market that sets caps on greenhouse gas emissions from the power sector. As part of the process to rejoin RGGI, New Jersey sets a cap of 18 million short tons that steadily declines through 2030.[56] The current RGGI allowance price is $5.65 per short ton.[57] While RGGI sets a carbon price for the power sector, RGGI does not extend to other sectors, notably transportation and heating fuels. The state is participating in the Transportation and Climate Initiative that includes 11 other states to work on regional solutions to reduce carbon emissions in the transportation sector. Since carbon emissions are a societal issue, the state has and should continue to work with other states to determine appropriate carbon values that address price and environmental considerations. New Jersey should rely on a market to set a value on carbon.

(iv) How would preferentially procuring clean energy resources affect reliability outcomes?

Because PJM will continue to determine and impose reliability requirements that reflect the evolving resource mix over time, preferentially procuring clean energy resources will not affect reliability outcomes. However, as the penetration of variable clean energy resources such as wind and solar increase, the capacity value earned by such resources is likely to decline.

[56] See https://www.state.nj.us/dep/aqes/docs/njac7_27c.pdf
[57] See https://www.rggi.org/auctions/auction-results/prices-volumes

c. Discuss whether the State should consider adopting an energy market carbon dispatch price, in addition to RGGI, in lieu of an FRR approach.

The FERC's recent orders affect the PJM capacity market, but do not address energy markets. Should New Jersey adopt a state energy market carbon dispatch price that impacts wholesale markets, Rate Counsel believes that could be challenged in Federal courts since the state is still part of the regional wholesale energy market.

(i) How would such an approach work?

For an energy market carbon dispatch price to work, PJM would need to change its market rules, which would require considerable time and effort. New Jersey, alone, would not be able to affect this change without leaving PJM.

(ii) Discuss whether such a carbon price is a viable construct to ultimately get New Jersey to achieve the totality of the 2019 EMP goals.

A PJM stakeholder group, the Capacity Pricing Senior Task Force ("CPSTF"), is currently wrestling with the many complex issues that would arise if one or a group of PJM states wished to pursue energy market carbon pricing. While PJM has expressed its willingness to implement carbon pricing if requested by a group of states, it would likely take several years for any such program to go into effect. In addition, initial modeling suggests that such carbon pricing would likely have a modest impact on energy prices and incentives for zero- or low-carbon resources.[58]

d. Discuss whether there are any models for meeting the state's resource adequacy needs and advancing the state's clean energy agenda.

Rate Counsel is not aware of any other models at this time.

[58] See, for instance, PJM, Expanded Results of PJM Study of Carbon Pricing & Potential Leakage Mitigation Mechanisms, Carbon Pricing Senior Task Force meeting, March 27, 2020.

3. Can Modifications to the Board's Basic Generation Service Construct Facilitate Resource Adequacy Procurements aligned with the EMP Clean Energy Objectives?

Before determining whether modifications to the BGS process can be implemented to meet New Jersey's EMP Clean Energy objectives, it is important to review the original intent of BGS. The purpose of the BGS process was to provide residential and small commercial customers (RSCP) who did not choose an electric supplier with energy and capacity for a period of three years using competitive market prices and a competitive auction process based on the experience of sophisticated market participants.[59] Similarly, BGS provides larger commercial and industrial customers a one-year price. The goal of the BGS process was to reduce electricity costs to participants by dividing the state's participating load into equally sized tranches that BGS suppliers would then bid to supply over the course of the commitment period (three years for RSCP customers and one year for larger commercial and industrial energy pricing (CIEP) customers. The intent was to provide these customers with stable and lower prices, not to explicitly meet other policy objectives.

New Jersey's 1999 Electric Discount and Energy Competition Act (EDECA) created the concept of Basic Generation Service. Specifically, EDECA defined Basic Generation Service as follows:

> "Basic generation service" means electric generation service that is provided, pursuant to section 9 of this act, to any customer that has not chosen an alternative electric power supplier, whether or not the customer has received offers as to competitive supply options, including, but not limited to, any customer that cannot obtain such service from an electric power supplier for

[59] The state has two different BGS products. The BGS residential and small commercial product (BGS-RSCP), originally known as BGS-Fixed Price, is a three-year product for residential customers and commercial customers with peak loads of less than 500 kilowatts (kW). The BGS-Commercial Industrial Energy Pricing (CIEP) is for customers with peak loads of 500 kW or greater. The BGS-CIEP product is a single year product unlike the BGS-RSCP product. In addition, the BGS-CIEP product provides an energy charge based on hourly real-time energy prices. These differences result in the reporting of BGS-RSCP product in terms of $/kWh and the BGS-CIEP in $/MW-day.

any reason, including non-payment for services. Basic generation service is not a competitive service[60] and shall be fully regulated by the board;

N.J.S.A 48:3-51.

The electricity market has seen many changes since the first BGS Auction in 2002, and during this time the BGS auction has seen changes. However, the basic structure of the BGS auction has remained fairly constant. The three-year ladder structure enables prices that remain stable, since short-term market fluctuations are smoothed and only one-third of the portfolio for residential and small commercial customers is exposed to current market conditions. For larger commercial and industrial customers, the current BGS contract duration is only one year, but still provides stable, and hopefully, lower prices.

The Board has posed several questions regarding the adequacy of using the BGS construct to further the state's clean energy objectives. To answer these questions, some foundational information about New Jersey's energy and capacity requirements is necessary.

Current BGS statistics

The April 2020 switching statistics for the state indicate that approximately 87 percent the state's residential load (approximately 8,500 MW out of 9,843 MW) participate in the BGS process.[61] For commercial and industrial (C&I) sector, 38 percent the state's eligible load (3,946 MW out of 10,612 MW) participate in the BGS process. Overall, approximately 61 percent of the state's eligible load (12,481 MW out of 20,456 MW) participates in the BGS process.[62] As a result almost 40 percent the state's eligible load is currently outside the BGS process that would

[6060]Under EDECA, competitive service means any service provided by an electric public utility or a gas public utility that the Board determines to be competitive or that is not regulated by the Board. .

[61] The 8,000 MW also excludes approximately 540 MW of residential load participating in the state's Government Energy Aggregation (GEA) programs.

[62] Available at http://www.bgs-auction.com/bgs.dataroom.asp

not be affected by changes to the BGS process. Drastic changes to the BGS process may result in increasing load migration out of the BGS process.

New Jersey Energy Statistics (EIA)

The Energy Information Agency (EIA) compiles information regarding New Jersey's energy mix and consumptions. This information is summarized below to provide additional context to any proposed change to the BGS auction process. The EIA values will differ from the BGS and PJM values, since the EIA values are strictly based on actual generation and reported capacity that are independent from market participation either through the BGS process or PJM capacity market. The EIA numbers may be more applicable to the state's clean energy goals since the location and generation data will populate the state's emission inventory to measure compliance with the state's Clean Energy objectives. EIA Form 860 reports the state's generating capacity. The most recent form using 2018 data reports that there are 19,203 MW of generating capacity located within New Jersey.[63] That same form reported that PSEG affiliates (PSEG Fossil LLC, PSEG Nuclear, and PSEG) control 8,418 MW or 44 percent of capacity located within the state.[64] The fact that almost half of the existing in-state generation is associated with affiliates of Public Service Enterprise Group highlights political and regulatory considerations to any solution forwarded by the Board.[65]

On the energy side, EIA Form 923 reports New Jersey in-state generation of 71,299,910 MWh for 2019. Of which the PSEG affiliated units generated 38,171,509 MWh or

[63] EIA Form 861. Available at https://www.eia.gov/electricity/data/eia860/
[64] EIA Form 861. Available at https://www.eia.gov/electricity/data/eia860/. The form does not denote PSEG's 57 percent ownership percentage for the Salem nuclear units.
[65] Rate Counsel notes that the EIA capacity numbers are different than what PJM reports for the state for the purposes of the PJM capacity market. Should the entire state pursue an FRR, the market power concern regarding PSEG might be alleviated since the state would be part of a larger zone. PSEG and its affiliates, however, own generation outside the PS zone, so market power does remain an issue. On the other hand, if PSEG were to pursue a utility-specific FRR, then the market power concentration may be exacerbated.

approximately 53 percent.[66] Electricity sales data is collected in EIA Form 861, however 2019 sales data is currently not available. The 2018 data reports New Jersey electricity sales of 76,016,762 MWh and in-state generation of 75,033,600 MWh.[67] The difference between sales and generation shows that the state remains an importer of electricity. Unless the state increases generation and/or reduces demand, New Jersey will need to import some electricity from outside the state.[68]

The BGS-RSCP product is an all-in product in that it includes energy, capacity, and ancillary services, while the BGS-CIEP product is priced based on the capacity obligation for the BSG-CIEP customers served.[69] As stated earlier, the BGS process was designed to maintain price stability for customers who did not have the sophistication to manage their electricity costs. The BGS auction provided these customers with a stable electricity product that was designed to harness the competitive market to stabilize electricity prices by utilizing the expertise of the BGS suppliers competing to provide service for pre-determined tranches. The BGS RCSP three-year product was not designed to meet the state's clean energy policy goals. As shown in the data above, the BGS process does not cover all of the eligible load within the state, rather only just over half of the state's load. Therefore, changing the BGS process would be insufficient and inadequate mechanism to address the state's transition to 100 percent clean energy over the next 30 years.

A major change in the BGS process could also have the effect of increasing load migration to third party suppliers. This could upset the price stability goals of the BGS process

[66] See Response to Question 2b regarding market power concerns and a possible New Jersey FRR. EIA Form 923
[67] https://www.eia.gov/electricity/state/newjersey/
[68] The reality is even more complicated since New Jersey is interconnected to several mid-Atlantic states and New York. At any given moment, electrons are flowing in and out of New Jersey regardless of the actual source of the electron.
[69] The winning BGS-CIEP supplier is still obligated to provide BGS-CIEP customers with full electricity requirements.

since load requirements would be reduced thereby reducing the number of potential bidders to supply BGS loads due to the resulting tranches might be reduced in size and number. While third party suppliers will still need to meet New Jersey requirements, the Board's oversight of clean energy objectives may be blunted by increased switching of eligible load to third party suppliers that are not under the purview of the Board.

Finally and maybe most telling is that the FERC's April 16th Re-hearing order complicates the BGS process even more.[70] In that Re-hearing order, FERC determined that state default service procurement auctions are state subsidies. A change to the BGS process to make it a clean energy mechanism will certainly make it obvious to FERC that the BGS process should be seen as a subsidy under FERC's definition and will be subject to MOPR. This will have significant impacts on BGS auction results, driving up prices and driving away potential bidders. The end result may be to force New Jersey to exit the PJM RTO entirely. Should New Jersey exit PJM, the state could find itself in unchartered territory and without the lower prices produced by a larger wholesale market.

a. Discussion of a portfolio manager approach as a means of providing a wider range of resource options.

In 2003, Rate Counsel's consultant Synapse Energy Economics published a report on the portfolio management concept.[71] At a high level, the portfolio manager would be responsible for determining a procurement strategy that would encompass current participants in the BGS process. This role would essentially balance supply and load across the auction process. In 2003, Rate Counsel's goal for the portfolio management strategy was to provide ratepayers with

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[70] FERC Order on Rehearing and Clarification. Docket Nos. EL 16-49-002, EL 18-178-002. Issued April 16, 2020, Paragraph 386, Available at https://www.ferc.gov/whats-new/comm-meet/2020/041620/E-5.pdf

[71] https://www.synapse-energy.com/sites/default/files/SynapseReport.2003-10.RAP_.Portfolio-Management.03-24.pdf

affordable and reliable generation at reasonable cost to ratepayers. It was not to meet any specific clean energy objectives and it was meant to remain within the confines of the PJM wholesale market. FERC's MOPR order essentially eliminates the ability of a portfolio manager to negotiate long-term contracts with renewable generation that would not be considered a state subsidy and still remain in PJM.

The primary objective of a utility or default service provider is to procure reliable electricity services at just and reasonable rates. The state may have other objectives that include mitigating risk for ratepayers; maintaining customer equity; improving the efficiency of the generation, transmission and distribution system; improving the efficiency of customer end-use consumption, and reduction of environmental impacts. The more constrained the portfolio manager is, i.e., must purchase specific clean energy, the less competitive the process. This leads to higher prices, and more importantly, runs more clearly afoul of FERC's recent MOPR order.

A portfolio management process for just the BGS is not sufficient to enable the state to meet its 100% clean energy target by 2050. A portfolio management for just the BGS process would only be able to determine and implement the mix of electricity resources for the BGS customer. If BGS prices were to rise because of the portfolio manager's choices, more customers would migrate to third party suppliers, making any changes to BGS even less impactful. The portfolio process will not make the BGS process more able to do that which it was never designed to accomplish. Moreover, the portfolio manager process is complicated and may be difficult to implement.

The portfolio management approach would require several key steps. First, the portfolio manager would need to prepare load forecasts that represent the best assessment of the state's demands for generation, transmission and distribution services for the long-term future. Second, a portfolio manager would need to assess all the opportunities for cost-effective energy efficiency resources. Third, the portfolio manager would need to assess generation-related opportunities, including building power plants; purchasing from the wholesale spot market; purchasing short-term and long-term forward contracts; purchasing derivatives to hedge against risk; developing distributed generation options; building or purchasing renewable resources; and expanding transmission and distribution facilities. This would be similar to the development of resource plans for participating utilities and for the entire state.

Once a resource plan has been determined, the portfolio manager must flexibly and judiciously implement the plan. This would require ongoing evaluation and updating to address risk management, but will also allow portfolio managers to respond to unexpected developments in wholesale electricity markets and the industry in general. The portfolio manager would need to monitor and respond to: (a) acquisition and disposal of portfolio elements; (b) market conditions, environmental trends, and electric loads; (c) portfolio performance; and (d) potential new acquisitions or hedging instruments. In addition, the portfolio manager will need to monitor counterparty credit and settlement risk which require constant attention. It is not clear what entity in the state would have the authority and ability to perform such tasks. These requirements would require substantial effort on the part of the state and probably the creation of a new authority, making the portfolio manager process an unwieldy option to meet New Jersey's desired resource options.

b. Discuss potential changes to the BGS competitive processes to facilitate procurement of resources that meet the State's long-term clean energy objectives. Discuss efficiency implications of each option.

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The BGS process was expressly designed to procure resources from the competitive market to maintain stability and keep prices low for participants. The BGS process was not designed to meet New Jersey Clean Energy goals of 100% clean energy by 2050. Currently BGS suppliers are responsible for procuring RECs associated with their obligations. Changing the BGS process to meet the State's long term goals is simply not compatible with the BGS process's original intent. Moreover, as stated earlier, the FERC's April 16th Re-hearing Order has already found that the NJ BGS process may constitute a state subsidy subject to MOPR. Each of the proposed changes would only further support a potential FERC determination that the BGS process is a subsidy.

(i) Clean Energy Standard, utilizing certificates to demonstrate compliance.

Rate Counsel presumes that a New Jersey Clean Energy Standard would include technologies currently exempted from the state's renewable portfolio standard. Generally, these excluded technologies include nuclear energy, large-scale hydropower, and carbon capture sequestration. The three existing nuclear units in the state already receive zero emissions credits so a clean energy standard would need to ensure that nuclear units are not receiving double benefits. The larger point is that a New Jersey clean energy standard with certificates would be the subject of the FERC MOPR to the extent those resources participate in the PJM capacity market.

Rate Counsel as assumes Staff is asking how the BGS mechanism would account for requirements of a Clean Energy Standard within the agreements between BGS suppliers and the electric distribution companies (EDC). Currently, BGS suppliers provide RECs to the EDCs under the current Supplier Master Agreements. RECs themselves are not explicitly factored into the auction process. The BPU's question implies that clean energy certificates would be part of the auction process. The language in the SMA states: "to satisfy the Energy Portfolio Standards with respect to its BGS-RSCP Supplier Responsibility Share and to transfer to the Company Renewable Energy Certificates and Solar Renewable Energy Certificates in accordance with Section 7.4;"[72] A clean energy standard requirement would result in a change in the current supplier master agreements to include new clean energy credits. From a practical standpoint a clean energy standard would not necessarily impact the existing BGS process. The larger issue is that a clean energy standard through the BGS process would only exacerbate FERC's perception regarding the BGS process.

(ii) Obligations on BGS Bidders to procure clean capacity resources, potentially with locational requirements.

Like the previous question, an obligation for BGS suppliers to purchase clean energy resources with a locational requirement would probably be subject to the FERC MOPR, which would impact those resources ability to participate in the PJM capacity market. In addition, locational requirements could interfere with interstate commerce, implicating the limits on state authority under the Commerce Clause to the U.S. Constitution.

Rate Counsel assumes Staff is asking how the BGS mechanism would account for requirements of a Clean Energy Standard within the agreements between BGS suppliers and the electric distribution companies (EDC). As noted above, BGS suppliers currently provide RECs to the EDCs under the current Supplier Master Agreements outside the BGS auction process. The proposed mechanism for locational requirements would probably require a change in the current RPS regulations (N.J.A.C §14:8-2-7) in addition to the BGS language. Current

[72] BGS-RSCP Supplier Master Agreement. July 2019. Page 14.

regulations only require the energy from Class I or Class II renewable energy credits (RECs) to be "generated within or delivered into the PJM region, as defined under N.J.A.C 14:4-1-2."[73] That said, if NJ RECs are definitionally changed to require a locational attribute, then the current BGS SMA language would not need any additional changes, since BGS suppliers are already required to meet the state's RPS obligations. The semantic change to the BGS language would not address the bigger issue that a locational component to the RPS would likely be subject to the MOPR and other constitutional challenges that could have the impact of further deteriorating the BGS process.

(iii) Billing capacity obligations to BGS Bidders from a state FRR portfolio.

BGS RSCP suppliers currently provide an "all-in" product to the EDCs that includes a capacity component. BGS CIEP suppliers provide a capacity component and pass-through the energy costs. Without knowing the exact mechanism and structure of a proposed statewide FRR portfolio, Rate Counsel cannot comment at this time about how the state could create a FRR portfolio where a load serving entity responsible for the FRR would contract with generators inside and outside the FRR zone for capacity during the five-year FRR period. A billing change would require changes to the existing supplier-master agreements, and a change in the auction process to incorporate any overlapping capacity contract components in existing BGS suppliers since the BGS-RCSP product from the BGS 2021 incorporates a term that extends from June 1, 2021 to May 31, 2024 for one-third of the load. The next BGS auction for the period starting June 1, 2022 would extend to May 31, 2025. If New Jersey were to pursue an FRR that starts June 1, 2024, the state would need to create a mechanism to ensure that BGS participants are not paying for capacity twice, once through the BGS and once through the FRR.

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[73] N.J.A.C §14:8-2-7

(iv) Other potential BGS construct modifications to meet the state's resource adequacy needs and advancing the state's clean energy agenda.

Rate Counsel does not believe that the state should modify the current BGS construct to meet current clean energy objectives. The process to move the State to 100 percent clean energy over the next 30 years is a much larger process than just the BGS auction which only encompasses slight half of the state's eligible load. Changing the BGS process without considering the ramifications of customer migration, and possible customer collapse of the BGS auction process may complicate the state's clean energy objectives. It will almost certainly defeat the BGS auction process's original intent to promote lower, stable prices. Rate Counsel reserves its right to comment on other proposed BGS construct mechanisms.

c. **Discussion of the pros and cons of modifying the BGS construct to facilitate the State's long-term clean energy objectives**.

As commented earlier, the BGS construct was created to provide ratepayers, who did not elect to participate in retail choice, with an "all-in" product based on competitive market prices. These ratepayers were unwilling or unable to shop for retail suppliers. The BGS process enabled potential suppliers to provide the "all-in" product based on their participation in the competitive market. In addition, the BGS construct was created to mitigate short-term market volatility by creating a three-year ladder. The State's clean energy goal extends 30 years, well beyond the time horizon of any individual BGS auction period currently. The Board and the State would need to change fundamental aspects of the BGS process to align the procurement periods for new and existing resources over the next 30 years. As noted earlier, the BGS process accounts for 61 percent of the state's eligible load. Simply changing the BGS process without addressing third party supplier obligations may create leakage issues that could drive up costs for ratepayers.

Leakage to retail suppliers may also create oversight issues for the Board since the Board licenses, but does not regulate third party suppliers.

d. Discussion of legislative and regulatory limitations and potential amendments necessary to enable the BGS construct to effectively facilitate the state's long term clean energy objectives, through the options recommended above or other options presented.

Rate Counsel does not recommend using the BGS construct to drive the changes needed for the State's ambitious long-term clean energy objectives. For many years, the BGS construct has effectively provided reliable, competitively-priced electricity to New Jersey's residential and small commercial customers. Limiting the BGS product to renewable and carbon-neutral options, would severely limit competition within the BGS auction.

From a legal standpoint, whether the BGS construct could be used to effectively facilitate the EMP's policy objectives depends on whether the enabling legislation can be read to include authority for the Board to impose these new requirements. It is well-established that a government agency may not "give a statute any greater effect than its language allows." In re Centex Homes, LLC, 411 N.J. Super. 244, 252 (App. Div. 2009)(quoting In re Freshwater Wetlands Prot. Act Rules, 180 N.J. 478, 489 (2004)). Further, any regulations promulgated which are inconsistent with the enabling legislation will be invalidated if they "violate the express or implied legislative policies of the enabling act." Id. at 252 (quoting GE Solid State, Inc. v. Dir., Div. of Taxation, 132 N.J. 298, 306 (1993)(quotation marks omitted). Under N.J.S.A. 48:3-57, each EDC is obligated to provide basic generation service ("BGS"). The power procured by the EDCs must be "at prices consistent with market conditions." N.J.S.A. 48:3-57(a). The Board regulates the price that the EDCs can charge to BGS customers. The reasonableness and prudency of the EDC charges includes a review of "the cost of power purchased at prices consistent with market conditions . . . in the competitive wholesale marketplace and related ancillary and administrative costs." Ibid.

In this case, the BGS auction process was created in response to the legislative mandate for electric utilities to procure power for basic generation service on a competitive basis and at prices consistent with market conditions. Additionally, this mandate is premised on several legislative findings and policy statements that declare it's the policy of the State to lower the high cost of energy and improve the State's choices of service through diversity of supply and reliance on established competitive markets. Competition was therefore introduced to reduce the aggregate energy rates currently paid by the State's consumers. The Board retains authority to "restore a competitive market place" in the event that market-power results in anti-competitive or above-market prices. See N.J.S.A. 48:3-50. Thus, if the Board were to seek to change the goal and purpose of the BGS auction, it would need to seek a change in the statute.

Based on these findings and declarations, the clear intent of the EDECA legislation and the BGS construct was to lower prices for retail consumers through the competitive wholesale marketplace. To the extent that changes to the BGS construct, such as a Portfolio Manager or Clean Energy Standard, would result in higher prices which exceed market conditions, the changes may be inconsistent with the legislative intent of EDECA. Further, the Class I RPS requirements under N.J.S.A. 48:3-87(d), have a hard cost-to-customer cap of 7% following EY 2021. The reliance on competitive procurement through the wholesale market and hard cost cap together implies a strong intent that costs to ratepayers be a strong – if not the predominate factor – in the Board's policy regarding the BGS. Moreover, the EMP acknowledges that "New Jersey's current regulatory paradigm is anchored by . . . [EDECA], which in 1999 enabled market competition for electricity generation and established New Jersey's first RPS." EMP at

103. Thus, the Board's ability to mandate the changes to the BGS construct necessary to realize the EMP's long-term clean energy objectives without legislative amendments to the enabling statute is circumscribed by the statute's plain language and the intent of EDECA.

Additionally, although the BGS construct has been approved annually by Board Order, it is a quasi-legislative process subject to certain rulemaking due process requirements, namely, notice and opportunity for comment by the affected parties. See In re Provision of Basic Generation Serv. for Period Beginning June 1 2008, 205 N.J. 339, 352 (2011) (invalidating the shifting of solar alternative compliance payment costs from suppliers to ratepayers due to procedural deficiencies in the Board's decision-making process). Therefore, in addition to the legislative constraints, any regulatory change must include a quasi-rulemaking process similar to that of formal rulemaking procedure.

Based on these regulatory limitations, implementation of a Clean Energy Standard would require legislative amendments to the BGS enabling legislation under N.J.S.A. 48:3-57, as well as, the current RPS requirements under N.J.S.A. 48:3-87. The BGS construct was intended to procure power for basic generation service at prices consistent with market conditions. The procurement full requirements product of basic generation service customers from a zero-emission, clean energy sources will likely cost more per kilowatt-hour than procuring power from more traditional energy sources,,, and thus are inconsistent with the enabling legislation.

Similarly, the portfolio management approach, whether through a state agency or conducted by the EDCs, would likely require legislative amendments to the current BGS and RPS statutes, because the preference for zero-emission, clean energy sources to achieve the State's long-term clean energy objectives likely exceeds the market price for equivalent amounts of energy from traditional sources. Based on this fact, the EDCs may be foreclosed from procuring energy for BGS customers exclusively from such sources under N.J.S.A. 48:3-57, unless the prices meet market conditions. If portfolio management is governed by a state agency, the EDC's obligations to procure BGS may need amendment as well.

Finally, as stated above, transforming the BGS Auction into a mechanism that would favor particular generation resources would increase the likelihood that those favored resources would be subject to MOPR under FERC's recent order. Thus, the effect of FERC's decision will only be compounded if the State's mandated limitations on the BGS product and would result in BGS customers paying more without any tangible or incremental environmental benefits in return. Using the BGS construct would also not be particularly effective at achieving the State's clean energy goals, because customers could then simply flee the higher BGS rates for the lower rates of third-party suppliers.

e. Discussion of affiliate relations or market power concerns related to any proposed changes to the BGS construct.

Again, there are significant market power concerns. Under the construct, there are very few suppliers who can supply the clean energy generation New Jersey is seeking. For the most part, that generation is owned in whole or in part, by affiliates to the EDCs. This would also be a consideration for existing generation that is owned by affiliates of the electric distribution companies. As noted earlier, PSEG Fossil and PSEG Nuclear generated 53 percent of the energy generated within the state for 2019.

Under the existing BGS construct, BGS suppliers could in theory contract with generators located within PJM. A change in the BGS construct to impose locational requirements could result in New Jersey located generation having an outsized ability to set prices. Any proposed change to the exiting BGS construct would require a change in the Board's oversight authority to ensure the reasonableness of contracting arrangements.

f. Discussion of whether the BGS construct can ultimately get New Jersey to achieve the totality of the 2019 EMP goal.

The BGS (RSCP) construct was originally designed to insulate ratepayers from market volatility through the three-year all-in requirements and to lower electricity prices through the competitive process. The BGS construct cannot achieve the totality of the 2019 EMP goal since currently only half of the state's load participates in the BGS process. As noted above, drastic changes to the BGS process may only accelerate migration out of the BGS process, which may result in higher prices for remaining customers since there would be fewer and/or smaller tranches to attract bidders.

The State's clean energy goals extend 30 years, well beyond the time horizon of any individual BGS auction period currently. The Board and the State would need to change fundamental aspects of the entirety of the state' energy policy, not just the BGS process, to align the long-term resource needs (new resources and retiring existing resources) over the next 30 years to meet the state's goal of 100 percent clean energy by 2050.

g. Discussion of any related topics.

The BGS process does not address the entirety of the state's load and energy requirements. Notable exceptions to the BGS process include self-generation sites, customers on third-party-supplier, and Butler Electric Cooperative. Any changes to the BGS and/or long-term procurement of new "clean-energy" resources and the retirement of existing resources would require the state to consider stakeholders that may not fall under the purview of the Board.

The BGS Process is not appropriate to address the State's EMP Clean Energy Goals. Any attempt to do so will destroy the BGS Process's original intent and result in a process subject to MOPR and possibly other constitutional challenges. The BGS process was never to design to address environmental issues and would become a fundamentally different product were it redesigned to do so.

4. Can Other Mechanisms, such as a Clean Energy Standard or Clean Energy Market, Facilitate Achievement of New Jersey Clean Energy Goals?

a. Discussion of alternative competitive processes to facilitate the State's long-term clean energy objectives.

b. Discussion of implementation of a Clean Energy Standard.

c. Discussion of the pros and cons of various alternative market construct to achieve a clean energy future.

d. Discussion of legislative and regulatory limitations and potential amendments necessary to advance alternative market mechanisms to achieve the 2019 EMP goals.

e. Discussion of affiliate relations or market power concern related to proposed alternative mechanisms.

Rate Counsel has no comments on these issues at this time.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Power Providers Group	)	Docket No. EL11-20-000
v. PJM Interconnection, L.L.C.	)	
	)	
PJM Interconnection, L.L.C.	)	Docket No. ER11-2875-000
	)	
	)	(not consolidated)
	)	

AFFIDAVIT OF JAMES F. WILSON IN SUPPORT OF REQUEST FOR REHEARING AND FOR EXPEDITED CONSIDERATION OF NEW JERSEY DIVISION OF RATE COUNSEL

CONTENTS

AFFIDAVIT OF JAMES F. WILSON IN SUPPORT OF REQUEST FOR REHEARING AND FOR EXPEDITED CONSIDERATION OF NEW JERSEY DIVISION OF RATE COUNSEL

I. Introduction

1. My name is James F. Wilson. I am an economist and principal of Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. My experience, qualifications and past testimony were described in my affidavit filed on March 4, 2011 in this proceeding on behalf of the New Jersey Division of Rate Counsel and in my curriculum vitae, which was attached as Exhibit JFW-1 thereto.

3. This affidavit was also prepared at the request of the New Jersey Division of Rate Counsel. In an order issued April 12, 2011 ("April Order") the Commission accepted most of the revisions proposed by PJM Interconnection, L.L.C. ("PJM") on February 11, 2011 to the Minimum Offer Price Rule ("MOPR") associated with PJM's Reliability Pricing Model ("RPM") capacity construct. The April Order suggested that the Fixed Resource Requirement ("FRR") alternative defined in the PJM Reliability Assurance Agreement ("RAA") provides an alternative for satisfying capacity obligations while accommodating New Jersey policy initiatives. I was asked to evaluate whether FRR is a viable alternative for New Jersey given New Jersey's circumstances and policy initiatives.

II. Background and Scope of Analysis

4. In 2005, PJM proposed to implement the new, locational RPM capacity construct, largely out of concern that no new power plants had been built in New Jersey for several years.[1] Five years later (2010), despite RPM, this situation was largely unchanged, and the state of New Jersey took action by implementing its Long-Term Capacity Agreement Pilot Program ("LCAPP"). The state of Maryland has also considered actions to encourage construction of new capacity in that state. This proceeding largely resulted from concerns about the potential impact

[1] "PJM has seen few generation additions, but high rates of generation retirements, in some of the same areas in the PJM region where load is growing fastest. As a result of these trends, in particular a spate of actual and announced generation retirements, part of the PJM system – the state of New Jersey – faces violations of reliability criteria in each of the next four years." PJM's RPM Application in Docket No. ER05-1410, August 31, 2005, p. 5.

on RPM prices of these initiatives. The RPM rule changes approved in the April Order would likely thwart the New Jersey and Maryland initiatives by imposing minimum offer prices such that the capacity resulting from the initiatives would be unlikely to clear in RPM's auctions and, therefore, would neither count toward meeting capacity obligations nor receive capacity payments.

5. The April Order recognized that the new rules could cause new resources self-supplied by load-serving entities or assisted through state policy initiatives not to clear in RPM (likely resulting in such resources not being built), but suggested that this result was not too harsh because the FRR alternative could be used to permit construction of the same resources and accomplish the same objectives. The April Order states:

> "PJM's tariff also provides an alternative for those load serving entities that wish to bring new generation resources into the PJM capacity market without risk of being mitigated under the MOPR. They may avail themselves of the FRR option to satisfy their capacity requirements." April Order, P 192
>
> "The FRR option is the alternative for load serving entities that wish to secure their own capacity resources outside of a competitive market, whether as directed by state-authorized integrated resource plans, or pursuant to other considerations." April Order, P 193
>
> "Nor are we persuaded, as intervenors argue, that permitting new self-supply to be rejected at its preferred offer price is too harsh and too costly for ratepayers. First, as noted above, the FRR option is available for those load serving entities that want to secure capacity outside of the RPM market..." April Order, P 195

6. The Complaint and Request for Clarification Requesting Fast Track Processing ("P3 Complaint") filed by the PJM Power Providers Group ("P3") in Docket No. EL11-20-000 also suggested that the mitigation would not be unduly harsh and intrusive because the FRR alternative is available and provides broad flexibility in capacity arrangements that would not be subject to the MOPR:

> "Because FRR Parties are outside the purview of the Minimum Offer Price Rule, they remain free to make arrangements for capacity at any terms otherwise lawful, including at prices above the RPM clearing price, should they so choose. The availability of this option … should be a sufficient answer to any cavil that RPM with the Revised Minimum Offer Price Rule would be unduly harsh and intrusive to parties seeking to self-supply." P3 Complaint, p. 52

7. PJM's Independent Market Monitor also expressed the view that New Jersey could use the FRR alternative to regain control of decisions regarding resource adequacy for the state:

> "New Jersey clearly has the right and the obligation to address its own reliability needs if it does not think they are being adequately addressed through the PJM markets. The most direct option would be for New Jersey to require that LSEs opt out of RPM markets entirely via the Fixed Resource Requirement Alternative ("FRR"). Under FRR, New Jersey's procurement choices would have much less impact on other participants in RPM markets. New Jersey could make its own decisions about how best to reach required reliability levels." Comments of the Independent Market Monitor for PJM, March 4, 2011, p. 10

8. As the April Order noted (at P 137 and footnote 72) various other parties also suggested that FRR is an alternative for New Jersey to pursue its resource adequacy objectives.

9. I was asked to conduct a preliminary evaluation into whether the FRR option is a viable alternative for New Jersey as suggested in the April Order, *i.e.*, to evaluate whether FRR could be used to meet the capacity obligations of New Jersey loads in a manner that would also accommodate pursuit of legitimate state public policy objectives, including the resource adequacy objectives the LCAPP was designed to promote.

10. For my analysis I took as a starting point that the capacity obligations of New Jersey loads are presently satisfied primarily through RPM and at RPM prices. The owners of existing resources would consider RPM prices to be the "opportunity costs" of reaching agreement to provide capacity to a New Jersey FRR Entity for its FRR Capacity Plan. Therefore, without forecasting future RPM prices or evaluating their economic efficiency or reasonableness, I focused on the impact of electing the FRR alternative relative to the RPM status quo.

11. I have also not evaluated the regulatory or political feasibility of the FRR alternative. The RAA includes a "savings clause" that appears to allow a state to require jurisdictional utilities to become FRR Entities. My analysis assumes that most or all of the four electric distribution companies that serve New Jersey, and the various public power entities located within the four utility zones, could become FRR Entities either voluntarily or through state action.

12. My analysis considers the viability of the FRR alternative for all of New Jersey, and, for reasons that are explained, I also consider the possibility of FRR for only two or three of

New Jersey's four utility zones. While the FRR rules also allow FRR service areas that are smaller than a utility zone if certain requirements are met, I do not evaluate smaller FRR service areas. Some of the risks associated with the FRR alternative would be exacerbated by a smaller service area and served load, and the benefits, costs and risks would be concentrated on a smaller group of customers, making this relatively unattractive.

13. Finally, my evaluation assumes the FRR rules as they exist at this time. However, I also briefly discuss the risk that these rules will be changed.

III. Summary of Conclusions

14. The RAA permits an investor-owned utility, public power entity, or electric cooperative to become an FRR Entity and take responsibility for providing the entire capacity obligation for its FRR Service Area. Each FRR Entity must annually submit an FRR Capacity Plan for the five year period beginning three years into the future. An FRR Entity includes in its FRR Capacity Plan resources that it owns or for which it has entered into an agreement that commits the capacity to the FRR Entity. An FRR Entity generally does not participate in RPM base residual or incremental auctions (there is a restricted ability to sell some excess capacity). The RAA imposes many requirements that are similar to those applicable to RPM and various additional requirements specific to FRR status, several of which are further discussed below.

15. Based on my analysis as presented here, I conclude that FRR is not a viable alternative for meeting the capacity obligations associated with New Jersey loads. New Jersey FRR Entities would face substantial unmitigated market power in attempting to reach agreements on the capacity resources needed for their FRR Capacity Plans, leading to excessive prices and costs.

16. In addition, if New Jersey FRR Entities were able to construct the required FRR Capacity Plans, in managing their FRR resource portfolios they would be subject to additional costs and risks, due to various inflexible provisions of the FRR rules and uncertainties about load forecasts and locational resource requirements.

17. Finally, I note that additional new resources have the same impact on RPM prices whether offered into RPM at prices that clear or introduced within an FRR Entity's portfolio. Therefore, if New Jersey entities were to pursue the FRR alternative and plan to satisfy some New Jersey capacity obligations with new resources (such as those the LCAPP was designed to

encourage), there is considerable risk that some parties would call for the FRR rules to be changed.

IV. Evaluation of the FRR Alternative for New Jersey Loads

18. As a preliminary observation, I note that the idea that New Jersey should consider the FRR alternative did not originate with New Jersey or its load-serving entities ("LSEs"). To my knowledge, neither the state of New Jersey nor any of its load-serving entities have expressed a desire to withdraw from RPM and manage their own capacity procurement as FRR Entities. In particular, there is no evidence of a desire to take on the administrative burden and exposure to market power and various other costs and risks (discussed further below) associated with the FRR alternative. I also note that New Jersey and Pennsylvania utilities have benefited from interconnection and reserve-sharing since 1927, and there is no evidence that New Jersey seeks to turn away from the benefits of this arrangement at this time, as would result to some extent from the long-term and inflexible capacity procurement requirements imposed by the FRR rules. Nor is there any evidence that New Jersey wishes to cease relying on the RPM market for its intended purpose, as a residual capacity spot market balancing residual supply and demand.

A. There Is No Evidence the FRR Alternative is Viable Under New Jersey Circumstances

19. The suggestions by various parties that New Jersey should elect FRR are not supported by any history of the alternative being used under New Jersey's circumstances. Nor did any of the parties promoting the FRR alternative provide any discussion or analysis of how the alternative could work for New Jersey entities. To date, the FRR alternative has primarily been used by one large, vertically integrated and capacity-long entity, American Electric Power (AEP), and in fact the FRR alternative was largely designed with this one entity in mind.[2] As a

[2] As the Commission has recognized, the FRR alternative was developed at the behest of AEP to address concerns raised by AEP having to do with its particular circumstances. "As a solution, AEP suggested at the June 16, 2005 technical conference that individual LSEs should be allowed to "opt-out" of the forward procurement auction by identifying – prior to the four-year-ahead auction – enough capacity resources to satisfy the traditional 115 percent state requirement… In response to AEP's suggestion, PJM included in the August 31st Filing draft business rules that could implement an alternative to RPM under which an LSE could provide its own long-term fixed resource requirement." 115 FERC ¶ 61,079 (2006) at PP 100-101. The Commission acknowledged the connection between FRR and AEP three years later, and after two years of RPM operation, stating: "The Fixed Resource Requirement option was developed largely at the behest of AEP to provide it with greater certainty and stability in its forward capacity obligations." 126 FERC ¶ 61,275 (2009) at P 90.

result, the quantity of FRR load has been stable over RPM's eight delivery years, and the planning parameters for the 2014/2015 base residual auction held in May 2011 show FRR load only in the AEP zone (loads associated with procedures to integrate new service areas into PJM are temporarily treated as "FRR" for the purposes of some RPM auctions but are not FRR loads according to the rules in the RAA). Unlike New Jersey, there is only a small amount of retail access in AEP's service territory, and that retail access has resulted in litigation in FERC Docket No. EL11-32 regarding the capacity prices these loads will end up paying.

20. In addition, to date FRR load has existed only in the "Rest of RTO" region; there has never been any FRR load in any Locational Deliverability Area ("LDA") modeled in RPM. (LDAs are PJM-designated sub-regions for which separate RPM prices may be established; RPM prices have been much higher in LDAs than in the Rest of RTO Region.) All New Jersey loads are located in the Mid Atlantic ("MAAC") and Eastern MAAC LDAs, and some New Jersey loads are located in the PSEG and PS North LDAs. Thus, there is no historical evidence that FRR is a viable alternative for New Jersey, a retail access state in which all load is located in LDAs that are modeled in RPM.

B. In Seeking to Develop FRR Capacity Plans, New Jersey FRR Entities Would Face Substantial Unmitigated Market Power

21. New Jersey is a retail access state in which most of the generation formerly owned by utilities was divested or transferred to unregulated affiliates. Consequently, if New Jersey utilities are to become FRR Entities, they will have to reach agreement with the owners of existing or new capacity to fulfill the required, long-range FRR Capacity Plans. In addition, because the New Jersey FRR Service Areas would be located within defined LDAs, they would be subject to a requirement that a high percentage of the resources for the FRR Capacity Plans be located within the LDAs.

22. In an appendix to this Affidavit I review the capacity available to New Jersey FRR Entities to satisfy the requirements of FRR Capacity Plans. My analysis leads to the conclusion that in attempting to reach agreements on capacity resources for their FRR Capacity Plans, New Jersey FRR Entities would face substantial and unmitigated market power. The substantial market power results from the high internal resource requirements of the relevant LDAs (Eastern MAAC, PSEG and PS North); the concentrated ownership of the existing resources within these LDAs; and the presence of little or no excess capacity in these zones.

Under these circumstances, attempts to fulfill FRR Capacity Plans would very likely result in prices and costs that reflect substantial market power. While New Jersey FRR Entities could respond to this market power by sponsoring additional new generating resources (in addition to those contemplated in the LCAPP), this would result in duplicative and wasteful investment and the imposition on consumers of excessive costs.

23. I conclude that because New Jersey FRR Entities would face substantial unmitigated market power (as further developed in the appendix to this Affidavit), FRR is not a viable alternative for New Jersey.

C. Various Inflexible FRR Provisions Would Result in Additional Costs and Risks

24. Assuming New Jersey were nonetheless inclined to pursue the FRR alternative, the state and the participating load-serving entities would face additional costs and risks, primarily due to the inflexibility of the FRR provisions, the complexity of the FRR and RPM rules, and the uncertain market and regulatory environment in which FRR Entities would be obligated to build and manage FRR Capacity Plans. This section identifies several such challenges; a more detailed review would likely identify quite a few more.

25. **Five Year FRR Capacity Plans Submitted Three Years in Advance**. The FRR alternative is elected for a minimum five year period, and the FRR Capacity Plan submitted each year must identify resources for a five year period beginning three years into the future (meaning that an FRR Capacity Plan submitted in April 2012 would have to identify sufficient resources to satisfy capacity obligations for the 2015/2016 through 2019/2020 Delivery Years). While an FRR Entity is permitted to update its FRR Capacity Plan each year and to identify replacement resources, there are likely to be costs incurred to obtain the rights to include resources in the FRR Capacity Plan and to adjust the plan from year to year.

26. **Five Year Minimum Commitment**. An entity electing the FRR alternative commits to a minimum five year term (so an entity electing FRR in 2012 would be committed to it for 2015 through 2019). The only exception from this minimum commitment is in the event of a “State Regulatory Structural Change” that substantially changes the state’s retail access or default service rules.

27. **No Recognition of Short Lead Time Resources**. The RPM rules recognize that additional short-lead time resources for a delivery year become available after the three-year-

forward base residual auction by including a 2.5% Short Term Resource Procurement Target that reduces the resources that must be acquired through the base residual auction. The FRR alternative includes no such deduction or flexibility for Year 1 or even for Year 5 of the FRR Capacity Plan. The RAA specifies that any demand response or energy efficiency on which an FRR Entity intends to rely for a delivery year must be included in the FRR Capacity Plan submitted three years in advance of the delivery year.

28. **Changing Load Forecasts**. The FRR Capacity Plan must identify resources to meet forecast obligations eight years into the future (for a five year plan, three years forward). Load forecasting that far in advance is of course highly uncertain, and this requirement can lead to contracting a substantial quantity of resources that ultimately will not be needed. For example, PJM's forecasts of Eastern MAAC peak loads have been sharply reduced since 2008, and an FRR Capacity Plan in 2008 would have required 7.9% more capacity for 2015 than is now considered needed. PJM Load Forecast Reports, 2008 and 2011, Table B-10.

29. **Changing Internal Resource Requirements**. New Jersey FRR Service Areas would be located within defined LDAs and, therefore, subject to a requirement that a high percentage of the resources for the FRR Capacity Plan must be located within the LDA. The internal resource requirement is a function of the peak load forecast and also the estimated transmission capacity available to the LDA (Capacity Emergency Transfer Limit, or "CETL"). Both the load forecast and the CETL values have been volatile in recent years, causing large swings in the minimum internal resource values. Over the past three RPM base residual auctions, the minimum internal resource requirement for Eastern MAAC has ranged from 84.2 percent to 89.9 percent. As the internal resource requirement changes from year to year the FRR Capacity Plan must be adjusted accordingly, and such adjustments will likely result in additional costs.

30. **Changing LDAs and New LDA Internal Resource Requirements**. PJM has authority to define additional LDAs that could include portions or all of the New Jersey zones, based on tests reflecting transmission constraints or "if warranted by other reliability concerns consistent with the Reliability Principles and Standards." RAA Schedule 10.1. PJM has authority to include LDAs in RPM auctions if "such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels", or if PJM finds that including the LDA "is required to achieve an

acceptable level of reliability consistent with the Reliability Principles and Standards." PJM Tariff Attachment DD section 5.10.ii.C. The fact that a zone was entirely served by an FRR Entity would presumably not change this authority. If PJM chooses to model an additional LDA in RPM, it must notify the market of the new LDA and of the corresponding FRR minimum internal resource requirement by March 31 before the base residual auction. This would give an FRR Entity only a few weeks to adjust its FRR Capacity Plan, due one month before the base residual auction, to conform to the new minimum internal resource requirements.

31. **Restrictions on Sale of Excess Capacity**. An FRR Entity must either carry a "threshold amount" of excess capacity above the obligation based on forecast peak load, or commit to not selling any excess capacity into RPM auctions. This may not be a problem under the circumstances contemplated here, because the FRR Entity would likely simply release any excess resources from contractual obligations, although arranging and exercising this flexibility would likely entail additional cost.

32. **FRR and Retail Access**. New Jersey's retail competition program sets prices for the coming three years, so it dovetails with RPM that set prices more than three years forward. As FRR operates on the same three-year-forward schedule as RPM, the timing would not seem to introduce any additional issues. Under the FRR rules, a state can define its own rules for allocation of capacity costs as customers switch between load-serving entities (alternatively, the FRR rules describe a default plan if the state does not have one). However, as noted above, the one major FRR entity at this time has filed a complaint concerning the treatment of capacity costs for its small amount of retail access load. Use of the FRR option in a state with substantial retail access load, such as New Jersey, would likely surface additional unanticipated issues.

33. **Possible Rejection of FRR Plan**. The RAA states that PJM can reject an FRR Plan if it is found to not satisfy the FRR Entity's capacity obligations, and the FRR Entity would be given five business days to cure the insufficiency. If the FRR Entity is unable to cure the insufficiency, it would be subject to an FRR Commitment Insufficiency Charge equal to two times the Cost of New Entry for the relevant location (currently $379.85/MW-day), times the shortfall in MW, "for the remaining term of such plan." RAA Schedule 8.1, section D.7.

34. **Various Penalties for Non-Compliance or Resource Non-Performance**. The RAA specifies various penalties for non-compliance with the FRR requirements or non-performance of the resources used to meet the FRR obligations, rendering any failure to

accurately manage the portfolio of resources used to fulfill the FRR capacity obligations costly. FRR Entities might choose to carry excess capacity (at additional cost) to mitigate the risk of the various penalties.

35. These and other provisions of the FRR rules impose highly inflexible capacity procurement requirements and substantial penalties for any non-compliance that are not founded on or required by the resource adequacy needs of the system. Many of these provisions reflect the consensus achieved among the parties to the RPM settlement to make the FRR alternative unattractive, and are not necessary to ensure that an FRR Entity bears its share of the capacity needs of the system. No capacity-short load-serving entity would acquire commitments to meet 100% of forecast needs eight years in advance, as required by the FRR rules, nor would any state require its load-serving entities to do so. This requirement is especially inefficient under current circumstances, characterized by slower and increasingly uncertain peak load growth and an abundance of short lead-time new resources, most notably demand response.

D. If New Jersey Tried To Use FRR, There Is Substantial Regulatory Risk That the Rules Would Be Changed

36. In its March 4, 2011 filing in this proceeding, the PJM market monitor stated that "Under FRR, New Jersey's procurement choices would have much less impact on other participants in RPM markets." I disagree. The impact of the LCAPP resources (or any other new resources) on RPM prices would be the same if introduced through an FRR Capacity Plan as they would be if offered directly into RPM at prices low enough to clear.

37. When a load-serving entity elects the FRR alternative, both its capacity obligation (based on its peak load), and the capacity identified in its FRR Capacity Plan to meet that capacity obligation, are removed from RPM's base residual auctions. Assuming the capacity chosen for the FRR Capacity Plan would have cleared if offered into RPM, the RPM price for the region in which this load is located will be unchanged by the FRR election. Removing an amount of load and a corresponding quantity of cleared capacity from an RPM auction shifts the supply and demand curves the same amount, with the clearing price unaffected.

38. Similarly, when a new resource is offered and clears in RPM, the clearing price will generally be lower than it would have been had the new resource not been offered, because the supply curve shifts while the demand curve is unchanged. And if a new resource is included

in an FRR Capacity Plan, it has exactly the same impact on RPM prices as would occur if the resource was offered directly into RPM at a price that clears, because the other supply displaced from the FRR Capacity Plan by the new resource will likely be offered into RPM.

39. Consequently, while the April Order states that the FRR alternative allows bringing new resources into the market "without risk of being mitigated under the MOPR" (P 192), if New Jersey were to pursue the FRR alternative and plan to satisfy some New Jersey capacity obligations with new resources chosen based on public policy objectives such as those behind the LCAPP, there is risk that some parties would again respond by seeking changes to the rules. And, as this proceeding has demonstrated, the RPM rules can be changed very quickly.

40. The regulatory risk surrounding an RTO's resource adequacy rules, and the impact of the April Order on this perceived risk, was recognized recently in comments of the staff of the Organization of Midwest States ("OMS") in a Midwest ISO ("MISO") context:

> "At the [MISO Supply Adequacy Working Group] meeting on April 7th and 8th, 2011, the Midwest ISO acknowledged a need for those LSEs that own their resources to be able to self-supply in a manner that holds their load harmless. Our continued concern stems from: (1) a sense that the Midwest ISO lacks the authority to realize such assurances; (2) the recent FERC Order on the minimum offer pricing rules in PJM; and (3) draft tariff language provided by the Midwest ISO's Independent Market Monitor (IMM). These instances highlight the fact that a regional transmission organization's planned market design might end up being substantially modified by the Federal Energy Regulatory Commission, either on its own volition or in response to the comments of the Midwest ISO's IMM or other Midwest ISO stakeholders. In other words, whatever the intentions of the Midwest ISO's planned approach, a different approach might end up being imposed, in order to better serve different policy ends than those contemplated here." (Comments of OMS Staff on Midwest ISO's Presentation Materials from the April 7 & 8, 2011 MISO Supply Adequacy Working Group meeting, p. 1-2)

41. The complexity of the FRR and RPM rules, the fact that FRR has never been elected for loads in an LDA modeled in RPM or by a large, capacity-short entity, and that the only intersection of FRR and retail access has led to litigation, provide additional reasons for concern that FRR election by New Jersey entities would reveal additional shortcomings in the rules or consequences considered unintended or undesirable by some interested parties. To note just one issue that would likely lead to a change in the FRR rules, the RAA calls for the percentage internal resources required for each LDA to be calculated in a manner that does not necessarily result in a value less than 100% (this is because LDA Reliability Requirements are considerably larger than the sum of capacity obligations). In fact, for the 2013/2014 delivery

year, the value for the Mid Atlantic zone, calculated using the formula in the RAA, was 101.5%, although PJM chose to override the formula and set the value to 100% in the planning parameters for this auction. However, if this arose in an LDA with FRR load, PJM would undoubtedly propose some change to the rules, as allowing the FRR Entities to only provide 100%, when a greater quantity is necessary to meet the Reliability Requirement, would jeopardize reliability.

42. While pursuing the FRR alternative would likely entail substantial administrative cost due to its many requirements and inflexibility, and substantial market costs due primarily to market power, there is also considerable risk that the rules will be changed to impose additional onerous requirements or costs after an FRR Entity has elected FRR and become committed to its minimum five year term.

Appendix: Availability of Resources for Inclusion in New Jersey FRR Capacity Plans

43. An FRR Entity is required to file an FRR Capacity Plan one month before each RPM base residual auction, showing qualified resources sufficient to meet the capacity obligations of the FRR Service Area for a five year period beginning with the RPM delivery year three years forward. This appendix discusses the resources that would be needed and that would be available for FRR Capacity Plans to serve New Jersey loads.

44. The greatest challenge that would be faced by a New Jersey FRR Entity would be obtaining agreements with the owners of existing resources and sponsors of new resources sufficient to meet the RAA requirements for the FRR Capacity Plan. The RAA requires that the FRR Capacity Plan identify unforced resources equal to the forecast peak load of the FRR Service Area times the Forecast Pool Requirement ("FPR"; 1.0809 for the 2014/2015 delivery year). If any part of the FRR Service Area is located within an LDA modeled in RPM's auctions, there is an additional requirement that a minimum percentage of the resources must be located within the LDA.

A. Capacity Demand and Supply in Eastern MAAC and New Jersey LDAs

45. Table 1 shows the peak loads of the New Jersey and other Eastern MAAC zones based on the forecast for 2014/2015. The New Jersey zones represent 61.3% of the load in Eastern MAAC. If all New Jersey zones become part of FRR Service Areas (including both

investor-owned utilities and public power entities), this percentage of the Eastern MAAC load would be served under FRR and a corresponding quantity of capacity resources would be required to develop acceptable FRR Capacity Plans.

46. An FRR Capacity Plan can include existing generation, demand response, and planned resources (generally the same resources that are eligible to offer into RPM base residual auctions). However, to meet the capacity requirements of the Eastern MAAC zone, whether they are satisfied through RPM, FRR, or some combination of both, recent RPM results show that virtually all available capacity would be required.

Table 1: Peak Loads and FRR Obligations, 2014/2015
(New Jersey and Eastern MAAC Zones)

Zone *(subzonal LDA)*	Peak Load 2014 (MW)	FRR Obligation (peak x FPR)	Percent of Eastern MAAC	Percent of New Jersey
Public Service Electric and Gas Co. (PSEG)	10,901	11,783	32.4%	52.8%
of which, PS North LDA	*4,960*	*5,361*	*14.7%*	*24.0%*
Jersey Central Power and Light Co. (JCPL)	6,539	7,068	19.4%	31.7%
Atlantic Electric Co. (AEC)	2,773	2,997	8.2%	13.4%
Rockland Electric Co. (RE)	433	468	1.3%	2.1%
PECO Energy Co. (PECO)	8,911	9,632	26.5%	
Delmarva Power and Light Co. (DPL)	4,121	4,454	12.2%	
of which, DPL South LDA	*2,369*	*2,561*	*7.0%*	
Total, Eastern MAAC	33,678	36,403	100%	
Total, New Jersey	20,646	22,316	61.3%	100%
Total, New Jersey excluding PSEG Zone	9,745	10,533	28.9%	47.2%

FPR = Forecast Pool Requirement, for 2014/2015, 1.0809. PS North = PSEG zone north of Linden Station. DPL South = DPL zone south of Chesapeake and Delaware Canal.

Sources: RAA, Planning Parameters for the 2014/2015 Base Residual Auction.

47. The Eastern MAAC supply curve for the RPM base residual auction for the 2012/2013 delivery year (the last delivery year for which a meaningful supply curve has been provided) showed that only 600 MW was offered at prices between $230/MW-day and $420/MW-day. This suggests that in the 2013/2014 base residual auction, in which the clearing

price in Eastern MAAC was $245/MW-day, virtually all available capacity cleared. The market monitor's report on this auction identified 0 MW of unoffered capacity and 196 MW of uncleared installed capacity in Eastern MAAC. Monitoring Analytics, *Analysis of the 2013/2014 RPM Base Residual Auction, Revised and Updated*, September 20, 2010, p. 42.

48. An owner of Eastern MAAC generation that lacks market power (that is, that controls only a very small amount of Eastern MAAC generation) might be expected to offer its capacity to an FRR Entity at prices similar to those the owner anticipates from the corresponding future RPM base residual auctions. Therefore, but for market power, an FRR Entity could expect to pay prices for capacity agreements similar to anticipated RPM clearing prices. Unfortunately, however, as PJM's market monitor has consistently concluded, market power is "endemic" in the PJM capacity market. The 2010 State of the Market Report for PJM (p. 361) states:

> "Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market."

49. In applying market structure screens for each RPM base residual auction, PJM's market monitor has consistently found that even in the very large RTO and MAAC regions, there is a single supplier who is "pivotal", that is, who owns enough capacity that the total demand for capacity cannot be met without some portion of this supplier's resources. Monitoring Analytics, *Preliminary Market Structure Screen for the 2014/2015 Delivery Year*, p. 2.

50. Table 2 provides statistics on the ownership of generation in New Jersey and Eastern MAAC. Ownership of generation in Eastern MAAC is quite concentrated, with the largest entity (combined with affiliated entities) controlling one third of the generation. The PSEG and PS North LDAs exhibit especially concentrated ownership of generation, with the largest entity controlling 89.4% of the generation in the PSEG LDA and 88.2% of the generation in the PS North LDA.

51. Table 2 also shows that an FRR Entity would be required to supply over 60% of its capacity obligations in the PSEG and PS North LDAs with resources located within these LDAs. Consequently, a substantial quantity of the resources from the entity that owns 88 or 89

percent of the generation resources in these LDAs would be required for any FRR Capacity Plan for these LDAs. The alternative would be for the FRR Entity to incur the additional (and wasteful) cost of sufficient new resources to displace the existing resources.

Table 2: Generation Market Shares in the New Jersey and Eastern MAAC Zones

Zone (subzonal LDA)	Highest Market Share	HHI	FRR Internal Resource Requirement	
			Percent	MW UCAP
Public Service Electric and Gas Co. (PSEG)	89.4%	8027	62.6%	7,376
of which, PS North LDA	88.2%	7825	71.6%	3,839
Eastern MAAC	33.1%	1966	87.4%	31,816
MAAC	17.6%	1038	99.7%	66,491

Source: Monitoring Analytics, Preliminary Market Structure Screen for the 2014/2015 delivery year, p. 2; Planning Parameters for the 2014/2015 Base Residual Auction.

B. Capacity Demand and Supply in New Jersey Excluding the PSEG Zone

52. The remainder of this Appendix evaluates capacity supply and demand for New Jersey excluding the PSEG zone (including only the JCP&L, Atlantic Electric, and Rockland Electric zones). Because the Rockland Electric zone is small (the FRR obligation for 2014/2015 would be 468 MW) this analysis is roughly the same with or without the Rockland Electric zone. Similarly, New Jersey's public power entities serve relatively small loads and the analysis does not depend on whether they are assumed to elect the FRR alternative.

53. These three zones are located in the Eastern MAAC LDA, and smaller LDAs including part or all of these zones have to date not been modeled in RPM's auctions. Assuming no additional LDAs will be modeled, the evaluation can focus on Eastern MAAC. The three New Jersey zones would have an obligation of 10,533 MW based on the 2014/2015 forecast peak, and would represent just under half of the New Jersey load and just under 30% of the Eastern MAAC load (as shown in Table 1). Of the 10,533 MW, 87.4%, or 9,206 MW, would have to be met with Eastern MAAC resources. An FRR Capacity Plan for these loads could at least theoretically be satisfied without the resources of the PSEG companies, or those of the other very large Eastern MAAC capacity seller, Exelon. Exelon has roughly a 25% share of Eastern

MAAC generating capacity. As a very large seller whose resources are mainly located outside New Jersey, but with a large market share in Eastern MAAC, Exelon possesses substantial market power and can be considered unlikely to offer capacity to a New Jersey FRR entity at competitive prices.

54. PSEG and Exelon control 58% of the generating capacity in Eastern MAAC, leaving roughly 14,000 MW of installed generating capacity owned by other entities, based on PJM's most recent public generation data reported to the Energy Information Administration (form EIA-411). An Eastern MAAC FRR obligation of 9,206 MW could be met with the demand response and energy efficiency resources located in these zones and new Planned Resources, in addition to these existing resources. Table 3 outlines how an FRR Capacity Plan could at least theoretically be fulfilled for these three zones. This outline would of course be affected by capacity changes over time, including new generation or demand response, retirements, or exports out of New Jersey to New York or Long Island.

Table 3: FRR Capacity Plan Parameters for New Jersey Excluding PSEG Zone

FRR Capacity Plan Element	***MW***
Peak load of JCP&L, AE, RE zones (2014/2015)	9,745
FRR Unforced Capacity Obligation (peak x FPR)	10,533
Minimum internal (Eastern MAAC) resource requirement, percent	87.4%
Resources that can be sourced from outside Eastern MAAC	1,327
Minimum internal (Eastern MAAC) resource requirement	9,206
Demand response and energy efficiency resources (2013/2014 values)	446
New Planned Resources (based on LCAPP and 5% EFORd)	1,900
Remaining Eastern MAAC unforced capacity need	6,860
Approx. existing Eastern MAAC capacity, excl. PSEG, Exelon	13,100

Sources: Planning Parameters for 2013/2014 RPM base residual auction; Results report for 2013/2014 base residual auction; PJM's most recent EIA-411 filing. The assumed 1,900 MW of new planned resources is based on the 2,000 MW value under the LCAPP program, reduced 5% for an estimated unforced capacity value.

55. Under this scenario, the FRR entities would still have to reach agreement and include in their FRR Capacity Plans about half of the non-PSEG, non-Exelon generating capacity

in Eastern MAAC. The majority of this other capacity is also held by entities with sizable portfolios of 1,000 MW or more in Eastern MAAC, so the FRR entities could expect their negotiations with capacity sellers to reflect the incentives that result from market power.

C. Capacity Demand and Supply: Conclusions

56. This analysis leads to the following observations regarding efforts to acquire resources for FRR Capacity Plans to satisfy New Jersey capacity obligations.

57. The high internal resource requirements of the Eastern MAAC, PSEG, and PS North LDAs, the concentrated ownership of the existing resources in these zones, and the absence of excess capacity in these zones result in substantial market power. Attempting to fulfill an FRR Capacity Plan for these areas would, therefore, likely result in prices and costs that reflect this market power.

58. While market power mitigation applies to the offers from existing generation into RPM auctions, FRR Capacity Plans are developed on a bilateral basis through negotiations between an FRR Entity and potential suppliers, and no market power mitigation applies.

59. Entities with market power will have strong incentives to demand prices for capacity well above resources' net avoidable costs (the competitive level); indeed, entities with market power will have strong incentives to demand prices above anticipated RPM clearing prices. There is no reason to expect capacity owners to offer their capacity to an FRR Entity for prices less than they would expect to receive through RPM, and for entities with market power, it must be expected that prices in excess of anticipated RPM prices will be required.

60. With regard to the PSEG and PS North LDAs, the entity that owns nearly 90% of the resources in these LDAs, PSEG Power (with affiliates), would have enormous market power in negotiations with an FRR Entity seeking to enter into agreements to meet the capacity requirements of FRR loads.

61. While the market power problem is not as severe under the assumption that only the JCP&L and Atlantic Electric zones (with or without Rockland Electric and the New Jersey public power entities) pursue the FRR alternative, the FRR Entities would still face substantial market power and would likely have to pay prices that reflect such market power to complete their FRR Capacity Plans.

62. As in any market, a buyer facing market power can turn to new resources. The physical or economic withholding of existing resources due to market power makes new resources more attractive; in this way, the exercise of market power often leads to uneconomic entry. To fulfill FRR Capacity Plans, New Jersey FRR Entities might need to sponsor additional new resources that are needed and attractive in part due to the withholding of existing resources. Thus, pursuing the FRR alternative for New Jersey would likely lead to exercise of market power and uneconomic entry, an inefficient result.

63. This completes my affidavit.