In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning

NJ BPU Docket Number EO11050309

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Comments of

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Good morning. Thank you for the opportunity to present my perspectives on capacity procurement and regional reliability on behalf of the New Jersey Electric Distribution Companies in the Board's Investigation.

While the NJ BPU is rightly concerned about maintaining reliable electricity service in the state, some characteristics of the market in and around New Jersey that seem to be eliciting concern are not signs of market failure or of a pending reliability crisis, but rather are evidence that electric service is generally more expensive and faces a greater number of challenges in eastern metropolitan cities and coastal regions than in more central, less urban parts of PJM that are often closer to fuel supplies. In fact, electricity market circumstances in and into NJ have generally improved in the past few years, and the outlook over the next few years seems likely to continue improving. As a result, there is no evident need for state-sponsored supplementation of the PJM capacity market auctions. More troubling, it is possible that "the cure could prove worse than the disease" if such procurement is pursued without first identifying a clear engineering need and developing a clear understanding of what kinds of economic problems are otherwise preventing a solution.

Some context for this decision

As a cautionary note, it is worth remembering that on a few occasions in the past, some long term, very costly and largely irreversible electricity supply decisions have been made (or seriously considered) based on long-term forecasts that turned out not as expected. Sometimes, this was due to utility projections and resource plans justifying large, expensive baseload plants. At other times, such as in the1980s when PURPA was implemented, legislative and regulatory rules combined with forecasts of Long Run Avoided Costs (LRAC) induced much more QF and NUG capacity at higher prices than was needed by customers. The result has been nearly well over a decade of stranded cost surcharges to customers. One of the primary motivations for restructuring the electric industry at the federal and state levels was to avoid putting these kinds of long-term supply cost recovery risks and burdens on the backs of ratepayers.

The question of whether New Jersey should conduct capacity solicitations such as LCAPP raises similar concerns, because they involve overlaying on the PJM market a set of NJ-specific criteria for power supply development that will lock NJ customers into 15-year financial commitments for new, in-state generation. Such commitments could eliminate the benefit NJ customers would otherwise enjoy from being able to rely on the large and diverse set of capacity and energy resources available in the much larger PJM market area. PJM has proven to be fairly effective in eliciting capacity thus far and has created a competitive electricity market which confers benefits to all participants. While PJM has not perfected its market design, the impacts of non-market-based and non-competitive entry are pretty irreversible, will interfere with the broader market (NJ and beyond), and may cause a feedback loop of dependence on future subsidies.

My detailed comments focus on four broad issues:

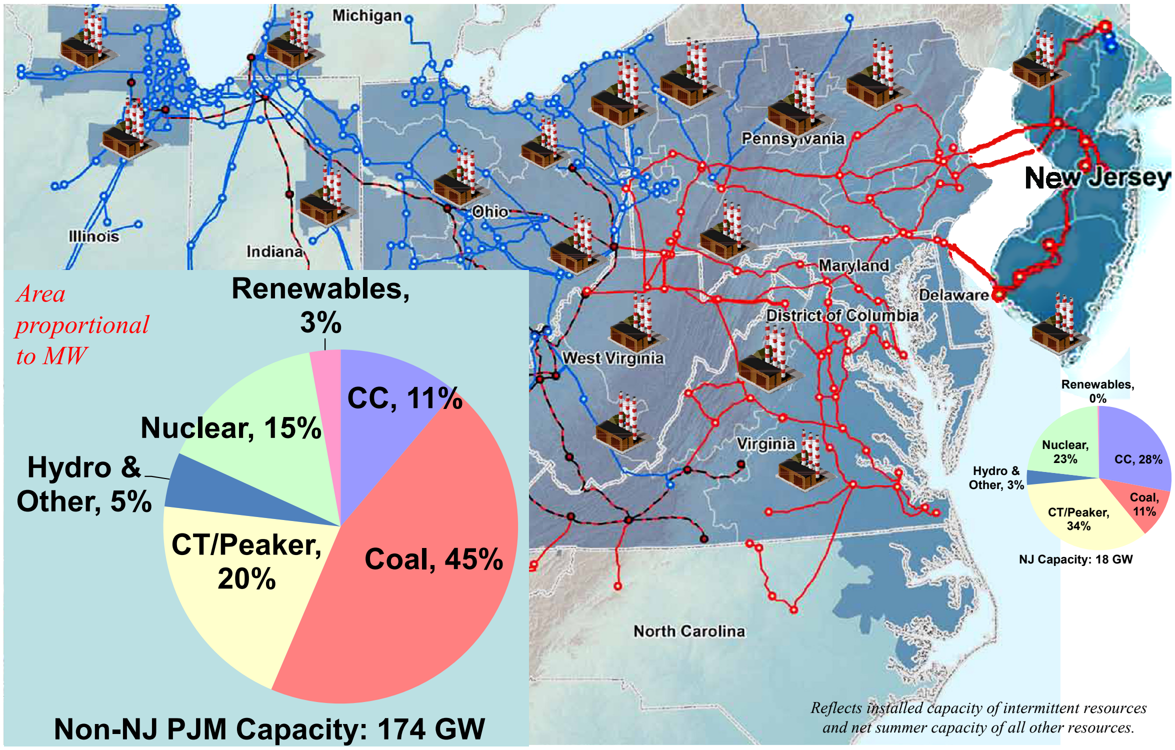
1. Whether an additional round of LCAPP procurement might have unintended consequences that would undermine its goals,
2. Whether there is a pressing need for additional LCAPP procurement at this time
3. How much confidence the NJ BPU can have in the economic benefits from current and possible additional LCAPP capacity, and
4. What the NJ BPU can do to address reliability and NJ electricity economics in the future, if it does not pursue LCAPP 2 at this time

My overall conclusions are that current and foreseeable market conditions do not require any kind of supplemental capacity procurement, and that pursuing one is likely to have adverse consequences that result in higher costs for NJ customers.

1. It is likely that there will be adverse, unintended consequences from NJ-specific supplemental capacity procurement

NJ is not a natural economic or physical "market" for wholesale electric capacity or energy; that market area is PJM, or occasionally constrained portions of it in eastern PJM. Figure 1 below shows the high voltage transmission connections NJ has with PJM that allow it to diversify its generation mix as well as to reduce its own reserve margins by relying on shared resources.

Figure 1
NJ as an Integral Part of PJM and Vice Versa[1]



Decisions made at the market level will have more economic rationale and be more efficient than localized efforts to modify or work around the larger market. It is prudent and appropriate for NJ regulators to review whether any critical needs are not being met by the larger market, but decisions and policies to solve such problems locally will inevitably be diluted in impact due to geographic spillovers and adjustments over time elsewhere. Trying to improve the market processes is more likely to be effective than trying to bypass them.

The likelihood of market adjustments and feedback effects that could be counter to NJ interests was noted in comments filed by the PJM Market Monitor in regard to LCAPP 1. There, Dr. Bowring observed that the LCAPP procurement process was likely to "artificially depress the Reliability Pricing Model (RPM) auction prices below the competitive level, with the result that the revenues to generators both inside and outside of New Jersey would be reduced as would the incentives to customers to manage load and to invest in cost effective demand side management technologies... [this may cause] significant unintended consequences for the business and residential customers who would have to pay the mandatory subsidy. The result of depressing RPM prices in New Jersey would also be to increase the probability that additional subsidies by

[1] PJM map from PJM Interconnection. Installed capacity data based on *Brattle* analysis of PJM installed capacity by state from Ventyx's Velocity Suite.

New Jersey ratepayers will be required for any future capacity additions, either in the form of generation or demand side resources, needed to maintain reliability in New Jersey."[2]

It now appears that NJ is considering pursuing a second LCAPP-style procurement. However, a second LCAPP procurement is likely to exacerbate the concerns raised by Dr. Bowring, because it would increase the extent of NJ efforts to bypass or alter the market, and it would signal an ongoing intent of NJ to intervene in this fashion.

A clear example of adverse, unintended consequences is the legacy costs from non-utility generation (NUGs) charges to meet regulatory mandates under PURPA. The table below shows the typical monthly charge for a residential customer (at 1,000 kWh per month) arising from the above-market costs for NUGs:[3]

Utility	Typical Monthly Charge (per 1,000 kWh)
ACE	$9.17
JCPL	$8.39
PSEG	$5.86
RECO	n/a

Such excess costs have been recovered for over a decade, and will continue to be collected for several more years. Analysis by JCPL indicates that cumulatively, its NUG charges have resulted in $1.5 billion in above-market costs for ratepayers since 2003. PSEG may have had $2 billion or more of comparable stranded costs, and utilities in New York, especially Niagara Mohawk, also incurred billions of dollars of out-of-market costs from NUG contracts.[4]

It is also expected (or hoped) that it will be economically beneficial to NJ by avoiding some of, and perhaps reducing, the regional market prices for capacity and energy. I comment below on the uncertainty surrounding these projected avoided costs. Price suppression effects, though plausible, are likely to have short lives, perhaps only a few years, due to several kinds of likely, normal negative feedbacks from the market, including:

- Reduced participation in future RPM auctions (e.g, fewer life extensions, less DR, less new development) due to some of the need already being satisfied by LCAPP 1 capacity
- Higher Net CONE prices due to lower LMPs – which cause less of the capital cost of a new entrant to be recoverable in energy charges
- Reduced interest from developers in using RPM at all for capacity cost recovery, due to expectations that NJ will do this again. Facing such concerns, merchant investors will be reluctant to put their own capital at risk, instead preferring to wait for the next LCAPP

2 Monitoring Analytics, The Independent Market Monitor for PJM, *Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market*, January 6, 2011.

3 Based on data provided by NJ EDCs.

4 Joint Comments by Public Service Electric and Gas Company, Jersey Central Power & Light Company, Atlantic City Electric Company and Rockland Electric Company, *In the Matter of the New Jersey Board of Public Utilities Review of the State's Electric Power and Capacity Needs*, Docket No. EO09110920, July 2, 2010, pp. 3-4.

- Risk/likelihood of LCAPP imitation by adjacent states (MD?) due to the political appeal of apparent short run benefits, and little recognition of the adverse longer term feedbacks

These feedback effects could ultimately undermine market-based capacity development in NJ to such an extent that all major capacity additions will have to come from state-sponsored price guarantee mechanisms, effectively putting capacity back into rate base at full development cost and at risk to ratepayers rather than to developers if the capacity becomes uneconomical. In addition, New Jersey would become dependent on a smaller, less diversified pool of capacity resources, and so its reserve requirements might increase.

2. There is no current need for additional LCAPP procurement

The NJ BPU appears to have several doubts about the sufficiency of capacity development in and around NJ under PJM's RPM, ranging from whether enough capacity is being added, to how RPM capacity prices for NJ customers compare to other parts of PJM and to new development costs, to whether there is some kind of market imperfection impeding the construction of new mid-merit and baseload capacity in eastern PJM.

<u>Reliability outlook/timeliness</u>

Many of the BPU's concerns about reliability are drawn from, or supported by, comments made by PJM in its RTEP and other reliability reports published prior to LCAPP 1 or the most recent PJM capacity auctions for 2014/15. While those earlier PJM statements indicated important concerns about potential reliability problems, circumstances have changed significantly in the past few years. In particular, those previous reports did not contemplate the effects of LCAPP 1 capacity being added, nor several of the transmission line expansions that are now underway, nor the load growth reduction effects of the severe recession induced by the credit crisis. More specific details about how NJ reliability may change over the next several years are summarized below in Figure 2, a timeline of the major near-, mid-, and long-term market resource changes.

Figure 2
Timeline of Known Major Resource Changes[5]

	Not affected by LCAPP 1 or 2			Affected by LCAPP 1, but not yet in RPM		Potentially affected by LCAPP 2 but needs not yet known		
Power Year	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
EMAAC RCP ($/MW-Day)	$140	$245	$137	n/a	n/a	n/a	n/a	n/a
PSEG RCP ($/MW-Day)	$140	$245	$137	n/a	n/a	n/a	n/a	n/a
PS-N RCP ($/MW-Day)	$185	$245	$225	n/a	n/a	n/a	n/a	n/a
Levitan NJ RCP* ($/MW-Day)	n/a	n/a	$190	$220	$290	$340	$285	$315
Generation Capacity	▪ Keep Hudson Unit #1 as RMR: 320 MW			▪ LCAPP 1: 1,949 MW ▪ Remove Hudson Unit #1 RMR: (320) MW		▪ Oyster Creek retire: (645) MW ▪ Coal retirements: (?) MW		
Load Growth	▪ Decreased load by 2014 due to improved forecast ▪ Addition of 1,200 MW of DR/EE in EMAAC			▪ 800 to 1,600 MW of projected load growth in NJ at 1-2%/yr growth		?		
Transmission Changes	▪ Reduced HTP firm capacity: (350) MW			▪ Susquehanna-Roseland 500 kV line: 1,612 MW		?		

*Estimated based on Figure 12, Levitan & Associates, Inc., *LCAPP Agent's Report*, March 21, 2011.

- Near term (2012-2014) -- *Problems once anticipated for this time frame are largely ameliorated and, even if any remain, they cannot be addressed with LCAPP 1 or another similar solicitation*. As summarized in Figure 2 above, the key concerns are the delayed Susquehanna-Roseland 500 kV line (S-R), now expected to come online beginning in mid-2014 or beyond instead of 2012,[6] as well as the 345 kV Hudson Transmission Partners (HTP) line from New Jersey into New York that is perceived as possibly drawing power out of NJ and impairing reliability or raising local prices. The delay of S-R and a reduction in HTP capacity have already been incorporated into the most recent RPM. To address S-R delay-related reliability concerns, PJM intends to extend the RMR contract for Hudson Unit #1 and to operate to the NERC category C double-circuit tower line contingencies that are driving the need for the line. The HTP project itself will be reduced by 350 MW, and recent load analysis indicates that the revised load forecast in EMAAC shows less loading on the transmission system than previously expected. Consequently, there has been an increase in the EMAAC LDA CETL in the most recent capacity auctions, as shown by the red line in the top graph in Figure 3 below.[7]

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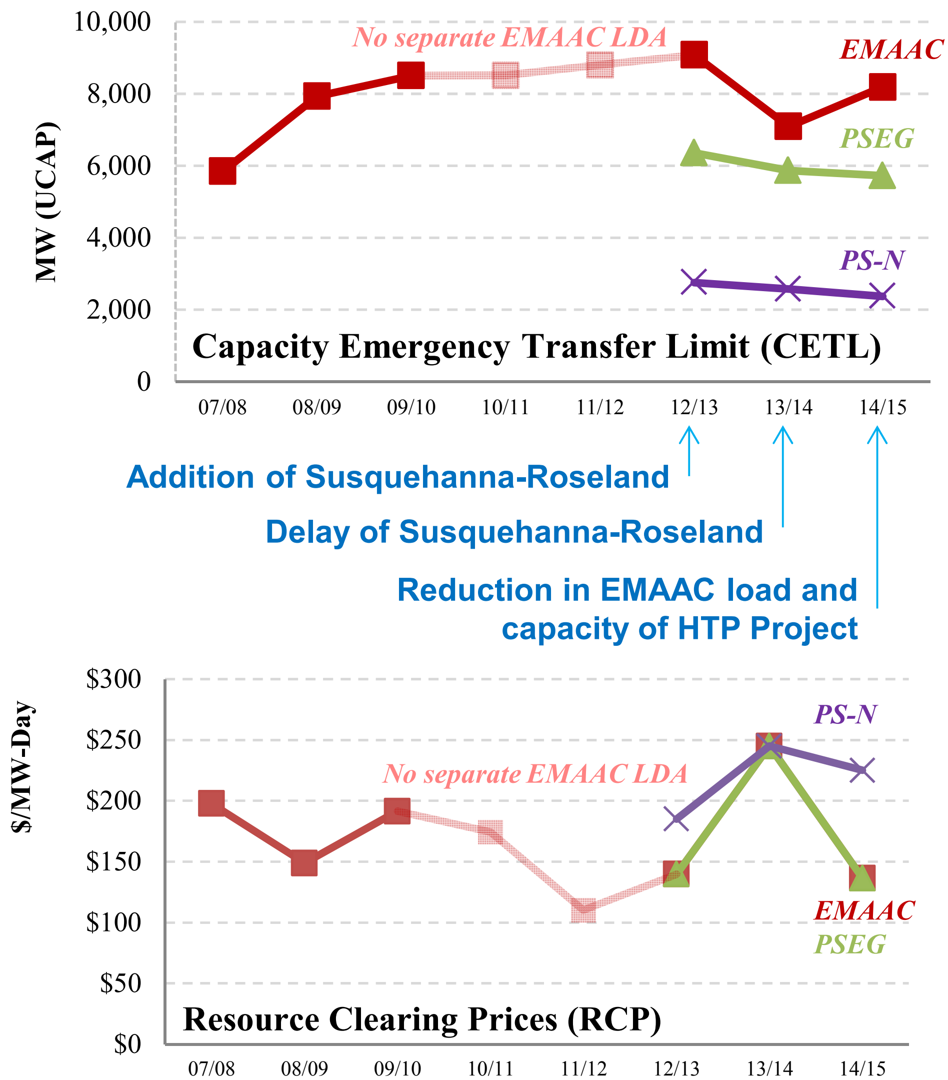
5 Based on *Brattle* analysis of PJM's RPM planning period parameters, auction resource clearing prices, auction results report and sensitivity analyses; PJM's 2010 RTEP; PJM's 2011 load forecast; and Levitan & Associates, Inc., *LCAPP Agent's Report*, March 21, 2011.

6 The National Park Service recently postponed the agency's issuance of a Record of Decision which may impact this in-service date.

7 PJM 2014/2015 RPM Base Residual Auction Planning Period Parameters, p. 5.

Figure 3
Selected EMAAC and New Jersey CETL and RCP[8]



- <u>Mid term (2015-2017)</u> – *Reliability and capacity prices in this time frame will be affected by the just completed LCAPP, but those impacts are not yet observable in PJM capacity auction supply or prices.* Specifically, the recent capacity auction prices for 2014/15 do not reflect the 1,948 MW of new gas generation elicited by LCAPP 1, or the planned completion of the S-R transmission line (where sensitivity analyses show an increase of about 1,600 MW of incremental transfer capability) by 2015. NJ and EMAAC load growth from 2011-2017 is projected to be about 1.3% per year on average. At this rate, NJ would have a higher peak by about 1,000 MW by 2015 (and EMAAC about 1,800 MW). This is less growth than the 3,500 MW of new resources from LCAPP 1 and

[8] Based on *Brattle* analysis of PJM's RPM planning period parameters and auction resource clearing prices.

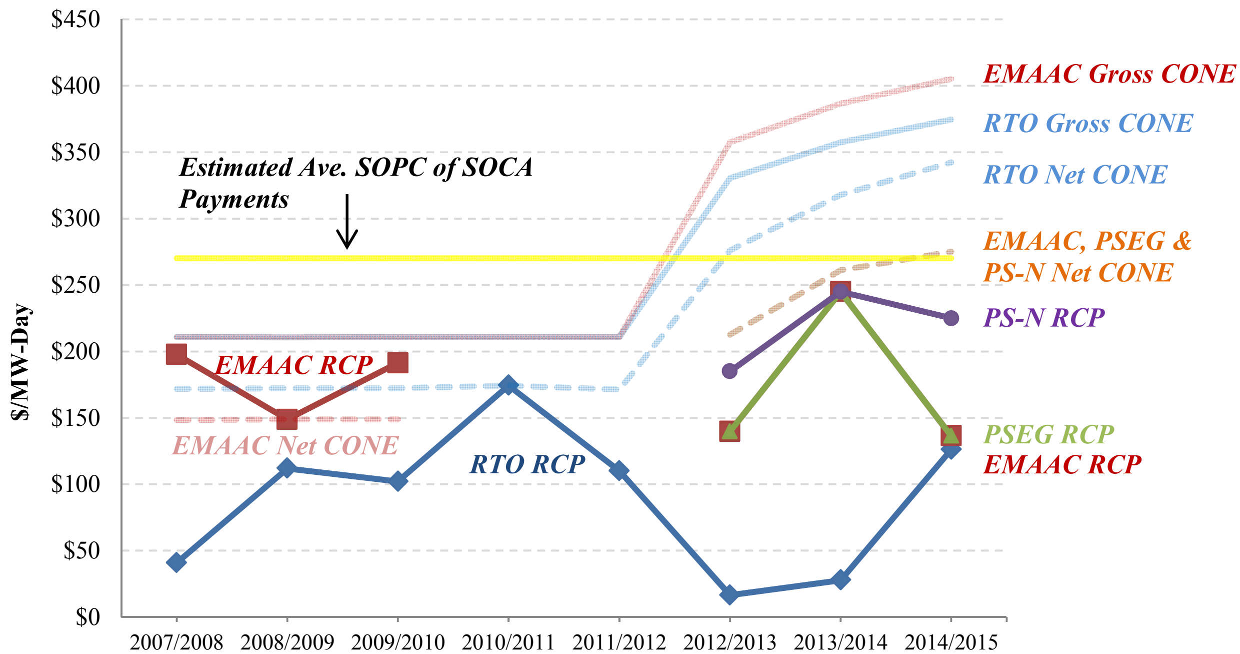
S-R, possibly creating a few years of low RPM prices. On the other hand, coal plant retirements due to tighter EPA regulations are foreseen throughout PJM; *The Brattle Group* estimated in 2010 that about 6,000-8,000 MW of coal plants may retire in EMAAC beginning around 2015, of which about 1,000 MW were in New Jersey. However, coal plants in New Jersey have undergone extensive upgrades recently and are mostly controlled with scrubbers, baghouses, and activated carbon injection (ACI) for mercury control. We now expect that only 200-300 MW are at risk of retirement in New Jersey. Moreover, retirements in the larger PJM market are not likely to all occur concurrently, as the implementation dates of the tightening environmental regulations are likely to be staggered, and there may be further, legislative adjustments to the time frames or requirements for these new rules.

- <u>Long term (2018-2020)</u> – The announced retirement of Oyster Creek (630 MW) and the likely prospect of some coal-fired generation retirements may occur in the long term, but there is adequate time available for future incentives and generation development, if needed. For example, CC development time frame is typically 3-5 years, with two of the LCAPP projects being developed in 4 years.

<u>RPM efficacy</u>

RCPs in NJ and EMAAC are generally higher than in rest of PJM, but in NJ and elsewhere they have been consistently below Net CONE (and the differences between east and west are converging across PJM) as shown in Figure 4 below where the dark solid lines indicate RCPs, the light solid lines indicate Gross CONE and the dotted lines indicate Net CONE. Similarly, Levitan projects that future RCPs in NJ will be below Net CONE for the coming decade.

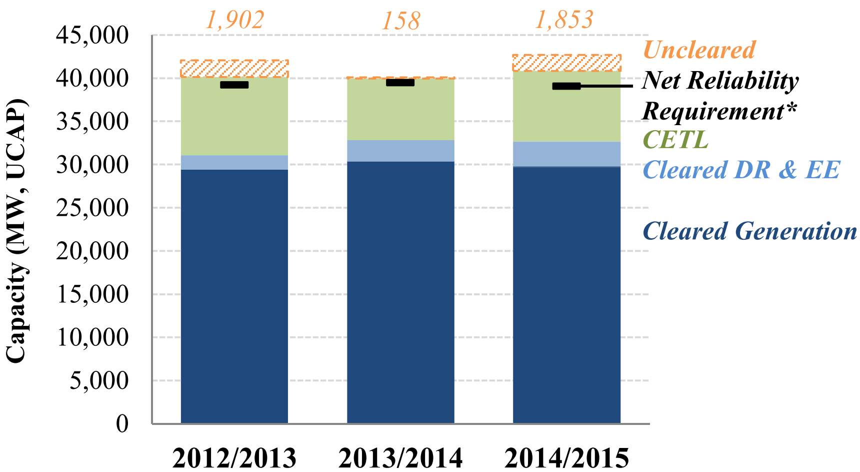
Figure 4
RPM Resource Clearing Prices (RCP) and CONE for Selected LDAs[9]



Enough new capacity has been brought forth by RPM in EMAAC to satisfy the reliability requirement, with additional available generation not clearing the market due to high offer prices. Figure 5 below shows that in the most 2014/2015 RPM, approximately 1,800 MW more generation cleared than was needed to meet the net reliability requirement for EMAAC, with another 1,900 MW not clearing the RPM. Substantial amounts of incremental capacity have been elicited by PJM's RPM, despite RCP prices being below Net CONE – creating significant customer benefits compared to having to pay for capacity at full cost-recovery rates.

9 Based on *Brattle* analysis of PJM's RPM auction planning period parameters and auction resource clearing prices. Estimated average standard offer capacity prices (SOPC) of the Standard Offer Capacity Agreements (SOCA) based on Comments of the New Jersey Electric Distribution Companies on Agent's March 21, 2011 Report, In the Matter of the Long-Term Capacity Agreement Pilot Program, BPU Docket No. EO11010026, March 24, 2011, p. 8.

Figure 5
EMAAC RPM Auction Supply and Reliability Requirement[10]



*Net of "Short-Term Resource Procurement Target" to be produced in incremental auctions.

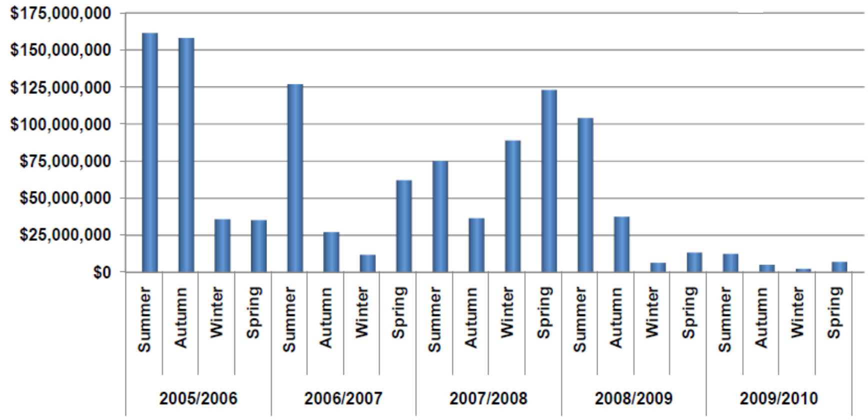
- DR & EE cleared capacity has increased by 74% between the 2012/2013 and 2014/2015 auctions
- Between 2012/2013 and 2013/2014, 830 MW of DR &EE were cleared, over 460 MW of which was in PSEG-N
- CETL decreased by 1,984 MW between 2012/2013 and 2013/2014 due to the delay of S-R, but increased by 1,094 MW between 2013/2014 and 2014/2015 due to a downward revision in EMAAC load projections and a decrease in HTP firm capacity

A significant part of the cleared capacity in recent PJM capacity auctions was DR,[11] which has the advantage of being able to be provided very soon, if/when reliability becomes tight and RCP prices rise.

Transmission capability (CETL) has also increased into EMAAC and NJ (refer to Figure 3) in the past few years, by about 2,000 MW. One important benefit has been that transmission congestion into NJ is down considerably in the past few years as shown in Figure 6 below. (Some of this reduced congestion is due to the recession and reduced demand, not just increased CETL.) This increased importation capability also creates access to more diverse sources and possibly improves competition (by increasing the number of suppliers able to reach NJ).

10 Based on *Brattle* analysis of PJM RPM result data and PJM Market Monitor analyses of PJM RPM results.
11 DR is a relatively new resource that has measurement concerns, but it is unclear at this time whether this will have a significant impact on the amount of DR in the market.

Figure 6
2005/06 -2009/10 Seasonal New Jersey Transmission Congestion[12]



For reliability purposes, *there is no difference in the value of an in-state new gas-fired MW and a MW from anywhere else in PJM* that has reliable transmission access to the eastern part of the RTO.

<u>Capacity costs</u>

The prices for capacity being extended to the three winning bidders in LCAPP 1 (not public, but estimated to be on average $270/MW-day with a potentially large variation amongst bids[13]) are higher than current and recent past RPM RCP (as shown by the yellow line in Figure 4) and are much longer lasting (the SOCP will remain in effect for 15 years). Capacity price-suppression from this new supply, though possible in the short run, was not treated as a predicted effect or economic benefit in the LCAPP 1 report. Thus, one of the primary motivators for LCAPP 1, and perhaps the key concern behind the LCAPP 2 investigation, was not deemed to be a benefit that could be reliably quantified. However, Levitan did conclude that the selected LCAPP 1 capacity was offered at prices below what it expected the future PJM RPM prices to be, resulting in about $190 million of present value savings (SOCP payments less avoided RPM prices for the new capacity). As explained further below, it is doubtful that this estimated benefit can be relied upon.

<u>Lack of baseload development in NJ</u>

Lack of new baseload construction is not a sign of market failure unless price signals are high enough to justify development but entry still does not occur. This has not been the situation. Instead, RCPs have been below Net CONE, while reliability has been maintained and continues to appear so. It simply has not been economic to develop a baseload plant because other,

[12] Kormos, M. and Herling, PJM Interconnection, "New Jersey Power Supply: Load and Capacity Data," presented at the New Jersey Capacity Issues Technical Conference, Docket No. EO09110920, June 24, 2010.

[13] Comments of the New Jersey Electric Distribution Companies on Agent's March 21, 2011 Report, In the Matter of the Long-Term Capacity Agreement Pilot Program, BPU Docket No. EO11010026, March 24, 2011, p. 8.

previously untapped sources of capacity-equivalent resources (DR, life extension, upgraded transmission, etc.) have been elicited by RPM and RTEP.

Frustrations over lack of long term PPAs from developers and some muni/coops likely reflect differences in preferences, not malfunctioning of the PJM capacity or energy markets: Developers may be looking for PPAs at nearly full cost recovery for a new unit (i.e., above RPM prices) while muni/coops looking for long term supply contracts may want to lock in low prices for a horizon longer than RPM. There is no middle ground between these positions, but that is not a market failure.

One of the benefits of being served by capacity from PJM's RPM is that it finds the cheapest available sources sufficient to cover the need. In the recent past, this has proven to be DR and changes in the life or size of existing units, rather than new plant development, all obtained at annual costs below the net carrying costs on new generation. The LCAPP approach forces the future solutions to all be new "iron in the ground", at higher prices and/or much lower risk than under RPM prices.

3. Economic benefits from LCAPP 1 are difficult to verify or extrapolate to LCAPP 2

In its report on LCAPP 1, Levitan provides an estimate of future RCP prices for 2015-2030, generally expecting these to be quite a bit higher than all years of past actual experience in eastern PJM, and often having RCP approaching or equal to Net CONE at $300-350/MW-day. Levitan compares the winning SOCPs of approximately $270/MW-day on average to this projection and concludes that the new capacity will cost less than the PJM NJ market prices, resulting in present value savings of around $190 million to NJ ratepayers. Levitan further finds that there may be an additional $1.6 billion of LMP reductions for NJ customers induced by the new LCAPP 1 plants.

There are several reasons to be cautious in embracing these findings and relying on them as proof of the value of supplemental procurements outside of PJM markets. One important fact to recognize is that the $1.6 billion of costs for SOCP payments now obligated by LCAPP 1 are quite certain to be borne by ratepayers (assuming the plants are in fact developed). In contrast, the benefits that are estimated to more than offset these costs are just forecasts, whose realization may be much worse or much better. NJ ratepayers now have a bird in the hand (the LCAPP costs), but they cannot be sure about the two birds in the bush (the LCAPP avoided cost and other economic benefits). Given this intrinsic difference of risk between the costs and the benefits, it would be perilous to rely upon the estimated benefits from LCAPP1 as justification for pursuing LCAPP2.

More specifically, there are several reasons to doubt that the avoided capacity costs benefits actually are greater than the committed costs:

- A finding of net capacity cost savings requires one to believe that the winning bidders are willing to develop new generation for SOCP payments that are below Levitan's assessment of RCP revenues they could otherwise collect -- and those RCP prices are themselves mostly below Levitan's estimate of Net CONE for new, efficient generation. However, a logically consistent estimate of Net CONE prices cannot be above the price level that efficient new generation requires in order to justify entry -- or else the latter ought to be setting Net CONE!

- It is very difficult to forecast future RCP. Levitan's forecast may well be quite credible and very carefully reasoned, but it can only describe one scenario out of many possibilities. RCP modeling is subject to considerable uncertainty, and it is inherently very sensitive to key assumptions (such as natural gas prices, technology development costs, transmission expansion, financing costs, and so on). It is very likely that the winning bidders offered prices below Levitan's RCP forecast because those bidders have lower RCP expectations and scenario forecasts. (Indeed, the disparity in their bids suggests that they had very different views than each other, further showing how little confidence should be placed in benefits evaluated from just one forecast.) If the developers' forecasts are as or more likely than Levitan's, there would be little or no expected RCP savings. To the contrary, one should expect there to be some <u>increased</u> cost.

- It is possible that bidders <u>are</u> willing to accept an SOCP that is below the RCPs they expect in PJM's RPM, <u>if</u> they prefer the lower risk and longer contracting horizon of the LCAPP 1 contracts to the shorter term, more variable results of the PJM RPM. But if this is the motivation, it is not correct to quantify the present value of the SOCP payments at the same discount rate as the avoided RCP prices. [14] The SOCP payments have essentially no price risk (and very little volume risk, as long as the plant retains the same size and health), and so they are akin to a fixed rate bond with a low interest rate. On the other hand, the RCP prices are highly variable and sensitive to ups and downs with the growth and changing annual costs in the regional and macroeconomy. This means they are much more "systematic" and financially risky, requiring a higher discount rate. Levitan has discounted both cash flows at the same rate (8.4%), finding a net customer savings of about $190 million. If instead, a bond-like rate of 5% is applied to the SOCP payments, their present value cost increases considerably (by about $380 million), while the present value of the avoided RCP payments remains the same. This correction reverses Levitan's findings and shows that there would be a small <u>increase</u> in present value costs to ratepayers from incurring the lower risk SOCP payments instead of the RCP prices.

The last point above is quite important and may be counter-intuitive. One way to think about this is that if investors are not willing to develop new plants for a risky, uncertain future RCP with an expected price of, say, $300/MW-day over the next 15 years, but they are willing to do so at a fixed SOCP price of $270/MW-day, then they are effectively asking customers to pick up risk worth $30/day. When ratepayers guarantee the SOCP, they are implicitly shouldering the

[14] Mechanically, Levitan has applied the same discount to both the costs and benefits implicitly, by calculating the annual differences between the two streams and discounting that net amount at the rate of 8.37%. This is mathematically equivalent to discounting them separately at that rate, and then taking the difference in the two present values.

$30/MW-day of risk, so that amount of apparent savings is not a true economic benefit. It is possible that this kind of risk transfer may be helpful or even necessary to induce more generation expansion, but if so, that should be done at the market level (in the PJM RPM) not at the state, partial market level.

Energy savings of $1.6 billion were estimated for LCAPP 1 per the Levitan report. This was obviously the result of a substantial amount of detailed analysis, and it is certainly plausible that energy cost savings could arise for a while, but how much and for how long depends on numerous complex, uncertain factors, such as fuel prices, demand growth, and what other generation would otherwise be installed. If one assumes those savings would be captured uniformly over all 15 years of the LCAPP 1 contracts, they would arise from a $3/MWh reduction in LMPs in 70% of the hours of each year for all NJ load. This is around a 4-5% reduction in LMPs -- not an inconceivable result, but also not one that is large compared to the uncertainty in future average LMPs.[15] Reported details on the assumed conditions in the reference scenario are insufficient to assess how robust these savings may be. If this finding is predominantly the difference in costs between a base case with and without the new capacity, it may not represent an equilibrium view of how markets may evolve. For instance, it may not capture how suppressed LMPs will discourage subsequent entry of new technology, or whether the reduced LMPs will increase Net CONE. Or, it may not adequately reflect what would have been built in and around NJ absent LCAPP 1. It is not possible to know how much confidence to place in this expectation without disclosure and public review of the assumptions and detailed results.

Environmental benefits – Emission reductions are plausible from new gas generation, but like energy savings, it is not clear what conditions prevail in the but-for world from which these reductions are to be achieved, such as whether they rely on projections that assume no similar gas or low emissions capacity would have otherwise been forthcoming, absent the LCAPP 1. If some new gas CCs would have been built anyway, say by 2018, then the emission reductions are for only a short period (and so may be overstated by Levitan).

There are several impending air quality regulations falling largely on coal plants that should make imported power from western PJM cleaner than it has been in the past, so the environmental benefits from gas are likely to be declining over time.

4. Recommendations

On review of recent market developments, I find little reason to believe that there is a significant unaddressed problem of impending capacity adequacy or unreasonable capacity prices under the PJM market mechanisms. Of course, this situation could change, so it is prudent to review it (as in this investigation) and to have ongoing monitoring and contingency plans, if serious concerns should arise. I also do not find enough specific information about the estimated benefits from

[15] In all likelihood, such savings would arise in a more concentrated manner in a smaller number of super-peak hours, especially in the first few years of the LCAPP 1 contracts. However, this would tend to discourage other new plant entry, thereby creating the seeds of its own undoing.

the initial LCAPP 1 procurement to use its results as a motivation for continuing with supplemental capacity procurements. Instead, I recommend the NJBPU take several preparatory steps that will help shape a future procurement if/when needed:

1) *Release more information to the public about the winning bids and the estimated benefits from the LCAPP 1 procurement.* In my experience, it is very unusual for a state regulatory authority to make large resource development commitments and customer cost guarantees for many years forward on such a fast pace, with so little public vetting of the cost/benefit analysis. This would require much more disclosure of what the terms of the winning bids were, and what economic conditions were assumed in the assessment of the projected benefits.
2) *Monitor how LCAPP 1 and new transmission projects affect the next few years* of RPM prices, market performance, and how resource needs evolve. Any short term problems cannot be solved by LCAPP1 or 2, and any longer term risks can be addressed later, at less risk of over-committing to unneeded or unduly expensive capacity.
3) *Study barriers and impediments to other possible solutions* – esp. transmission permitting and siting, and perhaps DR participation. Lack of liquidity for long term forward purchases and sales may also be worth investigating, since the ability to sell far forward would help provide financing for new plants (and it would eliminate the dilution effect that new transmission and generation have, of driving down the energy and capacity prices that would otherwise make the entry profitable).
4) *Campaign for improvements to PJM markets including RPM*, if there are aspects of the market design that NJ believes is inhibiting merchant development of supply – e.g, possible longer term commitment periods under RPM, in particular for new entry, contracting, or changes in the requirements for DR to be recognized and monitored

This completes my comments.