CONTINENTAL ECONOMICS

In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning	))))	**Docket No. EO-11050309**

Comments of

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I. INTRODUCTION AND SUMMARY

Good morning. Thank you for allowing me to testify today on behalf of Exelon Corporation about capacity procurement and ensuring electric reliability. The questions that have been raised deal with fundamental issues about competitive electric markets and whether those markets are working as intended.

I have had the privilege of testifying previously before the New Jersey legislature, as well as the legislatures in Maryland and Ohio regarding electric market restructuring and competition. In 2006, I also testified previously on behalf of the BPU regarding the proposed merger between Exelon and PSEG, and last year testified for the Maryland Public Service Commission regarding the merger between FirstEnergy and Allegheny Energy. I also worked as the Director of Planning for the Vermont Dept. of Public Service, the consumer advocate for that state. I believe strongly in the benefits of competitive electric markets and in appropriate oversight of those markets.

The Board of Public Utilities (Board or BPU) has set out ten broad topics for which it seeks answers at this hearing. Most of them address "perceived" shortcomings in the PJM capacity market and how to address those "perceived" shortcomings. My comments will focus on the following BPU questions:

- Is there sufficient capacity to ensure "the lights stay on" in New Jersey? How has the economic recession affected PJM's load forecast and the need for new capacity to ensure reliability is maintained?

- Why are higher [Reliability Pricing Model] RPM market-clearing prices in New Jersey not incenting construction of new generating resources in the state, even though such resources are being built in other parts of PJM that have lower market-clearing prices?
- Is it possible to develop baseload and intermediate (*i.e.*, mid-merit) generating resources under the current RPM design, or are longer-term contracting mechanisms needed?
- How have lower demand forecasts and changes in planning parameters affected the need for new capacity in New Jersey?
- Should the state's local electric distribution companies (EDCs) withdraw from RPM and instead provide capacity under the Fixed Resource Requirement (FRR) alternative?

These are all reasonable questions to ask, and I hope my comments today will help answer them. However, I use the word "perceived" because some of the questions reflect an incomplete understanding of how PJM's wholesale electric capacity market operates.

In brief, I believe the PJM capacity market is working well. The market results are competitive and the Independent Market Monitor (IMM) rigorously monitors the capacity market to ensure it remains so.[1] The PJM Capacity market has also been found to be competitive and working well in two independent assessments by the Brattle Group.[2] Moreover, RPM capacity prices have been

[1] *See e.g.*, IMM, *2011 Quarterly State of the Market Report for PJM: January through June*, at 117.

[2] *See* The Brattle Group, "Review of PJM's Reliability Pricing Model (RPM)," June 30, 2008, and "Second Performance Assessment of PJM's Reliability Pricing Model Market Results 2007/08 through 2014/15," August 26, 2011 ("Brattle Report").

shown to be much lower than what was initially predicted when electric restructuring began.

One of the reasons RPM works is by incenting the lowest cost capacity resources to be added to existing capacity supplies when required to meet demand. Over 6,700 MW of new capacity in the form of generator uprates, repowerings, and new generating capacity have been added in PJM since RPM began in 2007. In addition, RPM has brought almost 15,000 MW of demand response capacity to the market since 2007, with over 2,000 MW of that from New Jersey. These additions make sense, because consumers benefit most when the lowest-cost resources are added first. Uprates and repowerings of existing generation are less costly than building new plants. Existing businesses and industry can provide demand response which, unlike new generation, does not require lengthy siting and environmental approvals, and delays the need for new generation in some areas.

This is not to suggest that the current RPM market design cannot be improved. For example, in his June 17th comments before the NJ BPU, Joseph Bowring, the PJM IMM, suggested several RPM market enhancements to reduce uncertainty over future planning parameters.[3] More recently, on August 26th, the Brattle Group, from whom Mr. Frank Graves is here today to testify, issued its second assessment of the PJM RPM.[4] That report suggests several

[3] Comments of the PJM Independent Market Monitor, June 17, 2011, at 2-3.

[4] The Brattle Group, "Second Performance Assessment of PJM's Reliability Pricing Model Market Results 2007/08 through 2014/15," Report prepared for PJM Interconnection LLC, August 26, 2011 ("Brattle Report").

modifications to further improve RPM design, such as the addition of voluntary longer-term auctions to ensure greater price certainty for generators and help incent new generating capacity when it is needed.

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Nevertheless, the topics raised for this hearing reflect concerns about whether RPM is really working as it should be. This leads to two fundamental policy questions: first, can markets be trusted to ensure "the lights stay on in New Jersey?"; second, does New Jersey need to adopt "non-market" or "command-and-control" approaches to ensure the lights stay on.

First, markets <u>can</u> be trusted to ensure the lights will stay on in New Jersey. Because electric reliability is what economists call a "public good,"[5] a separate market-based capacity structure, such as PJM's RPM, makes economic sense. As the New England and New York ISOs did, PJM developed a market-based capacity structure to help ensure sufficient capacity would be available when needed.[6] RPM continues to incent sufficient capacity, including existing capacity, new capacity, and demand side resources. Furthermore, completion of the Susquehanna – Roseland 500 kV transmission line, which the Federal government has identified as a high priority, will relieve transmission constraints and increase New Jersey consumers' access to lower cost supplies throughout PJM.

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[5] For a more detailed discussion, *see* J. Lesser and G. Israilevich, "The Capacity Market Enigma," *Public Utilities Fortnightly* 143 (December 2005): 38-42.

[6] *Id*.

Secondly, New Jersey should not adopt more "command-and-control" measures to ensure the lights stay on. Non-market solutions substitute the judgment of politicians and regulators for the rigorous discipline of the marketplace. Yet, history has shown repeatedly that politicians and regulators, however well-intentioned, fare far worse than markets in determining the most efficient "winners and losers" and that such non-market "solutions" always have unintended adverse consequences.

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Let me now turn to the topic: If RPM is working, why isn't more generating capacity being built in Northern New Jersey, especially since capacity prices there are higher than in PJM as a whole?

A number of factors contribute to this. As with all competitive markets, RPM is designed to elicit the lowest cost available capacity supplies first. Additionally, New Jersey has higher costs – land, labor, permitting, and so forth – that disincent new construction. In fact, **the cost of constructing a new CT or CCGT in NJ is higher than in all other areas in PJM**, as shown in PJM's calculation of gross CONE (*i.e.*, cost of new entry not including any energy or ancillary revenues) for the 2014/2015 RPM auction: the gross CONE for a new CCGT in the NJ zones was on average $18,000/MW-year higher than the average gross CONE for all other zones in PJM.[7] For a 500 MW CCGT, that means almost $1 million in higher construction costs that must be recouped annually.

[7] Source: http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110413-ct-cc-minimum-offer-price-for-2014-2015.ashx).

Perhaps most importantly, however, are the unintended adverse consequences from the state's Long-Term Capacity Agreement Pilot Program (LCAPP). Although FERC's Minimum Offer Price Rule (MOPR) has rendered the LCAPP strategy problematic, this state's decision to circumvent RPM and artificially reduce market-clearing prices has created investment uncertainty and a powerful "Do Not Invest in New Jersey" signal to generation developers.

Regulatory uncertainty is especially problematic for long-lived, capital intensive investments such as electric generating plants. Uncertainty over future non-market policies the state might choose to implement creates a powerful economic disincentive for any new, market-based investment. Thus, generation developers will be much less willing to risk making investments based on expectations of future market prices, if they believe the state will intervene in the market to artificially reduce those prices. The resulting self-fulfilling prophecy creates a vicious cycle: the state intervenes because it believes the market is not working and RPM prices are too high; such state intervention discourages new investment; that lack of new investment reinforces the belief that the market is not working, which produces more demands on the state to mandate additional non-market policies, which reinforces investor uncertainty. The lesson is clear: resist the urge to "do something," and let the market work as it is intended.

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A related topic identified asks whether the RPM can incent mid-merit and baseload capacity. In part, the answer is "it already has." This new generation primarily has come from uprates and repowering existing generating facilities, not the more expensive greenfield development. Significantly, however, given existing excess capacity supplies and reduced electric demand because of the economic recession, there is no current need for new baseload and mid-merit capacity. Recent analysis by CERA, for example, projects that PJM has sufficient capacity through at least the year 2020.[8] This also helps explain why only two new gas-fired generating facilities have come on-line since 2006 in the MAAC zone. The need for new generating facilities has been supplanted by plentiful capacity and lower-cost alternatives.

A second implied question within this topic is whether such generation can be built in New Jersey, or is it more likely to be built elsewhere? The higher construction costs in New Jersey, coupled with the tremendous investment uncertainty, will discourage major investment in baseload and mid-merit capacity.

As for improvements to the RPM market design, I have already mentioned recommendations by the Brattle Group for voluntary longer-term auctions to improve price certainty. I believe this idea has great merit and hope PJM can implement this idea in conjunction with the auctions for the 2015/16 planning year, which begin next May.

Regarding longer-term, fixed price contracts, unless those contracts are set by market forces I fear we simply would repeat the costly experience of the Public Utilities Regulatory Policy Act of 1978 (PURPA), which led to long-term

[8] In line with a sharp downward revision to the outlook for economic growth and electricity demand, IHS CERA now projects reserve margins in RFC-PJM to remain above the target level until 2020. The current pipeline of plants under construction, uprates to existing resources and strong growth in demand resources is expected to delay the need for new capacity additions despite projections of nearly 12 GW of capacity retirements by 2020. This analysis reflects the fundamentals of the broad market area; the year of need may vary slightly within a region depending on specific local transmission constraints.

expensive, far above-market generating capacity which raised customers' rates for many years.

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The last question posed by the Board inquires whether New Jersey should pursue the FRR alternative to avoid paying RPM prices. Based on my recent experience in Ohio, New Jersey consumers would not benefit under the FRR option, as FRR entities will try to recover the higher of their embedded capacity costs or the market price.

Currently, the only two FRR entities in PJM are AEP Ohio and Duke Energy Ohio (Duke Ohio). Both utilities have argued they are entitled to recover the full embedded costs of the generating resources they use to meet their FRR obligations, even though PJM rules provide no such guarantee.[9] Further, the embedded cost values they have calculated are far higher than RPM market-clearing prices. AEP Ohio, for example, has estimated its embedded cost at $355/MW-day,[10] which will increase with anticipated capital investments in new environmental controls. By comparison, the average RPM "Rest of RTO" (where both AEP Ohio and Duke Ohio are located) market-price for the 2011/12

[9] FERC rejected AEP Ohio's initial argument that it be allowed to charge a capacity cost sufficiently high to recover its embedded costs. *American Electric Power Service Corporation*, 134 FERC ¶ 61,039 (2011). In response, AEP Ohio has filed a Complaint pursuant to Section 206 of the Federal Power Act to amend Schedule 8.1, Section D(1)(8) of the RAA to permit it to file for new, cost-based wholesale capacity charges.

[10] *See* Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, Direct testimony of Kelly D. Pearce in support of the Stipulation and Recommendation on behalf of Columbus Southern Power Company and Ohio Power Company, September 13, 2011, Exhibits KDP-1 and KDP-2. This testimony is part of a contested partial Stipulation that AEP Ohio filed with the PUCO on September 7, 2011. This value includes transmission system losses.

planning year, which began on June 1, 2011, through the 2014/15 planning year, is $70/MW-day. **Thus, under its FRR, AEP sought to charge customers for capacity at five times the market rate.**

Similarly, Duke Ohio proposed to charge all customers, both shopping and non-shopping, for capacity at its embedded cost, net of 80% of profits for energy and ancillary services sales. Duke Ohio projects the resulting capacity charges to average about $220/MW-day over the four-year planning period. Although less than AEP Ohio's almost $355/MW-day price, **Duke Ohio's proposed FRR capacity price was still over three times the average PJM RPM market-clearing price.** Moreover, the Duke Ohio proposal essentially guarantees consumers have to pay an above-market regulated rate of return on the capacity investment.

In December 2008 testimony before the Pennsylvania Public Utility Commission, Dr. Roy Shanker compared cost-based capacity rates projected during PECO's electric restructuring filing against RPM's market-based capacity prices, concluding the figures demonstrated convincingly that allegations of excessive capacity payments under RPM are unjustified.[11] According to Dr. Shanker's analysis, even ignoring stranded costs associated with Pennsylvania generating units, the PJM RPM capacity prices, year over year, were comparable or lower than the capacity costs that would have resulted under traditional cost-

11 *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets," statement of Dr. Roy Shanker, December 18, 2008. Available at: http://www.puc.state.pa.us/electric/pdf/EnBanc-WEM/Ttmy-RShanker121808.pdf.

based regulation.[12] Commonwealth Edison's FERC-approved cost-based rate of $514/MW-day provides another example of embedded capacity costs that significantly exceeded the RPM clearing price.[13]

Finally, under PJM rules, an FRR designation requires a minimum five-year commitment. Thus, if New Jersey EDCs become FRR entities, New Jersey will have to live with the consequences—and likely higher capacity costs— for at least five years.

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In summary, I urge the BPU to resist the urge to "do something," and let the PJM RPM continue to work, as it has. The lights are not going to go out in New Jersey and further command-and-control solutions, whether new rounds of LCAPP or requiring EDCs to become FRR entities, will disincent current and future investment in the state and raise electricity costs. That, in turn, will damage the New Jersey economy and lead to lost jobs.[14]

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12 *Id*. at 13.

13 *See*, *Commonwealth Edison Co*., FERC Docket No. OA97-88. The cost-based capacity rate was filed in 1996 and accepted by FERC in 1998.

14 See "Electricity Competition at Work: The Link Between Competitive Electric Markets, Job Creation, and Economic Growth," Continental Economics, Inc., Report prepared for the COMPETE Coalition, September 2011. Available at: http://www.competecoalition.com/resources/new-compete-study-shows-competitive-electricity-markets-support-economic-growth-and-job-cr.