STATE OF NEW JERSEY
BEFORE THE
BOARD OF PUBLIC UTILITIES

In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning	))	Docket No. EO11050309

JOINT COMMENTS OF THE PUBLIC POWER ASSOCIATION OF NEW JERSEY AND THE AMERICAN PUBLIC POWER ASSOCIATION

The Public Power Association of New Jersey ("PPANJ") and the American Public Power Association ("APPA") submit these joint comments in response to the questions posed by the New Jersey Board of Public Utilities ("BPU") in the Notice of Public Meeting issued on September 28, 2011, in the above-noted docket.

Introduction

PPANJ and APPA commend the state of New Jersey and the BPU for continuing this important investigation. We greatly appreciate the opportunity to provide these comments. Our responses to the issues raised in the BPU's questions in this second hearing are based on our perspective that the RTO-operated wholesale markets, especially the centralized capacity markets, are fundamentally broken and cannot easily be fixed with tweaks to their myriad complex rules. Within the existing market paradigm, it is very difficult to overcome the financial interests of the incumbent merchant generation owners and develop the resources needed to ensure a reliable and cleaner supply of energy in the future. As stated in the comments at the June 17 BPU hearing, PPANJ and APPA support a phase-out of the centralized mandatory capacity markets, and the combination of resource adequacy requirements, a comprehensive transmission planning process, and long-term power supply and demand response arrangements as a far superior alternative.

PPANJ. The PPANJ is a non-profit association of locally-owned and controlled electric systems comprised of the municipal electric utilities of the Boroughs of Butler, Lavallette, Madison, Milltown, Park Ridge, Pemberton, Seaside Heights, South River, the Vineland Municipal Electric Utility ("VMEU"), and Sussex Rural Electric Cooperative, Inc. Each of these utilities is transmission dependent. With a combined peak demand in excess of 300 megawatts, the members of the PPANJ take transmission services from investor-owned utilities that are members of PJM Interconnection, L.L.C. ("PJM") under the terms of the PJM Open Access Transmission Tariff ("OATT"). The PPANJ members were among the first to take advantage of open access to acquire wholesale power and energy at market-based rates upon enactment of the Energy Policy Act of 1992. The PPANJ municipal members conduct periodic competitive procurements consistent with New Jersey municipal procurement rules to acquire electric wholesale energy supply for their customers. Each of the municipal PPANJ members purchases electric capacity from the PJM capacity market at PJM established prices, including Vineland (which is the only PPANJ member that owns some generating facilities). Each of these entities operates independent from BPU oversight, with the exception of Butler, the only member that serves customers outside of its municipal boundaries. To enhance their ability to operate more effectively in the PJM markets, the PPANJ members have pending before the New Jersey Assembly a bill to allow them to work together to purchase electricity and build generation to satisfy the needs of their customers. (Municipal Shared Services Energy Company Law, S. No. 2630, 214th Leg. (N.J. 2011).) If enacted, the pending legislation will create what 37 states already have, which is the right for municipal utilities and cooperatives in New Jersey to work together for purposes of electric procurement and generation construction.

APPA. APPA is the national service organization representing the interests of the approximately 2,000 not-for-profit, publicly-owned electric utilities throughout the United States that collectively serve more than 45 million consumers. Public power systems provide over 15 percent of all kilowatt-hour (kWh) sales to ultimate customers, and provide service in every state except Hawaii. APPA member utilities are owned by the communities they serve, operate on a not-for-profit basis, and have retained the legal obligation to provide retail electric service to their customers. Since they are owned by the customers they serve and have no outside shareholders, all costs are passed through directly to the customer. Public power systems own approximately 10 percent of the nation's electric generating capacity, but purchase nearly 70 percent of the power used to serve their ultimate consumers from the wholesale market. APPA's members therefore have an abiding interest in well-functioning wholesale power-supply markets and in the adequacy of supply to meet future load.

Generation Interconnection Process

For load-serving entities (LSEs) that are seeking to self-build or obtain long-term contracts for a new generation resource to avoid overreliance on volatile market prices, the delays in the interconnection process create special difficulties. A recent statement by the Delaware Municipal Electric Corporation (DEMEC) noted that "irreversible major financial commitments have to be made by the LSEs that self build (because of the long lead times caused by regulatory rules and the PJM generation interconnection process)."[1] One option that APPA and PPANJ recommend for consideration by PJM and other RTOs is to give a priority in the interconnection process to owned resources or resources that have a long-term (10 years or greater) contract with an LSE. Such an approach mirrors APPA's recommendation in the Competitive Market Plan (CMP) for RTOs to allocate long-term transmission rights (LTTRs) to LSEs to

[1] Statement of Patrick E. McCullar On Behalf of the Delaware Municipal Electric Corporation and the American Public Power Association, Docket Nos. ER11-2875-001, -002 and Docket No. EL11-20-001, July 28, 2011, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12719881

support bilateral contracts or owned resources, with a priority for power supply arrangements of 10 years or longer.[2]

These comments provide some broad observations on the problems with interconnection process across several RTO markets. A review of the 2011 ISO/RTO Metrics Report[3] shows that backlogs in the interconnection process are common throughout the RTOs. RTOs frequently cite the increasing complexity of interconnection studies due to a greater number of interconnection requests for wind generation and energy storage as a primary reason for the lengthening of the interconnection process timeframe. Another key factor is that the vast majority of projects within the queue are submitted but never completed. The New York ISO also noted that declining economic conditions since 2008 have caused developers to slow the pace of proposed projects.[4]

PJM reported that "[o]n average, approximately 12 percent – 15 percent of megawatts from potential projects result in the execution of an interconnection service agreement for new generating capacity. So, over 80 percent of the studies completed by PJM relate to potential projects that withdraw from the generation interconnection queue." PJM also notes that a "large number of those study requests were geographically concentrated in the western part of the PJM region with an increasing number of the potential developers investigating the use of storage technologies such as batteries, flywheels and compressed air, as well as wind and solar fuel sources. In terms of megawatts of potential new generating capacity, more than 40 percent of PJM's year-end 2010 interconnection queues relates to potential wind or solar plants." [5]

To reduce interconnection requests "based on speculative project proposals," ISO New England filed amendments to its tariff in 2009 that increased the deposit structure for large generating facilities seeking interconnection.[6] According to the Brattle Group, PJM began also requiring deposits that increase each month that the project remains in the queue and include both a refundable and a non-refundable element.[7]

The Midwest ISO reports that it reduced the study timeframe by requiring that customers show progress in non-transmission aspects of their project to proceed to later phases. But MISO also noted that in 2010

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2 APPA's Competitive Market Plan: A Roadmap for Reforming Wholesale Electricity Markets, 2011 Update, p. 34, http://www.publicpower.org/files/PDFs/2011CompetitiveMarketPlanUpdate.pdf

3 2011 ISO/RTO Metrics Report, Docket AD10-5-000, August 31, 2011, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12751229

4 2011 ISO/RTO Metrics Report, p. 221

5 2011 ISO/RTO Metrics Report, p. 284

6 2011 ISO/RTO Metrics Report, p. 97

7 Second Performance Assessment of PJM's Reliability Pricing Model, The Brattle Group, August 26, 2011, p. 48, http://www.brattle.com/_documents/UploadLibrary/Upload972.pdf

nearly 40 percent of projects delayed their own processing by "elect[ing] to park rather than proceed to their next eligible stage."[8]

Given the reported presence of speculative projects, "zombie" projects that are "parked" indefinitely or submitted and later withdrawn from the interconnection queue, it is worth further investigating whether these requests have the effect of constraining the supply of new resources and thus increasing prices. APPA recommended in its CMP that "FERC should separately assess market-based rate applicants' generation market power in long-term power supply product markets. To the extent that applicants do not pass such long-term market power screens, their market-based rate authority would be appropriately conditioned or, if merited, revoked." [9] APPA and PPANJ reiterate this recommendation here. Such an analysis should incorporate an assessment of the degree to which the current interconnection process permits incumbents to retain market power in markets for long-term power supply products.

Regarding the question of whether PJM or a third-party entity should perform the engineering interconnection studies and identification of necessary transmission upgrades and costs instead of the transmission owners, to the extent that a financial incentive exists for the transmission owners and their generation affiliates to constrain the supply of generation, it might be beneficial to explore this option, or other ways to provide the necessary discipline and oversight. Where the increasing complexity of the requests is a factor, a third-party with knowledge of wind or storage interconnections also might provide useful expertise.

Regional Transmission Planning and RPM

Inconsistencies between the PJM Regional Transmission Expansion Planning ("RTEP") process and the transmission assumptions made in calculating the Capacity Emergency Transfer Limits ("CETL") highlights a fatal flaw in the RPM "market": RPM may not be addressing key reliability criteria. Although APPA and PPANJ do not have the expertise to evaluate the transmission assumptions made for the RTEP and the CTEL, APPA and PPANJ agree with the Organization of MISO States, which summed up its reliability concern with RPM in its recent filing on the FERC docket on the Midwest ISO's proposed Resource Adequacy Requirements (RAR) tariff revisions:

> Capacity is not a homogeneous, single-attribute commodity, a tacit assumption embedded in the arguments of the IMM and the Capacity Suppliers. Eastern-style auctions fundamentally separate generation capacity from its physical attributes such as: the generator's fuel source, fuel transportation, combustion process, emissions, cooling requirements, load following capability, electrical characteristics, and transmission system characteristics. These auctions do not incorporate

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8 2011 ISO/RTO Metrics Report, p. 162

9 APPA Competitive Market Plan, 2011, p. 28

> load forecast uncertainty due to weather and other drivers. The singular element of a capacity only auction compromises the transmission network's electrical dynamic and steady-state stability characteristics, as well as the Northern American Electric Reliability Corporation operating and planning standards. Resource adequacy is a long term planning process that cannot be split into separate, unrelated, commodities on the electrical network.[10]

To the extent that the capacity market may not account for all of the factors affecting reliability as determined through the RTEP, there is a danger of procuring resources through RPM while burdening consumers with the additional cost of Reliability Must Run (RMR) agreements to address reliability criteria not solely related to capacity. One recent example is the RMR for Cromby Unit No. 2 and Eddystone Unit No. 2, which had not cleared the RPM auctions for the 2011/12 or 2012/13 delivery years. According to the explanation provided by PJM:

> The RPM capacity construct uses PJM's load deliverability test procedures to determine the Locational Deliverability Areas (LDAs) that will be binding in RPM auctions. PJM's load deliverability criterion is only one of the criteria used to evaluate the reliability of the system under the regional transmission expansion plan ("RTEP"). The PJM RTEP evaluates a number of criteria violations including, but not limited to load deliverability. PJM performs many tests, including the Load Deliverability Test, when performing a deactivation study to determine the system's reliability needs. In this particular instance, the constraints requiring the retaining of the RMR Units are related to NERC Category C-3 (N-1-1) violations, not load deliverability.[11]

The Brattle Group also points out that the timing of the two processes is not in sync, stating that "transmission planning is conducted on a five- to ten-year forward basis by PJM and its transmission owners, while planning efforts for capacity resources are conducted by competitive market participants through RPM participation, which is on a three-year forward basis." [12] APPA and PPANJ support bilateral resource contracting and associated transmission rights that are more aligned with the five-to-ten-year time frame of transmission planning. The three-year forward pricing of RPM is not only inadequate for attracting new resources with longer lead times, but is not properly aligned with longer term transmission planning and bilateral contracting.

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[10] The Organization of MISO States' Motion for Leave to File and Answer to IMM and Capacity Suppliers, Docket No. ER11-4081-000, October 14, 2011, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12791690

[11] Motion of PJM interconnection, LLC for Leave to Answer and Answer to Comments of New Jersey Division of Rate Counsel and Constellation, Docket p.3, Docket No. ER10-1418-000, July 30, 2010, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12403489

[12] Brattle Group, p. 126

The broader underlying question is whether it makes any sense to procure capacity as a separate product through a centrally administered market. Not only does this separation create a disconnect between resource adequacy and transmission system reliability, but it also is not rational from an economic perspective. As Dr. Kenneth Rose pointed out in a recent paper, a copy of which is attached to these comments:[13]

> The second conceptual problem with the RTO capacity market approach is more fundamental from an economic theory standpoint. This approach attempts to construct a "market" to sell capacity to customers as if it were a final product that can be separated from other products that firms produce. This form of unbundling or separation may work for some outputs or products, such as byproducts or externalities where a separate market can be set up by regulators or the ancillary services market that RTOs have created with FERC approval. The capital investment that capacity markets intend to induce is different; it is actually an *input* in the production process of the firm, not an *output*. The cost curves described above are a function of the inputs firms use to produce output: capital, land, labor, energy, materials, and so on. Each of these inputs has separate "factor" markets in which electricity suppliers operate. But these markets are not what the RTO capacity markets are trying to supplement or correct. Rather, they are attempting to create a final product market for something that is merely one input of many that are needed to generate electricity.[41]
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> [41] It might be fair to ask: why not have a market construct for every input used, not just one for capacity?

Given the flaws inherent in the creation of a separate capacity market, APPA and PPANJ reiterate the recommendation in the Competitive Market Plan for a phase-out of the capacity markets. It would be far better to use a combination of resource adequacy requirements, a comprehensive transmission planning process, and bilateral power supply and demand response arrangements with a variety of terms and types to ensure adequate supply resources in RTO regions. State requirements and policy preferences for fuel diversity (such as state RPS and energy efficiency goals, and state/regional carbon mitigation regimes) should be honored in developing LSE resource portfolios. The RTO would ensure that the LSE resource portfolios developed are, taken as a whole, both technically feasible and operationally reliable.[14]

Effectiveness of Price Signals in RPM

The absence of a correlation between the location of new capacity and prices in the Base Residual Auctions (BRAs) is a refutation of the continued reliance of RTO markets on pricing incentives. In one of the earliest studies released under APPA's Electric Market Reform Initiative (EMRI), Synapse Energy

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[13] An Examination Of RTO Capacity Markets, By Kenneth Rose, Ph. D., September 1, 2011, http://ipu.msu.edu/research/pdfs/Working-Paper-Rose-Capacity-Markets.pdf

[14] See the Competitive Market Plan, Chapter X, for a more detailed discussion.

Economics found that the areas where LMP prices are the highest, and thus transmission facilities are the most congested, do not correspond with the areas where the greatest investments in new generation and transmission have been made.[15] Synapse found that one interpretation of the data is the decision to build new generation may be more dependent upon factors such as access to fuel, availability of land and labor, and the extent of likely local opposition. Moreover, even where there are persistent price differentials between LDAs, the prices themselves fluctuate significantly. The uncertainty of this revenue stream makes financing a new project more difficult. These same findings hold true for RPM today; yet there is a continued reliance on the use of locational pricing differentials as an incentive for the development of new resources in constrained areas.

Another important factor in the inverse relationship between prices and resource development is the perverse financial incentive to keep higher priced zones constrained in order to maximize the revenues paid to existing plants. APPA and PPANJ's statement in the June 17 Comments to the New Jersey BPU is worth repeating here:

> The continued reliance on locational pricing in the design of RPM represents a continued misunderstanding of the "on the ground" dynamics of the market and the practical decision-making of incumbent generation owners and new generation developers. Simply put, incumbent owners of existing generation face a financial disincentive to build substantial new generation in constrained areas, as this would reduce their profits. RPM has also become an increasingly important source of profits for the incumbent owners of unregulated generation, who often earn returns on equity exceeding 20 percent.[9] New generation developers, on the other hand, would like to enter the market, but cannot do so without obtaining the needed financing.
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> 9 See *Financial Performance of Owners of Unregulated Generation in PJM: 2010 Update*, http://www.publicpower.org/files/PDFs/FinancialPerformance2010UpdateMay2011.pdf

RPM provides the greatest benefits to older, depreciated plants. Instead of reliance on this centrally administered construct, a more effective means to achieve the development of new needed resource types is through a head-to-head competitive resource procurement process operated by a state or individual utility, or self-builds by LSEs.

Long-Term Capacity Procurement

Financing of new baseload or mid-merit generation units and their high capital costs, requires longer-term contracts that provide a steady stream of revenue over a number of years. If a reformed New Entry Price Adjustment (NEPA) or PJM-operated voluntary auction were able to produce such contracts and to

15 *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers* by Ezra Hausman, Robert Fagan, David White, Kenji Takahashi, and Alice Napoleon, Synapse Energy Economics, February 2007, http://appanet.cms-plus.com/files/PDFs/SynapseLMPElectricityMarkets013107.pdf

do so at just and reasonable rates to LSEs, the result could be a greater amount of non-peaking resources. But it is difficult to determine whether such efforts would be effective if the current RPM framework is maintained. Incumbent generation owners would likely view RPM prices as a benchmark and would be unlikely to participate in any alternative that did not produce the same contribution to profitability. There are many reports of LSEs facing difficulties in obtaining long-term contracts within RTO regions. For example, according to DEMEC, "[a]fter extensive discussions with existing suppliers over several years, DEMEC could not find a bilateral contract arrangement to satisfy its long-term energy and capacity needs at a cost that was less than the self-build option."[16]

The effectiveness of the RTOs themselves to promote long-term contracts on a voluntary basis within the current mandatory "market" context is therefore questionable. In October 2008, FERC required each RTO to dedicate a portion of its web site for buyers and sellers to post offers to buy or sell power on a long-term basis, concluding "that greater transparency from a bulletin board for long-term power sales will benefit long-term contracting."[17] A multiple-RTO bulletin board was set up in response, but appears to have been of limited use. Periodic visits after the initiation of the bulletin board found no more than four contract offers posted at a given time, which were of limited length. By September 21, 2010, only one contract offer was posted -- for the sale of 2 MW of capacity for a one-year time frame. No offers were posted on the bulletin board, when it was again visited on April 15 and October 17, 2011.[18]

A long-term voluntary capacity auction could have the potential to attract participants only if the short-term market is also voluntary. Suppliers who can sell into a short-term market with high prices, that is mandatory for buyers, have little incentive to offer longer-term arrangements into a voluntary market.

Structural Market Power

While PPANJ and APPA are not asserting any incumbent generators have taken specific steps to block new entry, merchant generation developers within RTO markets face substantial economic barriers. Owners of large amounts of existing capacity have a financial incentive to restrict the supply of capacity. For example, in testimony filed in 2010 in the FERC docket on the New England Forward Capacity Market, James Wilson found that the degree of concentration of generation ownership within the Mid-Atlantic zone (MAAC), Eastern MAAC, and Southwest MAAC creates "strong disincentives to offer

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[16] Statement of Patrick E. McCullar on Behalf of the Delaware Municipal Electric Corporation and the American Public Power Association, July 28, 2011, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12719881

[17] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 125 FERC ¶ 61,071, 73 Fed. Reg. 64,100 (October 28, 2008), p.165

[18] https://esuite.pjm.com/mui/bulletinBoard/guestViewPostings.jsp

incremental capacity, and strong incentives to withhold from these zones" for a large proportion of the capacity in these zones.[19]

Withholding may occur through mechanisms allowed within the rules, such as the inclusion of Accelerated Project Investment Recovery (APIR) to raise the offer cap or through broader decisions whether or not to retire, upgrade or construct a new plant. [20] Several analyses of the impact of pending EPA rules on the closure of coal plants acknowledge that existing merchant power plants will benefit from the closure of other coal plants and a tightening of supply.[21] A centralized capacity market where prices are strongly susceptible to shifts in the supply curve strengthens such incentives.

Short of phasing out RPM itself, a simple near-term step to addressing structural market power is to give self-supply rights back to the public power systems and rural electric cooperatives. Allowing LSEs and the states to procure or build new generation can acts as a check on the market power of the incumbent generators. In the RPM settlement, public power and the cooperatives negotiated for the right to develop their own generation and long-term supplies and bid in as price takers, which is the only reason they agreed to a mandatory "market." But in a FERC order issued in April 2011[22] changes were made to what is known as the Minimum Offer Price Rule (MOPR), which establishes minimum price offers for certain new resources in the capacity auctions. These changes included the removal of the exemption from the MOPR for resources designated as self-supply for LSEs and for state-sponsored resources developed in response to a projected capacity shortfall. (FERC has granted a rehearing of the applicability of the MOPR to self-supply.[23]) Without changes to the revised MOPR, new natural gas-fired resources procured by either the state or another LSE, such as a public power utility or a cooperative, would be

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19 Direct Testimony of James F. Wilson in Support of First Brief of the Joint Filing Supporters, Docket Nos. ER10-787-000, EL10-50-000, and EL10-57-000, p. 34-38, July 1, 2010, http://www.wilsonenec.com/FCM_Testimony_July_1.php

20 Wilson, 2010, p. 32 and 39.

21 For example, Credit Suisse concluded that "the retrofit / closure decision will not occur in a vacuum such that plants 'on the bubble' for investment could be attractively economic as other plants are pulled from the market." *Growth From Subtraction: Impact of EPA Rules on Power Markets*, Credit Suisse Equity Research, September 23, 2010, http://op.bna.com/env.nsf/id/jstn-8actja/$File/suisse.pdf, p. 36. Similarly, Fitch Ratings concluded that: "Merchant generation that does not rely on coal (or coal-fired generation that is already highly controlled) could increase its profitability if a significant portion of coal-fired generation in the same region is retired and heat rates rise in the region due to stringent enforcement of new EPA rules." *Time to Retire? US Coal Plants in Environmental Crosshairs*, FitchRatings, February 2011, p. 2 http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=604365

22 Order Accepting Proposed Tariff Revisions, Subject To Conditions, And Addressing Related Complaint, 135 FERC ¶ 61,022 (April 12, 2011), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12617771

23 Order Granting Rehearing for Further Consideration and Establishing Technical Conference, 135 FERC ¶ 61,228 (June 12, 2011), http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12679308

likely to have their low-bids replaced with a higher offer price, making it very difficult for such resources to clear the market.

If a public power utility or cooperative can demonstrate the actual costs of a new resource, it should be able to bid in the new units or contracts using those demonstrated costs without any mitigation or negotiation. Over the long-term, APPA and PPANJ recommend that the RPM should transition into a voluntary market for the procurement of residual capacity not provided through bilateral arrangements. Another option would be to expand the Fixed Resource Requirement (FRR) to permit shorter-term participation and partial load requirements.

The benefits to New Jersey of allowing for self-supply are evident in the Post-Technical Conference Comments of the Public Power Association of New Jersey and the accompanying Affidavit of Joseph A. Isabella, Director of Municipal Utilities, City of Vineland, New Jersey, from August 29, 2011 which is attached to these comments.[24] In response to the insufficient construction of new generation in New Jersey to alleviate the high capacity and energy prices for the City of Vineland, the municipal utility is proposing to build a new 57 MW combustion turbine unit inside its municipal boundary for the purpose of serving its customers. Vineland is well along in developing the specifications for the proposed unit, but unless it can be assured that the unit will clear the RPM auction, then it will delay or cancel the unit. As a result, the new MOPR will have the direct effect of keeping the supply constrained and artificially propping up prices. As the Affidavit of Mr. Isabella shows, under a truly competitive market, this generating plant would easily clear the market. The projected cost of $129.65/MW day (a conservative estimate), is well below the net Cost of New Entry (CONE) of $275.02 /MW. That the costs of this unit are below what PJM has determined as the typical cost of construction demonstrates that this new plant would provide a net benefit to Vineland. If the MOPR is applied, however, this plant’s offer would be mitigated upward, meaning that the unit might not clear, potentially saddling Vineland customers with both high RPM costs as well as the sunk costs of preparing the unit for bid. This could happen regardless of whether Vineland’s unit is actually the lower cost unit. As PPANJ notes on p. 5 of its comments:

> Not only is this upward mitigation an anathema to the American free enterprise system in which those with a better product at a better price should be permitted free access to markets. It is also an anathema to the American principle of self-help governance in which citizens band together locally to solve their problems.

It is also worth noting that while Vineland provided detailed cost estimates for its plant in a publicly filed FERC pleading, representatives of merchant generators repeatedly oppose greater transparency based on the disingenuous argument that such transparency would weaken competition by encouraging collusion

[24] The Comments can also be found at http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13951019

between sellers.[25] Ironically, it is the buyers who support price and cost greater transparency even though they would in theory be harmed the most by the alleged collusion.

Load Forecasting

While the load forecast used in the 2011 BRA declined as compared to PJM's original predictions, the existence of an economic recession had a very limited effect on earlier PJM three-year forward load forecasts. The PPANJ believes the load forecasts had been overly optimistic and resulted in high load growth predictions. Recent forecast updates now predict that the level of load growth originally forecast for 2014 will not occur until 2020. PPANJ led a group of load-side representatives to seek an independent review of PJM's Load Forecasting Methodology. PJM retained a consultant who recommended changes that would have improved the accuracy and stability of the load forecast.[26] Those same recommendations would have reduced the load forecast used in the 2011 BRA. However, PJM delayed implementation when concerns were raised by the Planning Committee and the Load Analysis Subcommittee (LAS) of the Planning Committee. PJM continued to review the recommended changes throughout 2011. A plan to adopt limited change has been announced, but no formal action has been taken. The PPANJ would welcome the BPU's support as it continues to seek an improved PJM load forecast.

The PPANJ also recommend that the load forecasting conducted for purposes of the Base Residual Auctions should not be subject to approval of the PJM governance process. Because reductions in the load forecast can lower the prices in the BRA, the incumbent generation owners have an incentive to hold up approval of any downward revisions in the load forecast.

Fixed Resource Requirement (FRR)

The PPANJ is an active participant in a PJM stakeholder process on RPM-related issues – including the MOPR and FRR. In this process, PJM has introduced an outline for a voluntary capacity auction that would occur outside of the BRA. It is PJM's present intention that this auction would not be subject to

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25 See for example see the Comments of the Electric Power Supply Association, ISO/RTO Performance Metrics, AD10-5-00, March 5, 2010, p. 8-9, discussing EPSA' opposition to the release of data on generator costs and revenues, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12287117

26 Review of PJM Models, Itron Inc. Presentation, September 27, 2010, http://www.pjm.com/~/media/committees-groups/committees/pc/20100927/20100927-review-of-pjm-peak-forecasting-models.ashx; Phase I: Load Forecast Model Evaluation, Itron, Inc., Sept 28, 2010, http://www.pjm.com/~/media/committees-groups/committees/pc/20101006/20101006-item-09-load-forecasting-recommendations-phase-1-findings.ashx ;Phase II: Weather Modeling Methods, Itron, Inc., Sept 14, 2010, http://www.pjm.com/~/media/committees-groups/committees/pc/20101006/20101006-item-09-load-forecasting-recommendations-phase-2-findings.ashx

the MOPR. The Board should join in the development of this PJM proposal. It may provide the Board with a future option.

APPA and PPANJ are not recommending a particular course of action for New Jersey. The FRR as currently written is very restrictive, requiring the entire load of the FRR region to be served with resources outside of RPM over a period of five consecutive delivery years. During this time period, RPM cannot be used as a residual resource in the event that there is an unexpected need for additional power, or to sell back excess capacity that is not needed.

APPA and PPANJ recommend that to the extent that there is an FRR, it should be modified to permit its use for partial loads within a service territory, such as for specific delivery points, and should allow for modifications of the FRR plan within the five year time frame. Such changes would provide New Jersey and other states and LSEs with greater options for the procurement of needed resources for their own state or service territory, rather than relying on an ineffective "market."

Respectfully submitted,

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October 19, 2011

APPENDIX A

An Examination of RTO Capacity Markets

by Kenneth Rose, Ph D.

IPU WORKING PAPER

MICHIGAN STATE UNIVERSITY ▪ **INSTITUTE OF PUBLIC UTILITIES** REGULATORY RESEARCH AND EDUCATION

AN EXAMINATION OF RTO CAPACITY MARKETS

IPU WORKING PAPER NO. 2011-4

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SEPTEMBER 1, 2011 ▪ ipu.msu.edu

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Recommended citation
Rose, Kenneth. "An Examination of RTO Capacity Markets," IPU Working Paper No. 2011-4. Institute of Public Utilities, Michigan State University, September 1, 2011.

Acknowledgments
This paper was completed with funding from Citizens Against Rate Excess (CARE), Lansing, Michigan. The opinions expressed here are the author's and not necessarily those of CARE or any other person or organization.

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AN EXAMINATION OF RTO CAPACITY MARKETS

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SEPTEMBER 1, 2001

Introduction

Regional Transmission Organizations and Independent System Operators (both referred to here as RTOs[1]) have developed a mix of complex wholesale market mechanisms designed to simulate the operations of a competitive market. These mechanisms include energy markets (real-time and day-ahead markets), ancillary services markets (for example, frequency response service and spinning or synchronized reserve), and transmission congestion-based transmission rights. These market mechanisms operate within a complex framework of RTO operating rules and are overseen primarily by the Federal Energy Regulatory Commission (FERC) through FERC's rulemakings and regulations.

Three RTOs--PJM, ISO New England, and New York ISO--have also developed "locational" (that is, sub-regional) capacity markets intended to encourage building new capacity, retaining existing capacity, and permitting other resources, such as demand-response programs, also to participate in the market. The argument for creating a capacity market, in addition to the existing market mechanisms, is that markets for items such as energy and ancillary services do not provide sufficient revenues to recover the power suppliers' fixed costs. Also, for RTO system reliability a sufficient reserve margin is needed beyond what is necessary most hours of the year. A supplier that operates a "peaking" facility that runs only a small percentage of the year may not expect to recover its investment within a reasonable time to make the investment worthwhile. Capacity markets are intended to provide that revenue by creating an additional market mechanism.

This paper first looks at the economics of how a firm chooses a quantity to supply to a market and how that determines a regional market's supply curve. Next, it describes how the capacity markets work using PJM as an example. Finally, it examines how the economic theory and the RTO practice fit together within the context of recent FERC and capacity market developments.

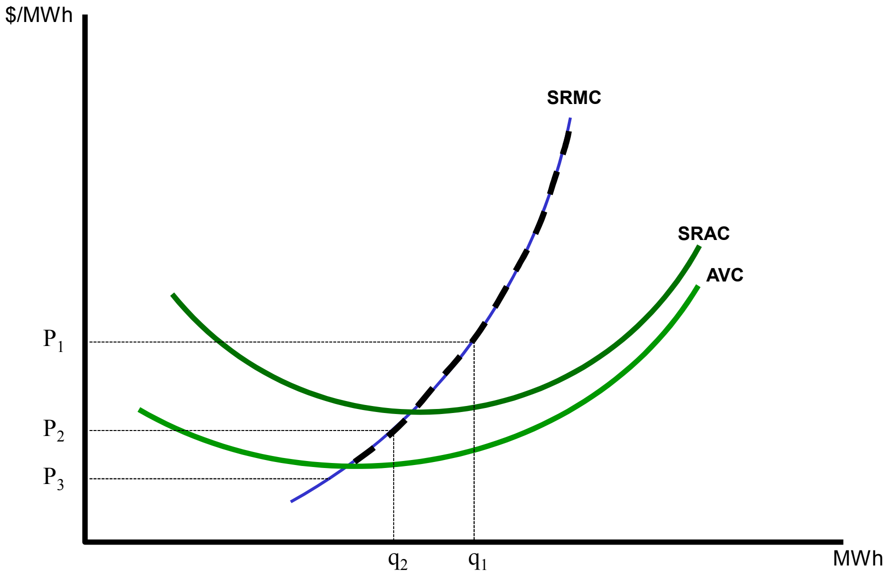
Economic Analysis of a Firm and Regional Supply

The argument for creating a separate capacity market is that energy market revenues are insufficient to induce an adequate amount of new capacity or to keep existing capacity from leaving the market. An additional capacity payment will, in this view, induce new entry and encourage existing facilities to remain or expand. This supposition is examined here using the tools of standard microeconomic analysis.

[1] The terms Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) have specific meaning and distinctions under Federal Energy Regulatory Commission (FERC) rules. For purposes of this paper, the term RTO is used generically to refer to an organization that operates an integrated wholesale electricity transmission system and an array of wholesale markets within the system.

Figure 1 shows the typical U-shaped short-run cost curves that illustrate a firm's decisionmaking on how much to produce given its cost structure.[2] The horizontal axis depicts units per output, or in this case, megawatthours (MWh). The vertical units are expressed in dollars per MWh. Average cost initially declines as the average per unit cost decreases as output increases. Average cost eventually increases at higher levels of output. The bottom curve is the average variable cost (AVC), or those costs that vary with output. The short-run average cost curve (SRAC) includes both variable and fixed costs; the difference between the two curves is the average fixed costs. The short-run marginal cost curve (SRMC) is the additional per unit total cost for each additional unit of output.

Figure 1. Firm short-run cost curves



The segment of the SRMC curve that slopes upward and lies above the AVC is the firm's short-run supply curve (depicted with a dashed line over the SRMC curve). This can be used to identify the quantity the firm is willing to supply for a given price. For example, at price P_1 the firm is able to earn a short-run profit; that is, revenue in excess of average costs. At P_2 the firm will incur a short-run loss, but continue to operate. This is because the firm can still recover all variable costs and at least some fixed costs. At P_3 the firm would be better off shutting down, since it cannot recover the variable cost from continuing operation.

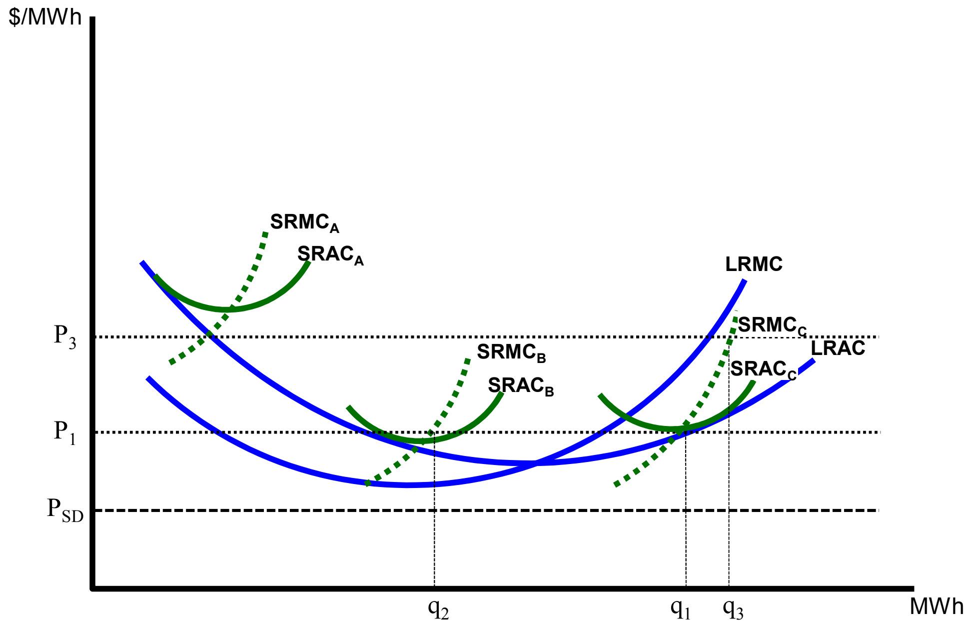
As the firm adds capacity (either capacity at existing plants or new units and entire plants), its potential output expands as well. Figure 2 shows the short-run cost curves for three capacity scales as a hypothetical firm expands capacity (A, B, and C).[3] The dashed lines are the short-run marginal cost curves

[2] The analysis used here is similar to what is used in standard intermediate microeconomic textbooks. This has a long pedigree in regulatory economics as well as it was used, for example, by Clemens, *Economics and Public Utilities* (1950) and Kahn, *The Economics of Regulation: Principles and Institutions* (1970).

[3] An actual firm would have many variations between these short run curves; only three are shown here for clarity of exposition.

for each level of capacity, and the short-run supply curves (again, the portion above AVC; in Figure 2 AVC is not shown). The short-run average cost curves trace the long-run average cost curve (LRAC), which represents the lowest average cost obtainable by the firm when all inputs are variable (since all costs, including capital costs, are variable in the long run).

Figure 2. Firm short-run and long-run cost curves



At price P_1, if a firm had expanded to capacity level "C" shown in the figure, the firm would choose to supply q_1 level of output. At this price and output level the firm would recover all its costs, both fixed and variable (since price is just equal to SRAC). If the firm had chosen a plant scale represented by the cost curves "B," output would be considerably lower, at q_2, but the firm would earn a modest (short-run) profit (since price is greater than SRAC). Note that at a price below P_{SD} the firm will not supply any output at any of the capacity scales shown.[4] Finally, at price P_3, the firm would earn a considerable profit at the capacity scale of "B" or "C," since this is considerably above average cost; at this price output would increase to q_3 at scale "C". However, if the firm was at capacity scale "A," the firm may produce no output at all; if it chose to it may recover only a portion of its fixed costs, depending on the location of AVC. Depending on the price and scale of operation, over the long run the same firm could vary output considerably and face considerable profit or loss.[5]

[4] There may be a capacity scale between "B" and "C" that would allow the firm to produce a positive output. In other words, the firm could expand capacity beyond "B" and move down the LRAC curve to where long-run and short-run average costs would be equal and is at minimum LRAC. Only three possible capacity scales for the firm are considered here out of many along the LRAC curve.

[5] The role of long-run marginal cost (LRMC in Figure 2) will be discussed later in this paper.

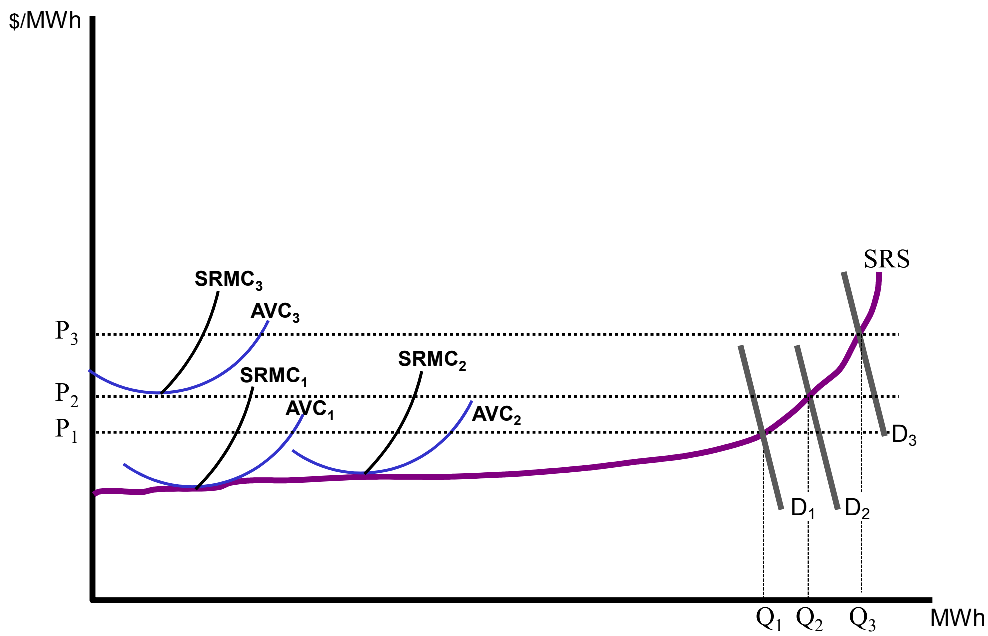
The downward-sloping portion of the firm's long-run average cost curve represents a well-known concept in electricity supply: the region of output where a firm has economies of scale—that is, where output can be increased by more than the proportional increase in total cost.[6] Where long-run average cost is increasing as output increases, there are diseconomies of scale. An output region may exist in-between where long-run average cost is flat, or where there are neither economies nor diseconomies of scale. Figure 2 shows the usual U-shaped average cost curve, but it is typically assumed that electricity production exhibits a wide output range where there are economies of scale and then flat long-run average cost for a range before average cost begins to increase (at least for very large systems). The implication is that one firm can supply a considerable amount of output (within some limited range of output) at a lower cost than two or more smaller firms.[7]

This analysis assumes the firm is a "price taker;" that is, the firm has no market power and cannot raise the price above a competitive level. The price is, therefore, determined by the interaction of many buyers and sellers in the market, of which this hypothetical firm is only one and too small to have a significant effect on the price. For this reason, the price level is shown as a horizontal line and also represents the firm's marginal revenue.[8] Given the conditions that exist in most RTOs, such as the high concentration of capacity ownership within RTO sub-regions, this is not a likely assumption. However, the primary task of this paper is to examine the argument that additional revenue is needed for capacity, beyond energy and other revenue sources.[9]

In a regional market with many sellers at different scales of operation, all the sellers together would determine the short-run supply curve. This would be the horizontal sum of all the firm SRMC curves (again, just the portion above AVC). Three AVC and SRMC (above AVC) curves are shown in Figure 3 for firms indicated with subscripts 1, 2, and 3 (the SRAC curves are not shown).[10] All the short-run supply curves for firms in the region taken together would determine the aggregate short-run supply curve (SRS). This can then be used to determine the price and quantity in the market for different levels of demand. Figure 3 illustrates this with an aggregate short-run supply curve and three different market demand curves. The price P_1 corresponds with the total quantity supplied for the region of Q_1, and P_2 and P_3 with Q_2 and Q_3, respectively.

[6] Another way of stating it is that this is a case where a doubling of the output results in a less than doubling of costs.
[7] If one firm can produce the *entire* output of a market at a lower cost than two or more firms, that firm is defined as a natural monopoly. This provides the foundation for cost-based regulation.
[8] A firm with market power would face downward-sloping *firm* demand and marginal revenue curves. The profit maximizing output level would still be where marginal cost equaled marginal revenue; however, the firm would be able to obtain a higher price based on its demand curve. The steeper the firm demand curve, the more the firm has pricing ability or market power.
[9] How market power in capacity markets is viewed by FERC is discussed later in this paper.
[10] In actual regional markets, there are many suppliers that form the short-run supply curve. For clarity, only three firms are shown to serve as examples.

Figure 3. Short-run firm cost curves and regional supply curve



In this scenario, no single firm is of sufficient scale to provide the entire region's output to meet demand and even the largest firms are relatively small compared to the output needed to meet regional demand.[11] At price P_1, both firms 1 and 2 would supply output (together providing about half the region's output with D_1 demand), but firm 3 would provide no output. For demand level D_2 with P_2 and Q_2, price and quantity, firms 1 and 2 again would supply output. But since the price is still slightly below firm 3's AVC, it still will supply no output. At price P_3, all three firms would supply output and, depending on where the firms' respective average cost curves are, all would likely earn a profit.

Applying this analysis to the electric supply industry requires several supply and demand distinctions to be made. For electricity, demand fluctuates considerably by season and by time of day, so the output levels needed to reach all three demand curves shown in Figure 3 *could occur within the same day*. In addition, to maintain reliable service demand must be met immediately ("on demand") by ramping generating units up or down as demand changes. How do these distinctions change the economics just described? In theory, it might be assumed that the firm simply adds plants when needed and shuts them down when demand falls; increasing and decreasing output by adjusting its capacity scale, effortlessly sliding along the long-run average cost curve. In practice, however, it is not easy to build new plants (and here the challenges of a "lumpy" capacity technology come into consideration). Depending on the type of facility, new plants generally require local permits, state regulatory approval, transmission and fuel access, and substantial financial capital. Even under the best circumstances, the process takes at least one and one-half to two years to complete.

[11] Although for some RTO sub-regions or transmission zones one supplier can provide nearly all the area's demand.

An electric utility serving a single service territory mostly with its own generation solves the problem of changing demand by having different kinds of generation resources on hand: base-load plants or units to run most hours because they have low operating costs (marginal costs) but cannot be ramped up and down quickly; smaller intermediate units that have higher operating costs but that can be up and running faster than base-load plants; and "peaking" units that can meet load quickly but have high operating costs and may run only during periods of high demand (for example, during the summer months for a summer-peaking utility). All of these units may be kept on hand year-round, even though some peaking units may not operate for months at a time. Customers typically pay a rate that is close to the average cost of the entire system, which includes all generating unit types.

An RTO combines (or at least attempts to combine) a number of utility systems into one regional system that faces the same problem of fluctuating demand, but on a broader scale and in a market context. Rather than relying on one utility to adjust its scale to meet demand, an RTO has a number of suppliers with a wide variety of operational scale. Suppliers use different generation technologies and fuels, and vary considerably by size (capacity of less than one megawatt to several thousand megawatts). A claimed benefit of an RTO system is that the RTO can dispatch from a wide array of supply and demand resources.[12] However, unlike a utility providing most of the electric supply for an area, an RTO may have suppliers of wider-ranging scale, including some that are relatively small in scale and that have high average and marginal costs. (One such firm is depicted by firm A in Figure 2.)

It is in the long run that firms change the scale of their operation since all inputs, including capital, are variable. Firms can be at different points on their long-run average cost curve, and long-run average cost is different across firms due to differences in technology and input costs. Typically, an average cost curve is drawn as a smooth continuous function (as shown in Figure 2). However, it is actually a dynamic function of changing technology, highly variable input costs such as fuel, and future investment decisions of the firm. For this reason, it is difficult to pinpoint what the price *should* be to encourage sufficient capacity expansion and retention to ensure reliability. As will be discussed, several RTOs have created separate capacity markets to provide additional revenues for suppliers. They have based the price of that capacity, in part, on an estimate of "new-entry" supply.

Several inferences can be drawn from this analysis. First, while there is a price below which a firm will shut down its operations and not produce any output, this depends on where the firm chooses to be in terms of capacity scale. It may be that by increasing capacity a firm may lower costs and provide an output. Second, smaller-scale operations may require a higher price, which may provide considerable economic profit (that is, a price greater that average cost) to other lower-cost suppliers. In the short-run, a firm does not include investment or capital cost when deciding how much output to produce (using the SRMC to decide), since it cannot quickly change its capital stock, but considers only whether it is able to recover its variable costs. In the long run, and looking at possible future capital decisions, a firm will compare expected average (total) cost with current average variable cost. If the prospective average total cost is lower than AVC, it makes sense to make the new investment; past investment costs, or sunk costs, should not be a decision factor. However, if the AVC is lower than expected average total cost, then

[12] The focus here is on supply resources. As will be discussed later, demand resources are often able to bid in capacity markets similar to supply resources. However, the intent of this is to reduce demand, often (but not always) during peak hours. This does not change the cost curves, since it is assumed that the firm will use the best available (most efficient) technology.

capacity investment may not make sense and the firm should stay with the current capacity. In other words, capital expenditures are considered only on a forward, not backward, basis.

RTO Capacity Markets in Practice

Several RTOs, including New York ISO, ISO New England, and PJM, have developed some type of capacity obligation and resource procuring mechanism. The names, designs, and terminologies are different but they share several basic elements, including:

1) an obligation on those responsible for serving end-use customers (load) to have sufficient capacity to reliability serve that load;
2) a methodology to determine a capacity reserve margin and future capacity needs for sub-regions within the RTO and for the entire RTO;
3) a process for soliciting qualified supply (and demand) resources to meet future capacity needs (for constructing an offer or supply curve);
4) some type of benchmark to judge the cost of new capacity;
5) a methodology or approach for creating a "demand curve"; and
6) a process (such as an auction) to select resources and determine a capacity "price."

PJM has a mechanism called the "Reliability Pricing Model" (RPM) which uses all these elements and will be described in more detail.[13] The RPM mechanism replaced the "Capacity Credit Market" (CCM) that required Load-Serving Entities (LSEs)[14] to own or acquire capacity resources equal to peak load served plus a reserve margin. Under CCM, LSEs could use their existing capacity, buy, or build new capacity; acquire capacity through bilateral arrangement; or use the CCM to meet the obligation. RPM replaced this approach with a capacity mechanism that is "locational" (sub-regional) and uses a three-year forward obligation for capacity. Auctions began in April 2007 with capacity prices determined by using an offer-based supply curve and a simulated downward-sloping demand curve.

PJM runs "Base Residual Auctions" (BRA) that procure forward capacity resource commitments for a delivery year three years in the future and three "Incremental Auctions" that may be held 20 months, 10 months, and 3 months before each delivery year. The first and third incremental auctions allow suppliers to procure replacement capacity for commitments they can no longer fulfill. The second incremental auction allows PJM to procure more capacity if the delivery year peak load forecast has increased since the base auction was conducted. Demand-side resources and new transmission projects can (and do) participate in the auctions.

LSEs must participate in the RPM for load served in a PJM control zone. LSEs pay a locational reliability charge equal to the daily "unforced capacity obligation"[15] in its zone multiplied by the final zonal

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[13] PJM's approach is complex and will only be summarized here. This discussion is not intended to provide sufficient detail for market participants and others that require more exhaustive detail. PJM provides training and training materials and also has extensive user documentation available on its web site (www.pjm.com).

[14] A Load Serving Entity is basically any entity that serves end-use customers within PJM and has been given the authority or obligation to sell electricity to end-use customers. This includes local distribution (or utility) companies and can be a qualified end-use customer (such as a large industrial customer).

[15] Unforced Capacity is defined by PJM as the installed capacity rated at summer conditions that are not on average experiencing either a forced outage or forced derating.

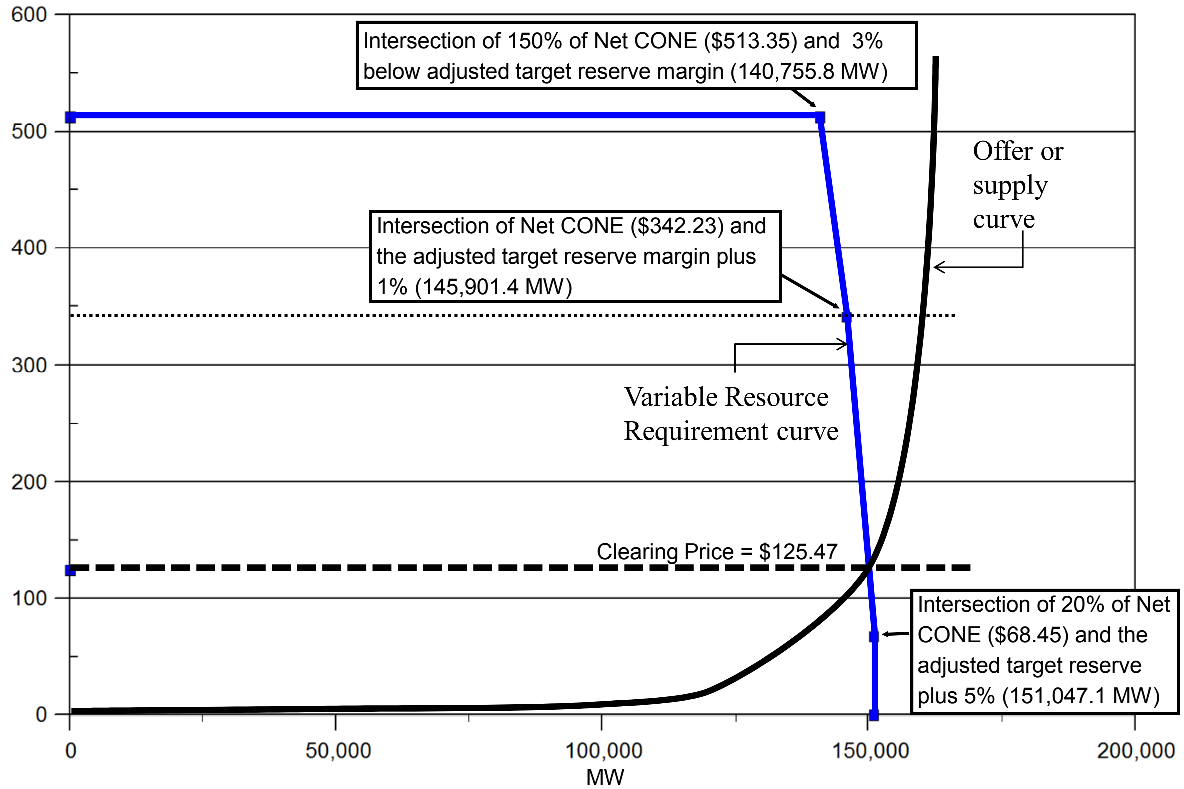
capacity price. LSEs in PJM can "self-supply" resources to meet their capacity obligations by designating resources they own or purchase bilaterally (but resources must be offered in base auctions). The base auction provides an opportunity to purchase capacity requirements beyond self-supplied resources. The "Fixed Resource Requirement" (FRR) allows LSEs to meet a fixed capacity obligation. The market clearing price is paid to all resources committed in the auction and may be offset by performance-based penalties.

The RPM process and results can be summarized using a diagram such as the one shown in Figure 4. The numbers used are from the Base Residual Auction for the delivery year 2014/2015 that was held in May 2011.[16] The vertical axis is in dollars per megawatt-day and the horizontal axis is in megawatts. The upward-sloping curve represents supply offers from the resources and is drawn as a close approximation, not the actual bids. The downward-sloping line (in blue) is the “Variable Resource Requirement” (VRR) or the “downward-sloping demand curve.” The VRR “curve” (actually constructed of four straight line segments) is found by connecting three points that are the intersecting points (on the horizontal axis) representing adjustments to the reliability requirement with points (on the vertical axis) representing adjustments to the net “cost of new entry” or net CONE (that is, the estimated cost of new entry—CONE—minus energy and ancillary service revenue offset[17]).

The top point on the VRR curve is the upper bound on the price or 150 percent of net CONE ($513.35) and the minimum target reserve margin, which is set 3 percent below the adjusted target reserve margin (140,755.8 MW). The middle point is the intersection of net CONE (set at $342.23 for this auction) and the adjusted target reserve margin plus 1 percent (145,901.4 MW). The lower point is the intersection of 20 percent of net CONE ($68.45) and the adjusted target reserve plus 5 percent (151,047.1 MW). The VRR curve depicts the PJM RTO for this particular auction. The intersecting points are recalculated for each auction and a VRR curve is found for the “locational deliverability areas” (LDA) that are part of the auction.[18] Note that while the VRR “curve” is often referred to as a “downward-sloping demand curve,” this does not represent actual demand for capacity resources. Rather, this is an engineering construct designed to find a “clearing price” based on estimated resource needs, estimated new entry costs, and offer prices.[19]

[16] The figure only shows, to present a clear example, the “limited DR [demand response] supply curve,” and does not include the “annual resource and extended summer DR supply curve” that was also used for this auction. The resource clearing price shown of $125.47 was found by the intersection of the limited DR supply curve and the “VRR curve,” shown in blue in Figure 4. The clearing price to meet the “minimum extended summer resource requirement” was $125.99 in the same auction.
[17] “Net CONE” is calculated by beginning with an estimated levelized revenue requirement (in $/MW-year; for the 2014/2015 BRA held in 2011, the previous year’s estimate was used and adjusted using a regional Handy Whitman Index). The process then deducts the estimated annual energy revenue based on 2008-2010 zonal or average LMPs and the estimated annual ancillary services revenues. This annual number is then divided by 365 (arriving at a number that is in $/MW-day) and there is an “unforced capacity” adjustment (based on probable unit availability). Net CONE was calculated for five zones in eastern PJM and for the entire RTO for the 2011 BRA.
[18] Currently, PJM has identified 25 sub-regions as Locational Deliverability Areas (LDAs). Not all LDAs are included in each auction.
[19] This construct is based on a view that capacity can be separated from other input factors and from the final product (electricity). Why this is likely mistaken is discussed in the last section of this paper.

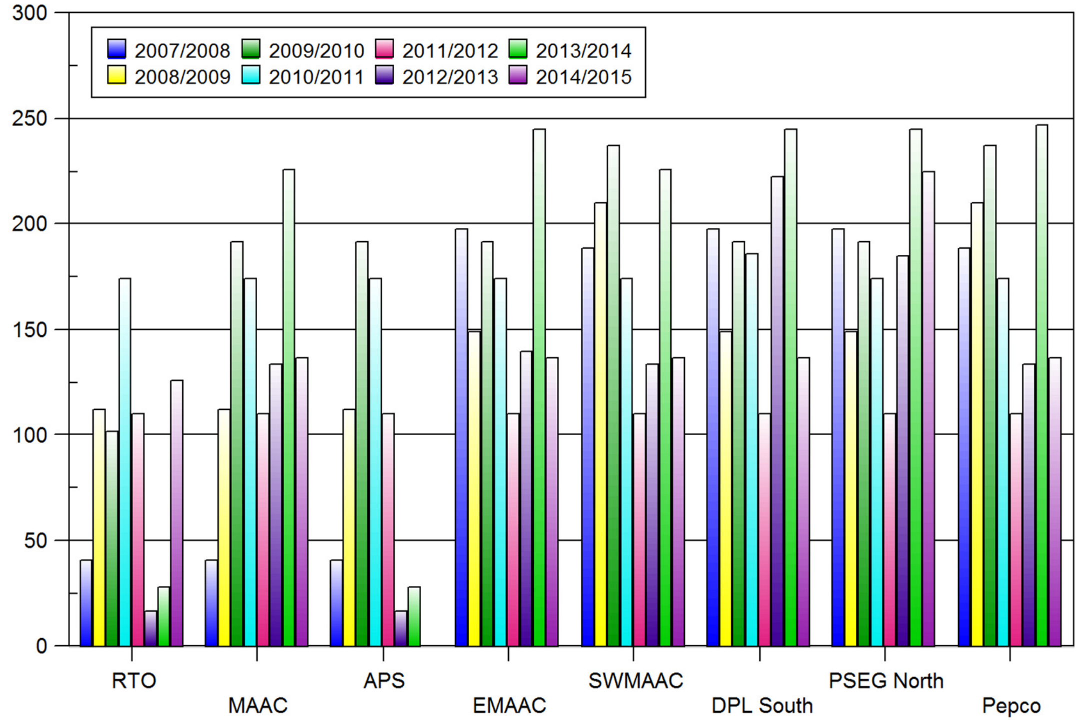
Figure 4. PJM 2014/2015 base residual auction ($/MW-day)



Source: Based on information from PJM, http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

Figure 5 graphs BRA clearing prices for delivery years 2007/2008 through 2013/2014 (auctions held in 2007 through 2010).[20] The RTO price increased significantly until the 2010/2011 delivery year (the auction held in 2008), then dropped considerably until the 2011 auction shown in Figure 4 where the RTO price reached nearly $126. The drop in prices after 2008 is likely due to the recession's impact on the need for future capacity. Prices in the APS (Allegheny Power System) area followed a pattern similar to the RTO. However, the MAAC area (which encompasses most of Pennsylvania, New Jersey, Delaware, central and eastern Maryland, and the Delmarva Peninsula of Virginia[21]) has experienced significantly higher prices since the RPM mechanism began. For the 2014/2015 delivery-year auction held in 2011, the MAAC area capacity price fell to $136.50.[22] The higher prices in the eastern part of PJM are generally attributed to transmission constraints and higher capacity costs.

Figure 5. BRA clearing prices 2007/2008 through 2014/2015 ($/MW-day)



Data Source: 2010 State of the Market Report for PJM, Monitoring Analytics, LLC, 2011 and "Base Residual Auction Results," PJM, 2011.

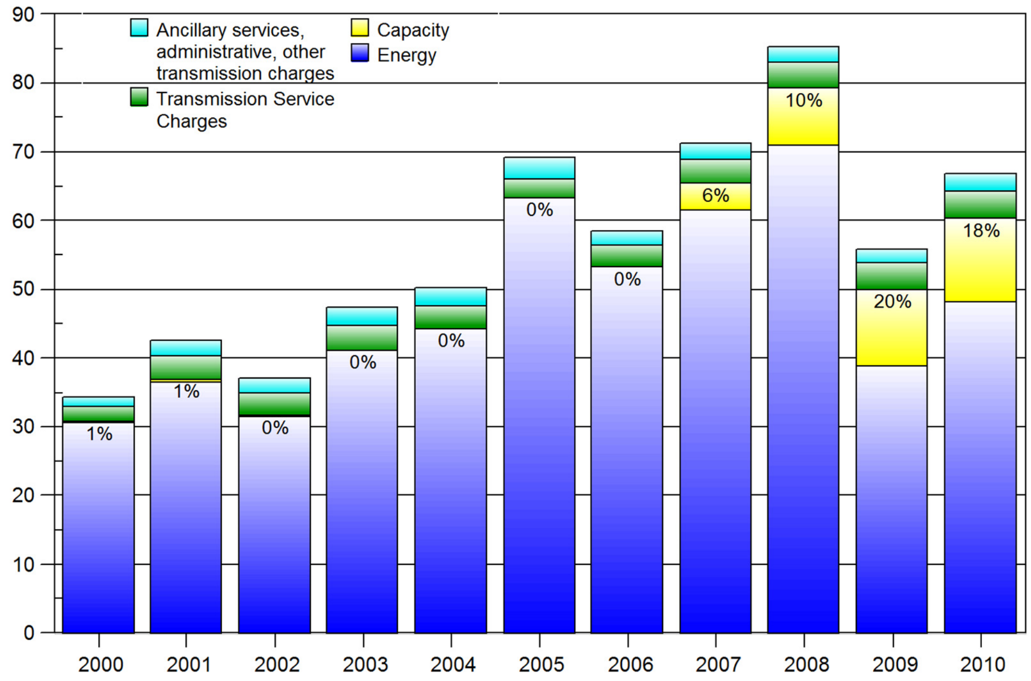
[20] A delivery year is June 1st through May 31st.

[21] This is the transmission zones of Baltimore Gas and Electric Co., Metropolitan Edison Co., Pennsylvania Electric Co., PPL Electric Utilities, Atlantic City Electric, Delmarva Power, Jersey Central Power and Light Co., PECO, Public Service Electric and Gas Co., and Rockland Electric Co.

[22] The capacity price the area pays is the specific area's price, otherwise the RTO price applies everywhere else.

The capacity prices are specified in dollars per MW-day and are difficult to translate into what customers pay for power. Figure 6 provides a wholesale price breakdown by category over the 2000 through 2010 period for PJM. Energy is the single largest component of the wholesale price, with transmission service charges a distant second through 2006. The capacity component, while insignificant before 2007, became the second largest category after the RPM mechanism began in 2007 (the percentage figures are for the capacity portion of the price). The capacity component grew to 20 percent and 18 percent of the wholesale price in 2009 and 2010, respectively. The fourth price component includes ancillary services, administrative, and other transmission charges and remained a relatively small share of the wholesale price.

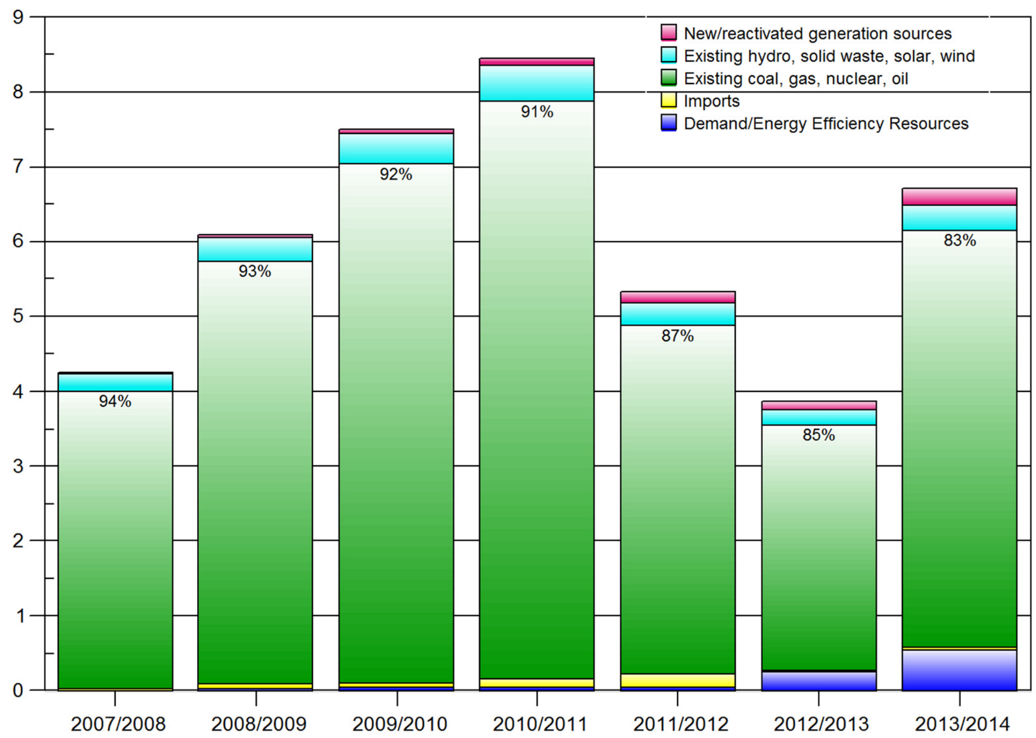
Figure 6. Total price per MWh by category, 2000 through 2010 ($/MWh)



Data Source: 2010 State of the Market Report for PJM, Monitoring Analytics, LLC, 2011.

Figure 7 shows trends for the revenue generated by the RPM mechanism by type of resource for each delivery year. Revenues have overwhelmingly been allocated to existing resources and, in particular, to existing coal, natural gas, nuclear, and oil generation. Taking into account all resources (which includes hydroelectric, solid waste, solar, and wind), 90 percent to 99 percent of revenues went to existing resources in the first six years of RPM. Only in the last delivery year did the percentage drop below 90 percent, to 88 percent in the 2010 auction (2013/2014 delivery year). New and reactivated generation sources received a small portion of the RPM revenues. Much is made also of the impact of demand management and energy-efficiency resources on the auction, but these resources, while significant and growing, are still (at least so far) a relatively small portion of annual revenues.

Figure 7. RPM revenue by type of resource ($ billions)



Data Source: 2010 State of the Market Report for PJM, Monitoring Analytics, LLC, 2011.

As part of the RPM, PJM also established a Minimum Offer Price Rule (MOPR) that, as FERC noted in a recent order, addresses the concern that "some market participants might have an incentive to depress market clearing prices [in the capacity market auctions] by offering *supply at less than a competitive level*" [footnote omitted, emphasis added].[23] PJM developed a "conduct screen" to use as a benchmark to determine if an offer is "uncompetitively low" and should be subject to mitigation. The conduct screen for combined-cycle (CC) and combustion-turbine (CT) technologies is 90 percent of the net CONE for both types of plants and 70 percent for unspecified plant technologies. Capacity resources that fail the conduct screen are re-priced at the same threshold levels; that is, 90 percent of the CC and CT asset class Net CONE, and 70 percent for other unspecified plant types.[24]

A number of resources are exempt from the MOPR and can offer a price below these thresholds (allowing zero-price offers), including nuclear, coal, integrated gasification combined cycle (IGCC), hydroelectric, wind, and solar.

FERC states that the MOPR apparatus is needed "to protect against *the exercise of buyer market power.*" FERC also requires that a sell offer failing the conduct screen must be subject to mitigation, reasoning that "*the uneconomic offer is increased to a competitive level*."[25] On the other side of the capacity market, the Independent Market Monitor (IMM) also monitors for *supplier* market power. The IMM "found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in the first three months of calendar-year 2011."[26] This is consistent with earlier IMM findings of serious structural problems but no exercise of market power.[27] The IMM found HHIs well above 3000 in five of seven RPM markets. Two markets were above 8000, considered extremely high concentration levels. These five areas all had market shares between 49 percent and 94 percent.[28]

Importantly, FERC only addressed "buyer market power" in its April 2011 MOPR Order, not seller or supplier market power. Of course, effective competition requires checks on both forms of potential market distortion. As will be discussed in the next section, a fundamental problem appears to exist with how the capacity market is defined that could lead to an erroneous conclusion that "buyer market power" is a problem.

[23] Federal Energy Regulatory Commission, 135 FERC ¶61,022, pp. 6-7, issued April 12, 2011. Two states, Maryland and New Jersey, concerned that they are paying unreasonably high prices for capacity through the RPM mechanism, have sought other means to bring additional capacity into the state. For further explanation, see *Public Power* magazine of the American Public Power Association, "A Tale of Two RTOs," vol. 69, no. 4, June 2011, at http://www.publicpower.org/Media/magazine/ArticleDetail.cfm?ItemNumber=32205.

[24] The information on the MOPR is from the April 2011 FERC MOPR Order, which authorized changes proposed by PJM. PJM has sought further clarification on the Order and FERC held a technical conference on July 28, 2011 (see http://www.ferc.gov/EventCalendar/Files/20110722160032-ER11-2875-001.pdf).

[25] These quotes are from paragraph 6 of the April 2011 FERC MOPR Order summarizing the 2006 RPM Settlement establishing the MOPR.

[26] 2011 Quarterly State of the Market Report for PJM: January through March, Monitoring Analytics, LLC, p. 134; www.monitoringanalytics.com.

[27] The IMM rarely finds market power being exercised in any market in the RTO. This is due to high thresholds being used to make a determination of when market power being exercised; that is, when comparing an estimated theoretical competitive market outcome with actual prices.

[28] Table 5-2 of the IMM Quarterly Report.

Analysis and Policy Implications

The rather elaborate construct or apparatus that PJM and other RTOs have created is primarily intended to maintain the reliable operation of the transmission system by paying suppliers an additional amount for capacity beyond what they receive in the energy and other markets.[29] However, there are at least two major conceptual problems with this approach that are at odds with the fundamental economics of electricity production.

Economic Efficiency

The first problem can be broken down into short-run and long-run cost considerations. The argument for creating a separate capacity market is that energy market and other revenues are insufficient to induce an adequate amount of new capacity and to keep existing capacity from leaving the market. Based on the analysis in the first section of this paper, this would mean the firm in the short run was operating below average variable cost (the "shutdown point") or was operating where the price was between average variable cost and short-run average cost (in other words, operating at a loss, but able to continue operating and recovering some fixed costs). If this situation were to occur, the additional capacity payment in theory would be equal to the difference between the firm's short-run average cost and the price. This would, again in theory, induce new entry and encourage existing facilities to remain or expand. However, the capacity mechanisms clearly do not attempt to do this. Rather, they rely on an artificial demand curve (based on cost of new entry, or CONE, and reserve requirements as described above) and the offers made by the suppliers to determine a "market clearing price."

The estimate of CONE is not an estimate of short-run marginal cost, but represents the cost of a new stand-alone CC or CT unit (in PJM's case) minus expected revenues from energy and ancillary services sales. This is not an actual firm's cost (average or marginal), and certainly is not a competitive price that would result from the interaction of firms with robust competition. FERC states that "Net CONE serves as a reasonable estimate for a competitive offer price,"[30] but is merely, at best, a short-term static estimate of a new firm's stand-alone entry cost.

As also shown in the first section, firm costs can vary considerably depending on the firm's operating scale. For example, at price P_3 in Figure 2 the firm operating at either scale B or C would earn a considerable profit. However, the firm operating at the scale shown by the figure's cost curves "A" would earn no profit at all and would consider shutting down, depending on expected future prices.[31] In other words, the same price can have very different outcomes for firms operating at different scales of operation. In reality, actual costs are dynamic and idiosyncratic to a particular firm's situation, and cannot be estimated by policymakers in advance and with a reasonable degree of precision.

In the long run, where all costs are variable, the firm in theory would choose an output where the price is equal to long-run marginal cost (LRMC in Figure 2, above).[32] In the output range where long-run

[29] These schemes are part of the RTOs' resource adequacy requirement for RTO planning and expansion, one of several FERC-mandated RTO functions.
[30] FERC MOPR Order, paragraph 43.
[31] Note that the firm could expand from that point and reduce cost.
[32] In theory, this is a common assumption. However, in practice it is difficult or impossible to pin down what the long-run marginal cost is, as noted some time ago by William Vickrey: "Another objection to the policy of setting price at marginal cost is based on the fact that reality does not conform to the regular and perfectly defined curves of the theorist, so that, in practice, marginal cost

average cost is increasing, the firm would earn a profit, since LRMC is greater than LRAC. While a firm would prefer to operate in the long run where price equals its long-run marginal costs, in an RTO market where other firms can expand or enter, the market price would be determined by a long-run supply curve, not the individual firm's or group of firms' long-run marginal cost.[33] The long-run supply curve would be determined by the interaction of all suppliers entering, expanding, or exiting the market, and by the changing conditions that affect the firms' costs, such as input costs and technology changes.

It is difficult to generalize about the shape of the industry's long-run supply curve without substantial further analysis. However, it is interesting to note that given the considerable expansion in U.S. output over the last half-century, real consumer prices for electricity (adjusted for overall price changes using gross domestic product implicit price deflator) have remained nearly constant. From 1960 to 2009, electricity generation increased by 420 percent, while the real price of electricity for all consumers fell by a comparatively small 7 percent.[34] This would imply a relatively flat long-run supply curve for the industry. Several important factors, of course, must be taken into account before any conclusion can be drawn about the supply curve's character or slope.

First, that 49-year time period between 1960 and 2009 saw considerable price variation, with a 59 percent difference between the lowest and highest real price.[35] Fluctuating fuel prices[36] and capital costs explain much of the variation. Also, the U.S. average price trend masks the substantial variation in price by region and state. Second, during this time period, the mix of fuels used for electric generation changed, including a drop in the use of fuel oil in the 1970s, a rise in the use of nuclear power in the 1970s and early 1980s, and increased use of natural gas beginning in the late 1990s and continuing to the present. Third, the increased use of natural gas reflects technology changes that reduced the efficient operating scale for power plants. The fuel costs and technological changes that occurred during the last half century served to effectively shift the long-run supply curve up (for example, from higher fuel prices) and down (for example, from technological improvements).

A flat long-run supply curve implies a constant-cost industry; that is, one where input prices remain the same as output expands.[37] Volatile fuel prices and technological changes would have the effect of shifting the curve up or down, but the long-run curve would be relatively flat. As noted, an analysis beyond the scope of this paper would be required to sort out the dynamic market changes that occurred during this period and to reach a conclusion about the nature of the long-run supply curve. If it is assumed that, at least for recent decades, the electricity industry has (or at least had) a flat long-run supply curve, these dynamics would suggest that as demand increased, new entrants and expanding output from existing firms

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may be not only quite difficult to determine with any approach to accuracy but also subject to extreme and erratic fluctuation, depending on the precise circumstances of the moment." William Vickrey, "Objections to Marginal-Cost Pricing," *The Journal of Political Economy*, Vol. 56, No. 3, (Jun., 1948), pp. 218-238.

[33] The industry long-run supply curve is not the sum of the long-run marginal cost curves of firms in the industry, as is the case with the short-run marginal cost curves as discussed in the first section (and shown in Figure 3).

[34] Based on U.S. Department of Energy, Energy Information Administration data, Table 8.2a "Electricity Net Generation" and Table 8.10 "Average Retail Prices of Electricity."

[35] The real price of electricity for all customers fell or was flat from 1960 until 1973, then increased considerably until 1982, fell again until 2000, and has been rising again since 2004.

[36] The cost of fuel used to generate electricity is discussed in "The Impact of Fuel Costs on Electric Power Prices," June 2007, prepared for the American Public Power Association (APPA). Posted at: http://www.appanet.org/files/PDFs/ImpactofFuelCostsonElectricPowerPrices.pdf

[37] In other words, the additional inputs of fuel, capital, and other inputs needed to produce higher output are obtained without an increase in the per-unit price of the inputs.

would drive the price back down to the long-run equilibrium price. It would do this either through regulatory or market processes. Fluctuating fuel costs would shift the curve both up and down,[38] but new technologies would most likely have shifted the curve down. The long-run average cost curve would also be relatively flat. This implies that creating additional compensation for capital based on short-run new-entrant costs will likely overcompensate suppliers with lower long-run average costs beyond what is necessary for them remain or expand in the market.[39] This would amount to a subsidy that has the effect of supporting higher-cost suppliers, while providing unnecessary compensation to lower-cost ones.

In summary, this analysis suggests that in the short run, paying separately for capacity would potentially help some small-scale new entrants (if the payment was high enough), but only overcompensate and add to the economic profit of many (perhaps most) existing suppliers. In the long run, if the market for electricity is operating efficiently, then the capacity payment is unnecessary since all costs, including capital costs, would already be recovered in the market price for electricity since that price would be at or above long-run average cost.

Inputs v. Outputs

The second conceptual problem with the RTO capacity market approach is more fundamental from an economic theory standpoint. This approach attempts to construct a "market" to sell capacity to customers as if it were a final product that can be separated from other products that firms produce. This form of unbundling or separation may work for some outputs or products, such as byproducts or externalities where a separate market can be set up by regulators[40] or the ancillary services market that RTOs have created with FERC approval. The capital investment that capacity markets intend to induce is different; it is actually an *input* in the production process of the firm, not an *output*. The cost curves described above are a function of the inputs firms use to produce output: capital, land, labor, energy, materials, and so on. Each of these inputs has separate "factor" markets in which electricity suppliers operate. But these markets are not what the RTO capacity markets are trying to supplement or correct. Rather, they are attempting to create a final product market for something that is merely one input of many that are needed to generate electricity.[41]

This may explain why the capacity construct that the RTOs are using has become so complex. Every aspect of the capacity market design has to be redesigned and readjusted to fit changing conditions, rather than allowing the market participants to adjust to market information over time, as happens generally in competitive markets. The "demand curves" are artificial constructs based on estimated required capacity and cost of new capacity. There is no actual "demand" from end-use consumers, since capacity alone is of little use to them; they require delivery in the form of usable electrical energy. Suppliers that make the offers that constitute the supply or offer curve know how other suppliers will behave and will bid accordingly. These are not the ingredients of a healthy competitive market. PJM's MOPR is a case in point. The MOPR requires significant intervention in the market created by PJM because it actually does

[38] The constant-cost assumption here means that input prices remain constant as output expands, not that there are no exogenous price increases or decreases for the inputs, such as fuel. As noted, fuel price changes shift the curve.
[39] This would be the case even if it was assumed that there was an increasing input costs, or an upward-sloping long-run supply curve; only the price would not decline back to the original equilibrium price, but at a price higher than the original and below the short-run price.
[40] For example, the sulfur dioxide allowance trading market created by the Clean Air Act Amendments of 1990 and administered by the Environmental Protection Agency.
[41] It might be fair to ask: why not have a market construct for every input used, not just one for capacity?

not operate as a self-sustaining competitive market. This shift of focus away from the primary problem of how to secure capacity for reliability purposes may explain why "buyer market power" is regarded as a "market" problem by the RTOs and FERC.

The complex mechanism of capacity markets is not self-sustaining, since the RTOs and regulators will need to continuously update and fix the apparatus as conditions change. But no adjustment can fix the underlying conceptual problem of trying to artificially create a market for a production input, as compared to a final product. A truly competitive market, in contrast, changes as circumstances change, without the stakeholders having to agree on changes and without the regulator having to insert its judgment by choosing and approving what it thinks will work.

Conclusion

Proponents have argued that the capacity markets construct works and that it has helped attract new entry and retain existing capacity.[42] There is little doubt that additional revenues for suppliers would increase and retain capacity—in effect these revenues raise the horizontal price line (or marginal revenue) from where it would be without the capacity revenue (as shown in Figures 1 though 3).[43] The consequence, as Figure 7 shows, is that the overwhelming amount of RPM revenue is going to existing resources and little is going to new or reactivated resources. This likely means the total price received from all sources of revenue exceed average cost. This means economic profit—perhaps substantial economic profit—for existing suppliers. This amounts to a subsidy or transfer payment to suppliers over and above what is necessary to earn a normal profit and to continue operating or expanding. Distorted incentives will tend to perpetuate supply-side inefficiencies in resource allocation and operations. This uneconomic subsidy is non-trivial for customers. In the PJM case, it amounts to almost $800 for each person who lived in the service area since RPM began in 2007 (and through 2010).[44] Given recent economic conditions, the region can ill-afford such generous subsidies.

The essential point of federal regulatory policy in the electricity sector is to ensure the operation of a reliable transmission and supply system that is responsive to changing market conditions and public policies. Policymakers may need to refocus their efforts on how to accomplish these goals in a sustainable way that is consistent with fundamental economic principles. The current approach falls short in these basic respects.

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[42] In a press release, PJM stated "PJM's analysis shows that, since the first auction in 2007, the RPM has retained and attracted 40,787 megawatts (MW) of power capacity resources compared to what would have happened without the RPM." From news release "Demand Resources and Energy Efficiency Continue to Grow in PJM's RPM Auction," May 13, 2011. Obviously, determining how much was retained due to RPM would be challenging.

[43] Figures 1 through 3 show costs as a function of electric energy produced or MWh; capacity payments are made in terms of capacity or MW. For this reason the marginal revenue curve would increase as output and capacity expanded in a nonlinear manner.

[44] According to PJM's independent market monitor, the total RPM revenue from 2007 through 2010 was $42,196,737,603, or just over $42 billion. PJM states that 54 million people live in their region. That works out to about $781 per person over the four-year period.

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APPENDIX B

Post-Technical Conference Comments

of the Public Power Association of New Jersey

August 29, 2011

UNITED STATE OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	**)**	
	)	
v.	**)**	**Docket No. EL11-20-000**
	)	
PJM Interconnection, L.L.C.	**)**	
PJM Interconnection, L.L.C.	**)**	**Docket No. ER11-2875-000**

POST-TECHNICAL CONFERENCE COMMENTS OF THE
PUBLIC POWER ASSOCIATION OF NEW JERSEY

In accordance with the Notice and the Amended Notice of the Federal Energy Regulatory Commission ("FERC" or "the Commission") dated July 28, 2011 and August 4, 2011, respectively, in Docket No. 11-2875 and EL11-20, the Public Power Association of New Jersey ("PPANJ")[1] hereby files these timely comments and the attached Affidavit of Joseph A. Isabella, Director of Municipal Utilities, City of Vineland, New Jersey, in response to the presentations made at the Technical Conference held by FERC in these dockets on July 28, 2011. These comments will help the Commission understand the real-world impact of the proposed Minimum Offer Pricing Rule ("MOPR") on a new power plant that is under consideration by Vineland, New Jersey, a municipal utility and PPANJ's largest member. PPANJ files these comments to encourage the adoption of the PJM MOPR amendments, and the rejection of the modifications advanced by the Independent Market Monitor ("IMM"), PJM Power Providers ("P3") and PSE&G.

[1] The PPANJ is a non-profit association of public power and rural electric cooperative systems in New Jersey comprised of the municipal electric utilities of the Boroughs of Butler, Lavallette, Madison, Milltown, Park Ridge, Pemberton, Seaside Heights, South River, the Vineland Municipal Electric Utility ("VMEU"), and Sussex Rural Electric Cooperative, Inc.

New Jersey is in obvious need of new electric generating capacity, and yet the IMM, P3 and PSE&G would keep Vineland, New Jersey from constructing a natural gas fired Combustion Turbine unit at its actual municipal cost of service. Public power entities have built their own generation to serve their own customers at their real costs of service in New Jersey for over one hundred years. Now, however, when new capacity is especially needed to serve constrained areas, these entrenched players argue that the "market" must be guarded against the likes of municipal government! PPANJ asks the FERC to reject these fallacious claims of buyer market manipulation and to adopt the well reasoned May 12, 2011 MOPR proposed by PJM in its compliance filing and supported by PJM Witness Mr. Ott in his July 22, 2011 Statement in this proceeding.

It is no secret that PJM "markets" for capacity and energy have been an abject failure for Vineland, New Jersey. Despite having among the highest congestion costs and the highest capacity costs of any area in PJM for years on end, there has been minimal new generation constructed in New Jersey to alleviate the high prices for Vineland. The administrative constructs that artificially add dollars to energy (congestion) and capacity (RPM) prices in PJM are not "markets" and they have failed to produce additional energy and capacity sufficient to quell the volatility and high costs. [2]

In response to this crisis, Vineland, New Jersey proposes to build a new 57 MW Combustion Turbine unit inside its municipal boundary for the purpose of serving its customers. The IMM, P3 and PSE&G consider such an act to be buyer market

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[2] To make matters worse, PJM significantly over-procured capacity required to serve the New Jersey market because it did not heed the warnings of PPANJ in 2008 at the beginning of the recession to reduce the load forecast used for capacity procurement. *Protest Regarding Load Forecast to be used in May 2009 RPM Auction*, FERC Docket No. ER09-412, January 9, 2009. Accordingly, this excess capacity procured at extremely high prices must be allocated across the remaining load that is already burdened with excessive above-cost prices for capacity and energy. This is evident in the Zonal Scaling Factors in the PSE&G and JPC&L Zones rising from approximately 5% in 2007 to as high as 10% in recent years.

manipulation that must be mitigated by artificially adding dollars to the actual Vineland cost of building the unit. (Why is it that artificially imposed dollars are always *added* to customer bottom lines; never *subtracted*?[3]) Vineland is well along in developing the specifications for the proposed unit, but unless it can be assured that the unit will clear the RPM auction, then it will delay or cancel the unit. (*See* attached affidavit of Joseph A. Isabella, Director of Municipal Utility, City of Vineland, New Jersey.) Vineland, as a municipal government responsible to its citizens, cannot afford to strap its customers to the cost of paying for both exorbitant Reliability Pricing Model ("RPM") costs and for the cost of the unit that may be stranded.[4]

Other public bodies have participated in these proceedings arguing that all self-supply units should be guaranteed to clear by allowing them to submit bids of zero into the RPM auction. PPANJ is sympathetic to this contention, and believes it is probably the right approach, but its members cannot take the risk of losing that argument. The situation in New Jersey is far worse than other places in PJM, and PPANJ is therefore willing to compete in RPM auctions based on its actual real costs. This is the essence of the compliance filing made by PJM on May 12, 2011 and PPANJ urges the Commission

[3] Indeed, the need for Reliability Must Run ("RMR") units in New Jersey has continued from the beginning of RPM until as recently as last week when PJM finally released PSE&G's Hudson No. 1 unit from mandatory service. *See* slide 36 of August 4, 2011 presentation of the PJM Transmission Expansion Advisory Committee found on the PJM website. PSE&G or PJM have yet to ask FERC to similarly release the $60 million that FERC approved six weeks ago for upgrades to the unit. *PSE&G Energy Resources and Trade LLC*, 136 FERC ¶61,072 (July 29, 2011). This is yet a fourth method that subjects which New Jersey customers to excessive prices.

[4] Mr. Ott correctly captured the core concern of the PPANJ members with this statement: "The central concern in the rehearing requests on the self-supply issue is that new entry resources developed through legitimate arrangements outside RPM, and relied upon by the relevant LSEs for their long-term capacity needs, may be mitigated by MOPR to an offer price level above the auction clearing price, thereby denying the load-serving entity credit in RPM for its planned resource and forcing it to pay for additional capacity from RPM." Ott at p. 4.

to adopt this proposal if it does not accept the arguments of the other public power entities that self-supply should be guaranteed to clear the RPM auctions.

I. The Vineland Unit – Buyer Self-Help not Buyer Manipulation

As Mr. Isabella explains in the attached affidavit, the unit that Vineland is proposing to build is a 57 MW combustion turbine gas fired generator to be built inside the Vineland City boundary on land already owned by the City and is to be used entirely to serve its own load. The feasible and desirable in-service date for this unit is PJM Delivery Year 2015/16, but this in-service date is in danger of being delayed or cancelled because the unit is so economical. (*See* Affidavit of Mr. Isabella at 3.) Yes, you read that right – the unit might be cancelled because it is such a good value. As Mr. Isabella explains, the estimated net total cost of the unit is $129.65/MW day. (Affidavit of Mr. Isabella at 3 and at Exhibit A.) This is a fairly conservative estimate because it uses the PJM-provided average energy and ancillary services values, even though the actual congestion costs at Vineland are significantly higher than the average in the Atlantic Electric Zone. A case could be made that the true cost of the unit is even lower than $129.65/MW day because the revenue offsets from congestion costs are likely to be higher. *Id.* Compare this to the PJM Net Cost of New Entry "CONE") of $275.02 /MW day and one could be forgiven for concluding that it is a "no-brainer" that the unit should absolutely be built, and without delay.[5]

The MOPR proposals of the IMM, P3 and PSE&G, however, contend that a unit this economical is unfair to other potential generators. A unit this inexpensive must be

[5] In defending RPM to the New Jersey Board of Public Utilities in a June 17, 2011 report, PJM's comments calculated the cost of RPM as $114,204/MW year and described it as "cheaper than the cost to build new generation resources in New Jersey." Comments of PJM Interconnection at 14, New Jersey Board of Public Utilities, Docket No. EO11050309 (June 17, 2011). In fact, however, Vineland's cost of $129/MW day is cheaper than the cost of RPM as calculated by PJM.

"mitigated up" to keep it from reducing the market entry pricing required of other less privileged (or perhaps foot-dragging?) competitors. [6]

We are not making this up, strange as it sounds. P3 Witness Mr. Shanker speaks of the "discriminatory benefit" associated with "uneconomic new entry" represented by units such as the one under consideration by Vineland. *See* Attachment Replies to Specific Technical Session Questions, Roy J. Shanker, July 28, 2011, page 2. PSE&G Witness Mr. Hogan states that "mitigation is necessary to address the problem of buyer market power manipulation." Initial Statement of William W. Hogan FERC Technical Conference, July 28, 2011, page 3. *See also* the Statement of Patrick E. McCullar on Behalf of DEMEC and the APPA, July 28, 2011, page 3 "[T]he IMM wanted to add 200 basis points to DEMEC's actual financing rate without any justification, among other upward adjustments proposed."

Not only is this upward mitigation an anathema to the American free enterprise system in which those with a better product at a better price should be permitted free access to markets. It is also an anathema to the American principle of self-help governance in which citizens band together locally to solve their problems. Not one shred of evidence can be produced that Vineland proposes to build the unit for any purpose other than to provide its customers with reasonably priced electricity, something that PJM

[6] This smacks of the socialism that Kurt Vonnegut lampooned in his short story "Harrison Bergeron", wherein the government required people to be burdened with handicaps so that everyone would be equal. The talented ballerina had to dance with a weight on her leg, the gifted scientist listened to a deafening noise in his ear every few seconds, and, in the similarly strange world of PJM "markets" Vineland is being asked to add costs to its bid that are not required to build the unit.

"markets" have failed to do.[7] This is not buyer market manipulation, but is none other than good, old-fashioned American buyer self-help.

Budget-driven municipal governments such as Vineland are particularly sensitive to volatile price swings such as have characterized RPM and congestion charges at the Vineland aggregate bus in recent years. (Affidavit of Mr. Isabella at 5-6.) Vineland, like all New Jersey municipalities, must answer to New Jersey State government oversight when its activities exceed budgeted amounts. As such, Vineland and other budget-driven entities have a compelling interest in controlling their costs and keeping them within known parameters. Having a plant in the ground is one of the few ways that municipal utilities in New Jersey can attempt to control their costs. Although FTRs may be used to hedge certain congestion costs, this is not an option insofar as the FTR market requires large amounts of collateral that Vineland and other municipal utilities that are legally forbidden from posting.

The reasons for the cost differentials between the Vineland unit and the PJM CONE price are many and varied. They range from Vineland's prior ownership of the land upon which the generator will be constructed, to tax-free financing enjoyed by municipal governments at the direction of the federal tax code. Affidavit of Mr. Isabella at 4. Another important consideration is the non-profit status of municipal generation that is owned by its citizens, contrasted with private investor-owned utilities that must pay a return to shareholders. *Id*. The PJM May 12, 2011 filing acknowledges such items as the legitimate cost advantages of municipal government that would not require

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[7] As described in PPANJ's Protest in this docket dated March 4, 2011, municipal utilities and rural electric cooperatives in general, due to their unique governance structure and non-profit status, are unable to exercise market manipulative behavior.

"mitigation up" before participating in the RPM Auction.[8] These cost savings are inherent to the municipal utilities everywhere, and Vineland did not undertake to propose the unit for the purpose of undermining the free and legitimate business practices of the investor-owned utilities in the state. Quite to the contrary, Vineland waited until the cost situation was nearly intolerable before finally embarking on the plan to build this unit. Despite this, the IMM, P3 and PSE&G contend that Vineland's municipal tax exempt financing and other similar advantages amount to a subsidy that unfairly hampers competition and will unduly depress market prices such that prices will be insufficient to attract the construction of new generation. (Mr. Hogan stated "[A]n unmitigated RPM would be vulnerable to buyer-side manipulation that would undermine the intent and relevance of capacity markets." Hogan at p. 4.) As should be obvious, the market was "unprotected" from this so-called buyer market power in the years from 2007 to 2010, and yet RPM prices were as high or higher in New Jersey as anywhere else in PJM, but such prices did not result in the construction of a sufficient level of new generation that reduced the costs in Vineland, New Jersey. Throwing more money at Vineland's bid price will not help New Jersey build more capacity. Buyer self-help, in contrast, is more likely to result in new capacity construction.

[8] PJM Proposed OATT §5.14 (h)(5)(iii) states in part: "A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, nominal levelized, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's ***business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs***, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4)." (Emphasis supplied.)

II. PJM “Markets” Have Failed Vineland, New Jersey and this Latest Proposed MOPR Adjustment Will Only Make Matters Worse

The argument of the IMM, PSE&G and P3 that to bid the actual costs of the Vineland unit is unfair to other generators would be easier to accept if the PJM “markets” had actually produced any significant amount of new capacity that served to reduce Vineland’s costs and volatility. Such additions would justify the extra cost as the bait needed to entice new generation to build in New Jersey. As Mr. Isabella explains, however, the PJM “markets” in New Jersey have failed to produce capacity resources sufficient to quell the high capacity costs and extreme volatility in Vineland. Affidavit of Mr. Isabella at 5-6. Indeed, the PJM Independent Market Monitor’s Quarterly State of the Market Report for PJM January through June 2011 at Table 5-10 at page 127 shows RPM “cost to load” fluctuating uncontrollably over the next few years.[9] In 2011/12 the RTO RPM “cost to load” is $116.16 per MW-day. This figure then jumps more than 20% for EMAAC customers to $141/MW day in 2012/13. It increases by nearly $100 (70%) to $240.41/MW day in 2013/14. It drops by 47% back to RTO-wide levels in 2014/15 to $125.94/MW day. According to this report, Vineland will continue to be whipsawed by extreme volatility into the foreseeable future.

Not only are capacity prices volatile, but the zone in which Vineland sits experienced the highest volatility in energy costs in 2010, according to the Market Monitor’s 2010 State of the Market Report at page 75, Table 2-39. [10] This table shows the zonal, real-time load weighted annual LMP for 2009 compared to 2010. The Atlantic City Electric Company (“AECO”) zone had a year over year change of 34%, higher than

[9] http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011/2011q2-som-pjm-sec5.pdf
[10] http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume2-sec2.pdf

any other zone. Vineland is among the most congested spots in the AECO zone. This type of volatility is very difficult for Vineland to budget around. Affidavit of Mr. Isabella at 6.

The extra "bait" has not worked. It is time for Vineland to take matters into its own hands and build this economical unit.[11] To prevent Vineland from doing so due to abstract "market" principles will impose unnecessary additional RPM costs on Vineland citizens. In contrast, if the Vineland unit is permitted to be bid into the RPM auction at its actual costs, without being "mitigated up" to PJM's Net CONE, the unit will more than likely clear the auction, be constructed and the citizens in Vineland, New Jersey will have reduced congestion costs.

If the unit is "mitigated up" so that it must compete at a higher bid price, Mr. Isabella explains why he will delay or cancel the unit. Affidavit of Mr. Isabella at 3. The reason is simply that Vineland cannot afford to bear the costs of stranding the investment, which is what nearly happened to DEMEC. (*See* Statement of P. McCullar at page 3.) Under the MOPR rules as adjusted by the IMM, P3 and PSE&G, the Vineland unit would not be guaranteed to clear (as the prior Vineland unit was so guaranteed when it bid in at zero), and may very well not clear if it is "mitigated up." Indeed, if all the units are "mitigated up" to the PJM Net CONE price, the low bid price for all the units will be close to the same. Thus, price discovery that is a defining feature of most auctions in other businesses will be eviscerated. Only bids that the IMM deems high enough will be accepted. Due to construction lead times, and the cost of securing financing in advance of the project construction, Vineland cannot economically construct the unit with this

[11] Indeed, Vineland built a very similar 57 MW unit which it bid into the 2009 RPM auction at zero and which cleared for the PJM Delivery Year 2012/13 under the prior MOPR. This earlier unit is expected to go on line in June 2012. Affidavit of Mr. Isabella at 2.

degree of uncertainty. It must put money down in order to secure certain aspects of financing and equipment costs. Vineland is willing to bet that its actual costs of construction will clear the RPM auction, but the threat of mitigating its actual costs by adding theoretical additional costs is too much risk for this small utility to undertake, and the unit will be delayed or cancelled if the IMM MOPR rule is adopted. Affidavit of Mr. Isabella at 3. Municipal utilities and rural electric cooperatives such as Vineland and the other PPANJ members are characterized by a unique vertically-integrated business model and member/voter controlled governance structure, as well as their non-profit status and small size. These attributes ensure that they will not abuse market power. More protection against these harmless actors is unnecessary. Stamping these types of utilities out of the generation business with the proposed rule changes is certainly overkill.

CONCLUSION

For the foregoing reasons, PPANJ respectfully requests that FERC adopt the MOPR rule filed by PJM on May 12, 2011 and reject the proposed amendments of the IMM, P3 and PSE&G. In the alternative, PPANJ requests that the Commission accept the requests to grant a self-supply exemption from the MOPR.

Respectfully submitted,

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Special Counsel for PPANJ

CERTIFICATE OF SERVICE

I hereby certify that I have, on this date, caused the foregoing document to be served on each person included on the official service list maintained for this proceeding by the Secretary of the Commission, by electronic mail or by such other means as designated by or for each such person, in accordance with Commission Rule 2010.

/s/ Jill M. Barker

August 29, 2011

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	**)**	
	)	
v.	**)**	**Docket No. EL11-20-000**
	)	
PJM Interconnection, L.L.C.	**)**	
PJM Interconnection, L.L.C.	**)**	**Docket No. ER11-2875-000**

AFFIDAVIT OF JOSEPH A. ISABELLA

IN SUPPORT OF

POST-TECHNICAL CONFERENCE COMMENTS OF THE PUBLIC POWER ASSOCIATION OF NEW JERSEY

Q. Please state your name, title and business address.

A. My name is Joseph A. Isabella. I am the Director of the Municipal Utility, City of Vineland, New Jersey. My business address is 640 E. Wood Street, Vineland, NJ 08360.

Q. What is the purpose of your affidavit?

A. The purpose of my affidavit is to support the Comments of the Public Power Association of New Jersey filed in response to the Technical Conference held by the Federal Energy Regulatory Commission ("FERC" or "Commission") on July 28, 2011, by explaining why a new

Vineland, New Jersey generation station should not be thwarted by amendments to PJM's Minimum Offer Pricing Rules ("MOPR").

Q. Are you familiar with the PJM MOPR filed on May 12, 2011 in this docket?

A. Yes. The PJM filing, as I understand it, would require a municipal utility such as Vineland to bid its unit into the Reliability Pricing Model ("RPM") capacity auction, rather than submitting such a bid at zero, as a price taker. This is a departure from past practice in which Vineland submitted and cleared a self-supply 57 MW unit into the 2009 RPM Auction as a zero bid price taker.

Q. How will the PJM proposed rule change affect Vineland?

A. Vineland is well along in developing another similar 57 MW combustion turbine unit, but with the new PJM MOPR rule in place Vineland would not be allowed to submit the unit into the RPM auction at zero. Instead, Vineland must bid its actual cost of constructing the unit. Vineland's estimated cost of developing the unit is approximately $129.65/MW day. (*See* Attached Exhibit A.) PJM's Net Cost of New Entry ("CONE") price for the period commencing June 1, 2014 is $275.02/MW day. Under these circumstances, if Vineland were to bid the unit into the RPM auction at its actual cost of service, it is very likely that the unit would clear the auction and that any up-front costs risked by Vineland would not be stranded.

Q. What changes to the proposed PJM MOPR are suggested by the Independent Market Monitor ("IMM"), PJM Power Providers ("P3") and PSE&G?

A. These entities have submitted various suggestions that, if adopted, would have the effect of "mitigating up" or increasing the bid price that Vineland would be allowed to submit for the unit into the RPM Auction.

Q. What effect would these IMM, P3 and PS&EG proposals have on Vineland?

A. The IMM, P3 and PSE&G proposals would require Vineland to increase its bid to a level that is higher than its actual cost of service. The process for doing this is vague, and involves a significant amount of judgment rather than clearly objective standards. Under these circumstances, Vineland's bid would be increased to a level that is approximately the same as the PJM Net CONE price, which is to the level that all other "mitigated up" bids would be brought. Accordingly, this significantly reduces the chances that the Vineland unit would clear the auction, since most of its competition would be "mitigated" to about the same price level. It is not clear to me how PJM would decide which units to clear if they all have the same price.

Q. Will Vineland go forward with the unit if the IMM, P3 and PSE&G proposals are adopted?

A. No. These proposals rob Vineland of the certainty associated with its unit clearing in the auction, and Vineland cannot run the risk of stranding up-front costs when the odds are so high that the unit will not clear. Although Vineland is PPANJ's largest member, it is a small utility by any other standard. It comprises roughly 5% of the demand in the Atlantic City Electric Zone, which is itself a rather small zone. Vineland is a creature of municipal government which is extremely conservative with large financial investments. Without a reasonable degree of certainty that the unit will clear the auction, I would recommend that the project be delayed or cancelled. I would not recommend that my City Council invest the up-front costs necessary to prepare the unit for bidding until we are certain that it can clear the auction. This will result in either delay or cancellation of the unit. This would be a shame as new generation is sorely needed in New Jersey, particularly at the highly constrained Vineland aggregate bus.

Q. What is the estimated cost of Vineland's unit?

A. $129.65/MW day. You can see the cost components of the unit on the attached Exhibit A. This is approximately half of the cost of PJM's Net CONE of $275.02/MW day. This cost is based upon PJM's provided average congestion and ancillary services revenue estimates at the Atlantic City Electric Zone, which are lower than those at the Vineland aggregate bus. In truth, the actual cost of the unit could arguably be lower than $129.65/MW day due to the likelihood of these higher revenue streams as offsets to the costs.

Q. Why is Vineland's cost so much lower than that of PJM?

A. The reasons that Vineland's costs are so much lower than those of PJM are many and varied. I will point out some of the primary reasons. First, Vineland already owns the land upon which the new plant will be constructed. It is the site of an existing substation. Second, Vineland's cost of municipal financing is extremely low compared to the cost of private financing. This is because the business model of municipal utilities is much less risky than the business model of investor owned utilities. Vineland has no retail competition, for example, and its customers are also its taxpayers. Third, Vineland has tax exempt status, as all municipal government has, which further reduces its costs compared to those of investor owned utilities. In addition, the municipal utility business model is based upon a non-profit foundation, and therefore no shareholder returns are required, in contrast to an investor-owned utility system which must pay significant returns to its owners. The IMM, P3 and PSE&G proposals would consider these characteristics of Vineland's time honored business model to be unfair subsidies.

Accordingly, the bid of Vineland for this unit would have to be "mitigated up" to make the Vineland bid reach a level much closer to the PJM Net CONE price.

Q. Is Vineland engaging in Buyer Market Manipulation by proposing the unit?

A. Absolutely not. Vineland is engaging in buyer self-help that is perfectly consistent with the way in which municipal utilities have operated in New Jersey for over 100 years. Vineland is a vertically integrated utility that does not speculate for sale into RPM. With the addition of this second unit, Vineland will still be capacity short and plans to use the entire output of the plant to serve its own load. There is no intention whatsoever that Vineland would manipulate the market for the purpose of undermining any other utility company in New Jersey or in PJM. In fact, the view that municipal government can manipulate utility markets is patently absurd, in my opinion. Municipal government is subject to sunshine laws. Further, it must adhere to certain strict requirements to keep its tax exempt financing and its non-profit status. These characteristics render municipal market manipulation a near impossibility. That is certainly not the intent of Vineland in proposing to construct the new unit.

Q. Is Vineland proposing the unit for the purpose of serving its customers?

A. Vineland is proposing the unit solely for the purpose of serving its customers – to reduce costs and volatility of costs. Despite years of extremely high PJM capacity and energy costs in the constrained areas of New Jersey, the PJM system of pricing (I hesitate to use the word "markets") has not produced significant capacity construction necessary to reduce these costs to Vineland. Vineland has concluded that it can serve its own customers out of this unit at costs lower than the recent RPM costs and congestion charges that are otherwise a fact of life for Vineland citizens. Secondly, RPM capacity and congestion costs at the Vineland aggregate bus represent extreme volatility that Vineland has been powerless to control. Vineland is a budget-driven municipal government, subject to New Jersey state laws that require oversight to ensure conformance to budgets. The extreme volatility that Vineland has experienced through RPM is very difficult to budget around. The proposed unit will help reduce this burdensome price volatility in both congestion and capacity costs experienced at the Vineland aggregate bus. Vineland concluded that by installing the unit rather than continuing to be subject to wild fluctuations in RPM and congestion costs, it could better serve its own customers and comply with required New Jersey State budget rules. Installing this unit is not buyer market manipulation, but is rather buyer self-help.

Q. Does this conclude your affidavit?

A. Yes, it does.

UNITED STATES OF AMERICA

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PJM Interconnection, L.L.C.	)	**Docket No. ER11-2875-000**

AFFIDAVIT

State of New Jersey
County of CUMBERLAND

Joseph A. Isabella, being first duly sworn, deposes and says that he has read the foregoing Affidavit and is familiar with the contents thereof, and that the statements set forth therein are true and correct to the best of his knowledge, information and belief.

Joseph A. Isabella

Joseph A. Isabella

Subscribed and sworn to before me this 25th day of August, 2011.

Denise A. Monaco

Notary Public State of New Jersey:

My Commission Expires:

DENISE A. MONACO
NOTARY PUBLIC OF NEW JERSEY
MY COMMISSION EXPIRES APRIL 12, 2015
I.D. #48380

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Vineland Municipal Electric Utility Proposed Unit 12 Estimated Cost

TOTAL CAPITAL COSTS	$69,000,000
ANNUAL FINANCE RATE	4.50%
TERM OF BONDS YEARS	30
UNIT SIZE IN MW	57
ANNUAL FIXED O & M	$1,000,000
FIXED O & M $/MW YEAR	$17,543.86
FIXED O & M $/MWDAY	$48.07
ANNUAL BOND PAYMENT	$4,236,016.46
ANNUAL BOND PAYMENT $/MWYEAR	$74,316.08
ANNUAL BOND PAYMENT $/MWDAY	$203.61
ANNUAL TOTAL COST	$5,236,016.46
GROSS COST OF ENTRY $/MWYEAR	$91,860
GROSS COST OF ENTRY $/MWDAY	$251.67
NET ENERGY REVENUE OFFSET $/MWYR	$42,339
NET ENERGY REVENUE OFFSET $/MWDAY	$116.00
ANCILLARY SERVICE OFFSET $/MWYR	$2,199
ANCILLARY SERVICE OFFSET $/MWDAY	$6.02
VMEU NET CONE $/MWDAY	**$129.65**
PJM NET CONE 2014/2015 CONE Area 1	$275.02

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