

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

P3'S COMMENTS AND PROTEST

Glen Thomas
President
PJM POWER PROVIDERS GROUP
1060 First Avenue
Suite 400
King of Prussia, PA 19406
(610) 768-8080

John N. Estes III
Paul F. Wight
Carl Edman
SKADDEN, ARPS, SLATE, MEAGHER & FLOM LLP
1440 New York Avenue, N.W.
Washington, DC 20005
(202) 371-7000

Counsel for the PJM Power Providers Group

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P3'S COMMENTS AND PROTEST

PJM Power Providers Group (“P3”)¹ hereby submits these comments in support of most of the issues covered by PJM’s recent section 205 filing (captioned above), and protest of certain remaining issues. We file this pleading concurrently in our own complaint docket, given our pending motion to consolidate the two cases and the need to ensure a complete record in both. In support, we attach testimony from Dr. Roy Shanker. We also attach a copy of our complaint to this submission, and incorporate it by reference both generally and as set forth below.

On a number of critical points, PJM’s proposed changes to its Minimum Offer Price Rule track our complaint. PJM has proposed to eliminate: (1) the impact test; (2) the exemption for entities not deemed net short; (3) any alleged exemption for self-supply; and (4) the one-year limitation on mitigation (replacing it with a more robust approach). We support these changes (or, in one case, do not oppose it). We commend PJM for taking these important steps to cure critical flaws in its buyer-market-power mitigation scheme. PJM’s treatment of these issues, together with our complaint (and the analysis below), proves that these revisions are just, reasonable and not unduly discriminatory.

¹ P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly designed and well-functioning electricity markets in the PJM region. Combined, P3’s twelve member companies own over 80,000 megawatts of power and over 51,000 miles of transmission lines in the PJM region, serve nearly 12.2 million customers and employ over 55,000 people in the 13-state and District of Columbia PJM region. The content of these comments and protest represents the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue. For more information on P3, please visit www.p3powergroup.com.

In several other important areas, however, the PJM filing falls short: *First*, as we explained in our complaint, it is unjust, unreasonable, and unduly discriminatory to apply any “discount factor” to the cost of new entry values used both to screen for, and to reprice, uncompetitive offers. The current PJM tariff uses an 80% “discount” for both purposes. PJM proposes to change that value to 90%. While higher is better, any value less than 100% is unlawful for the reasons given in our complaint and set forth below. As we explained in our complaint, this issue needs to be resolved before the May 2011 Base Residual Auction.

Second, the mechanism PJM has proposed to calculate energy and ancillary services offsets contains two significant flaws. Specifically, PJM erroneously proposes to calculate the offsets using only real-time prices, ignoring day-ahead. Capacity resources are obligated to offer day-ahead, and often clear there. As a result, using real-time prices instead of first considering whether the offered energy would clear in the day-ahead market will demonstrably overstate the offset calculations and thus understate the net cost of new entry used for mitigation. In addition, PJM erroneously proposes to use the highest Locational Marginal Price in the applicable zone to develop the offsets, even if the applicable node has lower prices. Both proposals are *per se* unjust, unreasonable and unduly discriminatory.

Third, there are several other problems with PJM’s filing, as explained below, but these issues can be deferred.

ARGUMENT

We begin with the issues we protest, dividing the discussion into (a) issues that need to be addressed now and (b) issues that can be deferred. We then comment in support on several remaining points.

I. *THE PJM PROPOSAL STILL CONTAINS SEVERAL FLAWS THAT THREATEN TO RENDER THE MINIMUM OFFER PRICE RULE INEFFECTIVE IN THE SHORT AND LONG RUN*

A. *Protested Issues That Need to Be Addressed Now*

1. *Mitigating New Entrants' Offers to Less than 100% of the Net Cost of the New Entry Ensures that Capacity Prices Cannot Reach Competitive—and Just, Reasonable and Non-Discriminatory—Levels*

The most critical and urgent flaw in PJM's proposal is that it permits the free exercise of buyer-side market power to suppress prices by 10% below the best available estimate of the competitive level. This unjustified discount and *de facto* cap will condemn PJM's capacity markets to a slow death. Even in the next Base Residual Auction, it will reward the exercise of market power with hundreds of millions of dollars of ill-gotten gains. For these reasons, we urge the Commission to require a mitigation level of 100% of the net cost of new entry starting in the May 2011 Base Residual Auction. Dr. Shanker's testimony reinforces this point. *See* Shanker at 13:21–19:12.

PJM seeks to justify its 10% discount by claiming that “such a factor is best viewed simply as a recognition that the RTO's administrative Net CONE estimate is merely an estimate, and a particular unit's actual costs could vary from that estimate.” PJM Proposal at 11. PJM proposes that “the factor selected is a matter of judgment, based on a balance of competing interests.” PJM Proposal at 11. “Retention of a percentage factor appropriately recognizes that PJM's administrative estimate is not perfect.” PJM Proposal at 11. From this PJM concludes that a 10% discount strikes “a reasonable balance between legitimate competing interests.” PJM Proposal at 11. Although PJM's premises are unobjectionable, its conclusion does not follow.

It is true that PJM's estimates of the net cost of new entry are estimates; as such, they will contain errors. We also agree that in order to account for this uncertainty, the Commission must carefully balance the “competing interests.” PJM Proposal at 11. In this context, that means

balancing the harms caused by a benchmark that is too high against the harms caused by a benchmark that is too low.

We categorically disagree, however, with PJM's conclusion that the "right balance" here calls for a 10% discount off the estimate. PJM Proposal at 12. To the contrary, as we have argued before, *see* P3 Complaint at 29-33, the right balance unambiguously calls for a benchmark of *at least* 100% of PJM's estimate, and in fact supports a *premium above* PJM's estimate, rather than a discount. This is because the costs created, and risks posed, by a benchmark that is too low are vastly greater than the competing considerations created by a benchmark that is too high.

a. A Mitigation Benchmark That Is Too Low Threatens the Viability of the Capacity Markets

The true net cost of new entry is by definition the amount of capacity market revenue that is sufficient, when combined with revenues from energy and ancillary services, for new entry to occur in the market. In other words, a competitive, unsubsidized potential new entrant must ask itself whether it can expect to receive capacity market payments, on average over the lifetime of the new resource, of at least its actual net cost of new entry. If its expected capacity market revenues are below its net cost of new entry, whether by 1% or 10% or 50%, it will not enter.

Capacity markets cannot survive if the mitigation benchmark falls below the true net cost of new entry of a competitive potential entrant. Yet PJM's 90% mitigation benchmark would effectively legislate this outcome into the tariff, capping recovery at a level 10% below the required level of revenues. The mitigation benchmark incorporated into the tariff will by necessity become a *de facto* cap on capacity prices. Buyer-side interests will be able to offer resources into the market at the discounted benchmark without triggering any review under the Minimum Offer Price Rule. And as long as the exercise of buyer market power is at all

profitable—and testimony by the market monitor and statements by New Jersey officials confirm that it is, *see* P3 Complaint at 61-64—it will happen to the degree permitted by the tariff, which, if PJM were to prevail, would be down to the level of the discounted benchmark. This means that under PJM’s proposal, capacity prices would never rise above 90% of the benchmark.

No rational developer will invest under these conditions—at least without subsidies. And without competitive entry, the only alternative would be centrally planned, state-sponsored, subsidized entry. Over time, subsidized resources would come to dominate the entire region’s generation fleet. Decisions about resource investments in PJM once again would be centrally planned and fully backstopped by consumers, rather than emerging from competition. All risks of bad investment or cost overruns once again would be borne by ratepayers instead of entrepreneurs.

In sum, far from fixing the buyer market power regime, PJM’s filing—because of this one narrow, but crucial, flaw—sows the seeds of destruction for the PJM capacity market, and with it the overall competitive market paradigm. *See* P3 Complaint at 29-33; Shanker at 9:8-11.

b. A Mitigation Benchmark That Is Too High—While Not Desirable—Will Affect Market Outcomes Only Marginally and Will on Average Still Result in Just and Reasonable Rates

While we do not advocate deliberately choosing a mitigation benchmark higher than competitive capacity price levels, the consequences of an error in that direction would be far less severe. *See* P3 Complaint at 31-32; Shanker at 17:6-21. There are two reasons for this:

First, the tariff, as proposed by PJM and, even more so, as proposed by us, contains features that would permit capacity markets to reach competitive levels—and no more—even if the mitigation benchmark is too high. As both PJM, *see* PJM Proposal at 13-14, and we, *see* P3 Complaint at 29, recommend, any resource that can establish to the Commission that its actual costs are below the mitigation benchmark will be permitted to offer at its actual costs (the “actual

cost exemption”). Thus, even if the mitigation benchmark were too high, resources with proven lower costs would constrain capacity prices from exceeding competitive levels. Moreover, as we propose, *see id.* at 29, 34-35, *infra* at 21-22, any potential resource that established that it did not receive any discriminatory subsidy would be permitted to offer into the capacity market at any price down to \$0/MW-day (the “no-subsidy exemption”). The actual-cost exemption from mitigation, alone or in combination with the no-subsidy exemption, thus prevents capacity prices from becoming un-competitively high, regardless of the mitigation benchmark.

Second, even if the mitigation benchmark were too high, *and* the exemptions from mitigation somehow failed to prevent capacity prices from becoming supra-competitive, the harm would be relatively minor. In that unlikely case, capacity prices could indeed rise to the mitigation benchmark before new entry occurred, but this would be short-lived. Once capacity prices reached the level of the mitigation benchmark, the result would be an influx of new entry seeking to take advantage of any supra-competitive price. This new entry would, in turn, result in a surplus of capacity, producing prices below the true cost of new entry for one or more capacity periods to come. Only once this surplus was absorbed, and new entry needed, would capacity prices again rise to the mitigation benchmark, at which point the cycle would repeat itself. In short, an excessively high mitigation benchmark, unalleviated by any mitigation exemption, would result in nothing worse than oscillation around the true cost of new entry. But over time capacity prices would still average to the competitive—meaning the just, reasonable and non-discriminatory—price.

c. Prudence Calls for a Benchmark of at Least 100% of the Estimate of the Net Cost of New Entry

We agree with PJM that its estimate of the net cost of new entry is, like any estimate, prone to error. As PJM knows, however, these errors can go in either direction. It therefore does

not follow that the mitigation benchmark should be discounted against the net cost of new entry estimate. To the contrary, the asymmetrical consequences of errors in the estimate of the net cost of new entry militate strongly against any discount in setting the mitigation benchmark.

On one hand, if PJM's estimate of the net cost of new entry is too low—that is, lower than the true net cost of new entry—even a mitigation benchmark of 100% of the estimate would be too low, and would have catastrophic consequences. Buyer market power would cap capacity prices at the estimate. And because the true cost of new entry, in this hypothetical is higher than the estimate, no rational competitive market participant will invest. The capacity market will fail.

On the other hand, if PJM's estimate of the net cost of new entry is too high—that is, higher than the true net cost of new entry—a mitigation benchmark of 100% of the estimate would do little harm. We explain this above.

Given that very little harm can flow from setting the benchmark too high, and a great deal of harm can flow from setting it too low, any uncertainty about PJM's estimates calls for a premium, not a discount. As Dr. Shanker explains:

The impacts of over- and under-mitigation are hugely asymmetric. Under-mitigation drives out private entry and destroys the market. Over-mitigation, on the other hand, may increase some administrative costs or—under my proposals—potentially shift supply among competing parties, but it does not destroy the market. In these circumstances, notions like the 10% “rule of thumb” should be left at the door. The 10% variance is designed to accommodate a bit of uncertainty about actual costs, but it does so with little or no adverse impact to the market and under materially different short-term conditions, as I discussed previously. I am aware of no similar circumstances where an uncertainty adder is used when it has such extreme consequences.

Shanker at 18:22–19:8. Under no circumstances can uncertainty justify the 10% discount that PJM proposes.

d. PJM's Arguments for a 10% Discount Point in the Opposite Direction

PJM offers two arguments in support of its proposed 10% discount, claiming that: (i) its methods for estimating the net cost of new entry are conservative, and (ii) PJM and the Commission traditionally include 10% adders in cost estimates. Each of these arguments cuts in favor of our position, not PJM's.

First, PJM argues that:

... the 90% factor is supported by the detail and variation already included in the Net CONE reference value as PJM is proposing it. PJM has developed separate estimates for a CC plant and a CT plant (unlike NYISO and ISO-NE, which use only the CT Net CONE). Within each plant type, PJM also has separate estimates for different sub-regions within PJM, and conservatively bases the energy revenue estimate for each CONE Area in the zone with the highest energy revenues.

PJM Proposal at 12. As we argue below, *see infra* at 12-13, it is true that PJM makes a questionable simplifying assumption exaggerating its estimate of the energy and ancillary services revenues, and therefore minimizes its estimate of the net cost of new entry. But as PJM concedes, “[t]his conservative assumption will tend to *reduce* the Net Asset Class CONE reference value.” PJM Proposal at 12 (emphasis added).

As Dr. Shanker notes, this renders PJM's argument illogical:

PJM notes that it selects the E&AS offset from the highest revenue location in a CONE Area. PJM also properly notes that it concludes that this makes for a larger offset and what it characterizes as a conservative, *lower* estimate of the net CONE value. Somehow PJM then concludes that using a lower biased estimate of its most accurate overall forecast of new entry costs justifies the 90% value. It would seem, however, that given PJM's initial overarching concern regarding accuracy, such a conclusion would support the use of a *higher* level. If the base estimate is calculated in a manner that is assumed to be low, then 100% would seem to be a much more reasonable value.

Shanker at 18:6-14.

Hence, if PJM's simplifying assumption is incorporated into the tariff—and we contend it should not be—it will result in estimates of the net cost of new entry that are too low, and

therefore mitigation benchmarks that are too low. Superimposing an additional 10% discount on the mitigation benchmarks will exacerbate, not mitigate, the error. Unless PJM's simplifying assumption is rectified, the mitigation benchmark requires a compensatory premium, not a discount.

Second, PJM contends that:

The Commission has “traditionally” approved ten percent adders “on the grounds that the ten percent adders recover incidental, miscellaneous expenses that are expensive or difficult to quantify.” Indeed, this principle is embedded in RPM's offer cap calculations, which permit a ten percent adder to costs.

PJM Proposal at 12 (footnotes omitted). While we do not concede that there exists a generalized principle recognizing that standard cost estimates underestimate costs by 10%, if there were such a principle, it would support our position, not PJM's. After all, if standard cost estimates were typically too low because of “incidental, miscellaneous expenses that are expensive or difficult to quantify,” then the same would hold for PJM's estimates of the net cost of new entry, and real-world costs of new entry would be 10% *higher* than PJM's estimates. In that case, any potential entrant offering to enter at a capacity price of only 100% of PJM's estimates should be viewed with suspicion, because either the entrant was unaware of the real world costs or it was trying to suppress prices artificially. In either case, the idea of costs not accounted for in its estimates of the cost of new entry calls for a premium, not a discount, in the mitigation benchmark. *See also* Shanker at 18:3-19.

2. *PJM's Proposal to Account for Energy and Ancillary Revenues in the Net Cost of New Entry Contains Flaws that Can Result in Unjust and Unreasonable Rates*

a. *Energy Revenues of Generators Should Be Properly Accounted*

A subtle, but significant, error in PJM's proposal concerns the calculation of the energy and ancillary services offset for combined cycle and combustion turbine resources. *See* Shanker at 21:16–22:11. This issue, while technical, can have a very large economic impact. In our view,

correcting this technical flaw should be non-controversial and capable of resolution in time for the May 2011 Base Residual Auction. We thus propose that it be addressed, and remedied, before then. Alternatively, if the Commission is unable to address this issue in that time frame, it can be deferred and a correction implemented for the May 2012 Base Residual Auction.

PJM proposes to estimate the energy and ancillary services offset by assuming a “peak hour dispatch” based solely on real-time prices. *See* Shanker at 21:16-22. As Dr. Shanker explains, this ignores reality in PJM:

The use of only real time prices tends to skew the results of the offset calculation to the high side. As PJM itself pointed out, the estimates are already “conservative” to the high side because they use the highest zonal prices in a CONE area as the basis for the calculation. *See* PJM Proposal at 10. Real time prices are subject to material excursions on the high side, so relying solely upon them increases the “conservative” bias.

Because PJM has a “must offer” policy for capacity resources in the day ahead market, a much more appropriate estimate of energy margins would be obtained by first seeing if the reference unit cleared in the day ahead market, and if not, then determining if the unit would be committed in the real time market, and calculating the margins based on this analysis.

Id. at 22:2-11. Dr. Shanker has previously testified at length on the significance of this distinction. *See id.* at 22:12–23:39; *see also id.* at 24:1-4 (noting support of PJM’s market monitor for Dr. Shanker’s conclusions).

While only PJM (and the market monitor) are privy to the complete set of resource dispatches necessary to calculate the exact magnitude of this discrepancy, it is possible to estimate it on the basis of public information:

There is data available that permits an approximation of the impact of reflecting only day ahead versus real time differences in energy margins. In the 2009 State of the Market Report the IMM conducts a number of comparisons and calculations of day ahead versus real time energy margins for CTs and CCs. These are available on an annual average basis and by load zone. These are all contained in the section of the 2009 State of the Market Report addressing net revenues for new entrants. ...

The available information uniformly suggests that using only real time data overstates energy margins and thus understates the asset class reference level used for screening and mitigation of new entrants. In table 3-19, the IMM calculated the average annual difference in energy market revenues for a combined cycle between real time and day ahead across the entire market. The average difference for the last three years (2007-9) was \$8,707/MW-year or almost \$24/MW-day. This is approximate amount by which PJM's methodology would understate the CC asset class net CONE.

Id. at 24:7–25:2 (footnotes omitted). In individual zones, the effect can be even larger:

For example, using PJM's standard of the highest E&AS offset within a CONE area, for CONE Area 1 the difference would be an approximately \$53.89/MW-day higher mitigation standard based on pricing for the Atlantic Electric load zone, which has both the highest day ahead and real time average margins. (That is, PJM would have designated this load zone as the basis for margin estimation regardless of whether it used day ahead or real time prices.) This would increase the Cone Area 1 levelized net CONE from \$205.40 to \$259.39 or by over 26%. The 90% mitigation level would increase the offset correspondingly. This is an enormous change in the results.

Id. at 25:16–26:2 (footnote omitted).

The proper solution to this problem is clear and, given the information available to the market monitor, entirely feasible. *See id.* at 26:7-10. To estimate the energy revenue offset correctly, it is necessary to calculate what the actual dispatch would have been on the basis of historical data. If a resource would have been dispatched in the day-ahead market, the energy revenue offset should only reflect revenues at day-ahead market prices. Only if a resource would *not* have been dispatched in the day-ahead market, but *would* have been dispatched in the real-time market, should the energy revenue offset reflect real-time market prices. This solution is entirely feasible as demonstrated by the fact that the market monitor already employs it to calculate thresholds for seller-side market power mitigation. *See id.* at 23:19-28 (quoting testimony in Docket Nor. ER09-1063-004). Failure to do so will overestimate the energy revenues of combined cycle and combustion turbine resources and therefore *under*-estimate their net cost of new entry (which is derived by subtracting *inter alia* the expected energy revenues

from the gross cost of new entry). And if the estimate of the net cost of new entry is too low, the resulting mitigation benchmark will be as well.

b. Energy Revenues Should Not Be Estimated on the Basis of Highest Energy Revenue in a Zone

PJM's proposed estimate of energy revenues is openly and deliberately excessive. PJM proposes that:

Instead of basing the energy revenue estimate on the zone where the generic "Reference Resource" is assumed to be built, PJM will base it on the zone within each CONE Area that has *the highest* energy revenue estimate.

PJM Proposal at 9 (emphasis added).

In other words, PJM proposes that a new resource's energy revenues will be assumed to be (i) the revenues the resource hypothetically would receive if it were located wherever CONE Area revenues would be highest, rather than (ii) the revenues the resource can *actually* expect to receive where it *actually* is located. This means that if the resource is located anywhere other than where peak energy revenues are highest, PJM's approach will overestimate energy revenues, possibly substantially so. An overestimate of energy revenues will result in an underestimate of the net cost of new entry. This will cause the mitigation threshold to be too low and therefore permit uneconomic resources to enter, clear the Base Residual Auction and artificially suppress prices. This outcome is neither administratively necessary nor just, reasonable and non-discriminatory.

PJM offers no argument for adopting this aggressive estimate of energy revenues. Rather, PJM notes that its proposed method would be more accurate than making estimates on the basis of energy prices at the location of the reference resource, which could be anywhere in PJM. *See* PJM Proposal at 9 ("This approach ensures that the sell offer of a new entrant will not fail the MOPR screen merely because it is located in a zone with higher LMPs than the zone in which

the hypothetical reference resource was assumed to be built.”). That may be correct, but it offers no explanation for why energy revenues should be estimated at the location of peak prices, which could be anywhere else within the CONE Area, rather than the resource’s actual location.

The correct solution is straightforward: When calculating the energy revenue offset for a new resource, the market monitor should estimate the energy revenues at the actual location of that resource. This necessarily will be more accurate than an estimate based on a different location with higher or lower energy revenues. And a more accurate estimate of energy revenues will lead to a more accurate estimate of the net cost of new entry, producing more accurate mitigation decisions.

Even if the market monitor considered it to be burdensome to make resource- and location-specific estimates of energy revenues, the PJM Proposal would still be flawed. The proper energy revenue offset to be used for a whole CONE Area should be based on the *lowest*, not the highest, energy prices in that CONE Area. While this may result in too-high estimates of the net cost of new entry, and therefore subject even some economical resources with higher expected energy revenues to scrutiny, the harm would be minimal. Any truly economic resource located where energy revenues are higher could readily support a location-specific estimate of those revenues to the market monitoring unit or the Commission. Any inconvenience would be administrative and ephemeral. Conversely, adopting PJM’s proposal on this issue would permit uneconomic resources to escape scrutiny entirely and cause permanent economic harm.

B. Protested Issues That Can Be Deferred

1. Exempting Most of the PJM Region from Mitigation Is Unjust, Unreasonable and Unduly Discriminatory

PJM proposes to retain the existing exemption of all resources in unconstrained zones from buyer-side mitigation. Specifically, PJM states that the “MOPR applies only in Locational

Deliverability Areas for which PJM has established a separate VRR Curve.” PJM Proposal at 18. And that is all it says on the point. PJM makes no effort to attempt to justify the continued exemption from mitigation of all resources outside of constrained zones. *See id.*

There is no justification for such a sweeping exemption, which would excise any buyer-market-power mitigation from the so-called RTO or PJM zone, also known as “rest-of-pool,” and from any unconstrained area, or any area projected to be unconstrained at the time of the auction. *See* Shanker at 20:2-8. The effect of this single sentence in PJM’s filing is that approximately two-thirds of PJM will escape any mitigation under the Minimum Offer Price Rule.

While unstated, there are only two potential explanations for such an exemption, and neither applies here. *First*, some may argue that the risk of the exercise of market power in a large, unconstrained zone is *de minimis*. But, as Dr. Shanker testifies, this is demonstrably wrong. *See id.* at 8:1–9:14, 20:11-19. Large or unconstrained zones—including the entire RTO or rest-of-pool zone—are susceptible to buyer side market power exercise just like small or constrained zones. The incentives to exercise buyer market power are exactly the same. *See id.* at 21:4-13. Because of the slope of the demand curve, a *one* percent increase in supply causes a *twenty* percent reduction in prices. *Id.* at 8:9-10. Across PJM, it takes only 1,400 MW of additional uneconomic capacity—less than either the Maryland or New Jersey schemes—to suppress prices in the RTO by 20%. *See id.* at 8:10–9:2 (footnote omitted), 20:14-16.

Second, PJM could claim that applying the Minimum Offer Price Rule to unconstrained zones would be unduly burdensome. PJM has not actually made any such claim, however, and in fact has already confirmed that there is no significant administrative burden associated with

screening for mitigation. In its discussion of the section 206 process that PJM proposes for resources found to be uneconomic, PJM explained that:

This process need not be burdensome. PJM receives relatively few sell offers in the RPM base auctions each year that are based on new combined cycle or combustion turbine power plants. And very few of those would be expected to submit offers significantly below the net cost of new entry each year....

PJM Proposal at 14 (footnote omitted). While we advocate ultimately expanding the mitigation beyond merely short-lead-time resources, *see infra* at 15-21, even then the administrative burden will not be that significant. But even if it were a significant undertaking, it would still be necessary. The alternative—permitting uneconomic entry to destroy the market—is untenable.

To be just, reasonable and non-discriminatory, the Minimum Offer Price Rule should apply everywhere. No area should be exempt from buyer market power mitigation.

As a matter of expediency, however, this issue can be deferred for action before the May 2012 Base Residual Auction. The exemption from mitigation in unconstrained zones is a critical flaw in the current Minimum Offer Price Rule that needs to be addressed for RPM to remain viable in the long term. But we are aware of no reason mandating immediate action.

2. *Exempting All Offers in the Incremental Auctions Is Unjust, Unreasonable and Unduly Discriminatory*

PJM apparently proposes to retain the current limitation in the Minimum Offer Price Rule that limits mitigation only to offers made into the Base Residual Auction. *See* PJM Proposal, Attachment B, Redlined Tariff Sheets § 5.14(h)(4). Offers into Incremental Auctions still would be outside the scope of the Minimum Offer Price Rule. It is unclear whether a sponsored resource that was prevented from clearing in a Base Residual Auction by the Minimum Offer Price Rule would nevertheless be free to offer whatever it wants into the subsequent Incremental Auctions for that same delivery year. Prices and volumes in the Incremental Auctions are

smaller than those in Base Residual Auctions, but they still can be significant, particularly since PJM holds back 2.5% of demand for the incremental auctions.

In sum, the exemption from mitigation in Incremental Auctions still would permit resources that are otherwise mitigated by the Minimum Offer Price Rule to begin to suppress prices (and earn some capacity revenues), perhaps even in the first year of operation. This should not be allowed. Mitigation should be applied in the incremental auctions, in addition to the Base Residual Auctions.

3. *Exempting All Resources Except Combustion Turbines and Combined Cycles from Mitigation Would Expose RPM to the Exercise of Market Power and to Unjust, Unreasonable and Unduly Discriminatory Rates*

The effectiveness of PJM's proposal also is threatened by a blanket exemption for all resources other than combustion turbine and combined cycle resources. *See* Shanker at 6:7–7:11. Such a blanket exemption is unjustified by either economics or factual circumstances, and practically invites would-be exercisers of buyer market power to switch to other resource types. For the RPM to remain viable in the long run, it will be necessary for other resource types, including long-lead time resources, renewable resources, and demand response resources, to be appropriately covered by the Minimum Offer Price Rule. As we already have noted, however, the Commission can examine this issue on a schedule that leads to a resolution in time for the May 2012 Base Residual Auction. *See* P3 Complaint at 54-57.

PJM's proposal maintains and expands upon the long list of resource types exempted from the current Minimum Offer Price Rule:

PJM proposes to keep the existing rule's tolerance of a zero-price offer for nuclear, coal and Integrated Gasification Combined Cycle facilities. ... PJM also is keeping the current rule's tolerance of zero price for hydroelectric resources, and is adding wind and solar facilities to that category.

PJM Proposal at 19. PJM offers no justification for any of the continuing exemptions and only a very weak defense for extending this exemption to renewable resources.

a. Long-Lead Time Resources Should Be Subject to a Slightly Different Mitigation Process, Not Exempt Entirely

As noted earlier, *see* P3 Complaint at 54-55, there is no economic, legal, or regulatory justification for the current exemption for long-lead time resources:

Currently the tariff exempts long-lead-time resources from mitigation. There is no justification for this exemption. These resources can achieve artificial price suppression just as readily as resources that can be developed within the three-year lead-time period built into the RPM auction process.

P3 Complaint at 54. Nothing in the PJM Proposal supplies this missing justification.

Long-lead time resources are almost as ready a tool for artificial price suppression and exercise of buyer market power as the covered resources. As Dr. Shanker notes, estimates of the net cost of new entry for certain long-lead time resources, such as coal plants, are within the same range as those for combined cycles and combustion turbines:

What PJM seems to ignore is that even if the new entrant were a coal plant, the economics still will support price suppression by buyers if they are unmitigated. The harm to suppliers stays the same, and net cost of out-of-market actions is not so different as to negate the incentive to exercise market power. Theoretically there should be no difference at all over time. For example, the PJM Independent Market Monitor estimated the average net CONE over the period from 1999 to 2009 for a coal plant was \$110,717/MW-year, or \$303/MW-day. This is only about \$53/MW-day different than the net costs for CTs. The difference in the cost for exercising market power using a coal plant in my example above is only \$74,200/MW-day $((\$303-\$250) \times 1400)$, compared to suppression impacts of \$7 million per day. This additional cost of an alternative capacity resource or technology is hardly the impediment to the exercise of buyer market power that PJM seems to believe it to be.

Shanker at 9:3-14 (footnotes omitted).

If buyer interests are barred from using combined cycles and combustion turbines to exercise market power, they can readily switch to the long lead-time resources exempted by the PJM Proposal. The New Jersey Legislation that triggered our complaint effectively admits as

much by expressly including base-load resources—a category that largely overlaps with the category of long-lead time resources—among those eligible to be subsidized and offered on uneconomical terms into the RPM auctions. *See* S. No. 2381, 214th Leg. (N.J. 2011), at 8. The only disadvantage of using uneconomic long-lead time resources to suppress prices is that the price suppression effect will be felt at a later point in time (after the “long lead time”). But this is almost trivial compared to the decades that these resources will be in existence.

We have recognized that even economic long-lead time resources may face special challenges and risks under the current structure of the RPM, and have proposed a tailored accommodation to alleviate these problems. *See* P3 Complaint at 55. But the current (and proposed) blanket exemption for long-lead time resources is unjustified, invites the exercise of buyer-side market power, and will result in unjust, unreasonable and unduly discriminatory rates. It should be rejected.

b. Renewable Resources May Be Granted Limited Regulatory Privileges, But Should Not Be Exempt Entirely

In addition to carrying forward the unjustified blanket exemptions of the current Minimum Offer Price Rule, PJM proposes to extend these exemptions to renewable resources. While environmental benefits not otherwise accounted for in the RPM may justify some leniency in the application of the Minimum Offer Price Rule to renewable resources, *see* P3 Complaint at 56, Shanker at 6:18–7:11, a blanket exemption is both unnecessary and a potential danger to the long-term viability of the RPM.

In defense of the blanket exemption for renewable resources, PJM offers three arguments, each unfounded:

First, PJM states that the “net cost of these intermittent resources will bear little relation to the Net Asset Class estimates that will be determined under the Tariff for CC and CT plants.”

PJM Proposal at 19. While this statement is correct, it does not support or require a blanket exemption. PJM’s current and proposed rules expressly recognize that different asset classes will have different gross and net costs of new entry. If the mitigation scheme can accommodate different asset class costs for combustion turbines and for combined cycles, why can it not also recognize separate asset class costs for wind farms or solar generation facilities? If the asset class costs of conventional resources form an adequate basis for mitigating conventional resources, then the asset class costs of renewable resources similarly form an adequate basis for mitigating renewable resources.

Second, PJM contends that the cost structure of renewables “may be complicated by credits and incentives with laudatory public policy objectives having nothing to do with capacity price suppression.” PJM Proposal at 19. Again, while this may very well be true in most cases, it is no reason to exempt renewables from mitigation. The cost structure of conventional resources also may be complicated by state-sponsored tax, credit, subsidy, or incentive measures. That is certainly the case for the conventional resources sponsored by New Jersey and Maryland, which triggered the present proceedings. With respect to subsidized conventional resources, PJM proposes—and we support—a Commission process to determine whether the purpose and effect is “laudatory public policy” or “capacity price suppression.” The same is appropriate for subsidized renewable resources.

Third, PJM argues that:

Under current circumstances, it seems more likely that a market participant with an objective to suppress prices would pursue that objective through a resource, such as a combined cycle or combustion turbine, that is more likely to be a marginal resource in the RPM auctions.

PJM Proposal at 19 (emphasis added). PJM refutes its own argument in its first three words. It may very well be true that *under current circumstances* conventional resources would be a more

effective tool for the exercise of buyer market power.² But circumstances change; in fact, our filing, like PJM's, affirmatively *seeks* to change the current circumstances by removing the attraction of using conventional resources to exercise buyer market power. If the implemented revisions are successful and conventional resources can no longer be used in this fashion, other resources, including renewables, will take their place.

To argue against a blanket mitigation exemption for renewables is not to deny the special benefits offered by such resources, or to demand that the tariff not recognize these benefits. There are, however, far less dangerous and more appropriate means of recognizing the special status of renewable resources. For example, as pointed out above, renewable resources that are subsidized for legitimate, extrinsic purposes could be exempted on a case-by-case basis by the Commission, just as PJM proposes for conventional resources.

Alternatively, if PJM finds itself unable to generate asset class cost estimates for renewables, renewables could be measured against the presumably lower asset class cost estimates for combustion turbines or combined cycles. This would permit subsidized renewable resources to enter the capacity market and receive capacity revenue whenever clearing prices are sufficiently high as to justify unsubsidized, competitive entry by new conventional resources. At the same time, it would prevent the use of renewables to suppress capacity price below competitive levels.

4. Demand Response Resources Should Not Be Exempt

PJM proposes to continue to implicitly exempt demand response resources from mitigation, but offers no argument or justification for this exemption. *See* PJM Proposal at 19.

² This advantage, however, does not appear to be absolute: Wind power projects were offered in response to the New Jersey Board of Public Utilities' solicitation of projects to be sponsored. *See* Mary Powers, *New Jersey Gets Proposals for More Than 6,400 MW*, PLATTS ELECTRIC POWER DAILY, Feb. 24, 2011, at 1 (attached hereto at P3 Exhibit 6).

As we previously noted, *see* P3 Complaint at 56, effective mitigation of buyer-side market power cannot exempt demand response resources. This issue, however, like the other resource exemptions proposed by PJM, does not need to be resolved by the next auction, but can be deferred for resolution by May, 2012.

5. *There Is No Justification for Mitigating Offers that Demonstrably Are Not Part of Any Scheme to Exercise Market Power*

Previously we have proposed to make the entire buyer-mitigation regime less burdensome for all stakeholders, and easier to administer, by creating an exemption for any resource that can establish that it will not receive any form of subsidy. *See* P3 Complaint at 34-36. The rationale for this exemption is straightforward:

New entry could fail a conduct screen for one of two reasons: (a) a competitive entrant may simply have expectations about future energy and ancillary service revenues that are different than the estimates embedded in the benchmark, or (b) a resource can have some other form of financial support, such as the type of contract proposed by the New Jersey Law. The first situation does not, in our view, need to be addressed through buyer mitigation—it is not causing artificial price suppression, and reflects, instead, normal business conduct. The second, in stark contrast, does need to be addressed through mitigation. We therefore can focus the mitigation process on resources most likely to cause artificial price suppression if we allow resources to exit that process by establishing that they are not receiving any subsidy.

P3 Complaint at 34.

Under PJM's proposed rule, however, no such exemption is granted. As a consequence even resources offered by an entirely and demonstrably independent supplier are subject to mitigation. This is not just and reasonable.

A supplier should have no inherent economic incentive to exercise market power to suppress prices. And any supplier who has received no subsidy or other discriminatory out-of-market payments should also be lacking any artificial incentive to suppress prices. If such a supplier offers a new resource into the capacity market, the purpose cannot be to exercise market

power. Under clear court and Commission precedent, absent the potential exercise of market power, there is no justification for mitigation. *See Edison Mission Energy v. FERC*, 394 F.3d 964, 968-70 (D.C. Cir. 2005); *see also Wisc. Pub. Power v. FERC*, 493 F.3d 239, 264 (D.C. Cir. 2007). The Commission therefore should adopt the proposed no-subsidy exemption from mitigation in time to be in effect for the May 2012 Base Residual Auction.

II. THE PJM PROPOSAL EFFECTIVELY ADDRESSES MANY OF THE MANIFEST DEFECTS OF THE MINIMUM OFFER PRICE RULE

PJM's filing includes several measures that are critical improvements to the Minimum Offer Price Rule and that are essential for just and reasonable rates. These measures are the same as—or are substantially similar to—proposals that we made in our complaint: (1) eliminate the impact test, (2) eliminate the net short exemption, (3) eliminate the implied exemption for self-supply resources, (4) justify uneconomic offers to the Commission, (5) extend the duration of mitigation, (6) update the calculation of CONE and (7) eliminate the sunset provision. We endorse these measures.

A. Eliminating the Impact Test Is Just and Reasonable

As we did in our complaint, PJM also proposes to eliminate the impact test. *See* PJM Proposal at 17-19; *see also* P3 Complaint at 23-24, 36-37; Shanker Compl. Test. at 54:5-6. This is an essential change that will bring PJM's mitigation rules more closely in line with those of NYISO and ISO New England—neither of which have a similar test. *See* PJM Proposal at 17.

The impact test in the current Minimum Offer Price Rule prevents mitigation of an otherwise uneconomic offer unless its “impact” on prices is at least \$25/MW-day or 20 to 30% (depending on the size of the Locational Deliverability Areas). These thresholds may at first blush seem relatively innocuous, but once applied across an entire Locational Deliverability Area, the permitted price impact before mitigation kicks in can be enormous. We included an example

in our complaint that showed that a price impact of \$590 million in the Eastern Mid-Atlantic Area Council region would be deemed to have no “impact” under this test. *See* P3 Complaint at 24; Shanker Compl. Test. at 26:8-15.

PJM explains that “[e]ven a small change in the clearing price from a below-cost offer can harm competition if it deters entry, or spurs retirement, of a resource that would have been competitive, had the MOPR seller offered at its true costs.” PJM Proposal at 18. And as PJM shows, the Commission would never tolerate a similar impact threshold applied to seller market power. *See* PJM Proposal at 18. We agree, and support elimination of the impact test.

B. Eliminating the Net-Short Exemption Is Just and Reasonable

PJM also proposes to eliminate the limitation in the current Minimum Offer Price Rule that applies it “only to a capacity market seller and its affiliates that have a substantial ‘net short position’ in the relevant RPM auction.” PJM Proposal at 16. Under this limitation, mitigation only applies to uneconomic offers if “the seller and its affiliate are effectively buying substantially more capacity from the auction than they are selling into it.” *Id.* As we discussed in our complaint, this limitation is easily gamed and should be eliminated. *See* P3 Complaint at 41-48; Shanker Compl. Test. at 30:16–31:15.

The notion behind this exemption is that only a net buyer of capacity would stand to benefit from suppressing prices. This notion, in and of itself, is not unreasonable, but crafting a mitigation exemption to apply it turns out to be completely unworkable. It is far too easy for net buyers to mask their offers or to use co-parties to bypass this test. In the most prominent example, a state contracts for a new power plant, or orders a utility in its state to do so. The offer is submitted by the new resource, which presumably will always be a net seller of capacity. The new resource is not an affiliate of the state or of the state’s utilities, and thus escapes mitigation under the net-short exemption, even though the state is plainly sponsoring the new capacity. In

sum, as PJM correctly characterizes it, the net-short exemption “opens considerable opportunities for a seller/buyer ... to structure the new entry transaction in [a] way that achieves the desired price-lowering effects without triggering the MOPR’s protective provisions.” PJM Proposal at 16.

The Commission recently rejected a substantially similar net-buyer test in NYISO. *N.Y. Indep. Sys. Operator*, 124 FERC ¶ 61,301 at P 29 (2008) (“[D]efining net buyers raises significant complications and provides undesirable incentives for parties to evade mitigation measures.”), *order on reh’g and clarification*, 131 FERC ¶ 61,170 (2010). The same is true here. The net-short exemption should be eliminated.

C. Eliminating Any Implied Exemption for Self-Supply Is Just and Reasonable

PJM proposes clarifying changes to the tariff to confirm that self-supply offers are not exempt from mitigation. *See* PJM Proposal at 20-21. PJM confirms that it “never intended to exempt self-supply offers from application of the MOPR,” and any ambiguity on this point was unintentional. *Id.* at 20.

This is a critical clarification in the tariff. If there were a self-supply exemption, it could easily be gamed by essentially all new entry to escape mitigation. *See* P3 Complaint at 50 (“Exempting self-supply would render the Minimum Offer Price Rule a dead letter. Anyone wishing to exercise buyer market power would effortlessly switch from (1) bidding uneconomic resource projects into the market at anti-competitive prices to (2) designating them as self-supply. Either approach creates exactly the same price-suppression effects.”); Shanker Compl. Test. at 32:8–33:4; *see also* P3 Complaint at 48-53 (discussing problems with failing to mitigate self-supply). Any ambiguity should be eliminated.

On this point, we may have been concerned about a non-issue because apparently PJM has always interpreted the Minimum Offer Price Rule to apply to self-supply. But to date, the

Minimum Offer Price Rule has never been triggered, so the ambiguity in the tariff with respect to self-supply had never been tested. PJM's clarification eliminates any ambiguity and confirms that offerors cannot bypass mitigation simply by designating themselves as self-supply.

D. All Uneconomic Offers, Including Those Mandated by States, Should Be Supported and Justified Before the Commission in Order to Escape Mitigation

PJM proposes to clarify the rules for an offeror to go to the Commission to challenge the determination that it is uneconomic and will be mitigated. *See* PJM Proposal at 13-16. PJM proposes that any such entity must submit a section 206 filing (under the Federal Power Act) at the Commission. PJM also proposes to extend this same process to any state-sponsored resources. *Id.* at 14.

These measures are consistent with Commission precedent and should be approved. The market monitoring unit and/or PJM should apply the tariff rules and determine in the first instance whether a resource passes the bright line tests and is economic or not. But any challenge to this determination should be in a proceeding before the Commission.

This is particularly true for any state-sponsored projects. PJM points out that the current tariff requires PJM "to pass on the adequacy of state administrative processes" in determining whether a state-sponsored project is legitimately needed to address a reliability shortfall. PJM Proposal at 15. We agree that PJM should not be put in this position. Moreover, since the states are the entities most likely to exercise buyer market power, the decision that a state-sponsored offer is uneconomic almost certainly will end up before the Commission. It is appropriate for the states to petition the Commission in these circumstances, just like any other entity. We support PJM's proposed changes.

PJM proposes tariff language that would ensure that any such Commission determination would have to be made "sufficiently in advance of the Base Residual Auction" so as not to

disrupt the auction. PJM Proposal, Attachment B, Revised MOPR § 5.14(h)(5). It may be necessary to establish a fixed process or firm deadlines to govern any such 206 filings to ensure that the Commission has time to rule before the relevant auction deadlines.

E. New Resources Should Be Mitigated for More Than One Year After They First Clear

PJM proposes to extend the period of time when mitigation will apply to an uneconomic resource. *See generally* PJM Proposal at 19-20. We proposed similar relief in our complaint. *See* P3 Complaint at 37-39; Shanker Compl. Test. at 57:12-21. While the details may be different, the basic principle is the same: uneconomic entry should be mitigated until it is “absorbed” by the market—until the point in time when it is no longer uneconomic.

Under the current Minimum Offer Price Rule, mitigation occurs only once, in the first auction. Thereafter the new resource is free to bid as low as it wants. Given the fact that new resources have a useful life of several decades, a single year’s mitigation is almost wholly ineffectual to prevent the abuse of buyer market power. *See* P3 Complaint at 25-26; Shanker Compl. Test. at 33:13-21. The Commission has recognized this and recently rejected a cap on the duration of mitigation in NYISO. *See N.Y. Indep. Sys. Operator*, 133 FERC ¶ 61,178 at PP 47-52 (2010), *reh’g pending*. In its place, the Commission approved mitigation lasting until “the capacity clears in 12 monthly auctions at the offer floor.” *Id.* at P 49. As Dr. Shanker explained, NYISO is a monthly auction, and the most likely months when new resources would be economic would be in the summer, so clearing in 12 monthly auctions in NYISO is roughly equivalent to clearing in two annual auctions in PJM. *See* Shanker Compl. Test. at 57:16-21.

Given this, we proposed in our complaint to extend mitigation until an offer cleared in two Base Residual Auctions. P3 Complaint at 38; Shanker Compl. Test. at 57:16-21. PJM somewhat differently proposes to mitigate a resource until it clears in a Base Residual Auction, but then only for an additional fixed term of two years, regardless whether it cleared again or not.

See PJM Proposal at 20. And under either proposal, if a resource has previously cleared only in part, it is still only the cleared part that becomes exempt from mitigation. See P3 Complaint at 38; Shanker Compl. Test. 55:1-2, 57:14-15.

We are not certain that PJM's proposal would in fact extend mitigation until the uneconomic resource becomes economic, as our proposal would. It seems more likely that a resource could take advantage of a quick spike in prices to clear in a single year, but then under PJM's proposal would only be mitigated for two additional years. Our proposal would require a resource to clear at least twice. We thus prefer our proposal, but we can support PJM's proposal as an interim measure, pending further consideration of our proposal for implementation by May 2012.

F. CONE Must Be Properly Calculated for Rates to Be Just and Reasonable

PJM proposes several changes to the calculation and application of the value for the cost of new entry. See PJM Proposal at 5-10. We support or do not oppose many of these changes. As discussed *supra* at 9-12, we do oppose PJM's apparent decision to use only real-time values in the energy and ancillary services offset (see PJM Proposal at 9-10) and PJM's proposal to base the energy offset on the CONE Area with the highest energy revenue estimate (see *id.* at 10). See *supra* at 12-13. But otherwise we do not object to the Commission adopting PJM's proposals related to updating the CONE reference values.

1. Updating the Estimates of Gross Costs of New Entry Is Required for Rates to Be Just and Reasonable

The gross CONE values in the tariff are out-of-date and inaccurate. PJM proposes an update using conservative measures of the most recent available values. See PJM Proposal at 6-7. PJM includes a detailed, "bottom-up" estimate of the cost of new entry by an outside expert, Raymond M. Pasteris. See *id.*, Attachment C.

We anticipate that several buyer-side interests are likely to oppose this update. They have no principled reason for doing so, however, because the current values clearly are wrong. PJM's calculations appear to be conservative and consistent with past practices, and we do not oppose their adoption here.

2. *Periodical Updates of the Construction Cost Estimates Underlying the Cost of New Entry Are Required for Rates to Be Just and Reasonable*

PJM also proposes an annual automatic adjustment to gross cost of new entry based on “applicable construction-cost indices, known as the Handy-Whitman Index, that are widely used in the utility industry.” PJM Proposal at 8-9. PJM will still have the ability under the tariff for a revised “bottom-up” estimate whenever it deems necessary, but the periodic update will permit the cost of new entry to automatically adjust with changes in construction costs. *Id.* at 9. Here again, we do not oppose this change. It is reasonable to adopt a process for updating construction costs in the estimate, and PJM's proposal again appears to be conservative.

3. *Levelizing the Costs of New Entry on a Nominal, Rather Than Year-One, Real, Basis Helps Render Rates Just and Reasonable*

In our complaint, we proved that for the tariff to be just and reasonable, it needs to change from using the “real” levelized cost of new entry to using the “nominal” levelized cost.

As Dr. Shanker explained:

Nominal levelized payments are calculated to create a constant annual stream of the same dollar amount each year that has a present value at a designated discount equal to a given amount. Real levelized payments reflect a stream of dollars increasing over time at the forecasted rate of inflation that has the present value when discounted equal to the same given amount. In this instance the “given amount” is the cost of constructing a new generating facility.

It is appropriate to base mitigation on the nominal stream because that is the cost stream that most closely matches the type of financial obligations associated with project financing. It basically is a cost structure similar to a mortgage.

Shanker Compl. Test. at 55:15-23.

PJM proposes the same change. *See* PJM Proposal at 7-8. PJM explains that the “real levelized approach produces a lower number in the early years of the project’s life than the nominal levelized approach.” *Id.* at 7. PJM then demonstrates that the nominal levelized approach is much more consistent with what a developer would actually require. *Id.* at 8. The Commission should approve this change.

G. Elimination of the Sunset Provision Is Just and Reasonable

PJM proposes to eliminate the sunset provision in the tariff that would eliminate the Minimum Offer Price Rule under certain conditions. *See* PJM Proposal at 21. We made a similar proposal in our complaint. *See* P3 Complaint at 39. As PJM explains, “the objectives served by the MOPR are not time-limited,” and “the MOPR should not be subject to automatic termination, no more than any other RPM protections against uneconomic conduct by sellers should be subject to automatic termination.” PJM Proposal at 21. We agree. The sunset provision should be eliminated.

III. SOME ASPECTS OF THE PJM PROPOSAL ARE NOT YET RIPE FOR FULL EVALUATION

Two issues raised in the PJM Proposal have not yet matured sufficiently for considered judgment on our part: (1) the date certain for changes to the New Entry Price Adjustment and (2) interconnection process reforms. We therefore merely note them here and reserve the right to comment on them in such a process as the Commission may deem to establish.

A. PJM Proposes a Date Certain for Changes to the New Entry Price Adjustment

PJM proposes to establish, in its tariff, a date certain for changes in its New Entry Price Adjustment rule. *See* PJM Proposal at 21-22.

RPM’s New Entry Price Adjustment (“NEPA”) currently provides a new entry project, in certain narrow circumstances, assurance that it will receive its “new entry” price, i.e., the clearing price from the first year the new plant decides to enter a constrained LDA, for two additional years. ... PJM is committed to

seeking solutions in this area to address both the possible need for greater revenue assurance and the Commission's concerns with possible undue discrimination. PJM recognizes, however, that it may be difficult to achieve a stakeholder consensus on these points, given the controversy resulting from past efforts to reform the NEPA rules. To help advance a solution, PJM asks the Commission to approve the enclosed Tariff change that sets a deadline of October 1, 2011 for PJM to file, following a stakeholder process, any NEPA reforms that can satisfy the twin objectives of supporting new entry while avoiding undue discrimination between new and existing units.

PJM Proposal at 22 (footnotes omitted).

We are not necessarily opposed to a stakeholder process to discuss changes to the New Entry Price Adjustment, but the request to hardwire this commitment into the tariff is unusual in PJM and likely unnecessary. It would also be more appropriate to discuss issues related to the New Entry Price Adjustment as part of the same omnibus triennial review process that PJM is about to embark upon to review many core parameters of the RPM construct, including the demand curve parameters and the level of gross CONE. *See* PJM Tariff, Attachment DD §§ 5.10(a)(iii), 5.10(a)(vii)(C); PJM Capacity Market Operations, PJM Manual 18: PJM Capacity Market RPM, Rule 3.4.1 (June 1, 2010), <http://www.pjm.org/markets-and-operations/~media/documents/manuals/m18.ashx>. Any new parameters already are due to be proposed by September 1, 2011. *See* PJM Tariff, Attachment DD §§ 5.10(a)(iii)(A), 5.10(a)(vii)(C)(1). The New Entry Price Adjustment cannot be judged in a vacuum, but is intertwined with the shape of the demand curve and other factors, and should be considered at the same time during the same process.

If the Commission is inclined to require a stakeholder review of the New Entry Price Adjustment, then we recommend that it do so as part of the triennial review process. And there is no need to clutter the tariff with this requirement; the Commission can simply order PJM to submit a compliance filing, as it routinely does in other cases.

B. PJM Proposes Interconnection Process Reforms

PJM also proposes to reform its interconnection service process:

PJM devotes considerable effort and resources to its generator interconnection process so as to treat all interconnection customers fairly while not burdening the process with undue delay. Although the current queue rules are just and reasonable and conform to Commission policy, there may be opportunities for greater efficiencies in this area, and for distinguishing between interconnection requests based on progress, objectively measured, towards the ultimate goal of delivering new capacity to serve the reliability needs of the PJM Region. PJM intends to lead its stakeholders this year in a review of possible queue reforms that can both advance reliability and reduce uncertainty and delays for project developers, and file any resulting Tariff changes with the Commission by the end of this year.

PJM Proposal at 22.

We agree that any administrative process, even a process that already meets the requirements of being just and reasonable, may admit of further improvement. Pending the development of the contents of these reforms, we express no opinion on them.

CONCLUSION

For the foregoing reason, the Commission should accept the PJM Proposal, modified to reflect the protests set forth above. Alternatively, the Commission could adopt the PJM Proposal, but without the mitigation threshold discount, for the upcoming Base Residual Auction and set the remaining issues for hearing.

Respectfully submitted,

/s/

Glen Thomas
President
PJM POWER PROVIDERS GROUP
1060 First Avenue
Suite 400
King of Prussia, PA 19406
(610) 768-8080

John N. Estes III
Paul F. Wight
Carl Edman
SKADDEN, ARPS, SLATE, MEAGHER & FLOM LLP
1440 New York Avenue, N.W.
Washington, DC 20005
(202) 371-7000

Counsel for the PJM Power Providers Group

March 4, 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

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served copies of the foregoing document upon each person designated on the official service lists as compiled by the Office of the Secretary in the captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated at Washington, D.C., this 4th day of March, 2011.

_____/s/
Carl Edman
SKADDEN ARPS SLATE MEAGHER & FLOM LLP
1440 New York Avenue, N.W.
Washington, DC 20005
(202) 371-7950

SHANKER TESTIMONY

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

)

Docket No. ER11-2875-000

*TESTIMONY OF ROY J. SHANKER, PH.D.
ON BEHALF OF THE PJM POWER PROVIDERS GROUP*

March 4, 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

)

Docket No. ER11-2875-000

1

INTRODUCTION

2 Q PLEASE STATE YOUR NAME AND ADDRESS.

3 A My name is Roy J. Shanker. My address is P.O. Box 60450, Potomac, Maryland 20859.

4 Q WHAT IS THE PURPOSE OF THIS TESTIMONY?

5 A On February 1, 2011, I submitted testimony in the Section 206 Complaint and Request
6 for Clarification Requesting Fast Track Processing of the PJM Power Providers Group
7 (“P3 Complaint”) (Docket Number EL11-20-000).¹ That testimony addressed material
8 problems with the existing PJM Reliability Pricing Model’s Minimum Offer Price Rule.
9 PJM Tariff Attachment DD, § 5.14. In the P3 Complaint, I was asked to review the
10 Minimum Offer Price Rule provisions to determine whether they effectively limit buyer
11 market power. That testimony presented my findings and specific recommendations to
12 modify the Minimum Offer Price Rule.

13 On February 11, 2011, PJM submitted a Section 205 filing addressing the same
14 issues (Docket ER11-2875-000) (“PJM Proposal”). PJM indicated that it would also
15 separately file comments in response to the P3 Complaint, but stated that their comments
16 would be substantially the same as the positions taken in their February 11 filing. I have
17 been asked by P3 to review the PJM Proposal, and present my conclusions regarding the
18 appropriateness of PJM’s proposed changes to the Minimum Offer Price Rule.

¹ P3 Exhibit 1 to the P3 Complaint (“February 1 Testimony”).

1 My February 1 Testimony offered a detailed criticism of the deficiencies in the
2 current Minimum Offer Price Rule. From the PJM Proposal, it is apparent that PJM is in
3 general agreement with my concerns. I will not repeat my prior discussion here, but
4 incorporate my earlier comments and recommendations by reference. *See generally*
5 February 1 Testimony.

6 In this testimony I focus on four specific areas where there is material divergence
7 between PJM's recommendations and those that I have previously made.

8 Q PLEASE SUMMARIZE YOUR QUALIFICATIONS TO PRESENT TESTIMONY IN
9 THIS MATTER.

10 A I provided a summary of my relevant experience in general and specifically on this issue
11 in the P3 Complaint and a detailed summary of my experience as P3 Exhibit 1-A.

12 Q HOW IS YOUR TESTIMONY STRUCTURED?

13 A PJM's filing conforms in almost all respects with my February 1 Testimony regarding the
14 flaws in the Minimum Offer Price Rule that make it unjust and unreasonable.² I agree
15 with most of the arguments and logic that PJM presents in support of the need for change.
16 Similarly, I conclude that based on PJM's own arguments, they concur in many if not
17 most of the conclusions that I reached regarding the failings of the current Minimum
18 Offer Price Rule. In a few cases, however, PJM's recommended relief falls short of what
19 is required to remedy the flaws in the rules that they do such a good job in describing. In

² *See, e.g.*, PJM Proposal at 4:

As will be evident from this filing, PJM generally agrees that the current MOPR is flawed and in need of reform. The current MOPR's low asset-class reference values, substantial discounts off those values, requirement for a large impact on clearing prices, application only to the very first time a new entry unit is offered in an auction, and numerous ambiguities, along with the net short requirement, all raise serious questions about the effectiveness of PJM's MOPR in its current form. Moreover, as discussed in this filing, PJM's MOPR does not reflect the Commission's precedent on MOPR-type provisions of other RTOs issued after the Commission's acceptance of the 2006 RPM settlement.

1 most instances, the better solution and more complete remedy would be achieved by
2 adopting the recommendations that I made on February 1.³

3 Thus the focus of my testimony in this filing is to comment on the inconsistencies
4 between PJM's support for change, and some of their specific recommendations that fall
5 short. Specifically, I identified four areas where I believe that PJM's recommended
6 "fixes" are flawed and inappropriate. These should be rejected by the Commission and
7 modified consistent with my February 1 recommendations.

8 Q WHAT ARE THE FOUR FLAWS IN PJM'S PROPOSED REMEDIES THAT YOU
9 IDENTIFIED?

10 A First, PJM proposes to apply mitigation only to new Combustion Turbines ("CT") and
11 Combined Cycle ("CC") generation technologies. This limitation on mitigation is
12 arbitrary and unsupported. In the P3 Complaint, counsel proposed to apply mitigation
13 only to CTs and CCs (short-lead-time resources) for the next auction—as a time-saving
14 measure—to ensure prompt implementation of the most critical reforms to the Minimum
15 Offer Price Rule by May 2011. PJM, however, proposes that mitigation should be
16 applied only to CTs and CCs *period*. It does not plan to add other types of resources for
17 mitigation in the auction after the next, or in any auction.

18 PJM provides almost no justification for omitting other supply alternatives from
19 mitigation. It only states that some alternative forms of supply are "laudatory,"
20 presumably meaning more laudatory than a CT or CC. But calling certain supply
21 "laudatory" hardly constitutes a substantive basis for concluding that such supply
22 alternatives cannot ever become a tool to exercise buyer market power. As I discuss, the

³ As part of its reply, P3 has summarized these important areas of agreement as well as the specific items where I find PJM's recommendations to be deficient.

1 difference in net cost of new entry (“CONE”) between a CT and a new coal plant is
2 relatively small (and should converge over time), so from an economic perspective, it is
3 just as feasible to exercise buyer market power using an alternative technology. This was
4 demonstrated by the responses to the recent solicitation that New Jersey had for new
5 subsidized generation. A wide variety of technology offers were received, including
6 plant expansion and repowering, all attempting to capture the subsidies offered to
7 suppress prices. The Commission should adopt my recommendation of applying
8 appropriate mitigation to all supply, regardless of technology. At minimum, the
9 Commission should review the offers of these other technologies and supply options to
10 determine whether they reflect the exercise of buyer market power.

11 Second, once uneconomic supply is identified, PJM arbitrarily sets the “mitigate
12 to” level of a substitute supply offer at 90% of the supplier’s nominal levelized net
13 CONE. Aside from a superficial and inapplicable analogy to energy mitigation, they
14 offer no justification for using anything less than 100%. Indeed their own arguments
15 support the use of at least 100%, as I have previously recommended. PJM has
16 emphasized the magnitude of effort and quality analyses that support its estimate of
17 CONE, yet it then limits the effectiveness of those results by arbitrarily reducing the
18 mitigation threshold. The effect is to set a cap on actual market recovery of capacity
19 costs that is below PJM’s own best estimate of the revenues that are actually needed. In
20 doing this PJM ignores a fundamental element of its own recommendations (and mine),
21 each resource’s option to “prove” that its unit specific costs are lower. With this option,
22 it is impossible for any party to be harmed by the imprecision that PJM appears to worry
23 about. You cannot be harmed by imprecision related to thresholds or mitigation so long

1 as you can prove your own costs and use them as the basis for offers in the capacity
2 auction.

3 Third, PJM arbitrarily applies the new rule to only a subset of the PJM market
4 (i.e., regions where there is a separate VRR curve). PJM offers no justification for failing
5 to mitigate market power in the remainder of the market. This makes no sense. Buyers
6 can still materially benefit from the exercise of market power whether within a single
7 region or throughout PJM as a whole. I present examples of this result on a scale that
8 would adversely impact all of PJM, even from just the current New Jersey and Maryland
9 programs. Further, there is nothing to prevent cooperative actions at the same level
10 between states on a going forward basis. As a result, the proposed mitigation, modified
11 as I have recommended, should apply to the entire market regardless of whether there is
12 locational separation or not.

13 Fourth, PJM has proposed to determine the nominal levelized net CONE using
14 real time energy pricing to establish the offset for operating margins earned in the energy
15 market. This is inappropriate and materially overstates the offsets. As I have previously
16 testified, the correct offset evaluates whether or not the reference technology would have
17 been first committed in the day ahead market and if not, whether it would then have been
18 committed in the real time market. Appropriate margins would then be calculated based
19 on the relevant day ahead or real time clearing prices. This is consistent with what the
20 reference technology could logically expect to earn in energy margins. It is also
21 consistent with the procedure and evaluations already conducted by the independent
22 market monitor (“IMM”) to calculate supply offer mitigation caps for existing units in the
23 RPM capacity market, so no one can say the calculation is too burdensome or difficult

1 (they are already doing it). The empirical evidence available shows that asset class net
2 CONE levels (and associated mitigation thresholds) in one region are inappropriately
3 lowered by over \$50 a MW-day or almost 25% by relying solely upon real-time prices.

4 *DISCUSSION*

5 *I. MITIGATION OF ONLY NEW COMBUSTION TURBINES AND COMBINED CYCLES IS*
6 *ARBITRARY AND UNJUSTIFIED*

7 Q WHAT CATEGORIES OF SUPPLY DOES PJM PROPOSE TO MAKE SUBJECT TO
8 THE MINIMUM OFFER PRICE RULE?

9 A PJM would apply mitigation only to new CTs and CCs or to expansions to these types of
10 resources. PJM explicitly waives mitigation of all other types of supply including long-
11 lead-time base load generation, wind, solar and demand response.

12 Q DOES PJM OFFER ANY CREDIBLE JUSTIFICATION FOR SUCH A LIMITATION
13 ON THE APPLICATION OF MITIGATION?

14 A No. PJM asserts that it would be difficult to exercise market power via the exempted
15 technologies. It further asserts that some supply—such as wind and solar—are
16 “laudatory.” None of this constitutes a demonstration of a legitimate need for exemption.
17 A simple evaluation of public information also shows that PJM’s conclusion is wrong.

18 Q WHAT IS THE HARM OF PERMITTING EXEMPTIONS TO MITIGATION?

19 A The best short explanation for why no resources should be exempted from mitigation is
20 stated by PJM itself:

21 To ensure continued economic investment in existing and new resources,
22 RPM must continue to send accurate price signals. Accurate price signals,
23 correctly indicating where new entry is needed on the system, and
24 accurately conveying the cost of that new entry, provide information that
25 is essential both for private bilateral contracts and for public policy
26 initiatives. RPM’s market rules therefore must ensure that new entrants
27 are not permitted to exercise market power to increase clearing prices
28 above the competitive cost of new entry. Those rules also must ensure

1 that market participants cannot use uncompetitively low new entry offers
2 to suppress clearing prices, which can deter new entry even in parts of the
3 system where it may be required.⁴
4

5 The Commission has reached this same conclusion itself in its recent decisions in New
6 York.⁵

7 It does not matter which technology is being used to distort prices. *All*
8 uncompetitive low offers can distort market prices, regardless how beneficial or benign
9 they may otherwise be. If an unneeded and uneconomic MW is distorting prices, RPM is
10 blind as to where it came from. And as PJM itself notes, RPM cannot present accurate
11 prices signals if uncompetitive low offers are not excluded. The source is irrelevant.

12 Q DID PJM MAKE OTHER INCONSISTENT STATEMENT REGARDING SUCH
13 EXEMPTIONS?

14 A Yes. From its discussion of the proposed evaluation of state mandates by the
15 Commission (at 15-16), it is very clear that PJM understands that state actions may be at
16 odds with pricing policy in the Commission's jurisdictional markets, and that action may
17 be needed to protect the markets. PJM recommends that the Commission itself, not PJM,
18 determine whether entry supported through such state action should be subject to
19 mitigation. PJM's decision here to limit mitigation only to a subset of technologies is
20 clearly arbitrary. Reading PJM's own statements leads to exactly the opposite
21 conclusion, that mitigation should be applied uniformly to all technologies.⁶

⁴ PJM Proposal at 2.

⁵ *See N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at PP 100-01, *order on reh'g*, 124 FERC ¶ 61,301 (2008).

⁶ *E.g.*, PJM Proposal at 15-16:

The sufficiency of state policy justifications is a matter much better addressed to the Commission. Indeed, the Commission recognized as much when it directed the NYISO to add to its MOPR-type provision a rule that parties seeking to justify a new entry offer on state policy grounds must

1 Q IS IT POSSIBLE TO EXERCISE BUYER MARKET POWER VIA THESE
2 EXEMPTED TECHNOLOGIES?

3 A Yes, of course. The levels of market price suppression are enormous compared to the
4 cost of new generation of virtually any type. In my February 1 Testimony, I gave
5 examples that demonstrate how uneconomic entry can have a very large price
6 suppressing effect because of the PJM demand curve. February 1 Testimony at 11:7–
7 12:11. These values were only for a single sub-region of PJM. If spread across the entire
8 PJM footprint of approximately 140,000 MW, the impacts will of course be even larger.
9 A one percent increase in supply yields a 20% decrease in price in the sloped portion of
10 the demand curve. The approximate net CONE for a CT provided by PJM is about \$250
11 per MW-day.⁷ Thus an expense of \$350,000 per day for an unneeded and uneconomic
12 new CT (1,400 x \$250) has the impact of artificially reducing payments to suppliers
13 market wide by approximately \$7,000,000 per day (140,000 MW x 20% x \$250) or \$2.55
14 billion for a year. Twenty percent of total capacity market revenues would be

submit an FPA section 206 filing to the Commission to obtain that relief. ... The Commission therefore announced that the NYPSC “may make a filing under section 206 of the FPA to justify a mitigation exemption for entry of new capacity that is required by a state-mandated requirement that furthers a specific legitimate state objective.

The same approach should apply here. As the Commission held when it rejected a challenge to the MOPR’s current exception on this issue, it is reasonable to acknowledge the possible legitimacy of “reliability projects built under state mandate,” because they “enable[] states to meet their responsibilities to ensure local reliability.”

However, such projects can have adverse price effects that run counter to the Commission’s purpose in approving RPM and similar capacity programs. Therefore, whether to allow capacity sell offers from such projects if they fail the MOPR screen can present difficult issues and likely would involve a balancing of competing policy interests. Such determinations go well beyond the limited role of a tariff administrator and are properly the province of the Commission. Accordingly, PJM is replacing the current, purportedly self-implementing, exception process for state-mandated reliability projects with an exception process, like that approved for the NYISO, that necessarily involves the Commission, through an FPA section 206 filing.

(footnotes omitted).

⁷ PJM Proposal, Attachment D.

1 inappropriately at risk for actions smaller than those recently proposed in New Jersey or
2 Maryland, neither of which limits eligible technologies.

3 What PJM seems to ignore is that even if the new entrant were a coal plant, the
4 economics still will support price suppression by buyers if they are unmitigated. The
5 harm to suppliers stays the same, and net cost of out-of-market actions is not so different
6 as to negate the incentive to exercise market power. Theoretically there should be no
7 difference at all over time. For example, the PJM Independent Market Monitor estimated
8 the average net CONE over the period from 1999 to 2009 for a coal plant was
9 \$110,717/MW-year, or \$303/MW-day.⁸ This is only about \$53/MW-day different than
10 the net costs for CTs. The difference in the cost for exercising market power using a coal
11 plant in my example above is only \$74,200/MW-day $((\$303-\$250) \times 1400)$, compared to
12 suppression impacts of \$7 million per day. This additional cost of an alternative capacity
13 resource or technology is hardly the impediment to the exercise of buyer market power
14 that PJM seems to believe it to be.⁹

15 Q BUT WHAT ABOUT THOSE “LAUDATORY” EXEMPTIONS THAT PJM WISHES
16 TO ALSO INCLUDE?

17 A PJM’s determination of what is “laudatory” is wholly arbitrary. A MW is a MW, and as
18 the Commission has continually noted, all competitive resources within a given location
19 should be compensated at the same price. *See* P3 Complaint at 17-18. Typically,

⁸ *See* Monitoring Analytics LLC, State of the Market Report for PJM, vol. II, sec. 3 at 166, tbl. 3-26 (Mar. 11, 2010), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec3.pdf (“2009 State of the Market Report”) $((\$274,163-\$163,446)/365)$.

⁹ For conventional technology, this is just the type of result one would expect over time, and actually the difference would be expected to be closer. In equilibrium it would be anticipated that the net CONE would roughly be equivalent across all resources, varying up and down based on changes in load shape, but averaging approximately the same value as the net CONE of a peaking unit.

1 “laudatory” initiatives are the result of state incentives and priorities that are
2 discriminatory by nature. This is true for subsidies for demand response and for
3 mandates for renewable energy via renewable portfolio standards. This does not mean
4 that discrimination is inherently wrong, nor that the states should not be free to pursue the
5 resources that it prefers. But the decision to subsidize one type of resource should not be
6 permitted to distort pricing for everyone else in the Commission’s jurisdictional markets.
7 To the extent that these state level subsidies provide out-of-market payments, they distort
8 the ability of RPM to provide the price signals that PJM states are vital to the correct
9 operation of the market. This occurs regardless of the technology.

10 It is amazing to me that PJM can conclude that state mandates in general should
11 be subject to a determination of relative harm to the market by the Commission, but then
12 choose to exempt those resources that it subjectively concludes are most “laudatory,” i.e.,
13 politically correct. At a minimum, this determination should be made by the Commission
14 after an objective evaluation on a subsidy-by-subsidy basis. Again, if economic
15 efficiency and the success of the market are the objective, then the conclusion is
16 transparent: all uneconomic entry should be mitigated.

17 Q EMPIRICALLY, IS THERE ANY INDICATION THAT A RANGE OF
18 TECHNOLOGIES MAY BE EMPLOYED IN UNECONOMIC ENTRY?

19 A Yes. The results of New Jersey’s recent solicitation demonstrate that many types of
20 offers can be used in the exercise of uneconomic entry. The responding technologies
21 included synthetic gas, nuclear upgrades and wind, as well as combined cycle
22 generation.¹⁰

¹⁰ Mary Powers, *New Jersey Gets Proposals for More Than 6,400 MW*, PLATTS ELECTRIC POWER DAILY, Feb. 24, 2011, at 1.

1 Q HOW DID YOU ADDRESS THIS ISSUE IN YOUR FEBRUARY 1 TESTIMONY
2 AND RECOMMENDATIONS?

3 A The proposal I put forward would have included mitigation of all supply alternatives that
4 receive out-of-market payments.¹¹

5 Q HOW WOULD YOUR PROPOSAL HAVE DEALT WITH THE DIFFICULTY THAT
6 PJM SUGGESTS EXISTS FOR ESTABLISHING AN ASSET CLASS COST FOR
7 VARIOUS ALTERNATIVE TECHNOLOGIES?

8 A My recommended approach incorporated a conduct test based on a simple cycle reference
9 unit and mitigation to unit specific nominal levelized net CONE.¹² In combination this is
10 the equivalent of an overall mitigation that is equal to the lesser of the CT reference net
11 CONE or unit specific net CONE. Thus in the absence of verifiable unit specific
12 numbers, a supplier could escape mitigation simply by offering slightly above the
13 reference resource's nominal levelized net CONE. So too, any resource with very high
14 unit costs would escape mitigation by offering slightly above the reference CT's nominal
15 levelized net CONE.

16 These results are consistent with providing the accurate minimal price signals that
17 PJM has argued are so necessary. The nominal levelized net CONE of the CT reference
18 unit is the equilibrium average payment that one would expect to be recovered by a new
19 entrant over time. This type of "pure" capacity is what should be at the margin for the
20 supply of capacity when the entire system is in equilibrium. At that point, the new
21 entrant has already exploited all opportunities to cost effectively build a more efficient,

¹¹ February 1 Testimony at 4:6-14.

¹² *Id.* at 4:17-5:2; 6:14-17.

1 higher capital cost unit, and to offset the increased cost of such a unit with savings from
2 the energy market.

3 Over time, both load shape and supply will change, so that it may be possible to
4 make enough energy profit from a more efficient unit (e.g., a CC) to offset the higher
5 capital cost. But in equilibrium you would always return to the starting point after
6 arbitraging away the “excess” from the energy market.

7 The cost relationship is clarified by notionally converting a CT into a CC.
8 Assume it costs \$300/KW-year to build a CT and \$400/KW-year to build a CC. Further
9 assume that you can convert the CT to a CC for the same \$100 in annual expense and this
10 can be done incrementally. Also assume that there is a mandated reserve of capacity
11 maintained for reliability. Assume that when the system is in balance, the CT rarely runs,
12 and if it does run, it sets price. In this world the reference CT earns no energy rents or
13 margins, and needs \$300 in annual capacity payments on average to break even.

14 Next assume that over time load shape changes and there is a need for higher run
15 times and prices for the marginal CT. And assume that someone calculates that energy
16 margins for the CT move up to just \$101 per KW-year. In this situation the owner of the
17 CT will convert the quantity of KW that it believes will get the \$101 in the energy
18 margins from a CT to CC, spending \$100 per KW-year in conversion costs. Under these
19 conditions the CT owner now has increased its annual cost by \$100, and revenue by
20 \$101. It remains “short” the annual the cost of a CT, the original required \$300. This
21 leaves the resource slightly better off with a net requirement of \$299 per KW-year for
22 capacity revenues, which is basically its original position.

1 In equilibrium we expect these energy margins to be low and/or to be driven to
2 zero as more expensive and more efficient new CCs are added with the same result, and
3 in turn, driving down energy margins. In steady state the marginal supply would still be
4 expected to be missing, on average, the annual net CT payment. Thus that amount needs
5 to be recovered in the capacity market for all technologies.

6 Q WOULD IT BE DIFFICULT FOR PJM TO IMPLEMENT THIS TYPE OF
7 RECOMMENDATION?

8 A No. Under my proposal, PJM would apply a conduct screen to all supply based on 100%
9 of the reference CT. And as PJM has also proposed, any resource could also demonstrate
10 to the Commission that it has lower costs. PJM also proposes a value of 70% of the
11 reference CT for any generation that is not a CT or CC and is not otherwise exempted
12 (although I am not sure what can fall into that category). The change here thus would be
13 trivial: PJM is already calculating the CT value in order to establish its 70% criterion, so
14 the information is available, and under my proposal they would simply use 100%, not the
15 lower value. If desired, PJM could maintain their proposed asset class references for CC
16 and CT offers instead of only a using the conduct screen of the CT, but as noted in the
17 next section, under my recommendation they would use a value of 100% for screening
18 and “mitigate to” in the absence of unit specific values.

19 *II. THERE IS NO VALID JUSTIFICATION FOR MITIGATING TO LESS THAN 100% OF*
20 *ASSET CLASS VALUES—LOWER VALUES SUPPORT BUYER MARKET POWER*

21 Q WHAT VALUE DOES PJM PROPOSE BE USED FOR THE OFFER FLOOR FOR
22 NEW ENTRANTS?

23 A PJM proposes a conduct screen for offers at less than 90% of the designated asset class.
24 New entrants would fail the conduct screen and be mitigated if they offer at less than

1 90% of their designated asset class. If they cannot then demonstrate (via a 206 filing)
2 actual unit specific costs at lower levels, they would be mitigated. PJM proposes to use a
3 substitute supply offer (the “mitigate to” level) of 90% of a nominal levelized CONE for
4 each asset class. PJM also proposes to use a value equal to 70% of the reference CT level
5 where there is no otherwise applicable net asset class figure.

6 The Commission in its discretion can also accept lower values in 206 filings
7 related to state mandates. As noted above, PJM would arbitrarily waive any mitigation of
8 entry sponsored through state mandates for wind, solar and demand response.

9 Q WHAT JUSTIFICATION DOES PJM OFFER FOR USING THE 90% OF NOMINAL
10 LEVELIZED ASSET CLASS NET CONE?

11 A The PJM Proposal (at 11-12), PJM makes three general arguments, none of which is
12 compelling, and one of which actually contradicts their conclusion. PJM’s first argument
13 is that the selection of the right conduct screen value and “mitigate to” level is a
14 balancing act. If the screen is set too high, most new offers will fail, administrative work
15 levels will be higher, but the potential to exercise market power will be reduced. If the
16 level is set too low, the exercise of market power is too easy. PJM claims that “[a] screen
17 of 90% sets a reasonable balance between legitimate competing interests: on the one
18 hand, recognizing the imprecision of ‘one-size fits all’ administrative estimates, balanced
19 against, on the other hand, preserving protections against an unreasonable exercise of
20 market power.”¹³

21 PJM’s second justification appears to be that in some undefined fashion 90% also
22 strikes a reasonable balance because it is based on highly detailed engineering estimates

¹³ PJM Proposal at 11.

1 and regional assumptions regarding energy and ancillary service income. PJM deems
2 these estimates to be conservative (i.e., high), which means that the values that are used
3 result in low estimates of asset class levelized net CONE based on PJM's own best
4 judgment.¹⁴

5 PJM's third argument is that the use of approximations or ranges such as 10% is
6 consistent with Commission precedent regarding uncertainty and 10% adders with
7 respect to other unknown or less precise cost components in both energy and capacity
8 markets.¹⁵

9 Q DO YOU AGREE WITH THESE THREE JUSTIFICATIONS?

10 A No. Each is flawed or inapplicable and any reasoned consideration would suggest that
11 PJM's second argument supports a higher value. I discuss them in turn.

12 With respect to PJM's first argument, it essentially equates to "it is too hard to get
13 the pricing right, so it is ok if the market fails due to price suppression." PJM recognizes
14 that 20% price suppression based on an 80% screen and 80% "mitigate to" level is too
15 great, but somehow concludes that 10% expected suppression is "just right." To the
16 contrary; it is at least 10% too low—by definition. If PJM is using the best data available
17 and is intentionally conservative, but is still further intentionally setting the bar below
18 100%, it is explicitly encouraging price suppression and discouraging new entry. *No*
19 *private party will reasonably invest in an environment where the RTO uses its best efforts*
20 *to develop a very precise measure that effectively will cap revenues at 90% of the*
21 *average amount the new entrant needs to receive over time just to break even. Nobody*

¹⁴ *Id.* at 12.

¹⁵ *Id.*

1 signs up for guaranteed 10% losses, unless they think that they can beat the market by
2 more than 10% or that they have much better data (and should that demonstrably be the
3 case, they would not be mitigated in the first place).

4 Structurally PJM has already accepted the fact that parties can petition FERC if
5 their individual costs are lower than the screen, so there is no problem with rejecting
6 legitimately low offers. If that suggests too much work, the IMM can also conduct cost
7 specific screenings and mitigation. My understanding is that the IMM already conducts
8 such studies for both generic new and specific real plant operations and modifications. I
9 see no reason why the very viability of the market should be sacrificed due to concerns
10 about the use of an administrative function that is already in place.¹⁶

11 Further, PJM's first argument is based on what appears to be a notion of parity or
12 balancing of the relative cost of the errors of over- or under-mitigating. This notion is
13 false. Under-mitigating, as discussed above, destroys the market function for new
14 capacity entry. Expectations that revenues will be lower than 100% assure that the

¹⁶ Further PJM itself seems to take a contradictory position regarding the burden of review to look into the costs of new entry. In describing the 206 process that it recommends at the Commission, PJM argues:

This process need not be burdensome. PJM receives relatively few sell offers in the RPM base auctions each year that are based on new combined cycle or combustion turbine power plants. And very few of those would be expected to submit offers significantly below the net cost of new entry each year. Notably, the PJM Region has had a process in place for many years by which generation providers file with the Commission their costs of providing reactive service under Schedule 2 of the PJM Tariff, and the necessary determinations have routinely been implemented on a timely basis under that process. Indeed, in many cases, since the MOPR screen is only a screen, capacity market sellers may offer a perfectly adequate explanation why their new entry offer is significantly below the Net Asset Class Cost of New Entry. A seller's specific project may legitimately have lower fixed costs, or higher reasonable revenue expectations (or a combination of both) relative to PJM's generic determination of the net costs for the particular asset class. In such circumstances, PJM would have no objection to advising the Commission, through written, on-the-record comments, of PJM's views on the seller's offered justification, and PJM presumes that the IMM would do so as well. Thus, the occasional case-specific exceptions to the bright-line MOPR test on acceptable sell offers would be resolved in a transparent fashion that promotes confidence in the integrity of the RPM auctions.

Id. at 14 (footnote omitted). We agree. It is not too burdensome to get the process right.

1 market will fail. However, over-mitigation can be addressed either competitively—by
2 assuring other competitive entrants have the opportunity to make unmitigated supply
3 offers—or administratively—by allowing unit specific costs to be “proved up,” as just
4 described. There is no harm in requiring a party to actually bid its own costs, and the
5 IMM already calculates similar numbers in numerous situations.

6 In my February 1 Testimony, I discussed at length the relative cost of the errors
7 from over- versus under-mitigation. February 1 Testimony at 22:22–25:2. I explained
8 the justification for a recommendation of using 100% of the reference unit net CONE for
9 a conduct screen and 100% of unit specific net CONE for “mitigate to” values. *Id.* at
10 20:11–25:2. My original recommendation included the type of administrative relief that
11 would allow any supplier to “prove up” their individual costs (eliminating one source of
12 risk or cost of errors for over mitigation). I also demonstrated that so long as competitive
13 entry options remained available, there really is no harm to the market by potentially
14 over-mitigating. *Id.* at 24:14-18. I explicitly provided for a path of entry where the new
15 entrant had the alternatives to either demonstrate unit specific cost or show that it had not
16 received any out-of-market payments. *Id.* at 53:1–54:2.

17 Under these exceptions there is no problem with over-mitigation. Legitimate
18 lower costs are recognized, and there is no impediment to unsubsidized competitive
19 suppliers entering the market regardless of their costs. While it is conceivable that a
20 specific individual competitor could be mitigated when it should not be (though
21 unlikely), the market function as a whole is left undisturbed.

22 PJM has failed to demonstrate a factual or logically sustainable basis for their
23 conclusion that 90% provides symmetry or, from their perspective, a presumably small

1 cost of errors. PJM has provided no response to the conclusion that under-mitigation
2 ends competitive entry.

3 Q DO YOU AGREE WITH PJM'S SECOND ARGUMENT THAT ITS
4 "CONSERVATIVE" E&AS ESTIMATES SUPPORT THE USE OF THE 90%
5 SCREEN AND MITIGATION LEVELS?

6 A No. This is illogical. PJM notes that it selects the E&AS offset from the highest revenue
7 location in a CONE Area. PJM also properly notes that it concludes that this makes for a
8 larger offset and what it characterizes as a conservative, *lower* estimate of the net CONE
9 value. Somehow PJM then concludes that using a lower biased estimate of its most
10 accurate overall forecast of new entry costs justifies the 90% value. It would seem,
11 however, that given PJM's initial overarching concern regarding accuracy, such a
12 conclusion would support the use of a *higher* level. If the base estimate is calculated in a
13 manner that is assumed to be low, then 100% would seem to be a much more reasonable
14 value.

15 As I stated in my previous testimony, considerations such as this and the relative
16 cost of errors justify adopting 100% as a conservative lower value for conduct screens
17 and mitigation levels. This is particularly true here where all resources can go to the
18 Commission and prove that they have lower costs, or show that they are not receiving any
19 subsidies.

20 Q DO YOU AGREE WITH PJM'S THIRD ARGUMENT REGARDING COMMISSION
21 CUSTOM AND THE USE OF 10% ADJUSTMENTS FOR UNCERTAINTY?

22 A No. The circumstances are different here. The impacts of over- and under-mitigation are
23 hugely asymmetric. Under-mitigation drives out private entry and destroys the market.

1 Over-mitigation, on the other hand, may increase some administrative costs or—under
2 my proposals—potentially shift supply among competing parties, but it does not destroy
3 the market. In these circumstances, notions like the 10% “rule of thumb” should be left
4 at the door. The 10% variance is designed to accommodate a bit of uncertainty about
5 actual costs, but it does so with little or no adverse impact to the market and under
6 materially different short-term conditions, as I discussed previously. I am aware of no
7 similar circumstances where an uncertainty adder is used when it has such extreme
8 consequences. Certainly it cannot be justified in capacity markets where the entire
9 function of the market would be compromised. In addition, it makes no sense to take
10 such risks with the viability of the market where any resource has the ability and ample
11 time to “prove” unit specific costs. There is no upside to putting the market in such
12 jeopardy.

13 *III. NO REGION OF PJM SHOULD BE EXEMPT FROM THE MITIGATION OF BUYER*
14 *MARKET POWER*

15 Q HAS PJM LIMITED THE AREAS WHERE ITS NEW MINIMUM OFFER PRICE
16 RULE WILL APPLY? O

17 A Yes. PJM proposes to limit mitigation to “any LDA for which a separate VRR Curve has
18 been established....”¹⁷ As I understand the proposal, mitigation thus will not apply to
19 new entry in the “RTO” or rest-of-pool unconstrained zone, or to any zone where the
20 absence of binding constraints over time removes the modeling of the LDA.

¹⁷ *Id.*, revised Tariff Attachment DD § 5.14(h)(4). In the same provision, PJM also continues to limit mitigation solely to the Base Residual Auction, and not to the incremental auctions. *Id.* Mitigation should apply to all auctions. *See* February 1 Testimony at 54:22–55:1; *id.* at 27:17–28:2; 34:14–18.

1 Q HAS PJM PROVIDED A JUSTIFICATION FOR THIS LIMITATION?

2 A No, and it makes no sense. Structurally, as discussed more thoroughly in my February 1
3 Testimony, the source of buyer market power stems from the interaction of the negative
4 slope of the demand curve (which decreases prices 20% for every 1% increase in supply)
5 and concentrated buyer market share. February 1 Testimony at 11:7–12:11. It is
6 materially facilitated by the complementary actions of local authorities to recover out-of-
7 market costs via a non-bypassable charge. These basic conditions are not geographically
8 limited.

9 Q IS IT POSSIBLE FOR BUYER MARKET POWER TO BE EXERCISED ON THE
10 SCALE OF THE ENTIRE PJM FOOTPRINT?

11 A Yes. As my example earlier in this testimony shows, *supra* at 8:4-14 , the mathematics
12 of uneconomic entry hold just as well for the entire PJM footprint when there is no price
13 separation in the LDAs as it does to a small LDA where price separation may occur. The
14 only difference is scale. Notably, in my earlier hypothetical example the impact was
15 based on only 1,400 MW across PJM as a whole. Actions taken by either New Jersey
16 (2,000 MW) or Maryland (1,800 MW), acting alone, far exceed my hypothetical. These
17 out-of-market programs were postulated by the states acting individually, yet as noted by
18 the IMM, the combined impact to the entire market based on the last auction could be
19 over \$3 billion of price suppression. *In re Whether New Generating Facilities Are*
20 *Needed to Meet Long-Term Demand for Standard Offer Service*, No. 9214, Comments of
21 the Independent Market Monitor for PJM at 4 (Jan. 28, 2011); *see also id.*, Attachment at
22 1-2. There certainly does not appear to be a barrier to actions of the scale necessary to
23 distort the entire regional market, even when undertaken by a single state. As noted by

1 the IMM, of the \$3 billion in price suppression, approximately one third occurs outside of
2 eastern MAAC and MAAC. *See id.* Presumably interstate cooperation could make this
3 type of price suppression across the entire footprint even easier to accomplish.

4 Q BUT ISN'T THERE LESS INCENTIVE TO EXERCISE BUYER MARKET POWER
5 IN UNCONSTRAINED AREAS?

6 A No. The underlying issue is where relative supply is versus the applicable demand curve.
7 So long as supply is clearing on the sloped portion of the curve, the incentives are
8 basically the same throughout PJM—except for locational differences in the net CONE
9 values. As load grows, units retire, and new transmission is built, the entire footprint
10 could be unconstrained, and there would still be the underlying 20 to 1 “payoff” for the
11 exercise of buyer market power when total supply is intersecting the sloped section of the
12 VRR curve. This is true regardless of whether there is locational separation or separate
13 VRR curves.

14 *IV. PJM SHOULD INCORPORATE DAY AHEAD PRICES INTO THE CALCULATION OF*
15 *ENERGY AND ANCILLARY SERVICES OFFSETS FOR THE REFERENCE UNITS*

16 Q HOW DOES PJM INTEND TO SET THE ENERGY AND ANCILLARY SERVICES
17 OFFSET ADJUSTMENT TO THE ASSET CLASS GROSS CONES?

18 A PJM will estimate historic three-year average margins based on real time LMPs and the
19 economic dispatch of both CTs and CCs. *See* PJM Proposal at 9 (“PJM is adopting the
20 same method already approved to calculate the EAS revenue estimate for the net CONE
21 used in the VRR Curve,” which is the “perfect dispatch” method that relies solely upon
22 real-time values.).

1 Q DO YOU AGREE WITH THIS APPROACH?

2 A No. The use of only real time prices tends to skew the results of the offset calculation to
3 the high side. As PJM itself pointed out, the estimates are already “conservative” to the
4 high side because they use the highest zonal prices in a CONE area as the basis for the
5 calculation. *See* PJM Proposal at 10. Real time prices are subject to material excursions
6 on the high side, so relying solely upon them increases the “conservative” bias.

7 Because PJM has a “must offer” policy for capacity resources in the day ahead
8 market, a much more appropriate estimate of energy margins would be obtained by first
9 seeing if the reference unit cleared in the day ahead market, and if not, then determining
10 if the unit would be committed in the real time market, and calculating the margins based
11 on this analysis.

12 Q HAVE YOU DISCUSSED THIS ISSUE PREVIOUSLY?

13 A Yes, in Docket No. ER09-1063-004 regarding PJM’s shortage/scarcity pricing proposal.

14 There I stated as follows:

15 PJM currently calculates this net offset amount, the E&AS offset, using
16 what is referred to as the “perfect dispatch” method, which incorporates a
17 back cast of what the reference unit would have earned each year,
18 averaged over the past three years based on real-time energy prices. PJM
19 has properly recognized that increased energy payments from shortage
20 pricing should increase the E&AS offset. Its proposal simply to roll the
21 potentially higher prices during periods of operating reserve shortages and
22 calculate the E&AS margin using real time prices only into the current
23 three-year average calculation, however, while correct at the conceptual
24 level is inappropriate as executed....

25 It would typically be expected that during periods of high demand much of
26 the supply would be committed in the day-ahead market.... Further, ...
27 the events triggering shortages in real time can be relatively unpredictable,
28 with hour ahead reserve pricing in advance of such events being set at
29 zero. In general, this means that one would not expect that scarcity
30 premiums to be present in the day ahead market, yet it is in this market
31 that most suppliers (particularly those with RPM awards that are required
32 to offer their capacity into the day ahead market) would be compensated

1 for the sale of their energy. For example, I reviewed the RTO day ahead
2 LMPs for July 7, 2010, a day in which PJM experienced high energy
3 demand over extended periods of time. During these extended periods,
4 energy prices were above \$100/MWh.¹⁸ To put this in context the
5 reference unit has a heat rate of approximately 10,000 BTU per kWh, and
6 Gas Daily indicated prices in Dominion at approximately \$5.19 per
7 MMBTU and at Chicago at \$4.82 per MMBTU. Using an approximate
8 gas price of \$5 results in a cost based offer price for the reference unit of
9 about \$50 plus variable O&M, well below the day ahead clearing prices
10 experienced during high demand conditions. Under these conditions, one
11 would expect the reference unit to be committed day ahead and would not
12 earn real-time energy margins.

13 On the other hand, if the E&AS offset, which reduces capacity payments
14 as it grows larger, is based solely on real time prices, there will be an
15 under recovery of scarcity revenues needed by suppliers for fixed cost
16 recovery. Capacity payments would be reduced based on the
17 consideration of historic scarcity rents that the suppliers, selling day
18 ahead, never had the opportunity to earn.

19 There is a simple solution to this, and it is actually already employed by
20 the PJM IMM when calculating the RPM reference prices (i.e., the ACR)
21 for each individual supplier in the market. Recognizing the potential
22 mismatch in margins between the real time and day ahead markets, the
23 ACR is calculated by first evaluating the specific unit to see if it would
24 have been committed in the day-ahead market. If so, for that day, the
25 relevant prices are from the day ahead market. If the unit is not committed
26 in the day-ahead market, it is evaluated again based on real-time prices,
27 and if committed, the real-time prices are utilized to calculate margins that
28 contribute to the ACR.

29 There is no reason that the E&AS offset for the reference unit should not,
30 or could not, be calculated in the same fashion. In fact, I have confirmed
31 that the IMM maintains all the data necessary for such calculations
32 through the ACR procedures, and it would not be difficult or burdensome
33 to make this modification. Such an adjustment – screening the reference
34 unit [either CC or CT for asset classes] for commitment first in the day
35 ahead market, and then in the real time market if not taken – prevents the
36 net CONE from being artificially lowered by real-time scarcity payments
37 that a generator never actually earned while appropriately recognizing
38 scarcity payments that the generator would be expected to earn. This
39 would also be consistent with the methodology used by the NYISO.”¹⁹

¹⁸ Available at <http://www.pjm.com/pub/account/lmpda/20100707-da.csv>.

¹⁹ *PJM Interconnection*, Docket No. ER09-1063-004, Comments and Limited Protest of the PJM Power Providers Group, Exhibit P3-1, Affidavit of Roy J. Shanker Ph.D. ¶¶ 61-65 (July 30, 2010).

1 Q DID ANY OTHER PARTY COMMENT ON THE CONCLUSION THAT AN
2 APPROPRIATE E&AS OFFSET WOULD CONSIDER DISPATCH IN BOTH THE
3 DAY AHEAD AND SEQUENTIALLY THE REAL TIME MARKETS?

4 A Yes. The IMM offered testimony that supported my conclusion.²⁰

5 Q HAVE YOU BEEN ABLE TO ESTIMATE THE IMPACT THAT THIS CORRECTED
6 CALCULATION OF ENERGY MARGINS WOULD HAVE?

7 A Yes. There is data available that permits an approximation of the impact of reflecting
8 only day ahead versus real time differences in energy margins. In the 2009 State of the
9 Market Report the IMM conducts a number of comparisons and calculations of day ahead
10 versus real time energy margins for CTs and CCs. These are available on an annual
11 average basis and by load zone. These are all contained in the section of the 2009 State
12 of the Market Report addressing net revenues for new entrants.²¹

13 Q CAN YOU SUMMARIZE THE TYPES OF DIFFERENCES YOU OBSERVED IN
14 THIS DATA?

15 A Yes. The available information uniformly suggests that using only real time data
16 overstates energy margins and thus understates the asset class reference level used for
17 screening and mitigation of new entrants. In table 3-19, the IMM calculated the average
18 annual difference in energy market revenues for a combined cycle between real time and
19 day ahead across the entire market.²² The average difference for the last three years

²⁰ *PJM Interconnection*, Docket No. ER09-1063-004, Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM at 19-20 (Aug. 26, 2010).

²¹ *See* 2009 State of the Market Report, vol. II, sec. 3.

²² *Id.* at 158.

1 (2007-9) was \$8,707/MW-year or almost \$24/MW-day. This is approximate amount by
2 which PJM's methodology would understate the CC asset class net CONE.

3 Table 3-18 contains the same market wide data for a CT. The corresponding
4 average was \$4,421/MW-year or \$12/MW-day.²³ Again this represents the average
5 expectation for understating the CT values just from considering day ahead versus real
6 time pricing.

7 Q IS SIMILAR DATA AVAILABLE ON A ZONAL OR LDA BASIS?

8 A Yes and it is more relevant. The system-wide average of approximately \$24/MW-day for
9 CCs between day ahead and real time is already material, but the specific results within a
10 CONE area can be much larger. This is due to PJM's "conservative" approach of using
11 the highest-priced zone's E&AS offset. *See* PJM Proposal at 10.

12 Q HAVE YOU DEVELOPED AN EXAMPLE FROM A SINGLE ZONE?

13 A Yes. The 2009 State of the Market Report contains estimates by load zone of the day
14 ahead and real time margins for CTs and CCs.²⁴ This information is not specifically
15 displayed as differences. I have calculated an example for CCs (attached as P3 Exhibit 4-
16 A). For example, using PJM's standard of the highest E&AS offset within a CONE area,
17 for CONE Area 1 the difference would be an approximately \$53.89/MW-day higher
18 mitigation standard based on pricing for the Atlantic Electric load zone, which has both
19 the highest day ahead and real time average margins. (That is, PJM would have
20 designated this load zone as the basis for margin estimation regardless of whether it used
21 day ahead or real time prices.) This would increase the Cone Area 1 levelized net CONE

²³ *Id.*

²⁴ *Id.* at 150, 157.

1 from \$205.40 to \$259.39 or by over 26%.²⁵ The 90% mitigation level would increase the
2 offset correspondingly. This is an enormous change in the results. Combined with
3 PJM's unjustified 10% reduction, and the conservative use of the highest energy and
4 ancillary service income load zone, this means that the mitigation level is at least 30%
5 below current best estimates.

6 Q ARE THESE THE EXACT RESULTS THAT YOU WOULD EXPECT?

7 A No, these are only approximations based on the public data available via the State of the
8 Market Reports and using only the day ahead versus real time comparison, not the
9 uniform sequential dispatch that I recommend. My understanding is that the IMM has all
10 this information and can readily produce exact results.

11 Q DOES THIS CONCLUDE YOUR TESTIMONY?

12 A Yes.

²⁵ This uses the PJM Proposal Attachment D result. Note that in Attachment D the PJM value for Zone 1 real time energy margins is \$104,964, and the 2009 State of the Market Report values from table 3-16 as displayed in P3 Exhibit 4-A show a three year average real time value of \$103,324.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

)

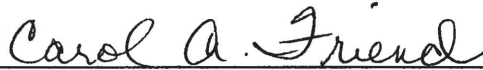
Docket No. ER11-2875-000

I, Roy J. Shanker, being duly sworn, depose and state that the contents of the foregoing Testimony on behalf of the PJM Power Providers Group is true, correct, accurate and complete to the best of my knowledge, information, and belief.



Roy Shanker

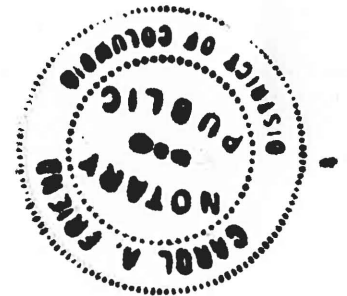
SUBSCRIBED AND SWORN to before me this 1st day of March 2011.



(Notary Public)

My commission expires: _____

CAROL A. FRIEND
A Notary Public of District of Columbia
My Commission Expires 2/28/14



DIFFERENCE IN DAY AHEAD VERSUS REAL TIME ENERGY MARGINS FOR COMBINED CYCLE
(SOURCE IMM 2009 STATE OF THE MARKET REPORT: TABLES 3-7,3-16)

Cone Area	RT				DA				\$ PER MW YR	\$PER MW DAY
	2007	2008	2009	3 YR AVG	2007	2008	2009	3 YR AVG	(DA-RT)	(DA-RT)
AECO	\$ 107,344	\$ 154,085	\$ 48,544	\$ 103,324	\$ 83,745	\$ 115,974	\$ 51,240	\$ 83,653	\$ 19,671.33	\$ 53.89
PSEG	\$ 105,692	\$ 119,564	\$ 47,113	\$ 90,790	\$ 87,724	\$ 106,457	\$ 47,111	\$ 80,431	\$ 10,359.00	\$ 28.38
JCPL	\$ 108,661	\$ 126,738	\$ 50,649	\$ 95,349	\$ 85,349	\$ 112,307	\$ 50,315	\$ 82,657	\$ 12,692.33	\$ 34.77
PECO	\$ 89,797	\$ 102,673	\$ 44,636	\$ 79,035	\$ 70,234	\$ 85,673	\$ 46,590	\$ 67,499	\$ 11,536.33	\$ 31.61
RECO	\$ 103,158	\$ 108,670	\$ 43,137	\$ 84,988	\$ 85,050	\$ 96,618	\$ 41,780	\$ 74,483	\$ 10,505.67	\$ 28.78
DPL	\$ 99,001	\$ 117,134	\$ 52,338	\$ 89,491	\$ 74,526	\$ 101,261	\$ 52,846	\$ 76,211	\$ 13,280.00	\$ 36.38

P3 COMPLAINT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group

v.

PJM Interconnection, L.L.C.

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Docket No. EL11-____-000

*COMPLAINT AND REQUEST FOR CLARIFICATION
REQUESTING FAST TRACK PROCESSING*

Glen Thomas
President
PJM POWER PROVIDERS GROUP
1060 First Avenue
Suite 400
King of Prussia, PA 19406
(610) 768-8080

John N. Estes III
Paul F. Wight
Carl Edman
SKADDEN, ARPS, SLATE, MEAGHER & FLOM LLP
1440 New York Avenue, N.W.
Washington, DC 20005
(202) 371-7000

Counsel for the PJM Power Providers Group

February 1, 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group)	
)	
v.)	Docket No. EL11-___-000
)	
PJM Interconnection, L.L.C.)	

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group)	
)	
v.)	Docket No. EL11-____-000
)	
PJM Interconnection, L.L.C.)	

*COMPLAINT AND REQUEST FOR CLARIFICATION
REQUESTING FAST TRACK PROCESSING*

PJM Power Providers Group (“P3”) hereby files this complaint seeking critical revisions to the fatally flawed buyer-market-power mitigation provisions in PJM’s Open Access Transmission Tariff.¹ The Commission repeatedly has affirmed the need to fully mitigate buyer market power, just as it repeatedly has fully mitigated seller market power. When it approved the PJM capacity market—known as RPM—the Commission obviously thought it was imposing an effective buyer-side mitigation regime. It now is apparent, however, that there are fatal—and unjust, unreasonable, and unduly discriminatory—flaws in the governing tariff scheme. We propose to repair these flaws with tariff changes largely tracking the Commission’s recent order improving NYISO’s buyer mitigation regime. In support, we offer the attached, at P3 Exhibit 1, testimony of Dr. Roy Shanker. We expect PJM to make a section 205 filing proposing similar mitigation measures in the very near future—a case that should be consolidated with this one.

By promptly granting our complaint, the Commission will maintain the efficacy of competitive capacity markets—markets the Commission itself created in order to benefit consumers by ensuring resource adequacy at the lowest possible cost. This will help provide all

¹ P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly designed and well-functioning electricity markets in the PJM region. Combined, P3’s twelve member companies own over 80,000 megawatts of power and over 51,000 miles of transmission lines in the PJM region, serve nearly 12.2 million customers and employ over 55,000 people in the 13-state and District of Columbia PJM region. The content of this complaint represents the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue. For more information on P3, please visit www.p3powergroup.com.

stakeholders with just, reasonable and non-discriminatory rates. In particular, prompt Commission action will create lower costs for consumers over the long term. It also will encourage effective load management programs. In fact, without meaningful relief, demand response resources face severe revenue losses, possibly forcing them to exit the market—elbowed aside by uneconomic and unneeded generating resources installed to exercise buyer market power.

We seek fast-track treatment in order to have the most critical revisions in place by mid-April 2011, *before* the next RPM auction is held. Other changes are, we submit, ultimately required in order to have a just, reasonable and non-discriminatory buyer mitigation regime. But we propose a “phasing” approach in order to facilitate prompt action on the items that are most important to ensure just, reasonable and non-discriminatory outcomes in the May 2011 auction. In the next section of this pleading, we explain the precise breakdown of issues needing immediate action versus those that can be deferred. In a nutshell, the Commission should revise the core mechanics of the mitigation regime: (1) how to screen for uncompetitive offers (the correct measure is 100% of the benchmark), (2) whether to have an impact screen (there should *not* be one), (3) how to re-price uncompetitive offers (100% of the benchmark is, again, the right answer), and (4) the duration of mitigation (mitigation should last, as in NYISO, until a resource demonstrates that it is competitive by clearing two auctions at competitive offer levels). All of these flaws in the existing mitigation regime need to be fixed at the same time, because a failure to resolve any one of them will render the entire scheme ineffective. When it comes to the core mechanics of buyer mitigation, the scheme as a whole is only as strong as its weakest link.

Ultimately this revised regime should apply to all capacity resources; anything less is unjust, unreasonable and unduly discriminatory. But for the next auction, we propose to apply

the revised mitigation regime only to combustion turbines and combined cycle resources. This phasing approach will leave certain more contentious issues, such as mitigation of renewable and demand response resources, for subsequent consideration. These deferred issues are critical to the long-term viability of the capacity market, but the Commission need not give them any substantive attention at this point in time. The Commission should, instead, order PJM to make a compliance filing addressing these issues, after a stakeholder process, on a time frame designed to ensure that additional tariff changes are put into effect before the May 2012 auction.

SUMMARY

Prompt action is critical because the State of New Jersey has just enacted legislation designed to procure, in a discriminatory manner, up to 2,000 MW of new generation that must be offered into PJM's capacity market at prices low enough to guarantee clearing. *See* S. No. 2381, 214th Leg. (N.J. 2011) ("New Jersey Law"), attached as P3 Exhibit 2. This potential new entry is not supported by market economics. As we explain in detail below, there is a surplus of generation in PJM. In addition, PJM's new energy forecasts show that demand for electricity has decreased substantially. Strikingly, PJM now predicts that New Jersey will not reach the demand previously forecasted for 2014 until at least 2020. PJM, Load Forecast Report at tbl.B-1 (Jan. 2010), <http://www.pjm.com/~media/documents/reports/2010-load-forecast-report.ashx>. The New Jersey Law is not need-based, because there is no need. Instead, the goal of the legislation is to artificially suppress capacity clearing prices for many years into the future. The total financial impact of adding 2,000 MW of unneeded, uneconomic generation is profound—totaling *\$2 billion in the first year alone*, with artificial price suppression continuing until the uneconomic capacity has been fully absorbed (by load growth and the premature retirement of otherwise economic resources). And there currently is nothing to prevent the recurrence of similar conduct again and again.

The Commission would never stand aside if alerted to alleged supplier conduct that could, without prompt corrective action, artificially inflate clearing prices by many billions of dollars. And it should not stand aside here. It should, instead, immediately grant fast-track treatment, and then grant the relief we seek—in time for the revised mitigation scheme to be in place for the May 2011 auction.

While the New Jersey Law is the triggering event driving expedited action here, unfortunately it is not unique. Buyer market power has proven to be a recurring and pervasive phenomenon in organized capacity markets. Maryland has, in fact, already announced a process that looks very much like New Jersey's exercise of buyer market power. *See In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, No. 9214, Request for Proposals for Generation Capacity Resources Under Long-Term Contract (M.P.S.C. Dec. 29, 2010) ("Maryland RFP"), attached as P3 Exhibit 3 (without attachments). Much as with New Jersey, the PJM market monitor has estimated that if 1,800 MW of subsidized uneconomic entry were to respond to this proposal, auction price outcomes would be artificially suppressed by more than \$1 billion in the first year alone.

According to the market monitor, the New Jersey and Maryland schemes in tandem have the potential to dramatically suppress clearing prices in PJM:

The Market Monitor's analysis indicates that adding 1,800 MW of installed capacity in the Pepco zone in Maryland, paying it through an out of market subsidy, and requiring it to offer at zero would result in a reduction in capacity market revenues to PJM suppliers of more than one billion dollars per year, including about 92 million dollars in Pepco. If the New Jersey legislation is approved and the proposed RFP is implemented, *the joint result would be a reduction in capacity market revenues to PJM suppliers of more than three billion dollars per year. ...*

This substantial reduction in revenue would affect the investment decisions of current owners of capacity and potential investors in capacity both in and outside of Maryland. The likely result is less investment in capacity. Depressing the price in Maryland would also mean that the required direct subsidy by Maryland

ratepayers would increase with perhaps significant unintended consequences for the business and residential customers who would have to pay the subsidy.

In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Serv., No. 9214, Comments of the Independent Market Monitor for PJM at 4 (M.P.S.C. Jan. 28, 2011) (“Market Monitor Maryland Report”) (emphasis added), http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf. In total, clearing prices under this scenario would be artificially suppressed by between approximately 35 and 40%. *Id.* at 13, 14.

As in New Jersey and Maryland, in most, if not all, instances, state governments and regulators are the driving force behind the exercise of buyer market power. The goal of these efforts is to drive costs lower in the short run. But the results are hardly benign. As the Commission has recognized, if prices are suppressed below competitive levels, society as a whole is worse off. *See, e.g., Amaranth Advisors*, 120 FERC ¶ 61,085 (2007) (“*Amaranth*”); *Energy Transfer Partners*, 120 FERC ¶ 61,086 (2007) (“*ETP*”).² The suppression of capacity auction prices creates inefficiencies that harm the public interest in general, the market, and consumers in particular. *See generally* Shanker at 16:3–18:15. If prices are suppressed below what would occur in a workably competitive market, society will have the wrong level of investment, coupled with the wrong retirement and consumption decisions. Investment decisions

² “The direction in which the manipulative conduct moves the price is immaterial to its legality.” *ETP*, 120 FERC ¶ 61,086 at P 31. The Commission’s rationale is equally applicable in market design as in enforcement cases: uncompetitive prices, high or low, ultimately hurt markets *and consumers*. *See id.* (“The academic literature takes a similar view; making no distinction between the harms resulting from upward or downward manipulations. These harms may include: *deadweight losses due to distortions in consumption, production, storage, and transportation, as well as a reduction in hedging effectiveness, and a decline in market liquidity.*”) (emphasis added); *Amaranth*, 120 FERC ¶ 61,085 at P 123 (“The harm to consumers from an upward manipulation is immediate. Harm from downward manipulation is more long term. ... Policing market behavior is about protecting the interest of *all participants, sellers and consumers alike.*”) (emphasis added). And the harm to society is the same irrespective of whether the price distortion is due to the exercise of market power or to market manipulation.

that would have been made at price outcomes produced by a workably competitive market will not, in fact, be made. *See id.* at 19:1-9.

In the long run, without effective mitigation, the exercise of buyer market power will sound the death knell of competitive markets—and with them the cost savings that markets create for consumers. *See id.* at 19:15-18. Competitive new entry—which is required to efficiently replace retiring plants and satisfy long-term load growth—can occur only if revenues from all of the bulk power markets are compensatory on an all-in basis. And capacity markets make an important contribution to the overall revenue stream needed to support new entry by compensating, among other things, for the effect of price caps in the day-ahead and real-time energy markets.

As the Commission repeatedly has observed, however, market participants will not commit capital to build new plants unless they believe that capacity markets will be allowed to operate as designed, and, over time, *average* the actual net cost of new entry. And this, of course, necessarily means that sometimes capacity prices will need to be *above* the net cost of new entry (when capacity is short) and sometimes *below* that level (when capacity is long).

If the Commission were to allow the unmitigated exercise of buyer market power, it would completely contradict the fundamental design and purpose of capacity markets. Buyer market power would produce a surplus of capacity resources by building unneeded capacity on an uneconomic basis. And that, in turn, would keep capacity prices permanently *below* the cost of new entry. All existing suppliers would be paid this artificially suppressed price, while a favored subset of suppliers would be paid higher prices on an uneconomic and unduly discriminatory basis.

The unmitigated exercise of buyer market power thus would start a vicious cycle that would eliminate competitive entry, ultimately destroying power markets—and the benefits they create for consumers. If auction clearing prices were to be artificially suppressed below the cost of new entry, then, by definition, the only way that new entry would occur is if it were supported by subsidies from consumers. Competitive suppliers would be unable to enter because prices would never reach competitive levels. And even subsidized entry would occur at elevated prices, because each new entrant would need to charge a risk premium—a deadweight loss to society—reflecting the fact that, once its subsidy ended it no longer would be a favored new entrant, and thus would be paid artificially suppressed prices along with all other existing suppliers. Efficient load management programs would disappear. Ratepayers would have to take the full ownership risk of new resources (including the risk of technology becoming outmoded). States that would have preferred to reap the long-term cost savings that markets bring would, instead, see their costs inflated above competitive levels by states that have chosen to exercise buyer market power. And the ongoing artificial suppression of capacity prices would effectively expropriate the investments of existing suppliers. *See* Shanker at 16:3-16, 18:11–19:18.

Given appropriate intent, and assuming a valid factual basis, buyer-side price suppression could constitute market manipulation under section 222 of the Federal Power Act, 16 U.S.C. § 824v. Certainly that was the analysis set forth in the *Amaranth* and *ETP* Show Cause Orders. There the allegations were that someone sold a commodity at an uneconomically low price, with the intent of reducing the prevailing price in a way that created countervailing profits in related transactions. Here we have load interests contracting for the construction of new capacity when there already is a surplus of existing supply, and then offering that capacity into the market at prices well below its actual cost, for the express purpose of reducing the price paid for all other

capacity supplies. We are not asking the Commission to determine whether this constitutes market manipulation. Instead we offer the obvious point that the market design should not create incentives for such conduct. The harm to the market is the same whether load interests are exercising buyer market power or actually engaging in market manipulation. And in either event, the price outcomes are unjust, unreasonable and unduly discriminatory—hence this complaint.³

We expect the primary opposing arguments to be that fully mitigating the exercise of buyer market power will (1) increase costs (at least in the short run), (2) interfere with state resource planning decisions, and (3) prevent states from contracting for new entry to ensure reliability. None of these arguments holds water.

First, paying capacity prices that, on average and over time, equilibrate around the actual net cost of new entry, is, at bottom, a bedrock cost (along with transmission) of the bulk power system. Similar costs would be expected in a vertically integrated context, without the efficiencies that markets bring. To see this, we need look no further than American Electric Power Service Corporation’s “cost-based” capacity tariff filing, which the Commission recently rejected. *Am. Elec. Power Serv. Corp.*, 134 FERC ¶ 61,039 (2011). There American Electric Power proposed a “cost-based” capacity rate of \$388/MW-day—well above RPM clearing prices, which have ranged from \$247.12/MW-day (in the PEPCO Locational Deliverability Area) to \$27.73/MW-day (in the unconstrained part of PJM).

³ This Complaint seeks to fix flaws in the buyer-side market power mitigation provisions in PJM’s Tariff. It does not address any issues concerning the legality of the New Jersey statute or any other state statute, issues that are beyond the scope of this Complaint. The Complaint likewise does not address any harm the New Jersey statute may cause to competitive power markets, other than the harm to the capacity market discussed herein.

Additionally, because the New Jersey Law requires generators selected by the state to “participate in and clear the annual base residual auction conducted by PJM” in violation of the Minimum Offer Price Rule, this complaint constitutes an administrative challenge within the meaning of section 4 of the Bill. New Jersey Law at 20.

The exercise of buyer market power gives the illusion of cost savings because the core strategy is to pay a price that reflects the cost of new entry only to new entrants, while paying existing suppliers much less. But as the Commission repeatedly has held, that would violate the Federal Power Act's prohibition against unduly discriminatory rates. It also would produce rates that are well below just and reasonable levels. And it is not how competitive markets work; in competitive markets all suppliers of fungible products receive the same price (a fundamental principle of economics called the "Law of One Price"). This produces the lowest prices, over the long term, for consumers. *See* Shanker at 16:17–17:6; Market Monitor Maryland Report at 4.

Second, effective wholesale buyer market power mitigation does not interfere with choices that states traditionally have been free to make about resource planning, including a choice to favor specific resource types. Within the limits posed by applicable Constitutional limitations, and the Commission's exclusive wholesale jurisdiction, states remain free to exercise their authority over generation facilities, determining whether or where to site generation of various types. They also remain free to sponsor new entry by generation facilities, even if uneconomic by any rational measure. Effective mitigation does not preclude state-sponsored entry.

All effective mitigation does is protect organized capacity markets from harm caused by any entity artificially suppressing wholesale price outcomes. Legitimate state-sponsored entry can occur, but its offers into the capacity market will be mitigated and, once mitigated, might not clear the auction. The Commission has exclusive jurisdiction over capacity markets, and taking steps to ensure that capacity prices are just, reasonable and non-discriminatory—thus producing lower costs for consumers in the long run—is at the core of its statutory mandate. *N.Y. Indep. System Operator*, 122 FERC ¶ 61,211 at P 111, *order on reh'g*, 124 FERC ¶ 61,301 (2008),

order on reh'g and clarification, 131 FERC ¶ 61,170 (2010). Conversely, declining to impose effective mitigation essentially would turn wholesale price-setting over to the states, contradicting the Federal Power Act and controlling court and agency precedent.

Underscoring the flexibility states have in resource planning, the PJM market design includes a Fixed Resource Requirement (“FRR”) option, which allows a state or region to decide to fully plan for all of its resource requirements. As a result, if a state truly thinks that the PJM capacity market is not meeting its needs, it can steer its own course through the FRR option. The one path it *cannot* take is (1) to selectively procure uneconomic resources to meet some of its needs, (2) to buy the rest of its capacity needs through the RPM auctions, and (3) to arrange for the subsidized resources to offer into the auctions on terms that artificially suppress price outcomes. Effective buyer-side mitigation firmly blocks that course of action—just as it should.

Finally, there is no basis for any claim that uneconomic entry is needed to maintain reliability—a contention made in the New Jersey Law. It is odd to see New Jersey make such a claim, given the case the New Jersey Board of Public Utilities and the Maryland Public Service Commission just finished briefing and arguing in the Court of Appeals for the D.C. Circuit, seeking to reset earlier RPM auction outcomes. As Dr. Shanker explains in his testimony, Shanker at 37:10-16, one argument these parties made to the Commission in the underlying proceeding was that PJM’s reliability standards are too strict, overstating the need for new entry. *See Md. Pub. Serv. Comm’n v. PJM Interconnection*, 124 FERC ¶ 61,276 at P 12 (2008), *reh’g denied*, 127 FERC ¶ 61,274, *appeal docketed sub nom. Md. Pub. Serv. Comm’n v. FERC*, D.C. Cir. No. 09-1296 (filed Aug. 14, 2009) (oral argument held Nov. 15, 2010). This contention always was misguided. Nonetheless, as the Commission has observed, RPM has been quite successful in attracting resources of many types, from demand response, to imports, to deferred

retirements, to new capacity additions, and so forth. *See id.*, 127 FERC ¶ 61,274 at P 23 & n.25. There is no looming reliability crisis. To the contrary, as noted above, PJM's most recent load forecast confirms that demand will only increase modestly over the next decade. PJM, Draft Load Forecast Report at tbl.B-c2 (Dec. 28, 2010), <http://www.pjm.com/~media/committees-groups/subcommittees/las/20110104/20110104-draft-load-report.ashx>.

While we have not seen PJM's capacity market attract material new green-field generation development, this reflects the simple and undeniable fact that auction clearing prices have not been high enough to support new green-field entry. We would expect new green-field entry only when prices are *at or above* the nominal levelized actual net cost of new entry, and are expected to average that level over the long term. But in constrained regions in PJM, prices have more often been below the actual net cost of new entry, and the pendency of some large transmission projects in the Eastern Mid-Atlantic Area Council ("EMAAC") region indicates that prices within that zone may drop in the future. *See Shanker* at 36:5-10. In addition, as noted above, according to PJM's most recent load forecast, demand levels formerly expected in New Jersey by 2014 now are not projected to materialize until at least 2020. And now that the New Jersey Law has highlighted the clear loopholes in PJM's buyer market power mitigation scheme, market-based entry will be further chilled by the prospect of uneconomic entry artificially suppressing future price outcomes:

I would expect the cost impacts to be spread more over time, but it appears that serious cost impacts have already begun. According to the January 28th release of Megawatt Daily (dated Jan 31, 2011), in an article on the likely impact of New Jersey's legislation, "Moody's said the potential in the long term is for the bill to be a material credit negative primarily to the unregulated power sector within New Jersey." As it turns out, this statement turned out to be issued on the same day that the New Jersey Governor signed the bill. I would expect markets to immediately react to these types of comments, driving down the value of stock and debt in the unregulated power sector, and in turn increasing the costs of funds to investors in electric utility infrastructure.

Shanker at 42:4-13. There is, in short, no economic basis for large-scale market-based new entry. It thus is no surprise that we have not seen such entry occur.

In sum, PJM's existing buyer market power mitigation scheme is fatally flawed and unjust, unreasonable and unduly discriminatory. Our proposed changes are just, reasonable and non-discriminatory. The Commission therefore should, at the outset, grant fast-track status. There is, in particular, no time for any stakeholder process, and all PJM market participants have been well aware that filings to fix the buyer market power mitigation scheme were close at hand. The Commission then should grant our complaint on an expedited basis, in time to allow mitigation to be strengthened before the next auction in May.

Alternatively, if the Commission were to decline to grant the expedited relief we seek—an outcome we would *not* consider consistent with the Commission's statutory mandate, or with the public interest—we set forth a request for clarification at the end of this pleading that could provide some measure of protection for the May 2011 auction, though nowhere near as effective as the tariff changes we seek.

OVERVIEW OF THE EXISTING TARIFF AND THE CHANGES WE SEEK

The PJM's Minimum Offer Price Rule has three stages. *First*, conduct screens are run to see whether mitigation will be triggered. *See generally* Shanker at 8:19–10:2. The conduct screen looks at each offered resource and reviews whether it offered below a specific threshold for an expected economic offer for new resources, or whether it proved to the Commission that it bid only its costs (minus PJM market revenues). If *either* of these conditions is met, the conduct screen is passed and the resource is not even evaluated for mitigation. *Second*, an impact screen is also conducted by rerunning the auction with mitigated offers to measure the effect of an uneconomic offer on market prices. The screen is passed unless the impact is large. *Third*, if

both conduct and impact screens are failed, the uneconomic offer is mitigated (increased) to a competitive level for *one auction*.

We summarize the problems with this scheme below, along with our proposed solutions. We first address the issues that need to be resolved by mid-April 2011. We then address the issues that can be deferred.

I. IMMEDIATE ISSUES

A. Scope

In order to facilitate Commission action by mid-April 2011, we propose, for the next auction only, to apply the mitigation measures set forth below only to combustion turbine and combined cycle resources.

B. The Conduct Screen

Under the conduct screen currently employed in PJM, offers are mitigated only if they are less than 80% of the real, levelized net cost of new entry for the “asset class” of similar resources (as calculated by PJM). If there is no asset class, offers are mitigated only if they are less than 70% of the net cost of new entry of a combustion turbine. As Dr. Shanker explains, this effectively *caps* market prices substantially *below* the levels they need to *average* in order to support new entry. *See* Shanker at 20:22–21:21.

We propose the following changes to the current conduct screen employed in PJM: Any resource would pass the conduct screen if its offer is at least 100% of the net cost of new entry of its asset class. A resource offering below this threshold still would pass the conduct screen by making either of the following two alternative showings:

First, a resource should be deemed to have passed the screen, and thus not be mitigated, if it demonstrates that it is offering at its nominal, levelized unit-specific costs—and thus is economic. The market monitor would make these determinations in the first instance, although a

resource could seek review by PJM. Both the market monitor and the resource could seek Commission review of any mitigation decision.

Second, in lieu of this review process, any resource, of any type, will be deemed to have passed the screen, and thus not be mitigated, if it establishes that it has not received any discriminatory payments, as determined at the time of the offer.

C. The Impact Test

Under the current tariff, if the conduct threshold is failed, then the impact test is applied. This test in effect reruns the auction to measure the impact that a mitigated offer would have on capacity clearing prices. Offers are mitigated only if there is at least a \$25/MW-day or 20 to 30% change in clearing prices (depending on the size of the zone). *See* RPM § 5.14(h)(3). The impact standard allows material, artificial price suppression without any justification. *See* Shanker at 25:12-14.

We propose simply to delete the impact screen. All offers that fail the conduct screen should be mitigated, regardless of impact on the clearing prices. This also has the side benefit of eliminating any need to rerun the auctions to determine whether to mitigate, which will greatly simplify the process.

D. Mitigating Resources

Under the current tariff, any short-lead-time resource that fails the screens has its offer mitigated to 90% of the asset class cost of new entry. If there is no asset class, the offer is mitigated to 80% of the net cost of new entry. And there is an exception that removes all long-lead-time units from mitigation. *See* RPM § 5.14(h)(3). Again, this allows material, artificial price suppression without any justification. *See* Shanker at 21:14–25:2.

Under our proposal, uneconomic offers are mitigated to 100% of the nominal levelized unit-specific cost of new entry of the offering resource.

E. Terminating Mitigation

Under the current tariff, mitigation ends after only one auction, regardless of whether the resource clears or not. *See* RPM § 5.14(h)(4). We propose to continue the mitigation at least until the entrant has cleared in two auctions. As Dr. Shanker explains, clearing in two base residual auctions is the closest approximation to the Commission’s recently approved standard for New York. Shanker at 57:12-21 & n.45.

In this same vein, the Minimum Offer Price Rule also has a sunset provision under certain conditions. We propose to eliminate that provision.

F. Exemptions to Mitigation

The current Minimum Offer Price Rule contains a number of exemptions. *See* RPM § 5.14(h)(1). We propose to immediately eliminate the following ones:

- (1) the exemption for resources who are not deemed to be “net buyers”;
- (2) the exemption for self-supply;
- (3) the exemption for certain state-sponsored projects; and
- (4) the exemption for resources that are not “Planned Generation Capacity Resources.”

II. DEFERRED ISSUES

We propose to defer the following issues, to be addressed in a subsequent PJM compliance filing:

- (a) We submit that all resources, without exception, should be subject to buyer market power mitigation. This encompasses within it the questions whether mitigation should, as we submit, apply to (1) long-lead-time resources, (2) demand response resources, (3) renewable resources, and (4) uprates to existing units.
- (b) In addition, if, as we propose, mitigation is applied to long-lead-time resources, certain adjustments will need to be made. For short-term resources, a determination of whether the resource is offering economically is made shortly before the auction. For long-lead-time resources, this determination should be made much earlier, at the time the interconnection agreement is signed.

- (c) The existing tariff uses asset-class benchmarks. We submit that the better approach is to use the Reference Resource (a combustion turbine) cost of new entry—a figure used elsewhere in the market design.

BACKGROUND

I. THE CORE PRINCIPLES OF CAPACITY MARKET DESIGN

While capacity markets are barely ten years old, they have become an indispensable part of all three eastern RTOs. See *PJM Interconnection*, 115 FERC ¶ 61,079, *order denying reh'g and approving settlement*, 117 FERC ¶ 61,331 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,318 (2007); *Devon Power*, 113 FERC ¶ 61,075 (2005), *order approving settlement*, 115 FERC ¶ 61,340, *order on reh'g and clarification*, 117 FERC ¶ 61,133 (2006), *aff'd in relevant part sub nom. Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464 (D.C. Cir. 2008), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 130 S. Ct. 693, *remanded by Me. Pub. Utils. Comm'n v. FERC*, 625 F.3d 754 (D.C. Cir. 2010); *N.Y. Indep. Sys. Operator*, 103 FERC ¶ 61,201, *reh'g denied*, 105 FERC ¶ 61,108 (2003); *N.Y. Indep. Sys. Operator*, 89 FERC ¶ 61,109 (1999), *order on reh'g and clarification*, 90 FERC ¶ 61,085 (2000). Even outside the RTOs, no control area operates without the equivalent of some mandated adequacy requirement, either directly or indirectly.

Capacity markets exist in order to cure the inefficiencies that occur whenever there are energy price caps, the need to achieve minimum requirements for installed capacity, and a desire to reduce volatility in cash flows for both generators and load in order to reduce the risk of price fluctuations reflected in the cost of capital. See *PJM Interconnection*, 115 FERC ¶ 61,079 at P 104 (noting the Commission's preference for designs that reduce price volatility). Ultimately, consumers benefit through more efficient market outcomes that result in lower consumer charges over the long run. See *PJM Interconnection*, 117 FERC ¶ 61,331 at P 141.

Arising out of this decade-long experience with capacity constructs are four general requirements for capacity markets to succeed, each based on bedrock economic theory and anchored in established Commission precedent. These requirements have become the screening criteria to consider initial capacity market design and design changes.

First, on average and over time, compensation needs to be sufficient to attract new entry and retain economic existing generation. *See ISO New England*, 125 FERC ¶ 61,102 at P 43 (2008), *reh'g denied*, 130 FERC ¶ 61,089 (2010). This means that on average and over time, the recovery from the bulk power markets for energy and capacity must result in payments equal to the net cost of new entry. *See Blumenthal v. ISO New England*, 117 FERC ¶ 61,038 at PP 82-87 (2006), *reh'g denied*, 118 FERC ¶ 61,205 (2007), *petition for review denied sub nom. Blumenthal v. FERC*, 552 F.3d 875 (D.C. Cir. 2009); *Devon Power*, 115 FERC ¶ 61,340 at P 114. Hence, if prices will be lower than average some of the time, they must be higher than average during other periods.

Second, capacity markets need to include locational and reliability price signals to reflect the fact that capacity in certain congested areas potentially has greater value than capacity located elsewhere. *See PJM Interconnection*, 119 FERC ¶ 61,318 at P 76; *Devon Power*, 103 FERC ¶ 61,082 at P 37 (2003). Capacity with attributes that provide for a differential reliability benefit should be recognized in the market design and compensated accordingly. This minimizes or eliminates the need for non-market arrangements such as Reliability-Must-Run contracts.

Third, all competitive resources within a given location need to be compensated at the same price. *See PJM Interconnection*, 117 FERC ¶ 61,331 at P 141; *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005), *reh'g denied*, 115 FERC ¶ 61,133 (2006); *Devon Power*, 110 FERC ¶ 61,315 at P 45 (2005); *N.Y. Indep. Sys. Operator*, 110 FERC ¶ 61,244 at P 65 & n.76,

order on reh'g, 113 FERC ¶ 61,155 (2005); *N.Y. Indep. Sys. Operator*, 103 FERC ¶ 61,201 at P 81. The law of one price for similarly-situated competitive units is a basic economic building block; price discrimination among competitive supply is inefficient and in the long run will increase costs. See *Blumenthal v. ISO New England*, 117 FERC ¶ 61,038 at P 83. Some exceptions might, however, be appropriate or necessary under circumstances where market power exercise and uneconomic entry already have distorted conditions. See *id.*

Fourth, the exercise of market power by both sellers and buyers needs to be mitigated to ensure that prices are neither artificially inflated nor artificially suppressed. See *N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at PP 32, 100; *Edison Mission Energy v. FERC*, 394 F.3d 964, 968-70 (D.C. Cir. 2005); *Midwest Indep. Transmission Sys. Operator*, 111 FERC ¶ 61,043 at P 78, *order on reh'g*, 112 FERC ¶ 61,086 (2005), *aff'd sub nom. Wisc. Pub. Power v. FERC*, 493 F.3d 239 (D.C. Cir. 2007). The exercise of market power by either side of the market is destructive for competition and long-term consumer welfare. See *Devon Power*, 115 FERC ¶ 61,340 at P 114.

II. COMMISSION PRECEDENT ON THE MITIGATION OF CAPACITY BUYER MARKET POWER

As noted above, each RTO with an organized capacity market has tariff provisions that seek to thwart exercises of buyer market power. They all work in a similar way. First they identify offers for capacity that are substantially below those that a competitive market participant would make. Then they mitigate those offers by repricing them to reflect an estimate of the price at which a competitive market participant would have offered the resource. Finally, the capacity auction is re-run with the substitute, competitive offers and the auction clearing price and capacity obligations are allocated accordingly. See *Shanker* at 9:5–10:2.

A brief review of the Commission orders addressing these provisions is instructive here.

With respect to the NYISO In-City Installed Capacity Offer Floor, the Commission has held:

We accept NYISO's proposal for net buyer mitigation, with modifications, in order to prevent uneconomic entry that would reduce prices in the NYC capacity market below just and reasonable levels.

Large net buyers may have both the incentive and the ability to depress prices through uneconomic entry. ... A large net buyer could acquire new capacity that is not needed in the market and whose costs exceed the market price. Such an investment would be inefficient, the net buyer would lose money on the capacity, and no rational seller would knowingly make such an investment. But the investment could benefit the net buyer because the additional capacity could reduce the market price for capacity and lower the net buyer's total capacity bill. If the newly added capacity represents only a portion of the net buyer's total capacity needs, the reduction in the buyer's total capacity bill caused by the lower prices could more than offset the loss on the newly added capacity investment. As a result, a large net buyer could have an incentive to make such an inefficient investment. However, this would result in the [load-serving entity's] captive ratepayers bearing the risk of uneconomic investment. The mitigation of net buyers' sales of capacity proposed by NYISO should help avoid this.

N.Y. Indep. Sys. Operator, 122 FERC ¶ 61,211 at PP 100-01. *See id.* at P 104 (“The Commission has accepted similar provisions to prevent uneconomic entry by net buyers in approving long-term capacity markets in both PJM and ISO-New England.”) (citations omitted). The Commission subsequently excised the net-buyer requirement from the NYISO In-City Installed Capacity Offer Floor. *See infra* at 46.

Similarly, with respect to ISO-NE's Alternative Price Rule, the Commission explained that:

[The rule] is a market power mitigation rule intended to discourage buyers who have the incentive and ability to suppress market clearing capacity prices below a competitive level from doing so. We have previously accepted rules to address such uneconomic entry in the capacity markets of ISO-NE, as well as in NYISO and PJM.

ISO New England, 131 FERC ¶ 61,065 at P 69 (citing *Devon Power*, 115 FERC ¶ 61,340 at P 113 (for ISO-NE)), *order on reh'g and clarification*, 132 FERC ¶ 61,122 (2010); *N.Y. Indep.*

Sys. Operator, 122 FERC ¶ 61,211 at PP 100-06; *PJM Interconnection*, 117 FERC ¶ 61,331 at PP 103-04).

Finally, in approving the PJM’s capacity model, the Commission held that the Minimum Offer Price Rule:

addresses the concern that net buyers might have an incentive to depress market clearing prices by offering some self-supply at less than a competitive level. ... The Commission finds the Minimum Offer Price Rule a reasonable method of assuring that net buyers do not exercise monopsony power by seeking to lower prices through self supply.

PJM Interconnection, 117 FERC ¶ 61,331 at PP 103-04. *See also PJM Interconnection*, 126 FERC ¶ 61,275 at P 191 (noting that the “Commission has previously expressed concern that uneconomic entry can be used by certain buyers to depress market clearing capacity prices and has authorized [Minimum Offer Price Rule]-type rules.”), *order on clarification*, 127 FERC ¶ 61,104, *order on reh’g and clarification*, 128 FERC ¶ 61,157 (2009).

PJM’s market monitor shares this understanding:

The primary purpose of the Minimum Offer Price Rule in the PJM tariff is to prevent market participants from submitting uneconomic offers based on the receipt of out of market payments to artificially depress RPM auction prices. While it is unclear if the [Minimum Offer Price Rule] would apply to the offers that would result from the [New Jersey] legislation, those offers are not consistent with the intent of the [Minimum Offer Price Rule]. As a result of this ambiguity, we expect that the results of the upcoming RPM Base Residual Auction would be challenged by stakeholders whether the [Minimum Offer Price Rule] is applied to offers under the proposed legislation or not.

Letter from Andrew L. Ott, Senior Vice President, Markets, PJM Interconnection and Dr. Joseph E. Bowring, President, Monitoring Analytics to Lee A. Solomon, President, New Jersey Board of Public Utilities (Dec. 3, 2010) (“Bowring Letter”), http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM-MMU_Letter_to_NJ_BPU_20101203.pdf.

ARGUMENT

Our argument has four parts. *First*, we establish that the core mechanics of the existing buyer market power mitigation regime—the conduct and impact screens and the mitigation itself—are unjust, unreasonable and unduly discriminatory. *Second*, we establish that our proposed revisions to these core mechanics *are* just, reasonable and non-discriminatory (with two targeted issues to be deferred). *Third*, we establish that there should be no exceptions or loopholes in the mitigation rules, which all are easily exploited (with several targeted issues to be deferred). And *fourth*, we establish the need for expedition by setting forth the looming threat posed by the New Jersey Law.

I. THE CORE MECHANICS OF THE EXISTING MINIMUM OFFER PRICE RULE ARE UNJUST, UNREASONABLE AND UNDULY DISCRIMINATORY

The Minimum Offer Price Rule was adopted as part of the RPM Settlement, *PJM Interconnection*, 117 FERC ¶ 61,331, and—absent any major attempts to exercise buyer market power in RPM—has never been triggered. But in light of the recent New Jersey and Maryland schemes, discussed below at 57, its flaws now stand out in sharp relief. As we explain below, the core mechanics of the existing Rule are unjust and unreasonable for the following reasons:

- (a) the conduct screen is too lax, effectively capping the market substantially below the actual net cost of new entry;
- (b) the impact test permits massive downward price suppression;
- (c) the “replacement” offers substituted by the mitigation scheme effectively cap the market substantially below the actual net cost of new entry; and
- (d) limiting mitigation to one year renders the entire scheme ineffective.

Effective action on all of these issues is essential for an effective mitigation scheme, because the overall scheme is only as effective as the weakest link. We address each point in turn.

A. *The Benchmark Discounts in the Conduct Test Are Unjust, Unreasonable and Unduly Discriminatory Because They Effectively Allow Buyer Market Power to Cap Auction Prices at a Substantial Discount Below the Cost of New Entry*

The Minimum Offer Price Rule evaluates offers into RPM auctions to determine whether mitigation will be triggered. The conduct of the offering resource and the impact of the offers on clearing prices each are evaluated according to specific thresholds. And mitigation is triggered only if *both* the conduct and impact screens are failed. *See* Shanker at 9:5–10:2. As we establish below, the current screens unlawfully permit the exercise of buyer market power. To remedy this problem, as we explain in Section II of the Argument, the conduct screen should be set at 100% of the relevant benchmark.

Under the current Minimum Offer Price Rule’s conduct test, a resource’s offer is compared to a benchmark of 80% of the cost of the resource’s asset class, or, if there is no asset class estimate, to 70% of the cost of a combustion turbine. RPM § 5.14(h)(2)(ii). Any resource may be offered at any price down to this floor and will escape the Minimum Offer Price Rule completely.

The Minimum Offer Price Rule’s heavy discounts off of the applicable conduct benchmarks are unjustified and permit market participants to substantially, anti-competitively and artificially suppress auction price outcomes. They effectively invite and sanction anti-competitive offers well below the benchmark, but just above the identified thresholds. A competitive supplier would not offer new capacity resources at a price lower than cost (which is what the benchmarks are intended to reflect). But the mitigation floor permits offers up to 20 to 30% *below* expected long-run average costs. A would-be exerciser of buyer market power offering a sufficient amount of capacity at a 20 to 30% discount can depress auction clearing prices continually—*without* failing the test.

Load would hardly be satisfied with a seller-side market-power mitigation scheme that sanctioned sellers pushing capacity clearing prices *up* by 20 to 30% with impunity. Conversely, it is hard to see why buyer-side market-power mitigation should sanction pushing capacity clearing prices *down* by 20 to 30%. *See infra* at 29 (text and discussion of Dr. Shanker cited there).

B. The Impact Threshold Is Unjust, Unreasonable and Unduly Discriminatory Because It Permits Large Downward Price Distortions

Under the impact test, PJM is required to conduct a sensitivity analysis comparing the capacity clearing price with or without mitigation. This test, by its terms, exempts offers already found to be uncompetitively low whenever they suppress capacity prices by less than (1) \$25/MW-day or (2) 20 to 30% (depending on the size of the Locational Deliverability Areas). As we explain below, this provision eviscerates the entire mitigation scheme and thus is unjust, unreasonable and unduly discriminatory. As we explain in Section II of the Argument, our proposal properly remedies the problem by simply deleting the impact screen.

Some simple examples easily prove the problems caused by the impact test. Turning first to the unconstrained part of PJM, the \$25/MW-day exemption effectively means that there currently is *no* buyer market power mitigation in that region. For the 2012/13 Base Residual Auction, the capacity clearing price in the unconstrained portion of PJM was \$16.46/MW-day. *See* PJM, *2012/2013 RPM Base Residual Auction Results* at 1, <http://ftp.pjm.com/markets-and-operations/rpm/~media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx>. Under the current tariff, capacity buyers would have been free to suppress capacity prices all the way to \$0/MW-day, and, because of the impact threshold, the Minimum Offer Price Rule would have had done nothing to stand in the way.

We would see similar results for the 2013/14 Base Residual Auction, where the capacity clearing price in the unconstrained portion of PJM was \$27.73/MW-day and over 150,000 MW of Unforced Capacity cleared. See PJM, *2013/2014 RPM Base Residual Auction Result* at 1, <http://www.pjm.com/markets-and-operations/rpm/~//media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx>. Once again, under the current tariff, the effect of the impact threshold would have been equally grave. Capacity buyers could have used their market power to suppress capacity prices by almost 90%, to \$2.74/MW-day. Annual capacity compensation in the unconstrained portion could have been reduced by almost \$1.4 billion. Yet even this substantial impact would have been considered so *de minimis* that no mitigation would have been required.

The impact screen eviscerates mitigation just as effectively in the constrained Eastern Mid-Atlantic Area Council region, which includes New Jersey. In the 2013/14 Base Residual Auction, approximately 33,000 MW of Unforced Capacity cleared at \$245/MW-day in that region. *Id.* at 10. A 20% price suppression, as the impact threshold permits for a region this size, would have reduced the clearing price by up to \$49/MW-day. A price suppression of this magnitude would have reduced annual capacity compensation (and hence the market signals for new entry) in that region alone by over \$590 million. See Shanker at 26:8-15. And once again, this would have been considered *de minimis* under the impact threshold, and therefore unworthy of mitigation.

C. It Is Unreasonable to Mitigate—or Effectively Reprice—Offers to a Discount off of the Applicable Benchmark

The current Minimum Offer Price Rule mitigates uneconomic entry to “90 percent of the applicable estimated” Net Asset Class Costs of New Entry, “or, if there is no applicable estimated cost, ... to 80 percent of the then-applicable” net cost of new entry of the Reference

Resource. RPM § 5.14(h)(3). Once again, this provision is unjust and unreasonable because it allows artificial price suppression of between 10 to 20%. This itself is enough to make the exercise of buyer market power feasible and profitable. As we establish below, the proper course is to reset offers to 100% of the applicable benchmark. *See infra* at 29 (text and discussion of Dr. Shanker cited there).

D. It Is Unjust, Unreasonable, and Unduly Discriminatory to Limit Mitigation to One Year

1. Mitigating for Only One Year Is Effectively the Same as No Mitigation at All

The Minimum Offer Price Rule mitigates an uneconomic resource only “for the first Delivery Year in which [the resource] qualifies” as a Planned Generation Capacity Resource. RPM § 5.14(h)(2). This means that no resource will be mitigated for more than one Base Residual Auction. And this renders the Minimum Offer Price Rule, as currently constituted, a dead letter. As explained below, we propose to continue mitigation until a resource proves that it is economic by clearing in two Base Residual Auctions.

As Dr. Shanker notes, even the single-year mitigation limitation is easily circumvented by offering a resource into an auction at a very high price prior to the time when it is anticipated to be ready. *See Shanker* at 34:1-20. It then would fail to clear, and finish its one-year mitigation period close to its start-up date.

Even without such machinations, a one-year mitigation period does virtually nothing to remove the ability and incentive to exercise buyer market power. The resources used to artificially depress capacity prices have a useful life of several decades. An uncompetitive resource will depress capacity market clearing prices for every year it participates, not merely the first one. Mitigating such a resource for just one year will deter only the most feebly motivated attempts at market power exercise.

Moreover, the Minimum Offer Price Rule only mitigates sell offers made into *Base Residual Auctions*. Offers into Incremental Auctions are outside the scope of the Minimum Offer Price Rule. Any sponsored resource that was prevented from clearing in one Base Residual Auction by the Minimum Offer Price Rule will face no obstacles if offered into the subsequent Incremental Auctions for that same delivery year. While prices and volumes in the Incremental Auctions may be smaller than those in Base Residual Auctions, the exemption for Incremental Auctions still permits resources that are otherwise mitigated by the Minimum Offer Price Rule to begin to suppress prices (and earn some capacity revenues) even in the first year of operation. In short, the Minimum Offer Price Rule at best will prevent market power distortions in the *first* capacity auction for *one* delivery year. After that, buyer market power has free rein. And that is unjust, unreasonable and unduly discriminatory.

2. *The Commission Just Required NYISO to Mitigate Indefinitely Until a Market Test Is Met*

While the inadequacy of limiting buyer-side mitigation to no more than one auction for one year is almost self-evident, the Commission recently provided guidance that effective buyer-side mitigation in capacity markets must meet a far higher standard before mitigation can be terminated. *See N.Y. Indep. Sys. Operator*, 133 FERC ¶ 61,178 (2010), *reh'g pending* (“*NYISO*”).

In *NYISO*, the Commission considered a NYISO proposal to modify the length of time resources are mitigated under the NYISO’s In-City Installed Capacity Offer Floor, the Minimum Offer Price Rule’s more effective sibling. At the time of the filing, NYISO’s In-City Installed Capacity Offer Floor mitigated resources for “the longer of: (1) six capability periods (approximately three years) ... or (2) the period of years that it takes the demand for capacity to grow into available supply.” *Id.* at P 3 (footnote omitted). Under NYISO’s proposal, resources

would be mitigated “for a number of years equal to the shorter time period calculated using two alternative methodologies, with a maximum duration of 30 capability periods (approximately 15 years) and a minimum duration of six capability periods (approximately three years).” *Id.* at P 12. NYISO argued that otherwise “mitigation might last for decades and might even surpass the life of a new entrant’s facility,” and that this was “beyond what is needed to discourage any realistic uneconomic entry strategy.” *Id.*

The Commission rejected the NYISO proposal to cap the length of mitigation. *Id.* at PP 47-52.

[W]e do not agree with NYISO that a thirty capability period maximum is justified or linked to the need for buyer-side mitigation. NYISO justifies this maximum with the argument that a rational potential market entrant will not be willing to accept mitigation for such a long time-period on the uncertain hope that it will reap the benefits of uneconomic entry. This assertion may be true, but a thirty capability period maximum is arbitrary and not related to the central objective of buyer-side mitigation, which is prevention of uneconomic entry by those that have the ability and incentive to use uneconomic entry as a tool of price suppression.

Id. at P 51. Instead, the Commission held that any “resource [that] is not clearing in the market ... is uneconomic,” and ordered that “mitigation should continue, *regardless of how long* [the resource] has already been subject to mitigation.” *Id.* (emphasis added). The only way a resource should be able to escape mitigation is by proving that it is economic and by clearing at its mitigated price, which, for any economic resource, can be expected to happen in a capacity auction:

[W]e find reasonable NYISO’s proposal to have the duration of in-City buyer mitigation turn on actual acceptance of the resource’s capacity in the market at the offer floor[.] ... [S]ubject to a minimum period of mitigation of six capability period (approximately three years), mitigation would be lifted for a new in-City generation resource when ... the capacity clears in 12 monthly auctions at the offer floor.

Id. at P 49. A resource that clears only in part would be freed from mitigation only to the degree it cleared. *Id.*

The Commission’s reasoning and ruling in *NYISO* is doubly instructive in this case: *First*, the Minimum Offer Price Rule ceases mitigating resources after *at most* one year, regardless of whether the resource clears or not. In *NYISO*, even the proponents of relaxing NYISO mitigation only argued that *fifteen years* of mitigation were sufficient to extinguish economic motives for market power exercise, *see id.* at P 16, and even they supported a *floor* of at least *three years* of mitigation. *Id.* at P 17. The Commission rejected that fifteen-year time limit on mitigation as arbitrary, and instead permitted mitigation to continue indefinitely. *Id.* at P 51. The Minimum Offer Price Rule’s cap of at most one year falls far below the much higher level that the Commission held to be too little in *NYISO*. *Second*, the Commission adopted a market test for when to end mitigation. Resources that prove themselves economic by clearing at a competitive price are freed from mitigation. Resources that do not pass this test are mitigated without any time limit. The Minimum Offer Price Rule should adopt the same test, with slight adjustments for the technical difference between the NYISO and PJM auction procedures.

II. THE CORE MECHANICS OF OUR PROPOSED TARIFF CHANGES ARE JUST, REASONABLE AND NON-DISCRIMINATORY

We propose several reforms to strengthen the Minimum Offer Price Rule. On the mitigation triggers, we propose to appropriately tighten the conduct screen and to eliminate the impact screen. We also propose to increase the mitigated-to price and to extend the mitigation period using a market-based clearing criterion. We also provide an example of what a revised, effective Minimum Offer Price Rule should look like. *See* Attachment A (“Revised MOPR”).

A. A Revised Minimum Offer Price Rule Should Revise the Conduct Screens

In order to effectively control buyer market power, consistent with the mitigation of seller-side market power and other parts of the Minimum Offer Price Rule, the thresholds for buyer-side mitigation should be revised as follows. We propose a revised conduct screen to measure whether mitigation should be triggered. *See* Revised MOPR (2). Under this revised approach, any resource would pass the conduct screen if its bid was at least 100% of the net cost of new entry for its asset class.

A resource bidding below this 100% threshold could still, however, pass the conduct screen—and thus be exempt from mitigation—if it met either of the following conditions:

First, a resource can pass the conduct screen if it demonstrates its unit-specific costs. *See* Revised MOPR (3)(ii). This would be the full, nominal, levelized costs of the individual unit, including projected costs and costs already sunk (if any), but using a market—not individual—cost of capital. Any unit could justify its costs at the time of the auction.

Second, a resource can satisfy the entire mitigation regime by establishing that it has not received any discriminatory payments, as determined at the time of the offer. *See* Revised MOPR (3)(iii).

We discuss key features of this proposal below.

1. A 100% Benchmark Is Just and Reasonable, Both as a Conduct Screen and as the “Mitigated-To” Price

Our first proposal is to replace the basic 80% (or, in some cases, 70%) conduct threshold to 100% of the appropriate nominal levelized cost of new entry. *See* Shanker at 52:15-21. Any resource bidding below this threshold will be deemed uneconomic unless it met one of the other screens excusing mitigation.

The 100% level is appropriate because a lower threshold permits a significant amount of buyer market power to be exercised. As Dr. Shanker explains:

A conduct threshold of 80% or 70% permits offers 20% to 30% below economic levels to go unmitigated. This permits the extensive exercise of buyer market power before mitigation is even triggered just by bidding in subsidized new entry at a level slightly higher than the screen, e.g., 81%. Consider the effect of a 20% threshold in the EMAAC LDA. The EMAAC net Cost of New Entry was approximately \$260 per MW-day for the last Base Residual Auction. Twenty percent equates to \$52 per MW-day. Applied to the approximately 33,000 MW of capacity inside the EMAAC locational delivery area, there would be a permissible total annual dollar exercise of buyer market power of \$626 million *before mitigation is even considered* ($\$52/\text{MW-day} \times 365 \text{ days} \times 33,000 \text{ MW} = \$626,340,000$).

Shanker at 21:3-13.

In addition, setting a benchmark below 100% also defeats one of the core objectives of the capacity market, by preventing the market from clearing, on average and over time, at the net cost of new entry. *See* Shanker at 56:7-17. We expect that opponents of effective mitigation may object that some discount nevertheless should be imposed in light of potential inaccuracies in the benchmark. But as Dr. Shanker explains, this objection is without merit:

Actually, in this specific situation that type of logic does not apply. In fact, other considerations support mitigation to a higher substitute Sell Offer, not a lower one. Ideally, any bid from a subsidized party would be excluded. However, if such bids are allowed, they must be mitigated to at least 100% of their nominal levelized costs to prevent adverse effects in the operation of the capacity market. There are two main reasons for using 100% as a lower bound. First, in the presence of market power, the mitigation floor offer is likely to become the *cap* on prices for capacity in the market. The definition of the “mitigated-to” target price in this situation is a nominal levelized long-term price that represents the *average compensation* that is needed to support new entry over time. Buyers with market power can act to eliminate the ability of prices to rise above the offer floor, which would be possible under the PJM demand curve structure, but for the market power. The notion that the prices would be capped at average some of the time, and less than average other times clearly points out the problem: who will privately invest under such conditions? Similarly, this clarifies that while the mitigation is to the appropriate average value, that value may be too low to achieve the goal of reproducing long-term competitive market conditions, as private entry will still be discouraged from entering the market absent a subsidy.

Shanker at 22:4-20.

In this same vein, opponents of effective mitigation also might argue that a discount off of the benchmark is appropriate here because the offers of sellers in the capacity and energy markets typically are mitigated to 110% of marginal cost.⁴ But this overlooks the very real point, stressed by Dr. Shanker, that the effects of setting the benchmark too low, versus too high, are wildly asymmetrical:

In the energy market, mitigation often occurs when there is a lack of competitive supply alternatives. Thus there is concern regarding not forcing a supply at what might be less than cost because the supply must be used, there typically is no alternative. That is not the case with the exercise of buyer-side market power in the capacity market. If the supply from a specific party offering subsidized capacity is mitigated, no barriers are created for others to put forward competitive alternatives. I discuss the importance of alternative competitive supply and its relevance to setting mitigation levels further below. The implications of this can best be seen by looking at the issue of replicating competitive results from a “cost of the errors” perspective. That is, what is the relative harm or benefit from choosing too high of a value for the substitute Sell Offer versus too low a value. When this analysis is done, and the availability of competitive alternatives is taken into account, the clear conclusion is that it is better to have an upward bias in the substitute Sell Offers, if there is going to be any bias at all. Indeed, a value greater than 100% could easily be justified in the current circumstances. For example, if the mitigated price set at the nominal levelized Unit Specific Net Cost of New Entry were deemed too high, what is the harm? The worst that happens is that the mitigated offer fails to clear, and presumably the new resource would not be built. This would occur because either there was no need for it, or if there was a need, it was filled by a lower-cost alternative competitive supplier. This is hardly a bad result, and in fact, is what should happen in a market. Empirically we know we have significant additional supply in PJM. Alternatively, if the mitigated price is too low, and effectively sets a cap on the market below the actual cost of new entry, competitive entry is eliminated, prices are suppressed,

⁴ For example, the RPM’s offer price cap for existing resources permits a premium of 10% above the estimated cost benchmark. RPM § 6.8(a) (including a 10% “Adjustment Factor” “to provide a margin of error for understatement of costs”). This premium, in contrast to the benchmark discounts discussed here, has at most a *de minimis* effect on price levels in a competitive market and no potential to unravel the market overall. There are several reasons for this. *First*, the premium is over an estimate of avoidable cost which by its nature is in order of magnitude smaller than the cost of new entry. Hence, the impact on auction clearing prices of 10% of the avoidable cost premium will be proportionately smaller and less significant than 10% of the cost of new entry discount. *Second*, because a healthy capacity market will equilibrate around the net cost of new entry, the avoidable-cost-based bids of existing generators can be expected to be heavily infra-marginal, with or without a 10% premium. As a consequence, one would expect this premium to have no effect on either clearing prices or capacity obligations.

and price discrimination is allowed. This assures the destruction of the market, because by definition the prices are being set at levels such that they will never be compensatory for a new entrant. No one will enter a market where the expected revenues are capped at less than the needed average price.

Shanker at 22:23–24:4. The “cost” of mitigating to too low a level is, in sum, *much* more severe than the “cost” of mitigating to too high a level. Setting mitigated prices too low can cause billions of dollars of deadweight losses, while setting them too high is basically cost-free.

The choice here, we submit, is simple: mitigate to 100%. This outcome, as Dr. Shanker’s testimony explains, conforms to the long-standing teaching of the United States Supreme Court that the purpose of the law is “the protection of *competition*, not *competitors*.” *Brunswick Corp. v. Pueblo Bowl-O-Mat*, 429 U.S. 477, 488 (1977) (quoting *Brown Shoe Co. v. United States*, 370 U.S. 294, 320 (1962)); *Copperweld Corp. v. Independence Tube Corp.*, 467 U.S. 752, 767 n.14 (1984); *Brooke Group Ltd. v. Brown & Williamson Tobacco Corp.*, 509 U.S. 209, 224 (1993); *NYNEX Corp. v. Discon*, 525 U.S. 128, 135 (1998) (a Sherman Act claim “must allege and prove harm, not just to a single competitor, ... but ... to competition itself”). The prime goal here should be to protect the market from distortion, because that is the greatest source of severe harm. Mitigating to 100% is the best way to achieve that goal.

We recognize that the other organized capacity markets, like the current PJM regime, use a discounted benchmark for buyer-side mitigation. But these provisions typically were implemented as the result of settlements. There has *never* been a litigated resolution of the arguments we present here. In particular, the Commission has never been presented with the stark contradiction between (1) the fundamental design criterion for organized capacity markets—the need to average the actual net cost of new entry—and (2) using a steep discount off the cost of new entry for detecting the exercise of buyer market power, effectively capping price outcomes so that they remain below competitive levels. This is a recipe for market failure.

It is neither a reasonable reading of the Commission’s prior orders, nor a just, reasonable, and non-discriminatory approach to setting rates, to create and maintain a market design that sows the seeds of its own destruction. The Commission thus should not—and, we submit cannot, consistent with its statutory mandate and minimum standards of reasoned decision-making—consider itself bound by prior precedent that did not give reasoned consideration to these critical core problems.

One final point on this issue merits discussion, though it can and should be deferred to the second stage of this case. Dr. Shanker concludes that, in his expert opinion, the ideal benchmark would be based on the net cost of new entry *for the Reference Resource*, a combustion turbine. Shanker at 56:9-13. We propose here to continue using the net cost of new entry for the asset class of the resource. *See Revised MOPR (1)*.

Dr. Shanker agrees that the asset class benchmark would be adequate. Shanker at 8:8-16. Ideally, however, he prefers to base the benchmark on the Reference Resource, because the Reference Resource is a combustion turbine and combustion turbines are expected to be the marginal resources in an effective capacity market in PJM.⁵

We propose to use asset class benchmarks for the purely practical reason that the current version of the tariff bases the benchmark on the asset-class cost. Given the urgent need for action, consideration of Dr. Shanker’s proposal to use the Reference Resource can be deferred with the other “phased” issues.

⁵ Dr. Shanker’s specific proposal is to screen conduct on the basis of the Reference Resource, a combustion turbine, and “mitigate to” a unit-specific net cost of new entry. This effectively results in mitigation to the lesser of the reference or unit specific value assuming rational behavior by bidders.

2. *The “No-Subsidy” Off-Ramp*

We also propose to make the entire buyer-mitigation regime less burdensome for all stakeholders, and easier to administer, by proposing simply to terminate the mitigation process for any resource that can establish that it will not receive any form of subsidy.

New entry could fail a conduct screen for one of two reasons: (a) a competitive entrant may simply have expectations about future energy and ancillary service revenues that are different than the estimates embedded in the benchmark, or (b) a resource can have some other form of financial support, such as the type of contract proposed by the New Jersey Law. The first situation does not, in our view, need to be addressed through buyer mitigation—it is not causing artificial price suppression, and reflects, instead, normal business conduct. The second, in stark contrast, *does* need to be addressed through mitigation. We therefore can focus the mitigation process on resources most likely to cause artificial price suppression if we allow resources to exit that process by establishing that they are not receiving any subsidy. Shanker at 53:2-12.

The market monitor already is recognized as capable of making these types of determinations because there are tariff provisions tasking it with detecting and reporting alleged seller-side market manipulation schemes. The market monitor also is well positioned to make the initial determination regarding subsidies because it has access to a broad section of both public and confidential information. However, such general information will need to be supplemented by specific information only available to the market participant who seeks to offer the new resource. *See* Revised MOPR (3)(iii).

Given the variety of possible schemes for subsidizing uneconomic entry, it is essential that the market monitor and PJM have the authority to acquire all necessary information for market participants seeking an exemption, and that they have the opportunity to subject any

potential arrangement to complete economic analysis, rather than being bound by narrow categorizations inviting evasion. *See generally Prohibition of Energy Market Manipulation*, Order No. 670, FERC Stats. & Regs. ¶ 31,202 (2006) (recognizing the need for flexibility in identifying market manipulation in order to avoid evasion). And the Commission would, of course, always have final say on any determination.⁶

We propose that the tariff require that the information submitted to the market monitor be accompanied by a certification executed by a responsible corporate officer. This is both common sense and common PJM practice. In similar circumstances, where the appropriate PJM decision depends on information properly within the knowledge of a market participant, the market participant must certify the accuracy of this information. *See, e.g.*, PJM Tariff § 6 (requiring “sworn statement of ... duly authorized officers or other representatives ... that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision”); § 29.2(vii) (requiring a “statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed” satisfy certain conditions); § 116 (requiring market participants to “file ... the Deactivation Avoidable Cost Rate, along with applicable cost support and a certification by an officer of the Generation Owner or its Designated Agent attesting to the accuracy”).

As in these other cases, intentional or reckless submission of false, misleading, or incomplete information would subject the market participant to very significant penalties. Under the Commission’s Revised Penalty Guidelines, an intentional misrepresentation of this type that leads to billions of dollars of artificial price suppression could potentially create very large

⁶ Needless to say, compliance with this tariff provision would not shield otherwise unlawful conduct of market participants from Commission review and prosecution. In particular, if a market participant were to devise a market manipulation scheme which somehow evaded the tariff’s definition of “discriminatory payments,” this would only render the scheme tariff-compliant. It would not protect the participant from a charge of market manipulation.

penalty levels (in addition to potential disgorgement of ill-gotten gains). *See Revised Policy Statement on Penalty Guidelines*, 132 FERC ¶ 61,216 (2010).

B. A Revised Minimum Offer Price Rule Should Eliminate the Impact Threshold

A preceding discussion amply demonstrates the excessive size of the Minimum Offer Price Rule's current impact thresholds. *See supra* at 23. In actuality, however, there is no justification for *any* impact threshold, no matter how moderate. *See Shanker* at 54:3-6. We are unaware of any Commission order holding that demonstrable, readily remediable exercises of market power in jurisdictional markets must be given a pass if they are not "too excessive." Rather, the Commission seeks to mitigate *all* instances where market power is exercised and has never confined itself to only the most extreme examples.

Mitigating the exercise of buyer market power without any impact threshold is readily workable. Other components of the Minimum Offer Price Rule ensure that only genuine exercises of market power are identified and targeted, and that the magnitude of the mitigation matches the magnitude of the exercise of market power. Large exercises of market power with large effects will result in substantial mitigation, affecting clearing prices and the assignment of capacity obligations in a commensurate manner. Small exercises of market power with small effects will result in only slight mitigation, affecting clearing prices and capacity obligations only marginally, if at all.

It might be argued that an impact threshold is wise if, for example, there was an enormous administrative or economic burden created by even the most minor mitigation. In that case, some might argue that mitigating truly *de minimis* market power exercises would, on net, do more harm than good. But that is not the case here. The entire apparatus of the Minimum Offer Price Rule—including data collection, verification, and review and calculation of the outcomes of various alternative, hypothetical capacity auction sensitivities—must be engaged

regardless of the impact threshold. Only after the various hypothetical auction sensitivities have been fully evaluated can PJM determine how large the impact of any particular identified market power exercise would be, and whether the impact threshold has been met. And at that point, there no longer is any doubt about whether the Minimum Offer Price Rule process is worth undertaking—all of the effort already has been expended. The only remaining question is whether an auction with an outcome artificially distorted by the exercise of market power should be allowed to go into effect, or whether, instead, an already-calculated alternative auction outcome, purged of the effects of market power, should be made effective. Even if, in some cases, the difference between distorted and correct auction outcomes is minor, there is no reason to pick the distorted outcome over the correct one.

In addition, none of the Minimum Offer Price Rule’s siblings in other RTOs—the NYISO’s In-City Installed Capacity Offer Floor and any version of ISO-NE’s Alternative Price Rule currently under discussion—have an impact threshold beneath which buyer market power exercise is permitted. Our proposal conforms the approach in PJM with these other markets.

In sum, the impact threshold is unnecessary and harmful. It should be deleted without replacement. *See Revised MOPR.*⁷

C. A Revised Minimum Offer Price Rule Should Mitigate Resources Until They Prove Economic

We recommend adopting similar rules to those recently approved in NYISO to address the period of time over which to extend the mitigation.

⁷ Eliminating the impact screen also has the side benefit of significantly simplifying the mitigation process. Without an impact test, there is no longer any need to run the capacity auction multiple times with different sets of mitigated and unmitigated bids. The market operator would just mitigate bids that fall within the Minimum Offer Price Rule’s constraints before the auction and then run the auction just once with all the bids as mitigated. The outcome of this auction would then just be to determine the price levels and capacity obligations. With this simplification, a great deal of tariff language can be eliminated and the Revised Minimum Offer Price Rule does so by eliminating section 5 entirely.

First, as in *NYISO*, 133 FERC ¶ 61,178, the Minimum Offer Price Rule’s implicit limitation to one Base Residual Auction should be struck. *See* Revised MOPR (2).

Second, in a way similar to *NYISO*, resources that clear in two capacity auctions should thereafter be permanently exempt from mitigation. *See* Revised MOPR (3)(i).

While *NYISO* required resources to clear for twelve auctions, each *NYISO* auction covers only one month. *NYISO*, 133 FERC ¶ 61,178 at P 49. Each capacity auction in RPM covers a delivery year. As Dr. Shanker explains:

[In *NYISO*], with a monthly clearing process, the requirement was to clear in twelve auctions, which didn’t necessarily need to be consecutive. Thus, because typically demand is higher, and capacity lower during the summer, the most likely clearing scenario is during two summer periods. Because PJM clears annually based on summer requirements, the use of two Base Residual Auctions is directly analogous.

Shanker at 57:16-21. Clearing in two RPM auctions thus is the rough equivalent of clearing in twelve *NYISO* capacity auctions.

Third, for a resource that previously has cleared only in part, it is only the cleared part that becomes exempt from mitigation. For example, if a 500-MW resource was offered in the previous Base Residual Auction, but only 200 MW cleared, the 200 MW thereafter become effectively exempt from the Minimum Offer Price Rule; the other 300 MW that did not clear remain subject to mitigation until they do clear. Accounting for the different time periods in *NYISO* and PJM capacity markets, this treatment is consistent with the Commission’s previously announced rule. *See NYISO*, 133 FERC ¶ 61,178 at P 49 (“only the consistently-cleared portion of the capacity of a given resource over a total of 12 monthly auctions should have its offer floor mitigation lifted”).

Fourth, we propose a related provision in the Revised Minimum Offer Price Rule to mitigate resources that originally were excused from mitigation because they were not receiving

discriminatory payments, but then are subsequently determined to have in fact received discriminatory payments. *See* Revised MOPR (3)(iii). This provision serves two functions. To begin with, it prevents market participants whose original disclosures of potential subsidies to the market monitor were incorrect or incomplete—willingly or, as is possible, due to lack of knowledge—from profiting as a result. If the market monitor or the Commission reverses a determination that a resource is exempt, in light of information later discovered, mitigation would restart prospectively. Additionally, in case the Commission is unable to rule on this complaint before the May 2011 Base Residual Auction, and New Jersey or Maryland successfully achieve subsidized uneconomic entry, market participants will nevertheless become subject to mitigation if the Commission approves a revision to the Minimum Offer Price Rule, and the market monitor determines that the New Jersey or Maryland resources received discriminatory payments (as they clearly do).

Finally, the Minimum Offer Price Rule currently includes a provision that entirely eliminates mitigation in certain circumstances if there is a positive net demand for new resources in two consecutive years. RPM § 5.14(h)(5). Mitigation can be reinstated only under certain limited conditions. There is no justification for this provision because new resources, even if mitigated, would be expected to clear when there is a need for new entry. It should be deleted.

See Revised MOPR. All buyer market power should be mitigated.

III. MITIGATION SHOULD APPLY TO ALL TYPES OF RESOURCES WITHOUT EXEMPTION, BUT ONLY SOME EXEMPTIONS NEED TO BE ADDRESSED NOW, WHILE OTHERS CAN BE DEFERRED

A. We Propose to Limit Mitigation of Certain Resource Classes Until More Contentious Issues Can Be Resolved in Further Proceedings

In our view, the full buyer mitigation regime should apply to all resources. But we recognize the reality presented by the compressed time frame here. We thus propose to apply

mitigation only to combustion turbine and combined cycle resources for the next auction. We propose to defer, to a subsequent stage of the case, the treatment of demand response, renewables, and long-lead-time resources.

The Commission previously has taken similar action to immediately mitigate *sellers* in organized markets, while setting more complex longer-term issues for future proceedings. As the Commission recently explained:

The Commission has found in other contexts that uncertainty at the start-up of a new market design justifies the implementation of interim measures to smooth the transition to a new market, so as to protect customers from potentially unjust and unreasonable rates during the early stages of implementation. ... The Commission concluded that this uncertainty justified the implementation of interim measures, during the first four months of its new market, to guard against potentially unreasonable prices during the early stages of implementation. We find that similar interim measures may be justified in this case. However, we also expect the CAISO to consider the effectiveness of the numerous other market power mitigation measures proposed.

Cal. Indep. Sys. Operator, 130 FERC ¶ 61,122 at P 56 (2010) (footnote omitted). *See also Okla. Gas & Elec. Co.*, 124 FERC ¶ 61,239 at PP 53-55 (2008) (imposing interim seller market power mitigation in context of merger); *Midwest Indep. Transmission Sys. Operator*, 120 FERC ¶ 61,250 at P 35 (2007) (imposing interim seller market power mitigation in light of the fact that “market will likely undergo significant changes, including the anticipated implementation of its long-term resource adequacy plan and development of demand resources, that may necessitate adjustments to the market monitoring and mitigation plan”), *reh’g and clarification denied*, 122 FERC ¶ 61,178 (2008).

To avoid any ambiguity, we propose tariff language that, for the May 2011 auction only, expressly limits the application of the new mitigation to combustion turbines and combined cycle resources, which are the principal threat to the integrity of the upcoming Base Residual Auction. *See Revised MOPR (3)(v)*.

It is essential, however, that the Commission set a clear time-table for further proceedings. While blanket exemptions for many resource classes hopefully will not adversely effect the May 2011 auction outcomes, future auctions will face more severe risks of downward price suppression. In order to avoid a replay next year of the same situation, it is critical to proceed with the examination of these other exemptions now.

B. Immediate Issues

1. The Commission Should Remove the Net-Short Requirement

a. Overview

The Minimum Offer Price Rule is fatally flawed because it permits mitigation of offers only by sellers that are considered net short (because their obligations to purchase capacity substantially exceed their capacity sales). Specifically, the Minimum Offer Price Rule predicates mitigation on the following condition:

The Capacity Market Seller and any Affiliates has or have a “net short position” in such Base Residual Auction for such LDA that equals or exceeds (a) ten percent of the LDA Reliability Requirement, if less than 10,000 megawatts, or (b) five percent of the total LDA Reliability Requirement, if equal to or greater than 10,000 megawatts.

A “net short position” shall be calculated as the actual retail load obligation minus the portfolio of supply.

An “actual retail load obligation” shall mean the [load-serving entities’] combined load served in the LDA at or around the time of the Base Residual Auction adjusted to account for load growth up to the Delivery Year, using the Forecast Pool Requirement.

A “portfolio of supply” shall mean the Generation Capacity Resources (on an unforced capacity basis) owned by the Capacity Market Seller and any Affiliates at the time of the Base Residual Auction plus or minus any generation that is, at the time of the [Base Residual Auction], under contract for the Delivery Year.

RPM § 5.14(h)(2)(iii). The Minimum Offer Price Rule never mitigates any capacity offer made by any Capacity Market Seller that is not net short.

The apparent rationale for this blanket exemption is the argument that a capacity market participant that does not, on net, purchase substantially more capacity than it sells would not benefit from price suppression, and therefore presumably would not have any intent to suppress prices. This rationale has some support in logic and economics but in practice is impossible to administer effectively. Not only is the specific net-seller requirement of the Minimum Offer Price Rule so overbroad as to allow easy circumvention of the entire rule, it appears to be administratively impossible to craft a net-seller requirement that does not suffer the same defect. Moreover, a net-seller requirement, even if possible, is not necessary. The Commission therefore rightly has ordered the complete deletion of any such requirement in other capacity markets.

b. The Minimum Offer Price Rule's Net-Short Requirement Exempts Even Substantial Capacity Buyers

The Minimum Offer Price Rule's net-short requirement, even accepting the rationale proffered above, is seriously flawed because it is in fact a *large*-net-short requirement. *See generally* Shanker at 30:16-20. Market participants can be substantial net purchasers of capacity (and have the concomitant incentive to suppress prices) and still be completely exempt from mitigation due to the Minimum Offer Price Rule's net-short requirement. Only when the net purchases of capacity exceed 10% of the Locational Deliverability Area's reliability requirement (5% in large Locational Deliverability Areas) does mitigation set in. So, for example, a load-serving entity that purchases up to 9.9% of all of the capacity in a small Locational Deliverability Area would be completely exempt thanks to the Minimum Offer Price Rule's net-short requirement. So would a load-serving entity that purchases 30% of all capacity in such a Locational Deliverability Area and sells 20.1% of the capacity in that Locational Deliverability Area to suppress capacity market prices.

The effect of the net short requirement on capacity prices can be substantial. *See* Shanker at 30:21–31:15 (showing example of price impact). The fact that the Minimum Offer Price Rule’s net-short requirement permits such substantial market distortions and exercises of market power with impunity, standing by itself, is sufficient to render the net-short requirement unjust and unreasonable.

c. The Net-Short Requirement Allows Complete Evasion of the Minimum Offer Price Rule

While the requirement of a *large* net-short position permits substantial evasion of the Minimum Offer Price Rule, a more substantial loophole in the net-short requirement makes it trivially easy to entirely bypass the Minimum Offer Price Rule: The Minimum Offer Price Rule’s net-short requirement is based on the position of the Capacity Market Seller who offers the resource into the auction. RPM defines this term as follows:

“Capacity Market Seller” shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

RPM § 2.11. There is, however, nothing in the economics of exercising market power that requires (1) the beneficiary of the scheme—the party that profits from the price suppression because it has an actual or constructive short position in the capacity markets—and (2) the capacity seller—the party that actually offers the resource into the capacity markets at uncompetitive prices, and thereby effects the price suppression—to be the same or even closely related. If one party offers the capacity resource, and another, separate party has the short position, the entire scheme will escape any mitigation under the current Minimum Offer Price Rule because of the net-short requirement.

The only argument that could be raised against such a separation is that the capacity seller would decline to participate because it would suffer a loss from the uncompetitive offer,

while all the benefits would accrue to the separate party with the short position. But, this missing link can easily be supplied. All that is required to coordinate the seller and the beneficiary is a contract or other arrangement in which the beneficiary shares a sufficiently large part of its profits to make the capacity seller's participation also profitable.

One effective type of side arrangement is a contract for differences requiring the seller to offer a resource at an uncompetitively low price in return for the beneficiary holding the seller harmless for the resulting price suppression. That is, of course, the arrangement used in the New Jersey scheme. *See infra* at 57-60. Other sponsors of buyer market power schemes have adopted the same arrangement for the same reasons. *See, e.g., Review of Energy Independence Act Capacity Contracts*, Docket No. 07-04-24, 2007 Conn. PUC LEXIS 219, at *82-83, *99 (Aug. 22, 2007); *see* discussion of proposed scheme in Maryland, *infra* at 64-66.

While contracts for differences are a common means of coordinating the beneficiary and capacity seller in buyer market power schemes, a net-short requirement that merely attempted to incorporate this type of contract into its definition of "net-short" or "seller" would remain ineffective. The reason is that the arrangements aligning the interests of the beneficiary and the capacity seller need not be contracts for differences, but can take a near-infinite variety of guises. For example, the beneficiary could enter into a derivative transaction that bestows upon the seller a synthetic short position in the capacity market—that is, a contract in which the beneficiary pays the seller an amount that increases as the clearing price in the capacity market drops. This would not be a traditional contract for differences but would serve the same end equally well.

Even an enormously intrusive and administratively infeasible Minimum Offer Price Rule—which examined every single contract, hedge, or other financial position of the capacity seller to determine if it could somehow be part of an indirect arrangement with a net-short

participant to suppress capacity prices—still would fail. A party that is net short in the capacity markets, and determined to suppress prices, could just build a new, uneconomical power plant and then sell it in an arm’s-length transaction to any willing buyer at an open-market price. The new owner would rationally offer the plant at its going-forward costs, which will be substantially below the cost of new entry, and thereby artificially depress the capacity price. The net-short party that built the uneconomical plant would have received less than it cost to build,⁸ but would be more than compensated on a portfolio basis by the price suppression effect. No possible net-short test applied to the new owner—who has no ongoing relationship with the beneficiary, rationally bids the plants into the capacity markets, and need not even be aware of any market-power scheme—could prevent this scheme from succeeding.

d. The Inclusion of Affiliates Fails to Close the Net-Short Loophole

The drafters of the Minimum Offer Price Rule appear to have been aware of the possibilities of the net-short requirement being used as a loophole, and attempted to foreclose such efforts by combining the “Capacity Market Seller *and any Affiliates*” for purposes of calculating the position. Unfortunately, the following tariff definition of “Affiliate” renders this inclusion unhelpful:

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

PJM Tariff § 1.0A.01. As demonstrated above, the capacity seller and the beneficiary of the scheme need not have any relationship within this definition of affiliation—or indeed any ongoing relationship at all.

⁸ If the net-short party that built the plants could sell them in an arms’-length transaction at a profit, they would by definition not be uneconomical or artificially suppress prices.

In particular, under the New Jersey scheme, none of the relevant actors are likely to be deemed affiliates. The relevant actors are the owners of the new eligible generation (which are obligated to offer the resources into the capacity auctions), the state's electric utilities (which are required to enter into the contracts for differences with the generators), the New Jersey Board of Public Utilities (which arranges for the contracts between the generators and the distribution utilities), and the State of New Jersey (whose bill set up the scheme). None of these are under common control with any of the others (unless they should happen to be so for unrelated reasons). In particular, the electric utilities (which have the net-short positions) and the owners of the new eligible generation (who offer the capacity) are, in a general sense, not under common control, and hence may not be deemed affiliates. Therefore, the electric utilities' net-short position may not be attributed to the owners of the new eligible generation, which would mean that the Minimum Offer Price Rule would never be triggered.

We argue below, in the alternative, that it would be appropriate to permit PJM to treat the electric utilities as affiliated with the owners of the new eligible generation. *See infra* at 73. While such an interpretation may be necessary to thwart attempts to evade the intention of the Minimum Offer Price Rule, this does not detract from the fact that a superior, long-term resolution for this issue is to eliminate the net-short test, mooted any issue regarding the definition of "Affiliate."

e. For These Reasons, the Commission Has Already Excised a Less Demanding Net-Short Requirement in NYISO

The Commission, in its original order approving NYISO's In-City Installed Capacity Offer Floor, had required that only net buyers of capacity be made subject to mitigation. *See N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at P 100. In response to the objections of NYISO and

others, *N.Y. Indep. Sys. Operator*, 124 FERC ¶ 61,301 at P 28, the Commission reconsidered and deleted the net-short requirement:

NYISO will not be required to modify its proposed market power mitigation rules for uneconomic entry so that they only apply to net buyers. *We find that all uneconomic entry has the effect of depressing prices below the competitive level and that this is the key element that mitigation of uneconomic entry should address.* Parties requesting rehearing have convinced us that defining net buyers raises significant complications and provides undesirable incentives for parties to evade mitigation measures. Accordingly, we grant rehearing on this issue[.]

Id. at P 29 (emphasis added). It is the depression of prices, not the mental state of any particular market participant—which may not be discernable in many cases, and will become far less discernable if it became outcome-determinative—that “is the key element that mitigation of uneconomic entry should address.” Mitigation should occur whenever uneconomic entry occurs, regardless of intent. *See id.*

The Commission was also persuaded that an effective net-short test was impracticable:

[NYISO and others] request that the Commission grant rehearing and not limit market power mitigation measures to net-buyers only. Essentially these parties note that the limitation is impractical to implement and would achieve little positive result. They argue that the limitation would give parties an incentive to create companies solely for the purpose of subsidizing uneconomic entry, or that governmental bodies could subsidize uneconomic entry under a public policy rationale. NYISO, in particular, emphasizes that limiting uneconomic entry mitigation measures to net buyers could undermine enforcement because buyers may behave strategically to avoid categorization as net buyers. NYISO also points out that the process for identifying net buyers is unclear and that this could also result in evasion of the mitigation measures. NYISO notes that “net buyer” could be defined a number of different ways, for example, as a single entity or as an entity including all affiliates that serve load. Such a definition would not consider generation affiliates that could construct uneconomic generation and escape mitigation. NYISO also explains that contractual relationships could be undertaken to circumvent mitigation of uneconomic entry and that these would be extremely difficult to identify. ... NYISO further emphasizes that if the Commission’s view that only “net buyers” have the incentive to engage in uneconomic entry is correct, the “net buyer” condition would be unnecessary since there would be no other sources of uneconomic entry.

Id. at P 28.

Notably, the Commission in *NYISO* pointed to nearly the *exact method* that the New Jersey Law, introduced more than two years later, would use to steer itself through the net-short loophole. *Compare id.* (“For example, ... a ‘contract for difference’ might allow a buyer to subsidize uneconomic entry in a way that would not be apparent to” the administrator of the capacity market.) *with* New Jersey Law at 15 (prescribing a subsidy for each MW of capacity “equal to the difference between the [fixed subsidy price] and the [auction clearing price]”).

2. *Self-Supply Should Not Be Exempt*

The current Minimum Offer Price Rule’s self-supply loophole is yet another fatal flaw. Even if mitigation goes into effect, the Minimum Offer Price Rule prescribes a particular order for the assignment of capacity obligations:

- (i) first, all Sell Offers in their entirety designated as self-supply;
- (ii) then, all Sell Offers of zero, prorating to the extent necessary; and
- (iii) then all remaining Sell Offers in order of the lowest price.

RPM § 5.14(h)(4). Under this priority, it appears that Sell Offers designated as self-supply will always be accepted in full, even if the Minimum Offer Price Rule otherwise indicates that they are uncompetitive and ought to be mitigated. The market participants who would benefit from the use of market power to suppress capacity prices—load-serving entities—can also freely designate their capacity resources as self-supply. The priority for self-supply thus effectively eliminates any constraint on the exercise of market power. This defect, standing alone, would be sufficient to render the Minimum Offer Price Rule unjust, unreasonable and unduly discriminatory.

a. A Self-Supply Loophole Is Unnecessary

The basic premise underlying the argument to exempt self-supply from review and mitigation is that self-supply cannot affect the auction clearing price and therefore cannot be a tool of price suppression. This premise is demonstrably false.

The unstated assumption implicit in this argument is that load interests would only add or designate an additional amount of self-supply if simultaneously choosing to add the same amount of load. Given this assumption, it is true that adding 100 MW of additional load, shifting the demand curve to the right by 100 MW, and adding 100 MW of self-supply priced at \$0, shifting the supply curve to the right by 100 MW, will not affect the price at the intersection of supply and demand.

The problem with this unstated assumption, and therefore the entire argument, is that it is without basis in the tariff and contradicted by the observed facts. Nothing in the tariff requires load to add self-supply only when it chooses to increase load by the same amount. In fact, load entities could never commit to add self-supply exactly in step with increases in demand, because, with uncommon exceptions, the overall level of demand growth is not within their discretion.⁹ Consumers decide independently whether, where and when to increase or decrease their demand, and PJM develops an aggregate load forecast reflecting expected peak loads in future years. Load then must proceed to decide how to meet that consumer-set demand.

Realistically, the choices available to load are quite different than those assumed by self-supply advocates. Any given load entity's overall level of demand is largely fixed. The only choice for load entities is whether to meet that demand through self-supply or by regular

⁹ Further, the market rules governing the use of self-supply designations are based on the capacity responsibility or Installed Capacity tags of the load serving entity at the time the self-supply request is made. As a result, self-supply is made based on historic peak load responsibility of the existing customers the entity serves.

procurement in the auctions. Under the current Minimum Offer Price Rule, if a load entity designates 1,000 MW as self-supply, the effect is to pre-clear that 1,000 MW, removing it from the auction and shifting the demand curve to the left by that amount. This will have *exactly* the same effect on price as if the load entity had offered that 1,000 MW into the auction at a price of \$0, shifting the supply curve to the right by that amount. Just as 1,000 MW offered into the auction at \$0 is an effective tool for artificial price suppression, so too is designating 1,000 MW of capacity as self-supply. The auction price impacts are indistinguishable.

Exempting self-supply would render the Minimum Offer Price Rule a dead letter. Load interests wishing to exercise buyer market power would effortlessly switch from (1) bidding uneconomic resource projects into the market at anti-competitive prices to (2) designating them as self-supply. Either approach creates exactly the same price-suppression effects.

The fact that self-supply is only possible up to the level of load served by the entity is not to the contrary. A load entity is unlikely to spend more money to self-supply *all* of its requirements. It is, instead, likely to pursue a strategy of self-supplying only a *portion* of its requirements, up to the point that it suppresses the auction sufficiently to create net benefits for the rest of its portfolio. And the load entities serving the largest amounts of demand have the most powerful incentive to artificially suppress capacity prices.¹⁰ Hence, this limit on self-supply would not bind the very entities to whom artificial price suppression is most attractive.

b. Efficient Self-Supply Benefits from Effective Mitigation

An effective Minimum Offer Price Rule without a self-supply loophole would be a benefit, not a harm, to efficient self-supply. A competitive, un-manipulated capacity price—such

¹⁰ The fact that some LSEs contract away their load responsibility to competitive market participants is not to the contrary. This current practice, and whatever state laws underlie it, would easily be changed once self-supply becomes the most effective loophole in the Minimum Offer Price Rule.

as would exist under an effective Minimum Offer Price Rule—reveals useful information to all market participants. This price information is particularly valuable for market participants that, for whatever reason, prefer to fulfill their capacity obligations through self-supply or bilateral arrangements outside the auction process.

Inefficient new self-supply—self-supply with costs above the mitigated clearing price—would be affected by mitigation. But outside of a price suppression goal, it is unclear why anyone would be eager to engage in inefficient new self-supply. Inefficient new self-supply, by definition, costs more than the auction clearing price. So any entity that uses inefficient self-supply *must* incur higher costs than if it had just relied upon the market to serve its needs.

c. Load Entities Committed to Self-Supply for Legitimate Reasons Retain the Fixed Resource Requirement Alternative

Schedule 8.1 of PJM’s Reliability Assurance Agreement permits parties to satisfy their capacity obligations outside of RPM. A party that chooses the Fixed Resource Requirement Alternative (or FRR Party), submits an FRR Capacity Plan, “a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of [the] Party.” RAA §§ 1.25, 1.29. The area covered by such a plan is:

... (a) the service territory of an IOU ...; (b) the service area of a Public Power Entity or Electric Cooperative ...; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, ...; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area[.]

RAA § 1.31. A FRR Entity meets all its capacity “obligations hereunder to provide Unforced Capacity by submitting and adhering to an FRR Capacity Plan and meeting all other terms and conditions of such alternative” and need not acquire any capacity in the RPM auctions. RAA § 7.4.

Effectively, FRR Entities exempt themselves from the Minimum Offer Price Rule and fulfill all of their capacity obligations by self-supply. Because FRR Parties are outside the purview of the Minimum Offer Price Rule, they remain free to make arrangements for capacity at any terms otherwise lawful, including at prices above the RPM clearing price, should they so choose. The availability of this option and its obvious attractiveness to the load parties who have chosen it, *see, e.g.*, PJM, *2013/2014 RPM Base Residual Auction Planning Period Parameters* at 2, <http://www.pjm.com/markets-and-operations/rpm/~media/markets-ops/rpm/rpm-auction-info/planning-period-parameters-report.ashx> (showing that about one seventh of PJM’s entire capacity obligation is met through FRR plans), even under the current ineffectual Minimum Offer Price Rule, should be a sufficient answer to any cavil that RPM with the Revised Minimum Offer Price Rule would be unduly harsh and intrusive to parties seeking to self-supply.

The only self-suppliers who would raise issue with the elimination of the Minimum Offer Price Rule’s self-supply loophole are those that insist on only *partially* self-supplying—those who seek to be free to suppress RPM capacity prices through their self supply, *and* wish to remain eligible to profit from the price suppression by covering the remainder of their capacity obligations at the prices they artificially suppressed. But no market participant can demand a right both to move prices *and* to profit thereby. The elimination of the Minimum Offer Price Rule’s self-supply loophole, in combination with the available FRR alternative, would only prevent load entities from having it both ways.

d. The Commission Approved the Minimum Offer Price Rule Expressly in Order to Mitigate Self-Supply

Perhaps the most remarkable feature of the current Minimum Offer Price Rule’s self-supply exemption is that it is directly contrary to the findings of the Commission approving the

Minimum Offer Price Rule. In its order, the Commission justified the Minimum Offer Price Rule on the basis of:

the concern that net buyers might have an incentive to depress market clearing prices by offering some *self-supply at less than a competitive level*. ... The Commission finds the Minimum Offer Price Rule a reasonable method of assuring that net buyers do not exercise monopsony power by *seeking to lower prices through self supply*.

PJM Interconnection, 117 FERC ¶ 61,331 at PP 103-04 (emphasis added). It is impossible to reconcile this justification with the language of the current Minimum Offer Price Rule, which gives priority “first, [to] all Sell Offers in their entirety designated as self-supply” regardless of mitigated price and ahead of all priced (or substitute priced) Sell Offers.

According to the Commission’s order, the purpose of the Minimum Offer Price Rule is to mitigate the exercise of market power through self supply. But according to its text, the Minimum Offer Price Rule appears to completely exempt self supply. The Tariff should be conformed to the Commission’s order. Our proposed Minimum Offer Price Rule does so. *See* Revised MOPR (5).

3. *State-Sponsored Projects Should Not Be Exempt*

The Minimum Offer Price Rule improperly exempts certain state-sponsored projects:

[A]ny Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard.

RPM § 5.14(h)(1)(iv). This state sponsorship exemption is unnecessary and harmful, and should be deleted.

It requires little prescience to expect an attempt by the states to use this loophole to shield schemes to exercise buyer market power. A mere evidentiary hearing giving PJM a chance to be heard—all that is currently required under the current tariff—would be unlikely to impede state-

sponsored price-suppressing entry. The Commission should eliminate this unnecessary loophole. And as discussed below, *see infra* at 67-69, closing this loophole in no way infringes on the legitimate power of the states.

4. *The Commission Should Remove the Tariff Language Limiting Mitigation to “Planned Generation Capacity Resources”*

As we established above at 25, because the current tariff limits mitigation to “Planned Generation Capacity Resources,” it necessarily imposes a one-year limit on the duration of mitigation. After the first auction, a planned resource will no longer be “planned”—it will be existing, and exempt from all mitigation. As we also established above, this is unjust and unreasonable. Mitigation should extend until a resource proves it is economic by clearing in two auctions.

In order to implement this badly needed fix to the mitigation scheme, it obviously is necessary to delete the language in the tariff limiting mitigation to “Planned Generation Capacity Resources.”

C. *Deferred Issues*

We propose deferred treatment of the following issues:

1. *Long-Lead-Time Resources Should Not Be Exempt, But Should Be Subject to a Slightly Different Mitigation Process*

Currently the tariff exempts long-lead-time resources from mitigation. There is no justification for this exemption. These resources can achieve artificial price suppression just as readily as resources that can be developed within the three-year lead-time period built into the RPM auction process. We thus propose to close this loophole.

That said, there is one unique consideration posed by long-lead-time units that merits a narrow but important change in the mitigation scheme we propose. As noted above, all resources have the option of satisfying the conduct screen by showing that their offer is cost-

justified. For long-lead-time resources, this showing should be made very early in the process. These resources, typically baseload facilities like coal and nuclear, take many years to build—longer than the Base Residual Auction’s three-year forward horizon. On the other hand, short-lead-time units, like combustion turbines, can easily be built within three years.

This has implications for the proper structure of the mitigation process. As Dr. Shanker explains:

For longer-lead-time units, it is important that market participants not be caught in a situation of having made a rational business decision at the time of commitment to essentially begin construction, only to subsequently find themselves subject to mitigation. This could happen if circumstances changed between the time of commitment and the first eligible Base Residual Auction.

Shanker at 44:17-21. But:

For shorter-lead-time units, this concern can effectively be ignored. Mitigation can instead be focused on behavior in the Base Residual Auction because the shorter-lead-time unit can be built within the three-year window between the auction and delivery. Offers will be mitigated if they are uneconomic, but the project will know before construction begins whether it will be subject to the mitigation of its Sell Offer in the capacity market auctions. Further, any project (long- or short-lead-time) that can demonstrate it has not received discriminatory benefits will be free from all mitigation. This allows market participants with legitimate, unsubsidized short-term projects to exercise their own private business decision-making, independent of the expectations of PJM or the Independent Market Monitor.

Id. at 45:2-11.

Long-lead-time resources thus should be exempt from mitigation if they can prove themselves economic early in their development, even if capacity prices move down later. *See* Revised MOPR (3)(iv). This offers long-lead-time units the flexibility to learn their mitigation status at an earlier point in time, when fewer costs have been incurred, thus increasing regulatory certainty. It is also consistent with the mitigation regime in NYISO. *See* Shanker at 45:19–50:8. This issue can be deferred, however, since, by definition, no such resources will be emerging anew in the short time frame presented by the May 2011 auction.

2. *Demand Response Resources Should Not Be Exempt*

In our view, there is no principled reason to exempt all demand response resources from mitigation. Demand response resources can just as readily be used to artificially suppress prices as generation resources, and, in fact, have been used for that purpose. *See infra* at 64. Mitigation appropriate to Generation Capacity Resources also is appropriate to demand response resources.

3. *Renewable Resources Should Not Be Exempt*

The same outcome is appropriate for renewable resources. These resources typically do not have high capacity values. But they nonetheless can create artificial price suppression. And they already are covered by the existing buyer mitigation regime. That coverage should continue. But we agree that this question should be addressed in the deferred stage of the case.

4. *Upgrades to Existing Units Should Not Be Exempt*

Upgrades to existing units also should be mitigated. The same logic that only excuses the cleared portion of a unit from future mitigation (*see supra* at 38), also requires the elimination of the blanket mitigation exemption for “any upgrade or addition to an existing Generation Capacity Resource.” In the above example, only the 200 MW of the 500-MW resource become exempt from mitigation, the other 300 MW still must clear at least once. Any upgrade or additional capacity to an existing resource will not previously have cleared in a capacity auction. There is no economic or legal justification for giving different treatment to (1) a 500-MW resource, of which 200 MW have cleared and 300 MW have not, and (2) a 200-MW resource that has cleared in full and that then undergoes a 300-MW upgrade. Consistency requires that the 300-MW upgrade must clear at least once on the basis of an appropriate, incremental measure of cost before it becomes exempt from mitigation.

IV. RPM FACES IMMINENT THREATS

The remedies that we propose above should be accepted to close loopholes in the current Minimum Offer Price Rule. We request fast track relief, however, to ensure that the rules will unambiguously prevent uneconomic entry of the kind that the New Jersey Law is designed to create.

A. *The States Have Shown That They Are Ready, Willing and Able to Exercise Buyer Market Power*

The states have been the greatest advocates for using the unmitigated exercise of buyer market power to suppress prices in the Commission-jurisdictional wholesale capacity markets. While not the only example, the New Jersey Law referred to above is a prototypical example.

1. *The New Jersey Scheme Is a Textbook Exercise of Buyer Market Power*

a. *Overview*

The New Jersey Law is a classic example of a market power scheme. It exhibits, in distilled form, both principal components. *First*, the scheme requires the state to subsidize, for up to 15 years, new capacity resources at a price substantially above any plausible express or implicit estimate of auction price outcomes. In fact, the New Jersey hearings failed to engage in a stand-alone evaluation of costs, and instead proceeded solely on representations of “savings” associated with the price suppression associated with the exercise of market power. *Second*, the scheme can be expected to substantially and artificially depress capacity market prices via the out of market support of uneconomic new entry. This price effect renders the entire scheme, including its uneconomic component, profitable overall in the short run. *See* Shanker at 38:4-39:14.

In sum, the New Jersey Law is no different than any other attempt to use market power to shift prices—including through economic withholding, which the Commission routinely

interdicts, investigates, and prosecutes. And yet, thanks to the flaws afflicting the Minimum Offer Price Rule set forth above, *see supra* at 18-57, it remains possible that the New Jersey scheme may escape mitigation completely. The Commission should act forcefully to protect its jurisdictional markets and to remove any confusion.

At the core of the New Jersey Law, are Standard Offer Capacity Agreements—styled as the Long-Term Capacity Agreement Pilot Program—to be entered into by eligible generators and the state’s electric public utilities, under the supervision of the New Jersey Board of Public Utilities. New Jersey Law at 18. Under the legislation, the state’s “electric public utilities shall procure 2,000 megawatts of financially-settled [Standard Offer Capacity Agreements] from eligible generators.” *Id.*

An eligible generator that enters into a Standard Offer Capacity Agreement obligates itself to build a “base load or mid-merit electric power generation facility.” *Id.* at 8. *Only* new resources “that commence[] construction after the effective date of the” New Jersey Law are eligible. *Id.* at 9. The New Jersey Board of Public Utilities (and its agent) get to decide the price and quantity of capacity eligible generators have to offer into the RPM auction. *See id.* at 18-19. If there was any question about how the Board will exercise this discretion, it is removed by the requirement that “eligible generators ... participate in and *clear* the annual base residual auction.” *Id.* at 20 (emphasis added). The only way an eligible generator could commit itself to clear the capacity auction is by bidding below competitive levels, or even as a complete price taker (at \$0/MW-day).

The compensation scheme under the statute is a straight “contract for differences.” The Board is ordered to:

establish a method and the contract terms for providing for selected eligible generators to receive payments from the electric public utilities for the difference

between the [contract price] and the [clearing price] multiplied by the [Standard Offer Capacity Agreement] capacity in the event the [contract price] is greater than the [clearing price] for any applicable delivery year and for providing for electric public utilities to receive refunds from the selected eligible generators for the difference between the [contract price] and the [clearing price] multiplied by the [contract price] capacity in the event the [clearing price] is greater than the [contract price] for any applicable delivery year;

Id. at 19. New Jersey ratepayers are the funding source for this subsidy:

The board shall order the full recovery of all costs associated with the electric public utilities' resulting [Standard Offer Capacity Agreements] ... from ratepayers through a non-bypassable, irrevocable charge.

Id. at 20.

b. The New Jersey Scheme Requires Conduct That Is Not Economically Rational on a Stand-Alone Basis

The net effect of these payments and remittances is to transfer all exposure to RPM capacity clearing price from the eligible generator to the state's electric public utilities—and ultimately from consumers. If the clearing price falls below the contract price, ratepayers will make the eligible generator whole, up to the contract price. If the auction clearing price rises above the contract price, the electric public utilities will reclaim all excess revenues. The selected eligible generators will charge the state's electric public utilities for the plant's capacity at the fixed contract price set by the state, not the price resulting from the RPM auction. In addition, the eligible generators have given up not only the economic interest in their plants' capacity, but also any discretion about how to bid the capacity into RPM; they are required to offer capacity as instructed by the state.

Finally, under this scheme, having purchased the capacity at a fixed contract price, the state turns around and offers it, via proxy, into RPM at uncompetitively low levels that are sure to clear the market. This is not the conduct of an economically rational, competitive participant in a single-clearing-price auction. An economically rational participant would offer a resource

into the auction at the marginal cost the participant would have to bear to acquire the resource. If the auction clearing price rises above that offer price, the resource clears and the participant stands to profit from the excess of the clearing price over its cost. If the auction clearing price drops below that offer price, the resource does not clear and the participant avoids taking a loss.

c. New Jersey Nevertheless Intends to Profit on a Portfolio Basis From the Scheme Through Its Price Impact

While facially uneconomic, the state's conduct in RPM is readily explained as an attempt to exercise buyer market power. Unless this exercise of market power is mitigated, the state's expected losses on the Standard Offer Capacity Agreements will be more than offset by its savings on the remainder of the state's portfolio of capacity obligations.

(i) Drafts of the New Jersey Law Repeatedly Suggest That the Purpose of the Scheme Is the Suppression of Capacity Prices

Although the most recent versions of the New Jersey Law have been scrubbed of most references to capacity price levels, earlier public drafts were less discreet. A draft identified the problem to be addressed that RPM, "as estimated by the [New Jersey Board] of Public Utilities, costs New Jersey ratepayers an additional \$1 billion per year for capacity." New Jersey Law, Introduced Version § 1.a (Oct. 18, 2010). The stated purpose of the bill was to "alleviate the cost burden" of RPM. *Id.* § 1.d. "[T]o avoid higher electricity prices" was declared State policy. *Id.*

These statements highlight the fact that the state is deliberately seeking to artificially suppress capacity price outcomes committed to the exclusive jurisdiction of the Commission. That the sponsors of the New Jersey Law saw wisdom in amending the bill to remove the above-quoted statements of intent from the draft strongly suggests that they too have belatedly become aware of the dubious legal ground underlying the legislation.

(ii) *New Jersey Hearing Testimony, and Subsequent Statements, Also Show That the Law Is Designed to Suppress Capacity Prices*

While the text of the New Jersey Law has become less forthcoming about the motives and expectations of its backers, witnesses in favor of the bill, called by the state's legislative committees and their allies, have remained frank.

Take, for example, the Director of New Jersey's Division of Rate Counsel, a state agency tasked with "represent[ing] and protect[ing] [load-side] interest." Stefanie A. Brand, Remarks Regarding A3442, Presented at the Assembly Telecommunications and Utilities Committee Meeting (Dec. 16, 2010), http://www.state.nj.us/rpa/docs/Remarks_of_Stefanie_Brand_A3442-Electric_Generation_Facilities.pdf. She testified as follows:

With the guarantee, these companies can get financing to build their plants. Ratepayers don't pay anything *unless we succeed in reducing the capacity prices* below the figure set in the Agreement, at which point we would pay the difference between the lower price and the set price. If that happens, it would mean that *we have been successful and that we will be saving more overall than we would be paying to these plants.*

Id. (emphasis added).

And according to the press, a spokesperson for one of the generators expecting to be sponsored under the New Jersey Law responded as follows to criticism that it represented a subsidy to the generator:

[He] said the payment is fully recovered in savings ratepayers will see because of a lower capacity price. "If the price goes down to \$200, there is a savings, that means the entire capacity market clearing price has also gone down, which means the ratepayers are now saving money relative to if that plant had not been in that market, in that auction for that particular year," he said.

Kelly Harrington, *N.J. Senate Clears in-State Generation Bill* (Nov. 29, 2010). The spokesman for one of the New Jersey Law's sponsors in the state Assembly was equally blunt: "Consumers have been paying inflated capacity charges[.] ... This is a chance to reverse that. How can that not be a good thing for consumers?" Andrew Maykuth, *Veto urged for N.J. power-plant bill*,

Philadelphia Inquirer, Jan. 13, 2011, http://www.philly.com/inquirer/business/20110113_Veto_urged_for_N_J_power-plant_bill.html.

Any claims that the purpose of the New Jersey Law is to address “projected capacity deficiencies in New Jersey,” New Jersey Law § 1.b, or “reliability concerns,” New Jersey Law § 1.e, or that it “ensure[] sufficient generation is available to the region, and thus the users in the State, in a timely and orderly manner,” New Jersey Law § 1.d, contradicts arguments that the New Jersey Board of Public Utilities—one of the principal proponents of the New Jersey scheme—and the Maryland Public Service Commission—the sponsor of the Maryland scheme, have made to *this* Commission, *see supra* at 10-11 (and the testimony there cited). When attacking the creation of RPM, these parties, far from expressing any concerns that RPM might procure insufficient amounts of capacity for reliability, argued the opposite, that RPM was designed to systematically *over-procure* more capacity than necessary to ensure reliability. *See, e.g., Md. Pub. Util. Comm’n v. PJM Interconnection*, Docket No. EL08-67-000, Complaint at 57 (May 30, 2008) (“PJM’s methods for calculating capacity needs are overly conservative”); *id.* (“An Excess Capacity Requirement Is Built Into The VRR Curve.”); *id.* (“PJM Overestimated Peak Load.”); *id.* at 58 (“PJM Used An Unreasonable [High] Reliability Standard For” Locational Deliverability Areas). Nor was this a generalized or theoretical complaint. New Jersey and Maryland specifically denounced the reserve requirements within their own areas as grossly excessive. *Id.* at 58-60. These parties should not now be heard to argue that they are forced to supplement RPM because it just does not procure enough capacity to ensure reliability.

In light of the fact that there is no requirement in either the drafts or the passed version of the bill that the sponsored resources need to be renewable or otherwise environmentally friendly, any claims that the purpose of the New Jersey Law was to address environmental concerns

would be similarly hard to credit. *See* New Jersey Law, Introduced Version § 3 (Oct. 18, 2010) (declaring any “natural gas fired, combined-cycle” facility eligible); New Jersey Law, Final Version § 3 (making any “base load or mid-merit electric power generation facility” eligible).

Nor is the New Jersey scheme likely to be contained to a limited quantity of subsidized resources. As the principal sponsor of the New Jersey scheme in the State Assembly recently noted, “the bill was expanded Thursday to 2,000 MW because Governor Christie wanted to make sure other regions in the state also have the opportunity to get new plants. ‘It’s politics,’ he said.” Mary Powers, *N.J. legislation would subsidize 2,000 MW*, *Platt’s Megawatt Daily*, Jan. 10, 2011, at 14; *see also* Market Monitor Maryland Report at 4 (summarizing impact of double-sized New Jersey Law and the Maryland RFP).

(iii) New Jersey’s Scheme Is Likely to Be Highly Profitable to Its Sponsors in the Short Run

Beyond the implications of New Jersey’s own statements, and the parallels to the actions of other states, one overarching economic fact powerfully points to the conclusion that New Jersey intends to profit from its scheme by suppressing capacity prices: the scheme as proposed can be expected to succeed at dramatically moving capacity price in New Jersey’s favor. As PJM’s independent market monitor, Dr. Bowring, testified:

Our analysis indicates that adding 1,000 MW of capacity in New Jersey, paying it through an out of market subsidy, and requiring it to offer at zero would result in a reduction in capacity market revenues to PJM suppliers of more than one billion dollars per year, including about 600 million dollars in EMAAC and about 400 million dollars in MAAC. The reduction in capacity payments to suppliers in New Jersey would be about 280 million dollars.

Dr. Joseph E. Bowring, Testimony of to New Jersey Assembly re: Assembly Bill No. 3442 (Dec. 16, 2010) (“Bowring Testimony”), http://www.monitoringanalytics.com/reports/Reports/2010/Bowring_NJ_Assembly_3442_Testimony_20121216.pdf.

Dr. Bowring testified with respect to the 1,000 MWs of capacity originally authorized by the New Jersey Law. Subsequent analysis by Dr. Bowring based on the full 2,000 MW of additional sponsored capacity increased the first-year estimate of the price impact of the New Jersey scheme to \$2 billion. *See* Market Monitor Maryland Report at 4. After the New Jersey Law was signed, a spokesman for the state’s governor endorsed this analysis. Naureen S. Malik, *New Jersey Passes Law to Build New Gas-Fired Power Plants*, Dow Jones Newswires, Feb. 1, 2011 (quoting Michael Drewniak, spokesman for Gov. Chris Christie, as saying “The new generation could cut \$2 billion in annual PJM capacity payments.”).

The text of the New Jersey Law confirms that its sponsors too are quite aware of this opportunity to profit from the exercise of market power. The New Jersey Law orders the Board of Public Utilities to “select[] [the] of winning eligible generators based on the *net benefit* to ratepayers.” New Jersey Law at 18 (emphasis added); *see also* New Jersey Law at 19 (ordering the board to “establish a method for evaluating and comparing the net value to ratepayers of each eligible generator’s offer price and term”). The subsidy to the sponsored new entrants can only be a cost to ratepayers. The only way for the state to profit from the scheme, and thereby realize a *net benefit*, is by suppressing capacity prices. The reference to net benefits thus tacitly admits the intent of the legislation.

2. *Maryland Is Initiating a Similar Market Power Scheme of Its Own*

In addition, Maryland recently has embarked on a similar scheme. The Maryland Public Service Commission in its most recent Draft Request for Proposal for New Generating Facilities summarized its scheme as follows:

The [Maryland Public Service] Commission is requesting proposals for Products, which must include Capacity, Energy and any available Ancillary Services and which may include Maryland Tier 1 RECs. The Products must be derived from Generation Capacity Resources (as defined in the PJM RAA) that will be located in or around Maryland so long as such Generation Capacity Resource is

interconnected to the System such that the Generation Capacity Resource's output is infed to a node east of the Western Interface and deliverable to Maryland east of the Western Interface avoiding likely transmission congestion.

Maryland RFP at 3.

In all essentials, the Maryland scheme is identical to the New Jersey scheme. Maryland, like New Jersey, seeks to suppress RPM capacity prices by sponsoring new entrants through unduly discriminatory new contracts for differences:

- (a) Only new resources are permitted to participate. *See id.* at 4 (“Capacity from the Generation Capacity Resource(s) must not have cleared any prior PJM capacity auction”).
- (b) The method by which these new resources are subsidized is a contract for differences. *Id.* (“The financial arrangement between the Buyer and a Supplier for Capacity, Energy and Ancillary Services will be a Contract-for-Differences (CfD)”).
- (c) The sources of the subsidy are the local electric distribution companies and their ratepayers. *See id.* at 5 (“For the Supplier’s Capacity and Energy, the financial arrangement between the [electric distribution company] and the Supplier will be a CfD between a) the Supplier’s contract Capacity price and the RPM Locational Deliverability Area clearing price applicable to the Maryland [electric distribution company]’s service territory, and between b) the Supplier’s contract Energy price and the hourly PJM nodal Locational Marginal Pricing (LMP) in the PJM DAM and/or RTM, as applicable, at the point of delivery into the [electric distribution company]’s service territory.”).
- (d) New resources are to be injected into the capacity auctions as rapidly as possible. *See id.* at 3 (“Generation Capacity Resources that can achieve a Commercial Operation Date (COD) on or around June 1, 2015 will be favored in this solicitation.”).
- (e) Conventional resources are permitted to participate in the Maryland scheme, defeating any suggestion that environmental concerns are at its root. *See id.* (“Generation Capacity Resources may be conventional or renewable generation technology”).
- (f) The Maryland Public Service Commission claims that the purpose of the Maryland scheme is to protect reliability. *Id.* at 1 (“The purpose of this RFP is to ensure the continued, long-term reliability of the electricity supply to Maryland customers.”); *id.* at 2 (justifying scheme on the basis that “Maryland law directs this [Maryland Public Service] Commission to ensure an adequate and reliable supply of electricity to Maryland citizens.”). These claims, just as New Jersey’s

parallel claims, are in direct contradiction to the Maryland Public Service Commission's statements to the Commission. *See supra* at 62.

- (g) The capacity from the new resources must be offered not at the competitive price, but at a price that guarantees that the resources will be obligated in the RPM and therefore impact the clearing price. *See id.* at 5 (“The Supplier must offer such Capacity into the PJM BRA so that it will clear and be committed, subject to the direction and timely notification of the [Maryland Public Service] Commission”).

In fact, the New Jersey and Maryland schemes are so close to being carbon copies that it is shorter to list their substantive differences:

- (a) The Maryland scheme covers up to 1,800 MW, compared to 2,000 MW for the New Jersey scheme. *See id.* at 4 (“The Commission may award one or more contracts to one or more Suppliers for Products derived from Generation Capacity Resources or may direct one or more [electric distribution companies] to construct new generation up to, but not to exceed, a total installed capacity of 1,800 MW.”).
- (b) The Maryland scheme requires participants to turn over all of their economic interest in not only the capacity markets, but also the energy markets via additional contract-for-differences payments. *See id.* at 5.

Neither of these details has any impact on the analysis of the scheme's purpose and impact in the capacity markets.

Finally, the admitted core purpose of the Maryland scheme is the same as that of the New Jersey scheme: to recoup the subsidy expense and reap profits on a portfolio basis from the artificially depressed capacity market prices. The Maryland proposal, while not quite as blatant as the draft New Jersey Law, still makes this purpose entirely clear by stating that proposals will be evaluated on the basis of “the impact of different Generation Capacity Resource portfolios on the *expected net benefits* realized by” Maryland. *Id.* at 16 (emphasis added). For there to be a *expected net benefit*, Maryland can only be counting on its portfolio profit from suppressed capacity market prices. In specifying this net-benefits criterium as the standard against which it will judge proposals, Maryland tacitly admits that it is engaged in artificial price suppression, that is, the exercise of market power.

3. *Nothing in the Revised Minimum Offer Price Rule Stands in the Way of New Jersey, Maryland or Any Other PJM State Enacting Policies Within Its Domain*

We expect that our opponents will claim that a strengthened Minimum Offer Price Rule will interfere with states' rights to formulate and implement policy about when and where to build generation, and what generation to build. This is a red herring.

Our proposed Minimum Offer Price Rule, just like the current Minimum Offer Price Rule, imposes *no requirements whatsoever* on states with respect to their local power supply policy. With or without the Minimum Offer Price Rule, states remain free to permit or not to permit new generation, or to choose some particular type of facility to further other state policy objectives (such as limiting greenhouse gas emissions). They also remain free to establish any local reliability or additional adequacy requirements they wish. Nothing in any Minimum Offer Price Rule under consideration will in any way threaten state action on these matters.

The sole effect of a Minimum Offer Price Rule is on the *price* of capacity—a matter undisputedly within the Commission's exclusive jurisdiction. Any attempt to argue that the Minimum Offer Price Rule somehow invades the proper province of state regulation runs head-long into binding precedent to the contrary. As the D.C. Circuit has ruled:

Of course, it is a basic principle of economics that prices affect supply—the auction clearing prices in each sub-region of New England will certainly influence the amount of capacity that generators are willing to supply. Indeed, one of the primary purposes of the new market mechanism is to provide incentives to attract new infrastructure where needed. But an incentive is not a mandate. The mere fact that the Forward Market will encourage new supply does not mean that it *regulates* facilities used for the generation of electric energy. Rather, the Forward Market is designed to address pricing issues, which fall comfortably within FERC's statutory authority over the sale of electric energy at wholesale in interstate commerce.

Me. Pub. Utils. Comm'n v. FERC, 520 F.3d 464, 479 (D.C. Cir. 2008) (internal citations and alterations omitted) (generally upholding *Devon Power*, 115 FERC ¶ 61,340, *order on reh'g and clarification*, 117 FERC ¶ 61,133; *ISO New England*, 117 FERC ¶ 61,132 (2006), *reh'g denied*,

119 FERC ¶ 61,044 (2007)), *rev'd in part on other grounds sub nom. NRG Power Mktg. v. Me. Pub. Utils. Comm'n*, 130 S. Ct. 693, *remanded by Me. Pub. Utils. Comm'n v. FERC*, 625 F.3d 754 (D.C. Cir. 2010).

The Commission similarly considered and rejected this same argument when used to attack NYISO's buyer mitigation rules:

Because uneconomic entry could produce unjust and unreasonable capacity prices by artificially depressing those prices, and NYISO's proposal provides a reasonable means to deter uneconomic entry in the in-City market, we deny NYPSC's request that the Commission reject the proposed minimum bid requirements for new capacity suppliers. Contrary to NYPSC's claim, we find that granting its request would adversely impact matters within the Commission's jurisdiction—in particular, the establishment of just and reasonable wholesale electric energy rates. Adoption of NYPSC's proposal would lead to artificially depressed capacity prices, thus both causing existing generators to be under-compensated and also directly and adversely impacting the Commission's ability to set just and reasonable rates for capacity sales in the in-City market. ...

The NYISO's offer floor proposal is an integral part of NYISO's proposal, which the Commission is adopting, needed to “promote long-term reliability while neither over-compensating nor under-compensating generators.” The issue before us in this proceeding is not how to meet the resource adequacy requirements of New York State, but how prices for capacity in the wholesale markets should be determined in order to remedy identified flaws in the ICAP market. As we have found previously, issues of resource adequacy are important to the Commission in meeting our statutory mandate under the [Federal Power Act] to ensure that the rates, terms and conditions of jurisdictional transmission and sales of electric energy are just, reasonable, and not unduly discriminatory, or preferential.

Further, we find that our action in approving NYISO's minimum bid proposal does not adversely affect NYPSC's regulation of resource adequacy in NYC. This new pricing methodology does not prescribe whether or what types of generation facilities should be built, contrary to NYPSC's concerns.

New York Ind. Sys. Operator, 122 FERC ¶ 61,211 at PP 110-12 (citations omitted).

In sum, the sole effect of our proposed Minimum Offer Price Rule would be to reduce the risk that uneconomic entry would distort the competitive price levels in the PJM capacity markets. If that is no part of the uneconomic entry sponsors' intent, an effective Minimum Offer Price Rule will not deter their behavior. If distorting the PJM capacity markets *is* the intent, then

the Commission is statutorily *required* to thwart such conduct and protect competitive wholesale power prices. States retain the power to pursue whatever lawful initiatives they wish, so long as they, not the market, pay the cost of the consequences of uneconomic designs. If they chose to bear these costs themselves, without distorting prices under the Commission's jurisdiction, they can do so. But they are not entitled to distort prices in the Commission's jurisdictional markets.

B. Fast Track Relief Is Essential

The next RPM auction is scheduled for May 2011. Given the imminent threats that the auction results will be affected by the exercise of market power, fast track relief is required.

The issues raised herein call for an expeditious resolution or, at least, a clarification that any action undertaken by a market participant, such as the execution of the New Jersey scheme, will not be deemed to have created facts that the Commission would be compelled to accept as *fait accompli* in any subsequent resolution.

The sponsors of the New Jersey scheme, seeking to exploit the flaws of the Minimum Offer Price Rule, PJM RPM § 5.14(h), show great concern with speed. *See, e.g., N.J. Senate Rushing Bill to Build New Power Plant*, [pressofatlanticcity.com](http://www.pressofatlanticcity.com), (Dec. 12, 2010, 1:00 PM), http://www.pressofatlanticcity.com/business/article_b5004b6f-38d1-5971-9d94-05786c6186f6.html (updated Dec. 13, 2010, 10:04 AM). The bill was introduced into the state senate on October 18, 2010 and the state assembly on October 25 and was immediately referred to the relevant committees, was passed by the legislature on January 10 and was signed by the governor on January 28. *See* New Jersey Law, Introduced Version (Oct. 18, 2010); Assemb. No. 3442, 214th Leg. (Oct. 25, 2010); Press Release, Office of the Governor of New Jersey, Governor Chris Christie Takes Action on Legislation (Jan. 31, 2011), <http://www.state.nj.us/governor/news/news/552011/approved/20110131b.html>. The bill waives “any provisions of the [state] Administrative Procedures Act” and sets a rapid schedule for completion:

The board shall initiate and allow such proceeding to be completed no later than 60 days after the effective date of [the New Jersey Law] to allow for the commencement of the [New Jersey scheme]. The [contracts] resulting from that proceeding shall be awarded and executed no later than 30 days after the approval of the form of the [contracts].

New Jersey Law at 17. This schedule is designed to permit the new sponsored resources to participate in the May 2011 Base Residual Auction. That this is the aim of the sponsors is confirmed by the instruction that “generators that can enter commercial operation for delivery year [2014/15] are to be provided with a weighted preference.” New Jersey Law at 18.

The clear implication is that the sponsors of the New Jersey scheme either deliberately seek to deny the Commission any opportunity to act in a timely manner, or at the very least deem the absence of Commission review desirable.¹¹ This is unsurprising. The sponsors of the scheme may very well hope that by acting before the Commission can react, they will be able to cram their resources into the upcoming Base Residual Auction unimpeded. If—thanks to the inadequate Minimum Offer Price Rule—these resources then clear in the auction, their sponsors undoubtedly will argue that any revisions to the tariff subsequently approved by the Commission cannot be applied to these resources, given the injunction against retroactive ratemaking and concern about the preservation of settled expectations. *Cf. N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at P 118 (exempting existing units from mitigation because deterrence of uneconomic entry is “by definition, is no longer possible”).

The Commission should interdict such efforts to avoid its jurisdiction and statutory mandate to ensure just, reasonable and non-discriminatory price outcomes in competitive markets:

¹¹ That the New Jersey Law contains a provision, added at the last minute, to permit the New Jersey Board of Public Utilities to suspend any provisions which are legally challenged, *id.* at 21, should offer little comfort. This suspension is purely within the discretion of the Board and, given that body’s stated preferences, unlikely to be exercised.

First, as we note below, *see infra* at 75, the present complaint is eminently well-suited for fast-track processing: the facts are not in dispute and the law and economics are unambiguous. Moreover, we have acted expeditiously in order to preserve the Commission's authority by preparing for litigation as soon as the New Jersey scheme became public knowledge and filing this complaint within days of the New Jersey Law's enactment. Furthermore, in order to reach a concrete solution as quickly as reasonably practical, we have also taken the uncommon step of proposing concrete revised tariff language in this initial complaint. As a consequence, the Commission is in a position to rule on this complaint in time for the May 2011 Base Residual Auction. We urge the Commission to do so.

Second, even if the Commission were unable to issue a ruling on the matters presented here before the next Base Residual Auction, this complaint gives notice that the legality of the New Jersey Law is very much in doubt. This awareness precludes any settled expectation that any resources used in the scheme will be shielded from future corrections to the PJM tariff ordered by the Commission. The filing of this complaint also establishes a refund effective date, *see infra* at 76, far in advance of the May 2011 Base Residual Auction.

Third, even if the Commission were unable to issue a ruling before the next Base Residual Auction and the charges arising out of that auction were deemed final and not subject to refund, this would not bar mitigation of the New Jersey scheme resources in future Base Residual Auctions. As the Commission ruled in the context of RPM, and at the urging of the Maryland Public Service Commission, even an exemption from mitigation expressly granted by the Commission remains subject to later rescission and prospective mitigation. *See Md. Pub. Serv. Comm'n v. PJM Interconnection*, 123 FERC ¶ 61,169, *reh'g denied* 125 FERC ¶ 61,340 (2008).

We find that imposition of mitigation on the previously exempt units is appropriate because we find the existing standard for whether to mitigate these particular units is no longer just and reasonable. ... Rather than having PJM establish an entirely new market power standard for [the previously expressly exempt] generators, we find that PJM should apply the same market power test to these generators as to all other generation. In sum, we find that the uncertainty and difficulty inherent in the administration of the currently effective “significant” market power standard can result in rates that are unjust and unreasonable and that this standard should be replaced with the standard used by PJM for assessing market power for all generators.

123 FERC ¶ 61,169 at P 43. If an RPM mitigation exemption expressly granted to certain generation resources and approved by the Commission can subsequently be rescinded, any New Jersey scheme resources that slipped through the Minimum Offer Price Rule loopholes—before they could be closed—can and should be subjected to mitigation in future auctions. The revised Minimum Offer Price Rule proposed herein is designed to “recapture” any resources that slipped through these loopholes. Any resources that were part of a market power scheme subsequently recognized by the Commission would be subject to mitigation from the time of recognition until they pass the market test establishing that they would have been created on the basis of their true, economic costs. *See supra* at 37.

Nevertheless, and for the foregoing reasons, an expeditious resolution of the issues raised in this Complaint is both feasible and highly desirable. We believe that the Commission will have sufficient time to fully consider the merits of the issue and order appropriate tariff changes before the next Base Residual Auction in May 2011. However, if the Commission should conclude that the complexities of the Revised Minimum Offer Price Rule proposed herein require more extensive Commission consideration, we urge the Commission to issue a stop-gap measure to prevent RPM from collapsing in the interim. In particular, one possibly effective stop-gap would be to apply a 100% benchmark to all offers from new combustion turbine and combined cycle generators in the upcoming Base Residual Auction. Such a change could be

implemented very quickly. The additional components of the Revised Rule could then be considered and implemented in time for the next auction.

V. *ALTERNATIVELY, THE COMMISSION SHOULD CLARIFY THAT PJM MAY TREAT CONTROLLING SPONSORS AS “AFFILIATES” WITHIN THE MEANING OF THE CURRENT TARIFF*

As a stop-gap measure, pending full consideration and implementation of a Revised Minimum Offer Price Rule, the Commission should clarify that PJM is permitted to interpret the tariff’s definition of “affiliate” to include parties which sponsor and effectively control the participation of other parties in the PJM capacity markets. Such an interpretation, while not entirely without challenges, *see supra* at 45, is appropriate under the special circumstances that the Commission and PJM face here and necessary—but perhaps not sufficient—to avoid a blatant avoidance of the intention of the Rule.

As explained above, the New Jersey scheme transfers not only all economic interest in the capacity to the New Jersey utilities, but also effective control of bidding behavior, from the putative owner and legal seller of the capacity to the state, working hand-in-glove with the utilities. *See supra* at 57-64. The same holds for the Maryland scheme. *See supra* at 64-67. For all economic and practical purposes, the state and its utilities would control the uneconomic capacity to be dumped into the auctions.

The tariff defines two entities to be affiliated when one “controls, is controlled by, or is under common control with” the other. PJM Tariff § 1.0A.01. Regardless whether the sponsored capacity market seller is controlled by a state or the utilities in a global sense, it is clear that under the structure of the proposed schemes, the sponsored capacity market seller is controlled by the state and the utilities as far as participation in the capacity markets is concerned. As this is the only issue relevant to the Minimum Offer Price Rule, it is appropriate to view the capacity market seller as an affiliate of the state and the utilities for this special purpose.

The purpose and effect of deeming the utilities, the state, and the capacity market sellers to be affiliates under the Minimum Offer Price Rule is to stop at least the most conspicuous and artless attempts to sidestep the intent of the Rule. Unless the utilities and the capacity market sellers are regarded as affiliated, the state could direct a net-short utility it regulates to enter into contracts with nominally independent capacity sellers to create artificially suppressed capacity price outcomes. This is, in fact, the basis of the current New Jersey and Maryland schemes. Until the Commission can eliminate the net-short loophole and other flaws entirely, PJM should be permitted to interpret the affiliation in a manner sufficient to narrow the loophole.

VI. OTHER MATTERS

A. Other Proceedings

In accordance with Rule 206(b)(6), 18 C.F.R. § 385.206(b)(6), we state that the specific matters raised in this complaint are not pending before the Commission in any other docket to which P3 is a party.

B. Negotiations Among the Parties

In accordance with Rule 206(b)(9), 18 C.F.R. § 385.206(b)(9), P3 verifies that it has attempted in good faith to resolve these matters, but that those attempts have been unsuccessful. P3 and its members, as well as PJM's independent market monitor, have testified to New Jersey legislative committees considering the New Jersey scheme and attempted to dissuade them from entering upon it for, among others, the reasons stated herein. We have long, but without signal success, sought reforms at the stakeholder level to improve and strengthen the Minimum Offer Price Rule. As such, we do not believe that it would be productive to utilize the Commission's informal dispute resolution procedures.

C. Financial Impact

In accordance with Rule 206(b)(4), 18 C.F.R. § 385.206(b)(4), we cite the independent market monitor's estimate that in the first year alone, the adverse financial impact of the New Jersey and Maryland schemes could be \$3 billion. *See* Market Monitor Maryland Report at 4.

D. Service and Form of Notice

In accordance with Rule 206(c), 18 C.F.R. § 385.206(c), we are simultaneously serving a copy of this filing on PJM, the New Jersey Board of Public Utilities and the Maryland Public Service Commission, which parties and regulatory agencies we reasonably expect to be affected by this Complaint. We have attached herein a Form of Notice suitable for publication in the *Federal Register* in accordance with Rule 206(b)(10), 18 C.F.R. § 385.206(b)(10).

E. Request for Fast Track Processing

The issues raised in this Complaint justify Fast Track processing under Rule 206(b)(11), 18 C.F.R. § 385.206(b)(11). As discussed more fully above, *see supra* at 69, timing is of the essence in resolving this complaint. The New Jersey scheme threatens to depress prices in the upcoming Base Residual Auction set to begin on May 2, 2011. While, as explained above, passage of these dates would not raise a legal bar to subsequent resolution of the claims in this complaint, practical considerations strongly favor an earlier resolution. Resolution before May 2 would protect PJM from having to subsequently rerun the 2014/15 Base Residual Auction and protect capacity market participants from having their revenues and liabilities adjusted after the fact. Resolution a few days or weeks earlier would help prevent administrative upheaval. Under these circumstances, the Commission is well justified in exercising its authority to resolve this matter on a Fast Track basis.

F. Refund Effective Date

We request the earliest possible refund effective date, which, by statute, is the date this complaint is filed.¹² Our purpose, as explained above, is for relief, in the form of just and reasonable tariff provisions, to be in effect for the 2014/15 Base Residual Auction, currently scheduled to begin on May 2, 2011.

G. Other Complaint Requirements

In fulfillment of the other requirements for complaints under Rule 206(b), we note as follows: In accordance with Rule 206(b)(1), 18 C.F.R. § 385.206(b)(1), we identify PJM's current, inadequate Minimum Offer Price Rule as the proximate cause of the complaint and note that this heretofore largely theoretical fault of PJM's Tariff threatens to become highly relevant due to the current or threatened actions of New Jersey and Maryland. In accordance with Rule 206(b)(2), 18 C.F.R. § 385.206(b)(2), we explain in detail how the Minimum Offer Price Rule allows violation of the Federal Power Act's requirement of just, reasonable, and non-discriminatory rates, *see supra* at 21-57, and how the various proposed schemes seek to exploit this flaw in PJM's Tariff, *see supra* at 57. In accordance with Rule 206(b)(3), 18 C.F.R. § 385.206(b)(3), we note that a successful exercise of buyer-side market power in the RPM would both expropriate P3 members' current investment in capacity and foreclose opportunities for future investment by P3 members, as explained in greater detail in the body of the argument. *See supra* at 16-74. In accordance with Rule 206(b)(5), 18 C.F.R. § 385.206(b)(5), we note that the relevant impacts are primarily financial, but that these financial impacts are of such

¹² This complaint will not give rise to the issues regarding the resettling of underpayments discussed in *City of Anaheim v. FERC*, 558 F.3d 521 (D.C. Cir. 2009). Here, in addition to this Complaint under section 206, PJM is expected to make a section 205 filing more than 60 days in advance of the May 2011 Base Residual Auction. Hence, the Commission will have authority to effect a new tariff, with a Revised Minimum Offer Price Rule, regardless of whether the change in revenue streams can be characterized as a refund. *See id.* at 524-25 (stressing the distinction between relief permitted under sections 205 and 206).

magnitude that they can be expected to affect all decisions (by P3 members and others) to enter or leave all PJM markets. In accordance with Rule 206(b)(8), 18 C.F.R. § 385.206(b)(8), we have submitted a proposed revision of the Minimum Offer Price Rule, *see* Attachment A, expert testimony by Dr. Roy Shanker, *Testimony of Roy J. Shanker, Ph.D. on Behalf of The PJM Power Providers Group*, P3 Exhibit 1, copies of the New Jersey Law, S. No. 2381, 214th Leg. (N.J. 2011), attached at P3 Exhibit 2, and the Maryland Draft Request for Proposals, *In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, No. 9214, Request for Proposals for Generation Capacity Resources Under Long-Term Contract (M.P.S.C. Dec. 29, 2010), attached at P3 Exhibit 3.

CONCLUSION

For the foregoing reasons and in accordance with Rule 206(b)(7), 18 C.F.R. § 385.206(b)(7), we respectfully requests that the Commission grant our complaint and order the Minimum Offer Price Rule to be revised as proposed herein.

Respectfully submitted,

/s/

Glen Thomas*
President
PJM POWER PROVIDERS GROUP
1060 First Avenue
Suite 400
King of Prussia, PA 19406
(610) 768-8080

John N. Estes III
Paul F. Wight*
Carl Edman
SKADDEN, ARPS, SLATE, MEAGHER & FLOM LLP
1440 New York Avenue, N.W.
Washington, DC 20005
(202) 371-7000

Counsel for the PJM Power Providers Group

February 1, 2011

* P3 requests that all further correspondence, communications and other documents relating to this docket be served upon these individuals electronically at gthomas@gtpowergroup.com and Paul.Wight@skadden.com.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group

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v.

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Docket No. EL11-____-000

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PJM Interconnection, L.L.C.

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ATTACHMENT A
*REVISED MINIMUM OFFER-PRICE RULE*¹

(1) For purposes of this section, the benchmark price for a resource shall be 100% of the asset-class estimates of competitive, cost-based, nominal levelized Cost of New Entry, net of energy and ancillary service revenues, based on an appropriate estimate of the length of service for each asset class. If there are no applicable asset class cost or length of service estimates, the benchmark price shall be based on the Reference Resource. In all other regards, determination of the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a) of this Attachment.

(2) In any Base Residual Auction or Incremental Auction, in any LDA for which a separate VRR Curve has been established, any Sell Offer shall be mitigated to its benchmark price before the auction if it is (a) below its benchmark price and (b) not exempt from mitigation under subsection (3).

(3) Notwithstanding subsection (2) a Sell Offer satisfying any of the following conditions shall be exempt from mitigation:

¹ This proposed tariff language only reflects the immediately required changes to the Minimum Offer Price Rule. As noted in the Complaint, *see supra* at 54, several additional issues need to be addressed in the longer run.

(i) Any Sell Offer from a capacity resource that has at least twice previously cleared in a Base Residual Auction. In so far as a resource only cleared partially or the Sell Offer otherwise is for a larger quantity than previously cleared (such as, for example, due to uprates), only the twice-previously cleared quantity is exempt from mitigation.

(ii) Any Sell Offer that the Market Monitoring Unit has determined to be no lower than the resource's nominal, levelized, competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets).

(iii) Any Sell Offer based on a resource that the Market Monitoring Unit has determined not to be the beneficiary of any discriminatory payments. A Capacity Market Seller seeking to obtain such a determination, must at such time prior to the auction set by PJM provide to the Market Monitoring Unit all information requested by the Market Monitoring Unit, accompanied by a sworn declaration by an officer of the Capacity Market Seller that such information is accurate and complete. The Market Monitoring Unit shall consider all of the following direct or indirect payments to the market participant to be discriminatory: capacity price subsidies, contracts for difference, state or local tax benefits that exclude existing resources, uncompetitive creation of assets, payments from non-bypassable retail charges, and any other contract, scheme, artifice, device or arrangement which could be used to suppress capacity prices artificially. If the Capacity Market Seller can demonstrate that the payment would have been equally available to a new or existing resource, the payment shall not be deemed discriminatory. Any resource or partial resource previously exempted from mitigation under subsection (i) or (iii) and which subsequently is determined by the Market Monitoring Unit to have been the beneficiary of

discriminatory payments shall become subject to mitigation until it becomes entitled to exemption again.

(iv) A Sell Offer based on a base load resource, such as nuclear, coal and Integrated Gasification Combined Cycle, which requires a period for development greater than three years.

(v) A Sell Offer for the Delivery Year 2014/15 based on any resource except a new combustion turbine or combined cycle generation facility.

(4) The Capacity Market Seller may seek review of all determinations made by the Market Monitoring Unit under subsection (3) with the Office of the Interconnection. Both the Capacity Market Seller and the Market Monitoring Unit may seek review of the decision of the Office of the Interconnection with FERC.

(5) Resources designated for self-supply or as price-takers in any capacity auction are not exempt from this subsection. Such designations will only be valid if (a) the resource is exempt from mitigation under subsection (3) and would have cleared at a price of \$0/MW-day or (b) if the resource is subject to mitigation under subsection (3) and would have cleared at its mitigated price.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group)
)
 v.) Docket No. EL11-____-000
)
 PJM Interconnection, L.L.C.)

NOTICE OF COMPLAINT

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Take notice that on February 1, 2011, PJM Power Providers Group (“P3”) filed a formal complaint against PJM Interconnection, L.L.C. (“PJM”) pursuant to section 206 of the Federal Power Act, and Rule 206 of the Commission’s Rules of Practice and Procedure, alleging that the tariffs governing PJM’s Reliability Pricing Model (“RPM”) are unjust and unreasonable and subject to manipulation. In particular, the RPM Minimum Offer Price Rule, designed to prevent the exercise of market power by capacity buyers and their proxies, contains several loopholes which render it ineffective: The Minimum Offer Price Rule ceases mitigation of new resources after, at most, one year; it is unnecessarily limited to sellers which can be identified as net-shorts; it only corrects for very large price impacts; and it does not address capacity designated as self-supply. Accordingly, P3 seeks to revise the Minimum Offer Price Rule to eliminate these loopholes.

P3 certifies that copies of the complaint were served on the contacts for PJM as listed on the Commission’s list of Corporate Officials and on parties and regulatory agencies PJM reasonably expects to be affected by this Complaint.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission’s Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent’s answer and all interventions, or protests must be filed on or before the comment date. The Respondent’s answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the “eFiling” link at <http://www.ferc.gov>. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at <http://www.ferc.gov>, using the “eLibrary” link and is available for review in the Commission’s Public Reference Room in Washington, D.C. There is an “eSubscription” link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service,

please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose
Secretary

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group

v.

PJM Interconnection, L.L.C.

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Docket No. EL11-____-000

*TESTIMONY OF ROY J. SHANKER, PH.D.
ON BEHALF OF THE PJM POWER PROVIDERS GROUP*

FEBRUARY 1, 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group)
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 v.)
)
 PJM Interconnection, L.L.C.)

Docket No. EL11-____-000

INTRODUCTION

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Q PLEASE STATE YOUR NAME AND ADDRESS.

A My name is Roy J. Shanker. My address is P.O. Box 60450, Potomac, Maryland 20859.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I have been asked by the PJM Power Providers Group (“P3”) to review the provisions of the Reliability Pricing Model (“RPM”), PJM Tariff Attachment DD, that relate to its Minimum Offer Price Rule, section 5.14. Specifically, I was asked to review the Minimum Offer Price Rule provisions to determine whether they effectively limit buyer market power. If they do not, I was also asked to identify specific changes to the Minimum Offer Price Rule that would effectively limit buyer market power and that could be incorporated into the PJM Tariff. I have identified essential changes, and counsel has prepared proposed tariff language that reflects these changes. They are attached as Attachment A to P3’s Complaint and Request for Clarification Requesting Fast Track Processing (the “Complaint”).

Q PLEASE SUMMARIZE YOUR QUALIFICATIONS TO PRESENT TESTIMONY IN THIS MATTER.

A I have extensive experience with capacity market design in ISO-NE, PJM and NYISO. I have previously offered testimony in Federal Energy Regulatory Commission (the “Commission”) proceedings related to capacity market design. I have also testified on a

1 number of occasions regarding the exercise of buyer market power in organized Regional
2 Transmission Organization capacity markets. I recently submitted testimony to the
3 Commission on four occasions in Docket Nos. ER10-787-000, EL10-50-000 and EL10-
4 57-000 related to the exercise of buyer market power in capacity markets in ISO-NE,
5 which is essentially the same issue raised in this case.¹

6 I have also been a long-term, active participant on several committees and
7 working groups addressing these issues in the NYISO and PJM markets. In NYISO, I
8 began working on the capacity market concepts prior to the start of the market; in PJM, I
9 participated for seven years in the development of the current RPM markets.

10 My resume is attached as P3 Exhibit 1-A.

11 Q HOW IS YOUR TESTIMONY STRUCTURED?

12 A I begin by summarizing my findings, conclusions and recommended changes to PJM's
13 mitigation rules for buyer market power in capacity markets. My main argument is split
14 into three sections. *First*, by way of background, I describe the Minimum Offer Price
15 Rule and the need to limit buyer-side market power. *Second*, I detail the flaws with the
16 current Minimum Offer Price Rule, and then discuss, by way of example, recent efforts
17 by New Jersey to circumvent the Minimum Offer Price Rule. *Third*, I propose solutions
18 to rectify the current problems with the Minimum Offer Price Rule.

¹ Some of the content of this testimony is based directly on previous submissions to the Commission. See *ISO New England Inc.*, Docket No. ER10-787-000, Motion to Intervene and Protest of the New England Power Generators Association, NEPGA Exhibit 1, Affidavit Of Roy J. Shanker Ph.D. (Mar. 15, 2010); *ISO New England Inc.*, Docket Nos. ER10-787-000 & EL10-50-000, Motion for Leave to Answer and Answer of the New England Power Generators Association, NEPGA Supplementary Exhibit 1, Supplementary Affidavit of Roy J. Shanker Ph.D. (Apr. 13, 2010); *ISO New England Inc.*, Docket Nos. ER10-787-000, EL10-50-000 & EL10-57-000, Opening Brief of the New England Power Generators Association, Inc., NEPGA Exhibit 1, Testimony of Roy J. Shanker Ph.D. (July 1, 2010); *ISO New England Inc.*, Docket Nos. ER10-787-000, EL10-50-000 & EL10-57-000, Second Brief of the New England Power Generators Association, Inc., NEPGA Exhibit 8, Supplementary Testimony of Roy J. Shanker Ph.D. (Sept. 1, 2010).

1 Auction where a Sell Offer by a new entrant is submitted. The Minimum Offer Price
2 Rule thus can only mitigate a transparently uneconomic and manipulative offer for *one*
3 *year*, regardless of whether the facility remains uneconomic. Further, a party may easily
4 circumvent this one-year effective period by gaming the anticipated in-service date of a
5 unit.

6 4—Finally, the Minimum Offer Price Rule only applies to a very limited, and
7 easily manipulated, subset of resources. There are too many exceptions to its application.
8 There are several, but I focus on three:² (a) the Minimum Offer Price Rule only applies
9 to net buyers of capacity, but as the Commission has previously determined, a net buyer
10 screen is easily circumvented to allow uneconomic entry and is ineffective on its own in
11 identifying anti-competitive conduct;³ (b) the Minimum Offer Price Rule's definition of
12 Planned Resources is far too narrow; and (c) the existing rules may ignore self-supply,
13 possibly permitting a seller to designate an uneconomic unit as self-supply and
14 circumvent any buyer-side mitigation. All of these exceptions should be eliminated.

15 Collectively these flaws make the current Minimum Offer Price Rule largely
16 useless to control and mitigate the exercise of buyer-side market power.

17 Q WHAT ARE YOUR RECOMMENDATIONS BASED ON THESE CONCLUSIONS?

18 A The Minimum Offer Price Rule must be modified and strengthened to create a viable
19 buyer market power mitigation tool for the PJM capacity markets. *First*, any resource
20 would pass the conduct screen if it bids at least 100 percent of the nominal levelized net

² I understand that counsel discusses other exemptions to mitigation in the rules. I agree that these other exemptions should be eliminated, but I have not undertaken to address in this testimony every loophole and exemption to mitigation in the current rules.

³ The net buyer test in the Minimum Offer Price Rule is even worse because the specific thresholds in the test approximate the *status quo*, permitting material price manipulation and suppression by buyers without the screens ever being triggered.

1 Cost of New Entry of the Reference Resource (a combustion turbine as defined in
2 Attachment DD of the PJM Tariff, section 2.58).

3 Any resource bidding below this threshold could still pass the conduct screen if it
4 establishes that it has not received any out-of-market payments, as determined at the time
5 of the offer. The Independent Market Monitor or PJM will look for any indication, direct
6 or indirect, of the seller being the beneficiary of discriminatory out-of-market payments
7 not generally available to all market participants (e.g., a contract supporting new entrants
8 only). Projects built by rate-based entities, or otherwise supported by non-bypassable
9 retail rates, shall be assumed to fail the screen. A senior officer of the new entrant or its
10 parent company shall certify the accuracy of all information provided to the Independent
11 Market Monitor. To the extent that any new resources represent an attempt to manipulate
12 market prices, they will be deemed to have failed the conduct test, whether specifically
13 falling into the above categories or not.

14 Q SHOULD ANY DISTINCTIONS BE MADE BETWEEN LONG-LEAD-TIME AND
15 SHORT-LEAD-TIME RESOURCES?

16 A Yes. Longer-lead-time new entrants are those that will take more than three years to
17 move from an Interconnection Service Agreement to commercial operation. Longer-
18 lead-time resources thus require a determination of mitigation status outside the time
19 horizon of the PJM capacity auction process. I recommend an initial determination of
20 whether a longer-lead-time unit is economic at the time the Interconnection Service
21 Agreement is signed. The unit's own nominal levelized Unit Specific Net Cost of New
22 Entry should be compared with a projection of future auction prices. If the unit is

1 economic under this test, then at the time of actual commercial operation, it may offer
2 into the market at its Avoidable Cost Rate or less.

3 If it is uneconomic, a new long-lead-time unit should be mitigated at its nominal
4 levelized Unit Specific Net Cost of New Entry as determined at the time of
5 Interconnection Service Agreement signing. Mitigation would only cease after the
6 facility clears at least two Base Residual Auctions. This is consistent with the remedies
7 that the Commission recently utilized in addressing the NYISO In-City Buyer-Side
8 Mitigation, as I explain below.

9 Short-lead-time projects that can be built within the RPM three-year-lead
10 window, presumptively including all new combustion turbines and combined cycle
11 generation units, would not have the same option. My recommendations recognize that
12 the RPM auction itself and associated clearing prices can be integrated into the mitigation
13 process for these short-lead-time resources.

14 Q HOW WOULD THE MITIGATION BE APPLIED?

15 A For any project failing the screen, the new entrant's offer in PJM capacity auctions will
16 be mitigated to 100% of the nominal levelized Unit Specific Net Cost of New Entry. As I
17 explain, this is the appropriate value to adopt in PJM given conditions in the market.

18 Q HOW WOULD SHORT-LEAD-TIME NEW RESOURCES ESTABLISH THEIR UNIT
19 SPECIFIC NET COST?

20 A Upon failing the conduct test, short-lead-time resources will receive a determination of a
21 nominal levelized Unit Specific Net Cost of New Entry as a mitigation level. The
22 Independent Market Monitor or PJM shall determine a nominal levelized Unit Specific
23 Net Cost of New Entry, subject to appeal to the Commission. The nominal levelized Unit

1 Specific Net Cost of New Entry shall be calculated based on the actual or projected costs
2 of the new entrant with the exception of capital costs, which should be the Independent
3 Market Monitor's current generic capital cost assumptions for similar new units in the
4 PJM markets. This value shall be calculated in the same way that PJM currently
5 calculates the annual nominal cost of the Reference Resource. The energy and ancillary
6 services offset for the Unit Specific Net Cost of New Entry shall also be calculated in the
7 same way that the Independent Market Monitor currently calculates it for the Avoidable
8 Cost Rate calculations.

9 Q HOW LONG WILL THE MITIGATION LAST?

10 A The mitigation offer floor shall remain in effect until a new entrant clears the Base
11 Residual RPM Auction at least twice. Mitigation should cease for only the MW portion
12 of a new entrant's mitigated offer that clears the market at least twice. The non-cleared
13 portion of the new entrant will continue to be mitigated to the applicable offer floor.

14 Clearing will be incrementally determined for the new entrant based on any
15 portion of the resource that clears. The new entrant cannot participate in any other PJM
16 auctions until it first clears two Base Residual Auctions at the nominal levelized Unit
17 Specific Net Cost of New Entry.

18 For all projects, both short- and long-lead-time, the Independent Market Monitor
19 shall have the ability to reinstate the mitigation offer floor if the Independent Market
20 Monitor determines that any party, regardless of whether the party is a new entrant, has
21 acted in a manner to improperly influence the clearing price of a Base Residual Auction.

1 Q DO YOU RECOMMEND ANY OTHER CHANGES?

2 A Yes. Consistent with the NYISO In-City Buyer-Side Mitigation, I recommend that the
3 net-buyer-of-capacity conduct screen should be eliminated. I also recommend that any
4 real or implied waiver of mitigation for self-supply should be removed. A mitigated new
5 entrant cannot be used for self-supply until it clears in two Base Residual Auctions. And
6 I recommend elimination of the limitation in the Minimum Offer Price Rule that restricts
7 its application only to some Planned Generation Capacity Resources.

8 Q DOES THE TARIFF LANGUAGE PROPOSED BY COUNSEL EXACTLY MATCH
9 THESE RECOMMENDATIONS?

10 A Not exactly. To allow expedited implementation, my understanding is that counsel has
11 prepared language that would initially use 100% of the *Asset Class* cost information for
12 the conduct screen and the “mitigate-to” values, rather than using the Reference Resource
13 as I recommend. My understanding is that this is an effort to expedite relief. I would,
14 however, recommend that the structure that I propose be implemented as soon as
15 possible, and no later than at the time of any required compliance filing by PJM in the
16 anticipated consolidated proceedings.

17 *I. BACKGROUND*

18 *A. THE MINIMUM OFFER PRICE RULE*

19 Q PLEASE SUMMARIZE THE MINIMUM OFFER PRICE RULE.

20 A The Minimum Offer Price Rule is contained in the PJM tariff, Attachment DD, section
21 5.14(h). The intent of the Minimum Offer Price Rule is to prevent uneconomic entry by
22 repricing Sell Offers that are less than the defined floors relative to the Cost of New
23 Entry. The goal of the Minimum Offer Price Rule is to mitigate buyer market power and
24 price discrimination and suppression. To achieve this goal, the Minimum Offer Price

1 Rule applies a general form of conduct and impact mitigation to the potential exercise of
2 buyer market power in the first Base Residual Auction in which a Sell Offer is
3 submitted—and *only* in the first Base Residual Auction in which a Sell Offer is
4 *submitted*.

5 Under the Minimum Offer Price Rule, the Independent Market Monitor develops
6 asset class estimates of real levelized net costs of new entry (the “Net Asset Class Costs
7 of New Entry”). The Independent Market Monitor then compares actual Sell Offers of
8 new entrants to these reference levels.⁴ The conduct screen is failed if the Sell Offer is
9 less than 80% of the Net Asset Class Cost of New Entry and if the Offeror is considered a
10 net buyer.⁵ At that point, the Offeror is informed of the conduct test failure and is given
11 an opportunity to justify the basis for offering at a lower price than the threshold.

12 The Independent Market Monitor also conducts an impact test by rerunning the
13 Base Residual Auction and using a substitute Sell Offer. The substitute Sell Offer is set
14 at 90% of the applicable Net Asset Class Cost of New Entry or 80% of the reference Net
15 Cost of New Entry if no other value is available. The impact test fails if the change in
16 Clearing Price for the locational delivery area exceeds the greater of: (1) \$25 or 20% for
17 a locational delivery area of 15,000 MW or more; (2) \$25 or 25% for a locational
18 delivery area of between 5,000 and 15,000 MW; or (3) \$25 or 30% in a locational
19 delivery area of less than 5,000 MW. If the impact test is failed, the original auction

⁴ Under the current tariff, reference levels are zero for base load resources, hydroelectric, upgrades or any new entry unit being developed in response to a state regulatory process that (1) is designed to resolve reliability needs, (2) allows PJM to participate, (3) gives due notice and (4) provides an opportunity to comment. If no Net Asset Class Cost of New Entry is available, the standard will be 70% of the reference Net Cost of New Entry for the specified locational delivery area.

⁵ The net buyer requirement is a function of the size of the locational delivery area. The net short criterion is 10% for a locational delivery area of less than 10,000 MW and 5% for a locational delivery area of 10,000 MW or more.

1 result is rejected and a new auction Clearing Price is established using the substitute Sell
2 Offer.

3 **B. BUYER-SIDE MARKET POWER**

4 Q THE GOAL OF THE MOPR IS TO LIMIT BUYER-SIDE MARKET POWER. WHY
5 IS THERE A NEED FOR BUYER-SIDE MARKET POWER MITIGATION?

6 A It has become increasingly clear to me that certain states and market participants operate
7 under the belief that price discrimination is a legitimate and desirable goal to be pursued
8 in a capacity market design. These entities repeatedly attempt to find ways to pay market
9 rates only to new entrants, and suppress prices for existing capacity suppliers. These
10 views persist notwithstanding the Commission's findings that such actions are
11 discriminatory and unjust. And while artificially suppressed prices may appear attractive
12 to consumers in the short run, they cannot be sustained, and actually result in higher costs
13 in the long run.

14 Q WHEN ARE BUYER MARKET POWER MITIGATION MECHANISMS
15 NECESSARY?

16 A Mechanisms to screen and mitigate buyer market power are necessary when there is
17 insufficient intrinsic competition, or if market shares are highly concentrated, or if it is
18 possible to circumvent the market for cost recovery. Such conditions exist in PJM.
19 Indeed, the potential exercise of buyer market power is of particular concern in PJM
20 because the design of the demand curve allows relatively small increases in supply to
21 significantly depress market-wide prices. This is coupled with the potentially
22 concentrated purchasing power of several buyers or representatives of buyers (e.g., states
23 or state agencies), who have the ability to make discriminatory investments in
24 uneconomic capacity resources through mechanisms such as out-of-market subsidies.

1 For example, buyers or representatives of buyers, can use state-sponsored contracts to
2 recover their uneconomic investments through direct or indirect non-bypassable charges.
3 Such non-bypassable charges include cost-of-service rate making, distribution level
4 billing surcharges or taxes.

5 Q CAN YOU PROVIDE AN EXAMPLE TO DEMONSTRATE THESE CONCEPTS
6 AND CONCERNS?

7 A Yes. While PJM has a multi-zone locational design, each with a locational reliability
8 requirement and demand curve, the general principles of market manipulation by
9 uneconomic entry are easily identified. Assume that the reliability requirement for
10 capacity—i.e., the quantity where the price on the Variable Resource Requirement or
11 demand curve equals net Cost of New Entry—is about 40,000 MW. For a frame of
12 reference, this is approximately the size of the Eastern Mid-Atlantic Area Council
13 (EMAAC). Assume there is a net internal requirement of approximately 32,000 MW
14 with 8,000 MW of import capability. Also assume that there is no net need for new
15 capacity and the target need was just filled by 1 MW offered at the nominal levelized
16 Reference net Cost of New Entry. Additionally assume that 400 MW of uneconomic
17 capacity was procured through a state-sponsored process and offered into the auction at a
18 price of zero. Assume further that the actual net Cost of New Entry used to develop the
19 location's demand curve is \$260 per MW-day and that this is the out-of-market price
20 actually paid for the 400 MW of excess new capacity procured through a governmental
21 entity's "new supply only" solicitation.⁶ Finally, assume that the slope of the Variable

⁶ The example is a rough approximation of the 2013-14 Base Residual Auction for EMAAC (a designated locational deliverability area in PJM). Note that in this recent auction, the net Cost of New Entry for EMAAC was \$261.06/MW-day, there was approximately 40,000 MW of unconstrained capacity required and the import capacity

1 Resource Requirement curve results in a 20% reduction in price (based on net Cost of
2 New Entry, this 20% equals \$52 per MW-day) for each 1% of additional internal supply
3 in the relevant region of the demand Variable Resource Requirement curve. This is
4 consistent with the slope of the PJM demand curve.

5 Based on these assumptions, absent the 400 MW of uneconomic entry, the
6 clearing price would be \$260 per MW-day. With the excess 400 MW (i.e., 1% of the
7 reliability requirement for capacity) under the Variable Resource Requirement curve, the
8 price would drop approximately 20% to \$208 per MW-day. Yet, 40,400 MW would be
9 purchased. Thus, the net effect of the price suppression of the unneeded 400 MW is a
10 reduction of payments of approximately \$570 million, even after accounting for the
11 purchase of the excess capacity.⁷

12 Q DOES THIS STRATEGY WORK WHEN THE BUYER REPRESENTS ONLY A
13 PORTION OF THE MARKET?

14 A Yes. While the above example is for the market as a whole, the mechanics of the process
15 still work even if the load-serving entity purchasing the excess serves only a portion of
16 the market. For example, consider what happens if the load-serving entity serves only
17 half of the load in the market. In this case, depressing the price by the same amount has
18 slightly less than half the impact for the buyer trying to manipulate prices. This is

was approximately 7,000 MW. Thus, approximately 33,000 MW cleared at the EMAAC price. For the example in my testimony, I have used 40,000 MW, 8,000 MW, and 32,000 MW, respectively.

⁷ The original annual internal costs are equal to \$3,036,800,000 (32,000 MW x 365 days x \$260/MW-day = \$3,036,800,000). After the uneconomic addition, the annual internal costs are equal to \$2,459,808,000 (32,400 MW x 365 days x \$208/MW-day = \$2,459,808,000) plus the remaining cost of \$7,952,000 (400 MW x 365 days x \$52/MW-day = \$7,952,000), which equals a total internal cost of \$2,467,400,000 following the uneconomic addition. This total amount reflects the full market cost of the uneconomic addition for a net savings of \$569,400,000. This assumes that imports would remain the same and due to capacity transfer rights the net effect on zonal imports would be a wash. Alternatively the example could be seen as applying to a stand alone system of 32,000 MW.

1 because the buyer still purchases all of the out-of-market uneconomic new capacity, but
2 only “saves” on a basis of 16,000 MW instead of 32,000 MW. In this case the net price
3 suppression is still very large, with a net reduction after paying for the uneconomic entry
4 of approximately \$281 million.⁸

5 Q WHEN THE PARTY EXERCISING BUYER-SIDE MARKET POWER CONTROLS
6 ONLY A FRACTION OF THE MARKET, WILL IT SUSTAIN A COMPETITIVE
7 DISADVANTAGE EVEN THOUGH ITS TOTAL COSTS ARE REDUCED?

8 A Yes. This occurs because the party exercising buyer-side market power—the party
9 bidding into the market below cost—incurs the “extra” cost of the uneconomic new
10 resource. It benefits from the price suppression, but it also has to incur the cost of
11 building a new unit. Everyone else—all of the remaining participants who purchase
12 capacity—get the same price suppression benefit without the expense of building the
13 unit. This is why the role of states as “partners” is an important element in this type of
14 behavior. The state can impose non-bypassable charges or other discriminatory practices
15 that assure recovery for the party bidding below cost, to permit it to make up the costs it
16 incurs to build the plant. The party exercising market power bids below market but
17 receives a discriminatory payment or subsidy from the state. As discussed later,
18 recognizing this factor becomes a crucial element in the appropriate design of a
19 mitigation strategy for short-term resources.

20 But if there is no state or other “partner” to protect the party seeking to exercise
21 market power, the party engaging in anti-competitive behavior will likely have an

⁸ When the savings are only on half the market, the calculations lead to an original annual internal cost of \$1,518,400,000 (16,000 MW x 365 days x \$260/MW-day = \$1,518,400,000). After the uneconomic addition, the annual internal costs is \$1,229,904,000 (16,200 MW x 365 days x \$208/MW-day = \$1,229,904,000) plus the subsidy payments for the 400 MW of \$7,592,000 (400 MW x 365 days x \$52/MW-day = \$7,592,000) for a total of \$1,237,496,000. This creates a net savings of approximately \$281 million.

1 average price that is significantly higher than its competitors who serve the remaining
2 load in the system (or locational delivery area). This occurs because while the party
3 engaging in anti-competitive behavior buys some power at the suppressed prices, it also
4 pays “market” for the additional uneconomic supply. Its competitors, on the other hand,
5 only pay the suppressed market-clearing price.⁹

6 Under a competitive regime where retail load may be served by multiple sellers,
7 this type of behavior, even though profitable in the short term for the party exercising
8 market power, cannot persist over the long term because, although the costs to the
9 exerciser of market power decline, the party exercising market power would have higher
10 average unit costs than its competitors because it is the only party that pays the price for
11 the distortion. Ultimately this factor would cause the party exercising market power to
12 lose market share to its competitors and, in turn, eventually lose the benefits of exercising
13 market power in the first place. Thus, while there may be a short-term incentive for this
14 behavior when there is competition for sales, it is not sustainable in the long term, at least
15 not without state help to socialize the cost of the exercise of market power across all of
16 the beneficiaries.

17 Q HOW, THEN, CAN A BUYER SEEKING TO EXERCISE MARKET POWER
18 BENEFIT FROM ITS BEHAVIOR?

19 A If a party with only partial market share can be *assured of recouping its investment* when
20 it purchases excess capacity in a discriminatory manner, it will always have the incentive
21 to exercise market power. It is protected from the long-term competitive downside noted
22 above. Market shares may adjust, but the guaranteed recovery will allow the party with

⁹ This assumes that there are multiple, independent capacity purchasers.

1 only partial market share to continue to make the uneconomic investment without
2 experiencing a loss, despite the fact that the uneconomic excess is simultaneously
3 dropping prices for the market as a whole.

4 Q WHAT DO YOU CONCLUDE FROM THIS?

5 A The exercise of buyer market power is surest, safest, most profitable, and most harmful
6 when it occurs under the direction of a state or regulatory agency. States or regulatory
7 agencies are in the best position to provide discriminatory mechanism(s) (e.g., contracts,
8 regulated recovery, etc.) to assure that the parties procuring or sponsoring uneconomic
9 resources recoup their expenses. States and regulatory agencies could act alone without
10 “partnering” with market participants, but market participants—particularly those with
11 only partial market share—typically must have the help of the states or regulatory
12 agencies to successfully exercise buyer market power.

13 Thus, to be effective, buyer market power mitigation must be focused not only on
14 those directly making uneconomic investments, but also on those for whom these
15 exercisers of market power may be acting as an agent. The Commission has correctly
16 recognized in the past that this use of a proxy in determining the source of uneconomic
17 entry is to be anticipated and prevented.¹⁰ The key observation is that access to assured
18 recovery via out-of-market payments or subsidies to support uneconomic entry is an
19 essential element of the effective long-term exercise of buyer market power.
20 Governmental or quasi-governmental entities provide the mechanisms to assure this
21 recovery. Any effective mitigation regime must examine the conduct of agents or proxies
22 that would indirectly exercise market power. Ideally these mechanisms would simply be

¹⁰ E.g., *N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at P 100, *order on reh’g*, 124 FERC ¶ 61,301 (2008), *order on reh’g and clarification*, 131 FERC ¶ 61,170 at P 133 (2010).

1 banned, but absent that ability, actions are necessary to keep this type of market power
2 from distorting prices in the Commission's jurisdictional markets.

3 Q DOES THE EXERCISE OF BUYER MARKET POWER REDUCE PRICES?

4 A Absolutely not. As the Commission has observed, while this exercise of market power
5 seems an attractive proposition for load—at least in the short run—it is disastrous for the
6 viability of competitive markets in the long run.¹¹ Suppliers are victimized by price
7 discrimination, wherein only new entrants receive the competitive market price, while all
8 other existing units receive an artificially suppressed payment. This effectively creates
9 an unjustified pricing structure where competitive existing suppliers are discriminated
10 against vis-à-vis subsidized new entrants. This occurs even though all market
11 participants provide the same reliability product or service. Certain individual new
12 entrants, by exercising buyer-side market power or cooperating with others who are
13 exercising market power, are simply paid a higher price and all other existing suppliers
14 unjustifiably are paid a lower price. There is no benefit to market efficiency here; there
15 simply is an unwarranted transfer of resources from sellers to buyers, coupled with the
16 waste of resources and distortion of prices and consumption.

17 The end effect of the exercise of buyer market power, then, is that no one will
18 seek to enter the market other than by subsidized bilateral agreements. A supplier
19 entering the market *without* such protection would be asking to be victimized as soon as
20 the initial “lock-in” period ends. It is not likely that the states will stop exercising market
21 power if they successfully can. In the short term, it always looks like it will be cheaper to
22 just pay new entry. But in the long term, it is disastrous. Eventually all favored “new

¹¹ *N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at PP 100-06 & nn.55-56.

1 suppliers” become “existing suppliers,” subject to victimization. To compensate for that
2 risk, any rational new entrant would seek to be protected by continuous price erosion via
3 ever higher new entry offers, thereby encouraging an even greater use of buyer market
4 power as the perceived cost of new entry rises. As the market structure is unwound, risk
5 shifts back to consumers due to the out-of-market payments, and one of the core benefits
6 of competitive markets is defeated.

7 Q DOES THIS TYPE OF BUYER MARKET POWER HAVE OTHER ADVERSE
8 IMPACTS?

9 A Yes. These additional adverse impacts relate to the retention of existing units that would
10 otherwise be economic but for the price distortion caused by the exercise of buyer market
11 power. By artificially depressing prices, some resources, which otherwise would have
12 been committed in a competitive auction, will fail to clear the market. These resources
13 will then retire (unless they are needed for reliability, thereby requiring another out-of-
14 market payment). This effect will inefficiently accelerate the “turnover” of the entire
15 capital generation stock and, as discussed below, will create a need for reliability must
16 run contracts.

17 In addition, basic consumer decision-making and resource allocation will be
18 skewed. Consumers will see distorted price signals. They become more likely to over-
19 consume electric capacity as prices are artificially suppressed. Resources will be directed
20 into electric consumption that should be used elsewhere, and the value of conservation
21 and associated demand response activity will be depressed.

1 Q ARE THERE OTHER ADVERSE EFFECTS ASSOCIATED WITH THIS BEHAVIOR?

2 A Yes. It also has the perverse impact of punishing those market participants that attempted
3 to control their own risk by entering into hedging agreements or similar arrangements to
4 limit their exposure to fluctuations in market prices for capacity. Such parties are forced
5 into making double payments. First, they pay for the costs they prudently incurred for
6 their own risk management, and they pay a second time when charges related to
7 supporting the discriminatory procurement of out-of-market new generation are imposed
8 on them. Over time, in the face of such market power, there would also be the
9 expectation that parties would cease to enter into their own risk management
10 arrangements, further distorting consumption decisions.

11 In sum, distorting the market by exercising buyer market power ultimately
12 transfers money from sellers to buyers. It harms prudent bystanders. This does not
13 benefit society, but instead decreases overall social welfare. The Independent Market
14 Monitor echoed these same conclusions in reference to the potential out-of-market
15 subsidy for uneconomic and unneeded new entry by the State of New Jersey.¹²

¹² The Independent Market Monitor stated as follows:

The result of such a subsidy by New Jersey ratepayers would be 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 substantial reduction in revenue would affect the investment decisions of current owners of capacity and potential investors in capacity both in New Jersey and in areas outside of New Jersey. The likely result is less investment in new and existing capacity, in the form of generation resources and demand response. Depressing the price in New Jersey would also mean that the required direct subsidy by New Jersey ratepayers would increase for the specified procured MW, with perhaps 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 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. The result of depressing RPM prices over a broad section of PJM would be to increase the probability that subsidies by ratepayers in other states will be required for any future capacity additions, either in the form of generation or demand side resources, needed to maintain reliability in that area.

1 Q WHAT IS THE LONG-RUN EFFECT OF THIS TYPE OF EXERCISE OF BUYER
2 MARKET POWER?

3 A These corrosive elements ultimately undermine incentives for independent private
4 investment. Eventually all capacity will either be based on the long-term discriminatory
5 procurements or reliability must run contracts. This effectively defaults back to a world
6 that looks like central rate-based planning, coupled with a pricing path over time that
7 distorts consumption and operational decision-making and destroys existing private
8 investment in the market. Unless fully mitigated, this combination of events assures the
9 demise of a market-based solution.

10 This is the very type of inefficient regime that led to the movement to competitive
11 markets in the first place. The only difference is that here the existing capacity that is not
12 the beneficiary of the discriminatory prices will receive the artificially reduced prices
13 rather than the same cost-of-service approach applied to all resources equally. There will
14 never be sufficient unsubsidized private new entry because prices over time will always
15 be well below the required average true Cost of New Entry. This risk will translate into
16 higher costs as those participants that obtain a discriminatory contract will add an
17 additional margin into their offers to address the fact that at the expiration of such an
18 agreement, they too will be ready victims of price discrimination in the ensuing years.

1 *II. THE MINIMUM OFFER PRICE RULE'S MATERIAL FLAWS AND HOW THEY CAN BE*
2 *EXPLOITED*

3 *A. THE MINIMUM OFFER PRICE RULE'S FOUR PRIMARY FLAWS*

4 Q HOW MANY FLAWS HAVE YOU IDENTIFIED IN THE MINIMUM OFFER PRICE
5 RULE WHICH PREVENT IT FROM MITIGATING BUYER MARKET POWER?

6 A I have identified four material failures in the design of the Minimum Offer Price Rule.
7 Each limits the Minimum Offer Price Rule's effectiveness to prevent significant exercises
8 of buyer market power. Collectively the flaws make the Minimum Offer Price Rule
9 virtually useless. Thus, the unjustness and unreasonableness of the Minimum Offer Price
10 Rule is practically transparent.

11 Q WHAT IS THE FIRST FLAW YOU IDENTIFIED IN THE MINIMUM OFFER PRICE
12 RULE?

13 A Both the cost benchmarks in the conduct screen and the substitute Sell Offers that are put
14 into effect when mitigation is triggered are too low. Under the Minimum Offer Price
15 Rule's conduct screen, offers are not mitigated unless they are less than 80% of the
16 applicable Net Asset Class Cost of New Entry, or if there is no applicable asset class for
17 that resource, to 70% of the Net Asset Class Cost of New Entry for a combustion turbine
18 (the Reference Resource). Then, assuming the conduct screen is failed and mitigation
19 will be applied, offers are re-priced to 90% of the applicable Net Asset Class Cost of
20 New Entry, or if there is none, to 80% of the Net Asset Class Cost of New Entry of the
21 Reference Resource.

22 These thresholds are too low. They permit huge cost shifts from sellers to buyers
23 through the exercise of buyer market power. They artificially cap market prices to levels
24 well below Cost of New Entry. This must be seen as unjust and unreasonable.

1 Q WHAT IS WRONG WITH THESE BENCHMARKS?

2 A Consider the basic objective of mitigation: to identify the exercise of market power and,
3 once identified, to take action to return pricing to competitive levels. A conduct
4 threshold of 80% or 70% permits offers 20% to 30% below economic levels to go
5 unmitigated. This permits the extensive exercise of buyer market power before
6 mitigation is even triggered just by bidding in subsidized new entry at a level slightly
7 higher than the screen, e.g., 81%. Consider the effect of a 20% threshold in the EMAAC
8 LDA. The EMAAC net Cost of New Entry was approximately \$260 per MW-day for the
9 last Base Residual Auction. Twenty percent equates to \$52 per MW-day. Applied to the
10 approximately 33,000 MW of capacity inside the EMAAC locational delivery area, there
11 would be a permissible total annual dollar exercise of buyer market power of \$626
12 million *before mitigation is even considered* ($\$52/\text{MW-day} \times 365 \text{ days} \times 33,000 \text{ MW} =$
13 $\$626,340,000$).

14 And assuming that mitigation is triggered, the overall mitigation is ineffective if
15 the resulting “mitigated-to” pricing or other actions do not replicate closely the
16 anticipated competitive levels that should have existed absent the exercise of market
17 power. In the case of the Minimum Offer Price Rule, the substitute Sell Offer—which is
18 used to establish new auction results when uneconomic entry is found—is too low. It is
19 unclear why any value below 100% of the nominal levelized Unit Specific Net Cost of
20 New Entry should be utilized for the substitute Sell Offers that constitute the “mitigated-
21 to” values.

1 Q TYPICALLY FOR “MITIGATED-TO” VALUES, SOME ADJUSTMENT WOULD BE
2 MADE FOR POTENTIAL INACCURACY WITH THE SUBSTITUTE PRICE. WHY
3 DOESN’T THAT JUSTIFY THE USE OF A VALUE BELOW 100%?

4 A Actually, in this specific situation that type of logic does not apply. In fact, other
5 considerations support mitigation to a higher substitute Sell Offer, not a lower one.
6 Ideally, any bid from a subsidized party would be excluded. However, if such bids are
7 allowed, they must be mitigated to at least 100% of their nominal levelized costs to
8 prevent adverse effects in the operation of the capacity market.

9 There are two main reasons for using 100% as a lower bound. First, in the
10 presence of market power, the mitigation floor offer is likely to become the *cap* on prices
11 for capacity in the market. The definition of the “mitigated-to” target price in this
12 situation is a nominal levelized long-term price that represents the *average compensation*
13 that is needed to support new entry over time. Buyers with market power can act to
14 eliminate the ability of prices to rise above the offer floor, which would be possible under
15 the PJM demand curve structure, but for the market power. The notion that the prices
16 would be capped at average some of the time, and less than average other times clearly
17 points out the problem: who will privately invest under such conditions? Similarly, this
18 clarifies that while the mitigation is to the appropriate average value, that value may be
19 too low to achieve the goal of reproducing long-term competitive market conditions, as
20 private entry will still be discouraged from entering the market absent a subsidy. Thus
21 100% has to at least serve as a lower bound.

22 Second, the cost of choosing too high a substitute Sell Offer is much less than the
23 cost of choosing too low a substitute Sell Offer. In the energy market, mitigation often

1 occurs when there is a lack of competitive supply alternatives. Thus there is concern
2 regarding not forcing a supply at what might be less than cost because the supply must be
3 used, there typically is no alternative. That is not the case with the exercise of buyer-side
4 market power in the capacity market. If the supply from a specific party offering
5 subsidized capacity is mitigated, no barriers are created for others to put forward
6 competitive alternatives. I discuss the importance of alternative competitive supply and
7 its relevance to setting mitigation levels further below.

8 The implications of this can best be seen by looking at the issue of replicating
9 competitive results from a “cost of the errors” perspective. That is, what is the relative
10 harm or benefit from choosing too high of a value for the substitute Sell Offer versus too
11 low a value. When this analysis is done, and the availability of competitive alternatives
12 is taken into account, the clear conclusion is that it is better to have an upward bias in the
13 substitute Sell Offers, if there is going to be any bias at all. Indeed, a value greater than
14 100% could easily be justified in the current circumstances.

15 For example, if the mitigated price set at the nominal levelized Unit Specific Net
16 Cost of New Entry were deemed too high, what is the harm? The worst that happens is
17 that the mitigated offer fails to clear, and presumably the new resource would not be
18 built. This would occur because either there was no need for it, or if there was a need, it
19 was filled by a lower-cost alternative competitive supplier. This is hardly a bad result,
20 and in fact, is what *should* happen in a market. Empirically we know we have significant
21 additional supply in PJM.

22 Alternatively, if the mitigated price is too low, and effectively sets a cap on the
23 market below the actual cost of new entry, competitive entry is eliminated, prices are

1 suppressed, and price discrimination is allowed. This assures the destruction of the
2 market, because by definition the prices are being set at levels such that they will never
3 be compensatory for a new entrant. No one will enter a market where the expected
4 revenues are capped at less than the needed average price.¹³

5 In sum, due to competitive entry, long-term market prices would not be expected
6 to change from competitive levels if the mitigation were set at too high a price. In stark
7 contrast, however, if the mitigation value selected were too low, prices would be
8 artificially depressed. This in turn would lead to the cascading failure of any market
9 solution: no party will privately enter the market if, even when buyer market power is
10 mitigated, prices are set below competitive levels. Taking the perspective of designing
11 mitigation measures to protect the *market*, as opposed to protecting individual market
12 participants, it becomes clear that the right course is, at minimum, to mitigate to the
13 nominal levelized Unit Specific Net Cost of New Entry.

14 With the above in mind there really is no harm to over-mitigation with a “too
15 high” substitute Sell Offer versus precipitating the destruction of the market with under-
16 mitigation via a “too low” offer. In this context, use of the 100% value for the substitute
17 Sell Offer is conservative. But under no circumstances could 100% be considered too
18 *high*.

19 I believe that this is an even more compelling logic given that the specific
20 mitigation I am proposing explicitly waives any mitigation for a true competitive entrant

¹³ A parallel logic applies to my recommendation regarding the conduct screens. A conduct screen below 100% also allows those seeking to exercise market power to simply bid just above the screen, and thus to suppress prices to less than the average Cost of New Entry. Thus, if the conduct screen is 80%, then market power can be asserted by simply bidding 81%, still well below average costs. This effectively caps the market at the level of the conduct screen, again assuring no private entry.

1 that can demonstrate no out-of-market/discriminatory support. Such a resource may offer
2 at as low of a price as they wish.

3 Q WHAT IS THE SECOND FLAW YOU IDENTIFIED IN THE MINIMUM OFFER
4 PRICE RULE?

5 A The impact thresholds in the Minimum Offer Price Rule are far too lax. In general,
6 mitigation approaches recognize that they can not directly prevent the exercise of market
7 power, but rather, they can identify it, and once identified, take actions to return pricing
8 to expected competitive levels. If the impact levels of a mitigation process allow any
9 material deviations from competitive levels without triggering any action, the mitigation
10 process is fundamentally flawed. This is the case with the Minimum Offer Price Rule.
11 Much like the conduct screen and the “mitigate-to” values that both set *de facto* price
12 caps, the impact level will represent an assured amount of price suppression.
13 Intentionally allowing a value greater than zero is the same as capping prices below the
14 average cost of new entry. Again this is transparently unjust and unreasonable.

15 As stated above in the description of the Minimum Offer Price Rule, if the
16 conduct test fails, the Independent Market Monitor implements an impact test. In the
17 impact test, the Independent Market Monitor reruns the Base Residual Auction using a
18 substitute Sell Offer. The substitute Sell Offer is set at 90% of the applicable Net Asset
19 Class Cost of New Entry or 80% of the reference Net Cost of New Entry if no other value
20 is available. The impact test fails if the change in Clearing Price for the locational
21 delivery area exceeds the greater of: (1) \$25 or 20% for a locational delivery area of
22 15,000 MW or more; (2) \$25 or 25% for a locational delivery area of between 5,000 and
23 15,000 MW; or (3) \$25 or 30% in a locational delivery area of less than 5,000 MW.

1 The original logic behind these types of thresholds was to allow some wiggle
2 room prior to triggering mitigation. However, with the existing Minimum Offer Price
3 Rule impact thresholds, the wiggle room equates to a mammoth gap in market power
4 mitigation and enforcement, and as discussed above, in this specific competitive
5 environment, such flexibility is not justified.

6 Q HOW DOES HAVING LAX IMPACT THRESHOLDS PREVENT THE MINIMUM
7 OFFER PRICE RULE FROM LIMITING BUYER MARKET POWER?

8 A The effect of lax impact thresholds is easily seen by example. Consider the 20% impact
9 threshold for locational delivery areas greater than 15,000 MW, such as the EMAAC
10 LDA, to use the same example as above. Assume that the clearing price in the last
11 auction was \$245 per MW-day. A 20% impact equates to \$49 per MW-day. Applied to
12 the approximately 33,000 MW of capacity inside the EMAAC locational delivery area,
13 there would be a permissible total annual dollar amount of price suppression of
14 approximately \$590 million before the impact threshold is even crossed ($\$49/\text{MW-day} \times$
15 $365 \text{ days} \times 33,000 \text{ MW} = \$590,205,000$). And that is for EMAAC only; the excess
16 supply would ripple through the rest of the market, increasing the effect of such lax
17 thresholds. In larger zones, even greater price suppression could occur without
18 mitigation ever being triggered. All that is needed to manipulate the market is to estimate
19 the quantity that can be added to the market without triggering the impact threshold.
20 Given the use of a demand curve, and known demand, it would not be difficult to derive
21 such values. Thus market power is likely to be exercised up to the allowable impact
22 threshold. Further, this effect would easily be compounded if multiple parties engaged in

1 the same behavior or a single party did it repetitively over time, or both, with the effect
2 being both cumulative and devastating.

3 Q WHAT IS THE THIRD FLAW YOU IDENTIFIED IN THE MINIMUM OFFER PRICE
4 RULE?

5 A The mitigation is too limited in its duration. The prohibition on uneconomic offer prices
6 only applies to the *first* Base Residual Auction. The Sell Offer is only mitigated one time
7 regardless of need and regardless of whether resource clears or not. Thereafter it can be
8 offered at any level, including zero. In the context of some of the long-term bilateral
9 agreements that have already been proposed to artificially depress prices, the loss of one
10 year's price suppression simply becomes part of the calculus of the "right" uneconomic
11 quantities to be subsidized.¹⁴ The loss of a single year, however, is insignificant to the
12 exercisers of market power in relation to the overall price suppression they can achieve.
13 They can easily make up the first year of losses with savings during the later years of a
14 bilateral agreement.

15 Further, the Minimum Offer Price Rule only applies to a single Base Residual
16 Auction, yet the Base Residual Auction is only one of the auctions that apply for any
17 specific delivery year. If a unit were mitigated under the Minimum Offer Price Rule in
18 its first Base Residual Auction, it would still retain the ability to be offered in each of the
19 incremental auctions. While this may not materially depress prices in the first year, it
20 does afford an Offeror who is engaging in the uneconomic investment additional

¹⁴ For example, one New Jersey proposal included a 15-year contract that would artificially suppress prices. S. No. 2381, 214th Leg., First Reprint (Nov. 15, 2010). In the discussion of New Jersey's proposed exercise of buyer market power, the Independent Market Monitor noted that 1,000 MW of uneconomic entry would depress prices by \$1 billion per year. IMM Analysis at 1. The total contract payments under the New Jersey proposal over 15 years had a nominal cost of approximately \$1.27 billion, allowing a market wide payback of about 15 months.

1 opportunities to reduce his overall costs of price suppression activities. The combined
2 impact is that in reality even a year of exclusion doesn't occur.

3 Q WHAT IS THE FOURTH FLAW YOU IDENTIFIED IN THE MINIMUM OFFER
4 PRICE RULE?

5 A The fourth major failing of the current Minimum Offer Price Rule is that it is full of
6 limitations, loopholes and exemptions that are easily gamed to permit the exercise of
7 buyer market power. All of these loopholes should be closed. I focus on three: the
8 exemptions for net buyers of capacity, self-supply, and Planned Generation Capacity
9 Resources, but counsel has identified others and they too should be closed.

10 Q WHAT IS THE EXEMPTION RELATED TO NET BUYERS OF CAPACITY?

11 A The Minimum Offer Price Rule conduct screen applies only to net buyers of capacity. In
12 theory, with no market concentration and atomistic supply and demand, it could make
13 sense to waive the mitigation offer floor in situations where the party offering the new
14 supply is not a net buyer in the markets. With no purchases being made at the market
15 price, there is no benefit to suppressing the price. But perfect competitive conditions do
16 not exist, and, as a result, what appears to be a simple screening rule is not simple at all
17 and can easily be circumvented.

18 Q HOW DOES REQUIRING THAT THE OFFEROR BE A NET BUYER PREVENT
19 THE MINIMUM OFFER PRICE RULE FROM LIMITING BUYER MARKET
20 POWER?

21 A The inefficiency of such a rule is easily seen in the current actions of the New Jersey
22 legislature with respect to the PJM RPM markets.¹⁵ The New Jersey legislature has

¹⁵ S. No. 2381, 214th Leg. (N.J. 2011), attached as P3 Exhibit 2 to the Complaint.

1 passed legislation that, for all practical purposes, attempts to circumvent the net buyer
2 requirement of the Minimum Offer Price Rule. The legislation subsidizes 2,000 MW of
3 *new* generation. Existing generation is ineligible, i.e., it is explicitly discriminatory. The
4 legislation directs those receiving the subsidies to bid in such a manner as to clear in the
5 PJM Base Residual Auctions (i.e., subsidy recipients must offer so as to assure being
6 accepted). The legislation creates agreements between a seller and the state regulated
7 distribution companies (which are Load Serving Entities). In these agreements, payments
8 are made via a contract for differences to the third party that owns the generation.¹⁶ The
9 contract for differences is designed to assure guaranteed revenues to the new generation
10 regardless of the market price.

11 The legislation effectively sets up a situation in which a seller only owns the
12 subsidized generation and typically would not fall within the definition of net buyer. The
13 seller is acting as an agent of the state, and the state represents buyers. Payments for the
14 contracts are supported by a non-bypassable surcharge on all customers. The state, in this
15 example, is the actual net buyer of capacity, but the state does not submit the bids into the
16 auction.¹⁷ The winning bidder, whose only asset might be the new generation, thus may
17 escape mitigation. Because legislation like the New Jersey proposed statute is intended
18 to circumvent the Minimum Offer Price Rule, the Minimum Offer Price Rule is

¹⁶ Under a contract for differences, there would be an agreed contract fixed price. The Seller would sell into the market directly and receive market rates (thus being a net seller). If the auction clearing rate is higher than the fixed price in the contract, the seller pays the difference to the buyer; if the auction clearing rate is lower, the buyer pays the seller the difference.

¹⁷ I take no legal position with respect to whether this approach to the exercise of market power falls within the scope of the existing Minimum Offer Price Rule. Both PJM and the Independent Market Monitor have explicitly taken the view that regardless of any such determination, it should. See Letter from Andrew L. Ott, Senior Vice President, Markets, PJM Interconnection and Dr. Joseph E. Bowring, President, Monitoring Analytics to Lee A. Solomon, President, New Jersey Board of Public Utilities (Dec. 3, 2010), http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM-MMU_Letter_to_NJ_BPU_20101203.pdf (“Bowring Letter”). Their concern suggests that they too recognize this potential limitation or ability to circumvent the current rule.

1 ineffective in actually limiting buyer market power. I discuss the New Jersey example in
2 greater detail below.

3 Q HAS THE COMMISSION RECOGNIZED THIS BASIC FLAW WITH THE USE OF A
4 NET BUYER SCREEN FOR MITIGATION?

5 A Yes, it did in the recent NYISO Order. In addressing the NYISO's mitigation process the
6 Commission stated that NYISO:

7 . . . will not be required to modify its proposed market power
8 mitigation rules for uneconomic entry so that they only apply to
9 net buyers. *We find that all uneconomic entry has the effect of*
10 *depressing prices below the competitive level and that this is the*
11 *key element that mitigation of uneconomic entry should address.*
12 Parties requesting rehearing have convinced us that defining net
13 buyers raises significant complications and provides undesirable
14 incentives for parties to evade mitigation measures. Accordingly,
15 we grant rehearing on this issue . . .¹⁸

16 Q ARE THERE ANY OTHER PROBLEMS WITH THE CURRENT MOPR'S NET
17 BUYER SCREEN?

18 A Yes. Regardless of the net buyer conduct test discussed above, the threshold related to
19 establishing a net buyer for small locational delivery areas in the current Minimum Offer
20 Price Rule is too high.

21 Q HOW DOES HAVING A HIGH THRESHOLD FOR SMALL LOCATIONAL
22 DELIVERY AREAS PREVENT THE MINIMUM OFFER PRICE RULE FROM
23 LIMITING BUYER MARKET POWER?

24 A Having a high threshold for small locational delivery areas allows for the exercise of
25 buyer market power regardless of whether an accurate determination of net buyer status
26 (without manipulation) can be obtained. This is seen by looking at an example using the

¹⁸ *N.Y. Indep. Sys. Operator*, 124 FERC ¶ 61,301 at P 29 (emphasis added).

1 10% criterion for a locational delivery area of under 10,000 MW. Assume that the local
2 reliability requirement of a locational delivery area is 9,500 MW, and it is served by a
3 single Load Serving Entity with a 10% net short position, or that, in other words, was a
4 net buyer of 950 MW. The conduct threshold would not be triggered in such a situation.

5 Now consider the impact of such a Load Serving Entity purchasing 380 MW of
6 unneeded/uneconomic capacity (i.e., 4% of the locational delivery area reliability
7 requirement). Using the approximately \$260 per MW-day net Cost of New Entry values
8 for PJM Eastern MAAC from the last Base Residual Auction, assume that \$260 per MW-
9 day net Cost of New Entry was the clearing price without any manipulation. Assume
10 also that any resulting price suppression caused by adding 380 MW to the Load Serving
11 Entity kept the locational delivery area price separated from the rest of the Regional
12 Transmission Organization. The result in this simplified example would be that the
13 clearing price would decline 80%, from \$260 to \$52 per MW-day. The price suppression
14 works for a net benefit of approximately \$36 million per year after accounting for the
15 cost of the uneconomic entry.¹⁹

16 Clearly, the 10% threshold in a small locational delivery area is an ineffective
17 screen. If the screen is interpreted to be simply 10% of a gross position, and other Load
18 Serving Entities held some of the “hedged” existing facilities, the benefit for exercising
19 market power would actually be higher because other Load Serving Entities would
20 purchase some of the uneconomic generation at the low market price, but still would
21 offset some of the costs incurred by the Load Serving Entity exercising market power.

¹⁹ The gross savings are \$72,124,000 (950 MW x 365 days x \$208 per MW-day = \$72,124,000), and the net cost of the uneconomic entry here is \$36,062,000 (380 MW x 365 days x \$260 per MW-day = \$36,062,000), for an annual net savings of \$36,062,000.

1 Q WHAT IS THE NEXT EXEMPTION THAT YOU IDENTIFIED IN THE MINIMUM
2 OFFER PRICE RULE?

3 A The next material exemption in the Minimum Offer Price Rule that I identified as
4 problematic is that it appears to completely ignore self-supply. Depending on an
5 interpretation of the term “Planned Generation Unit,” and what constitutes a Sell Offer, a
6 buyer may be able to successfully avoid mitigation by simply designating an uneconomic
7 unit as self-supply.

8 Q HOW DOES IGNORING SELF-SUPPLY PREVENT THE MINIMUM OFFER PRICE
9 RULE FROM LIMITING BUYER MARKET POWER?

10 A The omission of self-supply from the Minimum Offer Price Rule is a particularly
11 troubling omission given two basic elements of the PJM capacity market. First, there is
12 no inconvenience cost associated with simply bidding in self-supply as a price taker in
13 the auction when the capacity is economic and should not be subject to mitigation. This
14 is what is happening now, without the separate designation of self-supply.

15 Second, PJM, at least at a macro level, already provides for zones and other
16 limited loads to opt-out of the RPM process to serve their capacity needs. If a state truly
17 is concerned with reliability and not price manipulation, it can avail itself of this
18 alternative to assure reliability under its own criteria without distorting prices market-
19 wide. The Fixed Resource Requirement option allows parties, such as New Jersey, who
20 might think their reliability needs are not being properly addressed by the RPM process,
21 to effectively remove both their load and generation from the RPM market. In doing so,
22 the party is responsible for meeting its own requirements and is subject to certain
23 limitations with respect to purchases and sales with the rest of PJM. By opting for the

1 Fixed Resource Requirement option, of course, the party would lose the ability to
2 manipulate market prices for the entire PJM footprint through out-of-market support of
3 uneconomic entry. Presumably the party would also have to pay just and reasonable
4 prices to their own internal supply.

5 Q WHAT IS THE NEXT EXEMPTION THAT YOU IDENTIFIED IN THE MINIMUM
6 OFFER PRICE RULE?

7 A The next exemption that I identified in the Minimum Offer Price Rule is that it only
8 applies to a limited subset of Planned Generation Capacity Resources. In general a
9 Planned Resource, as defined in the Reliability Assurance Agreement, refers to any
10 resource entered in the interconnection process that passes certain milestones. A Planned
11 Generation Capacity Resource remains “Planned” until it becomes operational and takes
12 interconnection service.

13 The Minimum Offer Price Rule, however, does not use this definition
14 independently, but rather modifies its use in a fashion that limits its applicability and
15 undermines the ability to mitigate buyer market power. In section 5.14(h)(2), the
16 Minimum Offer Price Rule states that it applies only to “[a]ny Sell Offer that is based on
17 a Planned Generation Capacity Resource submitted in a Base Residual Auction for the
18 first Delivery Year in which such resource qualifies as such a resource, in any locational
19 delivery area for which a separate Variable Resource Requirement Curve has been
20 established” Thus, the universe of Planned Generation Capacity Resources to which
21 the Minimum Offer Price Rule could apply is severely limited.

1 Q HOW DOES THE LIMITED APPLICATION OF THE MINIMUM OFFER PRICE
2 RULE TO PLANNED GENERATION CAPACITY RESOURCES PREVENT IT
3 FROM LIMITING BUYER MARKET POWER?

4 A This limitation effectively cancels the applicability of the Minimum Offer Price Rule to
5 any new resource. To fully avoid the application of the Minimum Offer Price Rule, all a
6 party needs to do is to submit a schedule for its resource that identifies a commencement
7 date one year earlier than actually anticipated, and then bid a “high” price in the related
8 auction.²⁰ There is no penalty for commencing operations late. Thus, after failing to
9 clear once, the party’s unit is no longer subject to mitigation under the Minimum Offer
10 Price Rule and the party could offer the unit at any price (including zero) in subsequent
11 auctions without any adverse consequence. In fact, the party could offer the unit as a
12 price taker in the very next Base Residual Auction. Because a party can easily game the
13 entire system, the mitigation approach used in the Minimum Offer Price Rule is toothless.

14 And, as set forth above in my third identified flaw, if not fully bypassed by this
15 false commencement date scheme, the mitigation itself nevertheless remains too brief,
16 applying only to a single Base Residual Auction and thereafter to none of the incremental
17 auctions. It is easy to imagine someone procuring a “string” of uneconomic new entry
18 staged to enter the market over time in order to exploit this weakness. In sum, the
19 Minimum Offer Price Rule is completely ineffective at actually limiting any buyer
20 market power.

²⁰ While in general Sell Offers for new resources are not capped, some limitations apply. However, in the context of a party trying to suppress prices, a premature offer at the highest possible cap is unlikely to ever clear, as the entire strategy revolves around offering excess capacity to artificially drive prices below the Cost of New Entry, an environment where pricing would presumably be below the Cost of New Entry.

1 *B. The Minimum Offer Price Rule's Flaws Are Easily Exploited*

2 Q ARE THE FLAWS IN THE MINIMUM OFFER PRICE RULE EASY TO EXPLOIT?

3 A Yes. A recent example is New Jersey's new legislation to sponsor uneconomic entry, and
4 it apparently will soon be followed by similar actions in Maryland. Though these
5 schemes have not yet been fully implemented, they are clear signs that the rule is
6 vulnerable.

7 Q ARE THERE INDICATIONS THAT THE NEW JERSEY LEGISLATION IS
8 DIRECTED AT CIRCUMVENTING THE MOPR AND SUPPORTING
9 UNECONOMIC GENERATION?

10 A Yes. The Independent Market Monitor explicitly expressed its concern that the
11 legislation might be an attempt to evade the Minimum Offer Price Rule's applicability.²¹
12 PJM even warned the New Jersey Board of Public Utilities that regardless of any express
13 language, it would choose to interpret the Minimum Offer Price Rule as still applying in
14 situations where there is clearly an intent to circumvent its application.

15 Moreover, based on the analysis that has gone into the legislation, there is little
16 doubt here that price suppression is a major motivation for the state-directed
17 procurement. While the preamble to the bill does discuss reliability, the requirements of
18 the legislation do not link the new generation to any specific reliability constraint or
19 specific need or study result. Further, there was absolutely no indication of any analyses
20 related to the cost effectiveness of a state-directed procurement on a stand-alone basis
21 versus prices and resources available from the market under the existing RPM auction
22 process. In other words, no one ever compared the cost of the resources being given a

²¹ See Bowring Letter.

1 contractual payment floor to the current or expected market prices. It is hard to imagine a
2 more fundamental omission.

3 Thus, there was and is no research as to whether the proposed New Jersey plan is
4 cost justified—i.e., whether the proposal is more efficient than simply procuring
5 generation from existing resources at the market prices. In sensitivity studies conducted
6 by PJM on the 2010 Base Residual Auction results, prices in the EMAAC LDA would
7 have dropped from about \$245 per MW-day to approximately \$100 per MW-day upon
8 completion of several of the transmission facilities approved in the PJM transmission
9 expansion plan. This indicates a lack of long-term need for new entry to maintain
10 reliability.²²

11 Q IS THERE ANY INDICATION THAT NEW JERSEY IS EXPERIENCING A
12 SHORTAGE OF GENERATION RESOURCES?

13 A No. Prices in recent years have been near or well below the Reference Resource's Net
14 Cost of New Entry, and on the demand curve that price point is set at the local reliability
15 target. Thus, there is no indication of any reliability problem. This indicates that more
16 capacity is being procured than the reliability target requirements.²³ Similarly, PJM
17 provided comments to the New Jersey Board of Public Utilities indicating that reliability
18 targets were being met.²⁴ PJM explicitly plans to add necessary transmission
19 reinforcements on a mandatory basis should it identify potential reliability problems in

²² See PJM, Scenario Analysis Results, <http://www.pjm.com/~media/markets-ops/rpm/rpm-auction-info/scenario-analysis-results.ashx>, attached hereto at P3 Exhibit 1-B ("PJM Sensitivity Studies").

²³ See Statement of Roy J. Shanker, Ph.D. on behalf of Competitive Suppliers Coalition, Statement before the N.J. Senate Environment and Energy Committee, at 12 tbl.A (Nov. 15, 2010 & Dec. 9, 2010), attached hereto at P3 Exhibit 1-C (showing recent capacity clearing amounts versus requirements for relevant localities).

²⁴ *In re N.J. Bd. of Pub. Utils. Review of State's Elec. Power & Capacity Needs*, No. EO09110920, Comments of the PJM Interconnection, LLC (N.J.B.P.U. July 6, 2010).

1 any locational delivery area. As stated above, major planned transmission facilities will
2 also significantly increase capacity deliverability into the area (the Susquehanna-
3 Roseland line, PATH and MAPP). Indeed, one of the major benefits of the RPM design
4 is that prices will rise as the need for new transmission increases and the system
5 approaches the online date of the new transmission facilities, thereby encouraging both
6 the retention of economic existing resources as well as new entry. But in the overall PJM
7 market design, transmission additions will “lead” generation into constrained localities,
8 limiting the need for new generation in a locational delivery area until the system as a
9 whole approaches its reliability targets.

10 Further, what is equally telling is the fact that many “experts” in the electric
11 industry in New Jersey have been actively litigating a position where they represent that
12 PJM reliability standards are too strict, and that PJM’s current policies overstate the need
13 for new generation.²⁵ This includes the New Jersey Board of Public Utilities and the
14 New Jersey Division of the Rate Counsel. It is paradoxical that these same parties are
15 also urging the subsidy of new generation. Clearly the positions are inconsistent—unless
16 their motivation behind adding new capacity is actually to suppress prices.

17 Finally, new generation and entry are possible today in New Jersey when the price
18 is right. Currently there are over 900 MW of capacity exports from the region via
19 transmission ties, and approximately 1200 MW of generation is sited physically in New
20 Jersey but electrically chose to interconnect to New York City, with 500 MW of that
21 currently under construction. At minimum, the transmission line exports would be

²⁵ See *Md. Pub. Serv. Comm’n v. PJM Interconnection*, 124 FERC ¶ 61,276 (2008), *reh’g denied*, 127 FERC ¶ 61,274, *appeal docketed sub nom. Md. Pub. Serv. Comm’n v. FERC*, D.C. Cir. No. 09-1296 (filed Aug. 14, 2009) (oral argument held Nov. 15, 2010).

1 expected to reverse if scarcity and market prices indicated a need in New Jersey.
2 Additionally PJM identified approximately 850 MW of new capacity and approximately
3 1500 MW of demand response added to New Jersey under RPM.²⁶

4 Q WHY WOULD NEW JERSEY SPONSOR UNECONOMIC ENTRY?

5 A The PJM market is designed such that clearing prices less than nominal levelized net Cost
6 of New Entry indicate a surplus of supply over the target reliability level. Thus the fact
7 that New Jersey is proposing above-market subsidized prices is a *de facto* indicator that
8 there is no need for the proposed facilities. Instead, the legislation is merely a means of
9 exercising buyer market power.

10 Instead of examining whether the proposal is efficient, the only considerations
11 made by New Jersey were the price suppressing effects of the procurement of unneeded
12 capacity. Presentations by LS Power indicate that it believes energy prices as a whole
13 may be depressed by \$98 million per year under the proposed legislation simply from an
14 addition of only 650 MW of uneconomic supply.²⁷ This was not a measure of
15 improvements of efficiency or reduction in production costs. It simply measured shifts in
16 revenues caused by adding excess supply. Similarly, the New Jersey Rate Counsel
17 submitted recent comments to the New Jersey Board of Public Utilities estimating that
18 capacity prices would be suppressed on the order of \$465 million per year by adding 500
19 MW of otherwise unneeded capacity.²⁸ These alleged “savings,” however, are not true

²⁶ See *In re N.J. Bd. of Pub. Utils. Review of State’s Elec. Power & Capacity Needs*, No. EO09110920, Presentation at Technical Conference, New Jersey Power Supply Load and Capacity Data at 14-16 (June 24, 2010), <http://www.state.nj.us/bpu/pdf/energy/HERLING%20AND%20KORMOS.pdf>.

²⁷ LS Power, New In-State Generation, LS Power Energy Savings Analysis at 11 (Nov. 2010), attached hereto at P3 Exhibit 1-D.

²⁸ *In re N.J. Bd. of Pub. Utils. Review of State’s Elec. Power & Capacity Needs*, No. EO09110920, Comments of the Division of Rate Counsel at 8 (N.J.B.P.U. July 2, 2010).

1 savings; they are simply wealth transfers from unsubsidized, competitive sellers to
2 buyers, realized through the exercise of buyer market power.

3 The key observation here is that no one ever considered the underlying economics
4 of the transaction; they only considered the benefits of price suppression. Indeed, the
5 New Jersey Rate Counsel sees the legislation as a win/win proposition for just this
6 reason. In related testimony before the state legislature, the Rate Counsel justified the
7 subsidized contract solely on the basis of its price suppressing effect. The Rate Counsel
8 conducted analyses, estimating the price suppression at \$50 per MW-day, which would in
9 this case apply to all of EMAAC, or 33,000 MW. The Rate Counsel also noted that
10 should the capacity actually be needed, it would then be a really good deal, as then the
11 price of the contract would be “in the money.” But the Rate Counsel never considered
12 evaluating the possibility of there actually being a real stand-alone economic justification
13 for the contracts, or whether the contract was “in the money.” The price suppression
14 effect was all that was of interest.²⁹

15 Q ARE THERE OTHER WAYS THAT THE NEW JERSEY LEGISLATION TAKES
16 ADVANTAGE OF THE CURRENT MINIMUM OFFER PRICE RULE?

17 A Yes. The New Jersey legislation also exposes the second flaw that I identified above
18 regarding the impact thresholds for mitigation to be triggered. The ineffectiveness of the
19 current impact threshold is not speculative. The Independent Market Monitor re-ran the
20 2013-14 auction results, for example, to include 1,000 MW of uneconomic entry (a level
21 that the New Jersey legislation had previously proposed). That level of uneconomic entry

²⁹ See Stefanie A. Brand, Remarks Regarding A3442, Presented at the Assembly Telecommunications and Utilities Committee Meeting (Dec. 16, 2010), http://www.state.nj.us/rpa/docs/Remarks_of_Stefanie_Brand_A3442-Electric_Generation_Facilities.pdf.

1 would have *barely* failed the impact screen, suppressing prices from \$245 to \$191 per
2 MW-day, or slightly more than the 20%. The total cumulative annual impact would have
3 been \$1 billion.³⁰ PJM itself prepared sensitivity runs looking at an additional 1,000 MW
4 added in the EMAAC LDA at zero cost, and concluded that the revised price would be
5 \$195.33 per MW-day, again just slightly more than 20%.³¹

6 Assuming the impact is roughly linear, and conservatively using the Independent
7 Market Monitor's results, this means that if a party seeking to exercise buyer market
8 power fine-tuned its analysis, and added only 940 MW in one year instead of 1,000 MW,
9 the suppression would *only* be \$49 per MW-day, the impact test would be passed, and
10 there would be no mitigation. This means that a cumulative market-wide impact of
11 approximately \$940 million per year would go unchecked.

12 While the current legislation is for 2,000 MW, it will be spread over multiple
13 years, which will also easily allow the impact threshold to be sidestepped. This could
14 happen even though the PJM Independent Market Monitor determined an annualized
15 price suppression of \$2.16 billion for the market as a whole if the entire 2,000 MW were
16 added, based on the last auction results.³²

17 Absent a change in the Minimum Offer Price Rule by the Commission, New
18 Jersey or others could easily fine-tune their proposals to achieve just this result. Yet it
19 seems impossible (or at least disingenuous) to assert that a market mitigation rule that
20 allows almost \$1 billion a year in anti-competitive revenue transfers is just and
21 reasonable. And the impact of uneconomic entry could easily be staggered or phased to

³⁰ See IMM Analysis at 2-4 & tbl.1.

³¹ See PJM Sensitivity Studies.

³² IMM Analysis at 2-4 & tbl.6.

1 ensure that the impact screen is never failed. If spread over two or three years, even an
2 impact of \$2.16 billion could be deemed too insignificant to be mitigated under the
3 current rule.³³

4 Q ARE THERE ANY INDICATIONS THAT OTHER STATES MAY BE TAKING
5 SIMILAR ACTIONS?

6 A Yes. The Maryland Public Service Commission recently sent out a draft Request for
7 Proposal for comment. The Request for Proposal was for new electric generation
8 facilities in and around Maryland and included consideration of a new mandate that
9 would require electric distribution companies under the Maryland Public Service
10 Commission's jurisdiction to enter into long-term contracts to build new resources.³⁴ Up
11 to 1,800 MWs may be procured, but it would all be required to be new generation and to
12 offer into the RPM auctions so as to assure that the capacity clears. As noted earlier, this
13 is exactly the "formula" approach to the exercise of buyer market power by a state or
14 regulatory authority.³⁵

15 On January 28, 2011, the PJM Independent Market Monitor submitted comments
16 in response to the Maryland Public Service Commission that summarized the joint impact
17 of the New Jersey and Maryland actions, noting a combined price suppression of more
18 than \$3 billion per year based on recent auction results.³⁶

³³ These impacts would be for the first year of addition and would decline over time, assuming that there is no further exercise of buyer market power. However, given the obvious paybacks, it would make sense to continue with uneconomic additions continually over time.

³⁴ See generally *In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Serv.*, No. 9214, Request for Proposals for Generation Capacity Resources Under Long-Term Contract (M.P.S.C. Dec. 29, 2010).

³⁵ *Supra* at 15:4–16:2.

³⁶ See *In the Matter of Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Serv.*, No. 9214, Comments of the Independent Market Monitor for PJM at 4 (M.P.S.C. Jan. 28, 2011),

1 Q IS THERE ANY OTHER EVIDENCE THAT THIS TYPE OF MARKET
2 SUPPRESSION INCREASES COSTS?

3 A Yes, and immediately so. I would expect distortions of consumption to begin
4 immediately, thereby harming efficiency. I would expect the cost impacts to be spread
5 more over time, but it appears that serious cost impacts have already begun. According
6 to the January 28th release of Megawatt Daily (dated Jan 31, 2011), in an article on the
7 likely impact of New Jersey's legislation, "Moody's said the potential in the long term is
8 for the bill to be a material credit negative primarily to the unregulated power sector
9 within New Jersey." As it turns out, this statement turned out to be issued on the same
10 day that the New Jersey Governor signed the bill. I would expect markets to immediately
11 react to these types of comments, driving down the value of stock and debt in the
12 unregulated power sector, and in turn increasing the costs of funds to investors in electric
13 utility infrastructure.

14 Q WHAT CONCLUSIONS ABOUT THE MINIMUM OFFER PRICE RULE DO YOU
15 DRAW FROM NEW JERSEY'S AND MARYLAND'S ACTIONS?

16 A The conclusion here is clear: because a state legislature or state commission can
17 effectively vitiate the Minimum Offer Price Rule and allow the exercise of buyer market
18 power, the Minimum Offer Price Rule is unjust and unreasonable.

1 Q WHY DOES A STATE LEGISLATURE’S OR STATE COMMISSION’S ABILITY TO
2 CIRCUMVENT THE MINIMUM OFFER PRICE RULE RENDER IT UNJUST AND
3 UNREASONABLE?

4 A The New Jersey legislation and the Maryland Request for Proposal demonstrate that
5 bypassing the Minimum Offer Price Rule is easy. In both cases, all that was necessary to
6 potentially bypass the Rule was to establish contracts for differences via a proxy. In a
7 sense, it was so easy to bypass the rule that the process was done in an open and
8 notorious manner, almost flaunting the tariff. As noted above, PJM recognized this
9 potential deficiency in the Minimum Offer Price Rule and notified the New Jersey Board
10 of Public Utilities that it would take the position that such out-of-market purchases of
11 uneconomic capacity, in the proposed proxy fashion, would be deemed actions by a net
12 buyer regardless of the language of the Rule. But there should not be any doubt that such
13 behavior violates the purpose of the Rule and must be mitigated.³⁷ The rule should be
14 modified so that it is certain to fully mitigate uneconomic entry.

15 While my intent is not to give a tutorial on how to bypass the Rule, it should be
16 relatively transparent that a wide range of proxy arrangements, side payments, out-of-
17 market contracts and other tools—many of which are far less visible and much harder to
18 detect than state legislative actions or mandated state regulatory orders—can have the
19 exact same impact, thereby rendering the Minimum Offer Price Rule entirely toothless.

³⁷ See Bowring Letter.

1 *III. RECOMMENDED SOLUTIONS TO FIX THE MINIMUM OFFER PRICE RULE*

2 Q HAVE YOU IDENTIFIED AN ALTERNATIVE TO THE MOPR THAT WOULD
3 RESOLVE THE FLAWS YOU IDENTIFIED AND PROVIDE FOR THE EFFECTIVE
4 MITIGATION OF BUYER-SIDE MARKET POWER?

5 A Yes. In doing so, I have tried both to incorporate recent Commission precedent on the
6 issue of buyer-side mitigation, and at the same time identify a mitigation approach that
7 can incorporate and take advantage of the specific market characteristics of the three year
8 lead time utilized in the PJM Base Residual Auction.

9 This leads to a partitioning of the mitigation approach between:

- 10 (1) longer-lead-time units, where mitigation is still needed, but by definition
11 has to be based on longer-lead-time assumptions regarding the economics
12 and market projections of the resource at the time of commitment; and
- 13 (2) shorter-lead-time units, where it is possible to incorporate the market test
14 of the RPM Base Residual Auction as part of the conduct screen to
15 determine whether mitigation is needed.

16 Q WHAT SPECIAL CONSIDERATIONS APPLY TO LONGER-LEAD-TIME UNITS?

17 A For longer-lead-time units, it is important that market participants not be caught in a
18 situation of having made a rational business decision at the time of commitment to
19 essentially begin construction, only to subsequently find themselves subject to mitigation.
20 This could happen if circumstances changed between the time of commitment and the
21 first eligible Base Residual Auction.

22 Providing developers of long-lead-time units with assurances regarding the
23 mitigation status of their units before they commit to proceed with construction requires
24 some care. There will be a degree of substitution of the business decision-making of
25 developers for decision-making by either or both PJM and the Independent Market
26 Monitor.

1 Q DOES THIS ISSUE APPLY TO SHORTER-LEAD-TIME UNITS?

2 A No. For shorter-lead-time units, this concern can effectively be ignored. Mitigation can
3 instead be focused on behavior in the Base Residual Auction because the shorter-lead-
4 time unit can be built within the three-year window between the auction and delivery.
5 Offers will be mitigated if they are uneconomic, but the project will know before
6 construction begins whether it will be subject to the mitigation of its Sell Offer in the
7 capacity market auctions. Further, any project (long- or short-lead-time) that can
8 demonstrate it has not received discriminatory benefits will be free from all mitigation.
9 This allows market participants with legitimate, unsubsidized short-term projects to
10 exercise their own private business decision-making, independent of the expectations of
11 PJM or the Independent Market Monitor.

12 Preserving this private decision-making is an important element of maintaining
13 the viability of competitive markets and market solutions. To the extent this can be done,
14 while also protecting the market against the anti-competitive and discriminatory impacts
15 of buyer market power, it is a reasonable objective. I believe the bifurcated approach I
16 describe below has exactly this property. Imposing mitigation decision-making over
17 private business decisions is minimized where possible, while robust mitigation is
18 maintained.

19 Q WHAT IS THE BASIS FOR YOUR RECOMMENDED MITIGATION FOR LONG-
20 LEAD-TIME-UNITS?

21 A My approach here for long-lead-time new resources stems from the Commission's recent
22 decision in the NYISO in-city capacity market. The Commission issued an order³⁸ that

³⁸ *N.Y. Indep. Sys. Operator, Inc.*, 133 FERC ¶ 61,178 (2010), *reh'g pending*.

1 addressed and basically accepted as filed the NYISO's modified and refined capacity
2 buyer-side mitigation measures. It is possible to use provisions that were approved in
3 this recent decision that address the very weaknesses identified above. This would
4 reform the Minimum Offer Price Rule so that it truly has the potential to deter
5 uneconomic entry. I believe the NYISO in-city mitigation is an excellent building block,
6 particularly for units that have to enter into commitments to proceed with development
7 prior to the existing Base Residual Auction horizon.

8 Q BRIEFLY SUMMARIZE THE NYISO CAPACITY MARKET DESIGN AND HOW IT
9 COMPARES TO PJM.

10 A The NYISO capacity market clears from 6-month strip auctions to monthly spot auctions,
11 while PJM is an annual auction conducted three years in advance. Though the time steps
12 are different, the basic market design principles in PJM and NYISO are the same. The
13 NYISO capacity market is built around a clearing auction utilizing a demand curve.
14 NYISO's demand curve is completely linear, unlike PJM's shaped linear segments.
15 NYISO's demand curve has a fixed point at the net cost of new entry and at the target
16 reliability requirement of the installed reserve margin. In PJM the analogous points on
17 the curve are the net cost of new entry but the target requirement for the system as a
18 whole is set at installed reserve margin plus 1%. The NYISO market is locational, as is
19 PJM, and there are different slopes to the demand curve and different net Cost of New
20 Entry values for each of the current three localities in New York: New York City, Long
21 Island and everywhere else ("NYCA"). PJM maintains a similar shape for the locational
22 delivery area curves, but adjusts for different net Costs of New Entry. The clearing

1 “engines” in each market are slightly different, but each solves for the necessary
2 locational requirements and the overall market requirements as a whole.

3 For exactly the same reasons as PJM, NYISO instituted market mitigation
4 measures for the New York City locality to prevent price discrimination and suppression
5 by uneconomic new entry. This was clearly needed due to a very high concentration of
6 buyers and their associated ability to transfer potential out-of-market payments via non-
7 bypassable charges, typically via retail rate charges. Though the intent was similar, the
8 current NYISO design, reflecting the refinements of the current order, is superior in most
9 respects³⁹ to the PJM Minimum Offer Price Rule, and avoids most if not all of the
10 Minimum Offer Price Rule’s failings. In many ways, NYISO’s approach is the same as
11 the Minimum Offer Price Rule, just “fixed.”

12 Q PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF NYISO’S CAPACITY BUYER-
13 SIDE MITIGATION.

14 A The NYISO rule has a similar conduct and impact structure to the Minimum Offer Price
15 Rule. It has no net buyer exception, however, as the Commission rejected it. All new
16 Sell Offers in New York City are reviewed regardless of the market position of the
17 seller.⁴⁰

18 There is a market-based conduct screen with respect to any Sell Offer from a new
19 facility. In the terminology used above, a new Sell Offer fails the conduct screen if it is
20 below 75% of the net Cost of New Entry. Any new Sell Offer is mitigated to this level

³⁹ I discuss below the major exception I propose in PJM regarding the conduct and “mitigate-to” levels. Given the materially different competitive environments, I concluded that these levels should be set at 100% at minimum in PJM, versus the 75% used on the NYC market where there is limited competitive entry and highly concentrated demand.

⁴⁰ The only exceptions are certain “Special Case Resources,” which are certain interruptible end-use loads and distributed generators.

1 (or its own demonstrated unit cost, calculated in the same way that the net Cost of New
2 Entry is calculated)⁴¹ unless the NYISO determines that the new facility would be
3 anticipated to clear the market at its Sell Offer. This determination is based on a forecast
4 prepared by the NYISO of market conditions expected at the time of entry.⁴² The
5 forecast is prepared at the time the new entrant has to decide whether or not to enter into
6 an Interconnection Service Agreement, and commit to associated network upgrades. If
7 the new Sell Offer is forecasted to clear the market, effectively the new unit is deemed to
8 have passed the conduct screen and will not be subject to mitigation. Thus, it may offer
9 into the market at its Avoidable Cost Rate or less when it commences operation.

10 If, on the other hand, the new facility fails the conduct test (i.e., it is found not to
11 be anticipated to be economic), then it is subject to mitigation and its offer price will be
12 set at a floor level until the capacity clears in actual auctions. The floor level is equal to
13 the lesser of 75% of the reference net Cost of New Entry or the Unit Cost of New Entry
14 for the new entrant. Presumably with this information it may choose not to proceed. The
15 clearing determination is “divisible,” that is, if a portion—for example, 40%—of a unit
16 clears for a sufficient period, then that 40% would be no longer subject to mitigation at a
17 floor price, and only the remaining 60% would be subject to offering at the specified
18 floor price.

⁴¹ The specific levelized calculation of the unit specific net cost of entry is determined in a fashion that is parallel to the methodology that the NYISO has adopted in its demand curve reset process for the determination of gross and net Cost of New Entry.

⁴² As modified all new entrants in a “class year” would be evaluated simultaneously for a period three years in the future.

1 Q WHY DO YOU FOCUS ON THIS APPROACH FOR LONGER-LEAD-TIME NEW
2 ENTRANTS IN THE CAPACITY MARKET?

3 A Because by its very nature the NYISO approach is a forecast-based procedure, with
4 commitments to new units occurring well before the monthly time-step of the NYISO
5 market. If mitigation were applied at the time the new entrant actually could participate
6 in the seasonal or monthly market, the participant would be faced with the dilemma of
7 having to build a new unit without knowing if it might be mitigated because of changes in
8 market circumstances, regardless of the genesis of those changes. If mitigated, the new
9 resource might not clear in the capacity market after the unit was fully constructed. This
10 is directly analogous to long-lead-time units outside the RPM Base Residual Auction
11 window in PJM. As discussed further below, however, it is unnecessary for shorter-lead-
12 time units.

13 Q PLEASE IDENTIFY THE SPECIFIC ELEMENTS OF THE NYISO IN-CITY
14 CAPACITY BUYER-SIDE MITIGATION THAT RESOLVE THE DEFICIENCIES OF
15 THE MINIMUM OFFER PRICE RULE FOR LONG-LEAD-TIME UNITS.

16 A There are three specific items:

17 1—*All* new entry (other than Special Case Resources) is subject to screening for
18 market power and mitigated to an appropriate offer floor if deemed to be uneconomic.
19 The conduct screen basically establishes whether, at the time a commitment to proceed
20 with the unit is made, a rational decision maker would find the unit to be economic as
21 compared with a forecast of expected market outcomes. There are no exceptions to
22 mitigation for being a net buyer and only Special Case Resources are exempted. There is
23 no exclusion for self-supply.

1 2—If the initial conduct evaluation is failed, the offer is mitigated. There is no
2 subsequent impact threshold other than the offer floor; the unit either clears or remains
3 mitigated.

4 3—There is no limit on duration for uneconomic supplies being mitigated. Units
5 determined to be uneconomic remain constrained to offer at their mitigated price until
6 they clear the market for a sufficient period to be deemed economic.

7 With this foundation in mind, I now proceed to my recommended changes to the
8 Minimum Offer Price Rule.

9 Q WHAT CONDUCT SCREENS DO YOU RECOMMEND FOR LONG-LEAD-TIME
10 UNITS?

11 A The conduct screens that I recommend each review the offer to determine whether it will
12 be economic at the proposed time of new entry. This is similar to the conduct screen
13 used in the NYISO In City capacity mitigation. The nominal levelized Unit Specific Net
14 Cost of New Entry would be reviewed to determine whether it would be economic and
15 clear two Base Residual Auctions. If so, the unit would not be mitigated when ultimately
16 it becomes operational. If the long-lead-time unit is not forecast to clear, and the party
17 chooses to proceed with construction anyway, its capacity Sell Offers would be mitigated
18 to its forecasted Unit Specific Net Cost of New Entry until the unit cleared in two
19 auctions.

20 The evaluation of whether a long-lead-time unit is forecast to clear the market
21 would be based on a demonstrated nominal levelized Unit Specific Net Cost of New
22 Entry. This would be calculated in a similar manner to that currently used by PJM and
23 the Independent Market Monitor to make such determinations for the Reference

1 Resource. If the new entrant is deemed to clear for such a period, then its offers in the
2 capacity market when the unit actually commences operations would not be mitigated,
3 and it could offer into the market up to its then applicable Avoidable Cost Rate as
4 determined in accordance with the existing tariff.⁴³

5 This allows for a clean, bright-line evaluation of all new entry. If at the time of
6 the execution of an Interconnection Service Agreement, it is deemed rational to proceed
7 with the new facility, then regardless of subsequent actual events and prices, the new
8 entrant would not be mitigated. If deemed uneconomic, the party could still proceed, but
9 would face mitigation. This decision is prior to actually commencing construction or
10 signing the Interconnection Service Agreement.

11 This allows for a party to proceed with certainty regarding the status of its unit
12 when it enters the market, and avoids future second guessing regarding what constitutes
13 economic entry. Further, to the extent that a unit is mitigated, and actual prices turn out
14 to be higher than forecasted, the application of this criteria is self correcting, as the new
15 unit at the mitigated prices would then likely clear, be determined to be economic, and
16 then subsequently have the mitigated offer floor removed.⁴⁴ As mentioned, any unit that
17 can demonstrate it does not receive any discriminatory benefits is fully exempt from
18 mitigation.

⁴³ See revised tariff language at Attachment A to the Complaint.

⁴⁴ It can be argued that this type of determination could be made repeatedly, even after the Interconnection Service Agreement is executed, to assess whether it is still rational to proceed with the new unit. However, at the time a resource commits to PJM to build necessary transmission upgrades, which will be built regardless, it seems that this is a reasonable point to consider the unit “committed,” and to provide it with certainty regarding mitigation.

1 Q WHY DO YOU NOT RECOMMEND THAT THIS SAME SCREEN BE APPLIED TO
2 SHORT-LEAD-TIME RESOURCES?

3 A Unlike the situation in NYISO where commitments to proceed with new capacity must be
4 made prior to the actual auction, in PJM it is possible to first test the economics of a new
5 facility in the auction. There, a new resource can determine the need for new unit prior to
6 building it. By definition, a short-lead-time unit can be built within the three-year
7 window between the auction and the delivery year. This means that mitigation can focus
8 on the actual behavior of the new entrant. At the time of the auction, it can be determined
9 whether the new entrant is receiving out-of-market support or other types of
10 discriminatory payments that may be covered by non-bypassable charges through the
11 “real” project sponsor or beneficiaries of uneconomic entry. As a result a reasonably
12 straightforward mitigation approach for short-lead-time units can be implemented that
13 addresses uneconomic entry without the need to substitute a forecast by PJM or the
14 Independent Market Monitor for the business discretion of the project sponsor.

15 Q WHAT CONDUCT SCREEN DO YOU PROPOSE FOR SHORT-LEAD-TIME UNITS,
16 INCLUDING COMBUSTION TURBINES AND COMBINED CYCLES?

17 A Subject to the exceptions noted below, any resource—and, in particular, short-lead
18 units—would pass the conduct screen if its bid is at least 100 percent of the net cost of
19 new entry of the Reference Resource (a combustion turbine as defined in Attachment DD
20 of the PJM tariff, section 2.58). If it offers below 100 percent of its benchmark, the
21 conduct screen is failed.

1 Q ARE THERE ANY OTHER WAYS TO PASS THE CONDUCT SCREEN?

2 A Yes. A safe harbor will be created for any new entrant that can demonstrate conclusively
3 and warrant that it has not and will not be the beneficiary, directly or indirectly of any
4 out-of-market payments. This is the same as for long-lead time units. A discriminatory
5 or out-of-market payment is any payment, direct or indirect, that is not available to other
6 market participants, but is principally only available to new entry. Thus a payment is
7 discriminatory or out-of-market if it results from an auction or request for proposals for
8 new entry and excludes existing resources. A bilateral agreement for new entry, or a
9 more general bilateral agreement—like a futures agreement—is also discriminatory or
10 out-of-market if priced above market and in support of a portfolio that includes new
11 entry. It does not matter if the payment is directly to the project or to an affiliate or third
12 party. Rate-based recovery for a new resource is also discriminatory and out-of-market.

13 If, on the other hand, a payment is not contingent upon a resource being new,
14 there is a good chance it is not discriminatory.

15 To show its payments are not discriminatory or out-of-market, the new entrant
16 would have to provide the Independent Market Monitor or PJM with sufficient
17 information to allow a determination of whether the new entrant, its owners or affiliated
18 entities are the beneficiaries of any discriminatory payments or other out-of-market
19 benefits that may be recovered via some non-bypassable mechanism such as distribution
20 company tariffs, state taxes or similar mechanisms. Such information would have to be
21 provided with a sufficient level of detail so that mechanisms like contracts for differences
22 or other contract payments and arrangements via third parties would all be disclosed.
23 Further, such submissions, as well as an affirmation that no such arrangements exist

1 would have to be provided by an officer of the relevant companies involved. This waiver
2 of mitigation also applies to long-lead-time units.

3 Q IF ALL OF THE CONDUCT SCREENS ARE FAILED, WHAT IMPACT SCREEN DO
4 YOU RECOMMEND?

5 A I recommend eliminating the impact screen. If the conduct screens I outline above are
6 failed, the offers should be mitigated.

7 Q WHAT SUBSTITUTE SELL OFFER DO YOU RECOMMEND IN THE
8 MITIGATION?

9 A If a new entrant is not determined to be economic at the initial screening and does not fall
10 within one of the exemptions, it is then mitigated to an offer floor of 100 percent of the
11 nominal levelized Unit Specific Net Cost of New Entry. This substitute Sell Offer
12 applies for both long and short-lead-time units.

13 Q HOW WOULD THE SHORT-LEAD-TIME RESOURCE DEMONSTRATE ITS UNIT
14 SPECIFIC COSTS?

15 A The process would be similar to the screening of a long-lead-time unit at the time of
16 signing the Interconnection Service Agreement. A short-lead-time new entrant would
17 provide the Independent Market Monitor or PJM with sufficient information to support
18 such a calculation for nominal levelized unit gross Cost of New Entry (utilizing current
19 PJM and Independent Market Monitor capital structure assumptions). The Independent
20 Market Monitor or PJM would calculate location-specific energy and ancillary service
21 offsets in a way similar to that currently used by the Independent Market Monitor to
22 determine the net Avoidable Cost Rate for all offerers. Such mitigation would apply to

1 all PJM auctions, the Base Residual Auction and all incremental auctions. The mitigation
2 would continue for any portion of the unit until it cleared in two Base Residual Auctions.

3 Q WHY IS IT IMPORTANT TO USE THE GENERAL MARKET ASSUMPTIONS
4 REGARDING THE COSTS OF CAPITAL FOR A MERCHANT GENERATION
5 PLANT WHEN CALCULATING THE NOMINAL LEVELIZED UNIT SPECIFIC
6 NET COST OF NEW ENTRY?

7 A For any party with a long-lead-time unit that may be receiving an out-of-market payment,
8 the mitigated price needs to reflect the conditions and costs such a unit would face absent
9 the out-of-market payment. The principal distortion that such payments create is in
10 access to the cost of capital. Thus, mitigated unit specific costs must remove this bias.
11 This is accomplished by using the capital structure any third party would face absent the
12 out-of-market payments.

13 Q EXPLAIN WHAT IS MEANT BY NOMINAL LEVELIZATION AND WHY IT IS
14 THE APPROPRIATE METHOD TO ESTABLISH A MITIGATED PRICE?

15 A Levelized prices can be established in two ways, nominal or real. Nominal levelized
16 payments are calculated to create a constant annual stream of the same dollar amount
17 each year that has a present value at a designated discount equal to a given amount. Real
18 levelized payments reflect a stream of dollars increasing over time at the forecasted rate
19 of inflation that has the present value when discounted equal to the same given amount.
20 In this instance the “given amount” is the cost of constructing a new generating facility.

21 It is appropriate to base mitigation on the nominal stream because that is the cost
22 stream that most closely matches the type of financial obligations associated with project
23 financing. It basically is a cost structure similar to a mortgage. PJM and its Independent

1 Market Monitor have supported the use of the nominal levelized net Cost of New Entry
2 in the calculation of the net Cost of New Entry values for the Reference Resource. In the
3 current tariff, the first year of a real levelized stream of payments is used. To my
4 knowledge this departure from the general calculation procedure was never justified.

5 Q WHY DO YOU PROPOSE THE “MITIGATED-TO” VALUE TO BE 100% OF THE
6 UNIT SPECIFIC NET COST FOR BOTH LONG AND SHORT-LEAD-TIME UNITS?

7 A While NYISO utilizes 75% of the reference Net Cost of New Entry and PJM currently
8 would mitigate to 90% of that value, I concluded that these values are all too low. I
9 discussed this at length above. The Reference Resource’s Net Cost of New Entry is the
10 value that the market is expected to average over time. If the new entrant were the
11 Reference Resource, then mitigation to 100% of the Reference Resource essentially sets a
12 cap on capacity compensation at the average value. It is hard to see how payments
13 structured at average or less than average can be compensatory. Similarly as explained
14 above, such a mitigation level is consistent with minimizing the cost of errors in trying to
15 replicate competitive pricing levels. If anything, a higher value is needed to allow prices
16 to hit the average and make up for the below average years and assure that market prices
17 are not capped by mitigation at levels below that needed to support competitive entry.

18 Q ARE THERE OTHER REASONS FOR DEPARTING FROM THE NEW YORK CITY
19 PRECEDENT AND USING THE 100% VALUE?

20 A Yes. A major distinction between NYC and just about anywhere else is the issue of open
21 and competitive new entry. Most parties acknowledge that entry is very difficult in NYC,
22 but there is no indication of such limitations in PJM or specifically in New Jersey. As
23 noted, several thousand megawatts of supply have been originated in New Jersey to serve

1 New York, and several thousand MWs of generation and demand response have also
2 been procured for New Jersey via RPM. If new entry were constrained, this might justify
3 lower thresholds, but if competitive entry is already happening, it is difficult to reject the
4 logic of the two main arguments I presented in the last answer regarding using 100% as
5 the appropriate screen and mitigation levels.

6 In addition, under my recommendations, true competitive entry without a subsidy
7 would not be mitigated. If an unsubsidized unit so desires, it can even offer as a price
8 taker in the capacity auctions. This amplifies the point that not only is *competitive* entry
9 allowed, but that my recommended mitigation raises no barrier to its entry. Thus the use
10 of the 100% value for both the Reference Resource conduct screen and the unit specific
11 “mitigate-to” value is both reasonable and justified.

12 Q HOW LONG SHOULD THE MITIGATION LAST?

13 A The mitigation would continue until the new entrant’s mitigated offer clears two Base
14 Residual Auctions. The mitigation would also be divisible for each portion of the unit
15 that clears the auction. This period is consistent with the precedent in the Commission’s
16 recent NYISO In City Capacity mitigation Order.⁴⁵ There, with a monthly clearing
17 process, the requirement was to clear in twelve auctions, which didn’t necessarily need to
18 be consecutive. Thus, because typically demand is higher, and capacity lower during the
19 summer, the most likely clearing scenario is during two summer periods. Because PJM
20 clears annually based on summer requirements, the use of two Base Residual Auctions is
21 directly analogous.

⁴⁵ See *N.Y. Indep. Sys. Operator*, 133 FERC ¶ 61,178 at P 49.

1 Q WHAT OTHER CHANGES DO YOU RECOMMEND?

2 A As outlined above, I would remove the conduct screen regarding net buyer status, and
3 eliminate the ability of self-supply to circumvent any market mitigation. I would also
4 eliminate the Minimum Offer Price Rule's limitation of mitigation to Planned Generation
5 Capacity Resources as currently modified in the tariff and discussed above.

6 I also recommend a very strict anti-gaming provision that would provide that to
7 the extent that the Independent Market Monitor determines that a mitigated new entrant
8 cleared an auction due to any manipulation or scheme to circumvent the above
9 provisions, mitigation will be re-imposed. Similarly, to the extent that any party finds a
10 way to circumvent the above screens and mitigation, the Commission should actively
11 enforce its market manipulation protections. Because of the forward nature of the
12 markets, there is no reason why an auction should be settled without proper mitigation if
13 there is concern regarding manipulation.

14 Q SHOULD THE COMMISSION ADOPT YOUR PROPOSED MITIGATION?

15 A Yes. My proposal is consistent with the Commission's approval of the NYISO in city
16 capacity buyer-side mitigation and is otherwise economically efficient. Counsel has
17 prepared matching tariff language to incorporate these recommendations into the
18 provisions of Attachment DD of the PJM tariff.⁴⁶ I support the addition of this text into
19 the PJM tariff to resolve the concerns addressed in this testimony.

20 Q DOES THIS CONCLUDE YOUR TESTIMONY?

21 A Yes.

⁴⁶ See Attachment A to the Complaint.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

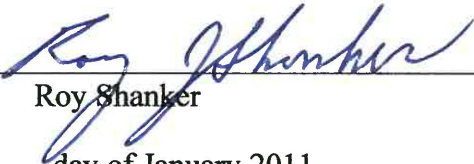
PJM Power Providers Group)
)

v.)

Docket No. EL11-___-000

PJM Interconnection, L.L.C.)
)

I, Roy J. Shanker, being duly sworn, depose and state that the contents of the foregoing
Testimony on behalf of the PJM Power Providers Group is true, correct, accurate and complete
to the best of my knowledge, information, and belief.



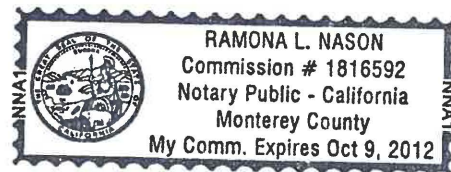
Roy Shanker

SUBSCRIBED AND SWORN to before me this ____ day of January 2011.

(Notary Public)

My commission expires: _____

State of California County of
Monterey
Subscribed and sworn to (or affirmed)
before me on this 28 day of January, 2011, by
Roy Shanker
proved to me on the basis of satisfactory evidence
to be the person(s) who appeared before me.
Signature Ramona L. Nason
(Seal)



**QUALIFICATIONS
AND
EXPERIENCE OF
DR. ROY J. SHANKER**

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Independent Consultant
Present P.O. Box 60450
Potomac MD 20854

Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.

1979-81 Hagler, Bailly & Company
2301 M Street, N.W.
Washington, D.C.

Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.

1976-79 Resource Planning Associates, Inc.
1901 L Street, N.W.

Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2010

New Jersey State Assembly and Senate. Statements on behalf of the Competitive Supplier Coalition addressing market power and reliability impacts of proposed legislation, Assembly Bill 3442 and Senate Bill 2381

Federal Energy Regulatory Commission. Docket ER11-2183. Affidavit on behalf of First Energy Services Company addressing default capacity charges for Fixed Resource Requirement participants in the PJM Reliability Pricing Model capacity market design.

Federal Energy Regulatory Commission. Docket ER11-2059 Affidavit on behalf of First Energy Services Company addressing deficiencies and computational problems in the proposed “exit charges” for transmission owners leaving the MISO RTO related to long term transmission rights.

Federal Energy Regulatory Commission Docket RM10-17. Invited panelist addressing metrics for cost effectiveness of demand response and associated cost allocations and implications for monopsony power.

Federal Energy Regulatory Commission Consolidated Dockets ER10-787-000, EL10-50-000, and EL10-57-000. Two affidavits on behalf of the New England Power Generators Association regarding ISO-NE modified proposals for alternative price rule mitigation and zonal definitions/functions of locational capacity markets.

Federal Energy Regulatory Commission Docket No. ER10-2220-000.
Affidavit on behalf of the Independent Energy Producers of New York.
Addressing rest of state mitigation thresholds and procedures for adjusting
thresholds for frequently mitigated units and reliability must run units.

Federal Energy Regulatory Commission Docket PA10-1. Affidavit on behalf
of Entergy Services related to development of security constrained unit
commitment software and its performance.

Federal Energy Regulatory Commission Docket No. ER09-1063-004.
Testimony on behalf of the PJM Power Providers Group (P3) regarding the
proposed shortage pricing mechanism to be implemented in the PJM energy
market. Reply comments related to a similar proposal by the independent
market monitor.

PJM RTO. Statement regarding the impact of the exercise of buyer market
power in the PJM RPM/Capacity market. Panel discussant on the issue at the
associated Long Term Capacity Market Issues Symposium.

Federal Energy Regulatory Commission Docket No. ER10-787-000.
Affidavit on behalf of New England Power Generators Association
addressing proper design of the alternative price rules (APR) for the ISO-NE
Forward Capacity Auctions. Second affidavit offered in reply. Supplemental
affidavit also submitted

Federal Energy Regulatory Commission Docket No. RM10-17-000.
Affidavit on behalf of New England Power Generators Association
addressing proper pricing for demand response compensation in organized
wholesale regional transmission organizations.

Federal Energy Regulatory Commission Docket No. RM10-17-000,
Affidavit on my on behalf regarding inconsistent representations made
between filings in this docket and contemporaneous materials presented in
the PJM stakeholder process.

2009

Federal Energy Regulatory Commission Docket No. ER09-1682. Two
affidavits on behalf of an un-named party regarding confidential treatment of
market data coupled with specific market participant bidding, and associated
issues.

American Arbitration Association, Case No. 75-198-Y-00042-09 JMLE, on
behalf of Rathdrum Power LLC. Report on the operation of specific pricing
provision of a tolling power purchase agreement.

Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortium of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session

regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

FERC Docket No. ER06-1474-000, FERC. Testimony on behalf of the PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

American Arbitration Association Nos. 16-198-00206-03 16-198-002070. On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

Federal Energy Regulatory Commission. Docket No. Docket No. EL03-236-003 Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cinergy Solutions regarding an energy services agreement related to a cogeneration facility.

Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacity credits.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affidavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacity within the New York Independent system operator.

Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

Federal Energy Regulatory Commission. Docket Number ER01-2076-000. Testimony on behalf of Aquila Energy Marketing Corp and Edison Mission Marketing and Trading, Inc. relating to the implementation of an Automated Mitigation Procedure by the New York ISO.

2000

New York Independent System Operator Board. Statement on behalf of Hydro Quebec, U.S. regarding the implications and impacts of the imposition of a price cap on an operating market system.

Federal Energy Regulatory Administration. Docket No. EL00-24-000. Testimony on behalf of Dayton Power and Light Company regarding the proper characterization and computation of regulation and imbalance charges.

American Arbitration Association File 71-198-00309-99. Report on behalf of Orange and Rockland Utilities, Inc. regarding the estimation of damages associated with the termination of a power marketing agreement.

Circuit Court, 15th Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limited Partnerships et. al. Analyses related to commercial operation provisions of a power purchase agreement.

1999

Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.

Federal Energy Regulatory Commission. Docket RM99-2-000. Analyses on behalf of Edison Mission Energy relating to the Regional Transmission Organization Notice of Proposed Rulemaking.

Federal Energy Regulatory Commission. Docket No. ER99-3508-000. On behalf of PG&E Energy Trading, analyses associated with the proposed implementation and cutover plan for the New York Independent System Operator.

Federal Energy Regulatory Commission. Docket No. EL99-46-000. Comments on behalf of the Electric Power Supply Association relating to the Capacity Benefit Margin.

New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.

1998

Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an application for a certificate for new generation facilities.

Federal Energy Regulatory Commission. Analyses related to a number of dockets reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

Circuit Court, Fourth Judicial Circuit, Duval County, Florida. Analyses related to the proper implementation of a power purchase agreement and associated calculations of capacity payments. (Testimony 1999)

1997

United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

United States District Court, Southern District of Florida, Case No. 96-594-CIV, Analyses related to anti-competitive practices by an electric utility and related contract matters regarding the appropriate calculation of energy payments.

Virginia State Corporation Commission. Case No. PUE960296. Testimony related to the restructuring proposal of Virginia Power and associated stranded cost issues.

Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New York Power Pool and the implementation of locational marginal cost pricing.

Federal Energy Regulatory Commission Dockets No. OA97-261-000 and ER97-1082-000 Analyses and testimony related to the restructuring of the PJM Power Pool and the implementation of locational marginal cost pricing.

Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

American Arbitration Association. Case 79 Y 199 00070 95. Testimony and analyses related to the proper conditions necessary for the curtailment of Qualifying Facilities and the associated calculations of negative avoided costs.

Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.

New York Public Service Commission. Case 96-E-0897, Analyses related to the restructuring of Consolidated Edison Company of New York and New York Power Pool proposed Independent System Operator and related transmission tariffs.

1996

Florida Public Service Commission. Docket No. 950110-EI. Testimony related to the correct calculation of avoided costs using the Value of Deferral methodology and its implementation.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Testimony and Analyses related to the estimation of historic market rates for electricity in the Virginia Power service territory.

Circuit Court of the City of Richmond Case No. LA-2266-4. Analyses related to the incurrence of actual and estimated damages associated with the outages of an electric generation facility.

New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

State of New York Supreme Court, Index No. 94-1125. Testimony related to system planning criteria and their relationship to contract performance specifications for a purchased power facility.

United States District Court for the Western District of Pennsylvania, Civil Action No. 95-0658. Analyses related to anti-competitive actions of an electric utility with respect to a power purchase agreement.

United States District Court for the Northern District of Alabama, Southern Division. Civil Action Number CV-96-PT 0097-S. Affidavit on behalf of TVA and LG&E Power regarding displacement in wholesale power transactions.

1995

American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

Circuit Court City of Richmond. Law No. LX-2859-1. Analyses related to IPP contract structure and interpretation regarding plant compensation under different operating conditions.

Federal Energy Regulatory Commission. Case EL95-28-000. Affidavit concerning the provisions of the FERC regulations related to the Public Utility Regulatory Policies Act of 1978, and relationship of estimated avoided cost to traditional rate based recovery of utility investment.

New York Public Service Commission, Case 95-E-0172, Testimony on the correct design of standby, maintenance and supplemental service rates for qualifying facilities.

Florida Public Service Commission, Docket No. 941101-EQ. Testimony related to the proper analyses and procedures related to the curtailment of purchases from Qualifying Facilities under Florida and FERC regulations.

Federal Energy Regulatory Commission, Dockets ER95-267-000 and EL95-25-000. Testimony related to the proper evaluation of generation expansion alternatives.

1994

American Arbitration Association, Case Number 11 Y198 00352 94 Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a NUG facility.

United States District Court, Middle District Florida, Case No. 94-303 Civ-Orl-18. Analyses related to contract pricing interpretation other contract matters in a power purchase agreement between a qualifying facility and Florida Power Corporation.

Florida Public Service Commission Docket 94037-EQ. Analyses related to a contract dispute between Orlando Power Generation and Florida Power Corporation.

Florida Public Service Commission Docket 941101-EQ. Testimony and analyses of the proper procedures for the determination and measurement for the need to curtail purchases from qualifying facilities.

New York Public Service Commission Case 93-E-0272, Testimony regarding PURPA policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

Circuit Court for the City of Richmond. Case Number LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

New York Public Service Commission, Case 93-E-0958 Analyses of Stand-by, Supplementary and Maintenance Rates of Niagara Mohawk Power Corporation for Qualifying Facilities .

New York Public Service Commission, Case 94-E-0098. Analyses of cost of service and rate design of Niagara Mohawk Power Corporation.

American Arbitration Association, Case 55-198-0198-93, Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power generation facility.

1993

U.S. District Court, Southern District of New York Case 92 Civ 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

State Corporation Commission, Virginia. Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.

Federal Energy Regulatory Commission. Docket ER93-323-000. Evaluations and analyses related to the financial and regulatory status of a cogeneration facility.

Federal Energy Regulatory Commission. Docket EL93-45-000; Docket QF83-248-002. Analyses related to the qualifying status of cogeneration facility.

Circuit Court of the Eleventh Judicial Circuit, Dade County, Florida. Case No. 92-08605-CA-06. Analyses related to compliance with electric and thermal energy purchase agreements. Damage analyses and testimony.

Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

State of North Carolina Utilities Commission. Docket No. E-100 Sub 67. Testimony in the consideration of rate making standards pursuant to Section 712 of the Energy Policy Act of 1992.

State of New York Public Service Commission. Cases 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.

Pennsylvania Public Utility Commission. Docket No. A-110300f051. Testimony regarding the prudence of the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

1992

Pennsylvania Public Service Commission. Dockets No. P-870235,C-913318,P-910515,C-913764. Testimony regarding the calculation of avoided costs for GPU/Penelec.

Public Service Commission of Maryland. Case No. 8413,8346. Testimony on the appropriate avoided costs for Pepco, and appropriate procedures for contract negotiation.

1991

Board of Regulatory Commissioners, State of New Jersey. Docket EM-91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.

Public Service Commission of Wisconsin. Docket 05-EP-6. State Advance Plan. Testimony on the calculation of avoided costs and the structuring of payments to qualifying facilities.

State Corporation Commission, Virginia. Case No. PUE910033. Testimony on class rate of return and rate design for delivery point service. Northern Virginia Electric Cooperative.

State Corporation Commission, Virginia. Case No. PUE910048 Testimony on proper data and modeling procedures to be used in the evaluation of the annual Virginia Power fuel factor.

State Corporation Commission, Virginia. Case No. PUE910035. Evaluation of the differential revenue requirements method for the calculation of avoided costs.

Public Service Commission of Maryland. Case Number 8241 Phase II. Testimony related to the proper determination of avoided costs for Baltimore Gas and Electric.

Public Service Commission of Maryland. Case Number 8315. Evaluation of the system expansion planning methodology and the associated impacts on marginal costs and rate design, PEPCO.

1990

Public Utility Commission, State of California, Application 90-12-064. Analyses related to the contractual obligations between San Diego Gas and Electric and a proposed QF.

Montana Public Service Commission. Docket 90.1.1 Testimony and analyses related to natural gas transportation, services and rates.

State Corporation Commission, Virginia. Case No. PUE890075. Testimony on the calculation of full avoided costs via the differential revenue requirements methodology.

District of Columbia Public Service Commission. Formal Case 834 Phase II. Analyses and development of demand side management programs and least cost planning for Washington Gas Light.

State Corporation Commission, Virginia. Case No. PUE890076. Analyses related to administratively set avoided costs. Determination of optimal expansion plans for Virginia Power.

State Corporation Commission, Virginia. Case No. PUE900052. Analyses supporting arbitration of a power purchase agreement with Virginia Power. Determination of expansion plan and avoided costs.

Public Service Commission of Maryland. Case Number 8251. Analyses of system expansion planning models and marginal cost rate design for PEPCO.

State Corporation Commission, Virginia. Case No. PUE900054. Evaluation of fuel factor application and short term avoided costs.

Federal Energy Regulatory Commission. Northeast Utilities Service Company Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000 and E190-9-000. Analyses of the implications of Northeast Utilities and Public Service Company of New Hampshire merger on electric supply and pricing.

Public Service Commission of Maryland. Re: Southern Maryland Electric Cooperative Inc. Contract with Advanced Power Systems, Inc. and PEPCO.

Puerto Rico Electric Power Authority, Office of the Governor of Puerto Rico. Independent evaluation for PREPA of avoided costs and the evaluation of competing QF's.

State Corporation Commission, Virginia. Case No. PUE890041. Testimony on the proper determination of avoided costs with respect to Old Dominion Electric Cooperative.

1989

Oklahoma Corporation Commission. Case Number PUD-000586. Analyses related to system planning and calculation of avoided costs for Public Service of Oklahoma.

Virginia State Corporation Commission. Case Number PUE890007. Testimony relating to the proper determination of avoided costs to the certification evaluation of new generation facilities.

Federal Energy Regulatory Commission. Docket RP85-50. Analyses of the gas transportation rates, terms and conditions filed by Florida Gas Transmission.

Circuit Court of the Fifth Judicial Circuit, Dade County, Florida. Case No. 88-48187. Analyses related to compliance with electric and thermal energy purchase agreements.

Florida Public Service Commission. Docket 880004-EU. Analysis of state wide expansion planning procedures and associated avoided unit.

1988

Virginia State Corporation Commission. Case No. PUE870081. Testimony on the implementation of the differential revenue requirements avoided cost methodology recommended by the SCC Task Force.

Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

Virginia State Corporation Commission. Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

Montana Public Service Commission. Docket 87.8.38. Testimony on Natural Gas Transmission Rate Design and Service Provisions.

Oklahoma Corporation Commission. Cause Pud No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

Florida Public Service Commission. Docket No. 8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

Arizona Corporation Commission. Docket No. U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987

Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factor application and relationship to avoided costs.

District of Columbia Public Service Commission. Formal Case No. 834 Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.

Florida Public Service Commission. Docket No. 860004 EU. Testimony in the 1986 annual planning hearing on proper system expansion planning procedures.

1986

Florida Public Service Commission. Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

Florida Public Service Commission. Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

U.S. Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

Public Utility Commission, New Hampshire Docket No. DR-86-41.
Testimony on pricing and contract terms for power purchase agreement
between utility and QFs. (Settlement Negotiations)

Florida Public Service Commission, Docket No. 850673-EU. Testimony on
generic issues related to the design of standby rates for qualifying facilities.

Virginia State Corporation Commission. Case No. 860024. Generic hearing
on natural gas transportation rate design and tariff terms and conditions.

Virginia State Corporation Commission. Commonwealth Gas Pipeline
Corporation. Case No. 850052. Testimony on natural gas transportation rate
design and tariff terms and conditions.

Bonneville Power Administration. Case No. VI86.
Testimony on the proposed Variable Industrial Power Rate for Aluminum
Smelters.

Virginia Power. Case No. PUE860011. Testimony on the proper ex post
facto valuation of avoided power costs for qualifying facilities.

Florida Public Service Commission. Docket No. 850004 EU. Testimony on
proper analytic procedures for developing a statewide generation expansion
plan and associated avoided unit.

1985

Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service
procedures and rate design for natural gas transportation service.

Arkansas Louisiana Gas. Louisiana Docket No. U-16534. Testimony on
proper cost of service procedures and rate design for natural gas service.

Connecticut Light and Power. Docket No. 85-08-08.
Assist in the development of testimony for industrial natural gas
transportation rates.

Oklahoma Gas and Electric. Cause 29727. Testimony and system
operations and the development of avoided cost measurements as the basis
for rates to qualifying facilities.

Florida Public Service Commission. Docket No. 840399EU. Testimony on
self-service wheeling and business arrangements for qualifying facilities.

Virginia Electric and Power Company. General Rate application No.
PUE840071. Testimony on proper rate design procedures and computations

for development of supplemental, maintenance and standby service for cogenerators.

Virginia Electric and Power Company. Fuel Factor Proceeding No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

1984

Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

Virginia Electric Power Company. Application to Revise Rate Schedule 19 - - Power Purchases from Cogeneration and Small Power Production Qualifying Facilities. Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of BPA; interactions between rate design, demand, system expansion and operation.

1983

Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

BPA Wholesale Rate Proceedings. Testimony on the theory and implementation of marginal cost rate design; financial performance of BPA; interactions between rate design, demand, system expansion and operation.

Idaho Power Company, PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

1982

Generic Conservation Proceedings, New York State. Case No. 18223. Testimony on the economic criteria for the evaluation of conservation activities; impacts on utility financial performance and rate design.

PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

Previous testimony before the District of Columbia Public Service Commission, Maryland PSC, New York Public Service Commission, FERC; Economic Regulatory Administration

Scenario #	Input Parameters Tab	Scenario Description	Auction Results	RTO	MAAC	SWMAAC	PEPCO	EMAAC	DPL-SOUTH	PSEG	PS-NORTH
BASE	BASE	Actual 2013/2014 BRA Results	Cleared MW	152,743.3	67,639.9	11,242.1	4,791.7	32,835.4	1,612.4	8,019.1	4,159.4
			Resource Clearing Price	\$ 27.73	\$ 226.15	\$ 226.15	\$ 247.14	\$ 245.00	\$ 245.00	\$ 245.00	\$ 245.00
1	Simulation 1	Revise VRR Curve (redefine curve using IRM-4%, IRM and IRM+4% instead of IRM-3%, IRM+1% and IRM+5%)	Cleared MW	151,442.4	67,424.2	11,139.6	4,709.8	32,744.5	1,612.4	7,950.8	4,091.1
			Resource Clearing Price	\$ 24.34	\$ 196.17	\$ 196.17	\$ 247.14	\$ 206.34	\$ 206.34	\$ 206.34	\$ 206.34
2	Simulation 2	Eliminate 2.5% Short-Term Resource Procurement Target (STRPT)	Cleared MW	156,493.0	68,308.1	11,768.2	5,288.9	32,977.5	1,612.4	8,033.1	4,173.4
			Resource Clearing Price	\$ 42.00	\$ 272.34	\$ 272.34	\$ 272.34	\$ 324.01	\$ 324.01	\$ 324.01	\$ 324.01
3	Simulation 3	Revise VRR Curve and Eliminate 2.5% STRPT	Cleared MW	155,192.1	67,865.0	11,453.2	4,973.9	32,849.4	1,612.4	8,033.1	4,173.4
			Resource Clearing Price	\$ 37.51	\$ 263.78	\$ 263.78	\$ 263.78	\$ 303.30	\$ 303.30	\$ 303.30	\$ 303.30
4	Simulation 4	Use 2012/2013 BRA IRM and FPR Values	Cleared MW	153,653.90	67,625.60	11,239.30	4,790.30	32,826.00	1,612.10	8,011.30	4,152.30
			Resource Clearing Price	\$ 30.00	\$ 226.06	\$ 226.06	\$ 247.14	\$ 245.00	\$ 245.00	\$ 245.00	\$ 245.00
5	Simulation 5	Use 2012/2013 BRA CONE Values	Cleared MW	152,743.30	67,338.50	11,053.90	4,660.60	32,744.50	1,612.40	7,950.80	4,091.10
			Resource Clearing Price	\$ 27.73	\$ 186.41	\$ 186.41	\$ 227.26	\$ 210.46	\$ 210.46	\$ 210.46	\$ 210.46
6	Simulation 6	Remove LDA Import Constraints	Cleared MW	152,743.3	62,690.1	9,578.7	3,783.3	30,394.3	1,184.7	7,191.5	3,927.5
			Resource Clearing Price	\$ 60.32	\$ 60.32	\$ 60.32	\$ 60.32	\$ 60.32	\$ 60.32	\$ 60.32	\$ 60.32
7	BASE	Remove 5000 MW from bottom of supply stack in rest of RTO	Cleared MW	152,743.30	67,639.9	11,242.10	4,791.70	32,835.40	1,612.40	8,019.10	4,159.40
			Resource Clearing Price	\$ 62.00	\$ 226.15	\$ 226.15	\$ 247.14	\$ 245.00	\$ 245.00	\$ 245.00	\$ 245.00
8	BASE	Remove 1000 MW from bottom of supply stack in rest of MAAC	Cleared MW	152,743.30	66,865.00	11,453.20	4,973.90	32,849.40	1,612.40	8,033.10	4,173.40
			Resource Clearing Price	\$ 28.85	\$ 261.23	\$ 261.23	\$ 261.23	\$ 261.23	\$ 261.23	\$ 261.23	\$ 261.23
9	BASE	Remove 1000 MW from bottom of supply stack in rest of EMAAC	Cleared MW	152,743.30	66,981.00	11,441.10	4,973.90	31,977.50	1,612.40	8,033.10	4,173.40
			Resource Clearing Price	\$ 28.52	\$ 256.05	\$ 256.05	\$ 256.05	\$ 330.93	\$ 330.93	\$ 330.93	\$ 330.93
10	BASE	Remove 400 MW from bottom of supply stack in PS-North LDA	Cleared MW	152,743.30	67,270.70	11,258.90	4,791.70	32,449.40	1,612.40	7,633.10	3,773.40
			Resource Clearing Price	\$ 27.73	\$ 243.07	\$ 243.07	\$ 247.14	\$ 286.98	\$ 286.98	\$ 286.98	\$ 286.98
11	BASE	Remove 400 MW from bottom of supply stack in PEPCO LDA	Cleared MW	152,743.30	67,591.80	11,194.00	4,726.80	32,835.40	1,612.40	8,019.10	4,159.40
			Resource Clearing Price	\$ 27.73	\$ 228.69	\$ 228.69	\$ 269.68	\$ 245.00	\$ 245.00	\$ 245.00	\$ 245.00
12	BASE	Remove 400 MW from bottom of supply stack in DPL-South LDA	Cleared MW	152,743.30	67,270.70	11,258.90	4,791.70	32,449.40	1,212.40	8,033.10	4,173.40
			Resource Clearing Price	\$ 27.73	\$ 243.06	\$ 243.06	\$ 247.14	\$ 286.96	\$ 286.96	\$ 286.96	\$ 286.96
13	BASE	Increase rest of RTO Supply by 5000 MW at \$0	Cleared MW	152,743.30	67,639.9	11,242.10	4,791.70	32,835.40	1,612.40	8,019.10	4,159.40
			Resource Clearing Price	\$ 16.06	\$ 226.15	\$ 226.15	\$ 247.14	\$ 245.00	\$ 245.00	\$ 245.00	\$ 245.00
14	BASE	Increase rest of MAAC Supply by 1000 MW at \$0	Cleared MW	152,743.30	68,487.50	11,119.20	4,791.70	32,835.40	1,612.40	8,019.10	4,159.40
			Resource Clearing Price	\$ 25.64	\$ 165.44	\$ 172.36	\$ 247.14	\$ 245.00	\$ 245.00	\$ 245.00	\$ 245.00
15	BASE	Increase rest of EMAAC Supply by 1000 MW at \$0	Cleared MW	152,743.30	68,070.10	11,221.50	4,791.70	33,308.50	1,206.80	7,937.30	4,077.60
			Resource Clearing Price	\$ 25.64	\$ 195.33	\$ 195.33	\$ 247.14	\$ 195.33	\$ 195.33	\$ 195.33	\$ 195.33
16	BASE	Increase PS-NORTH LDA Supply by 400 MW at \$0	Cleared MW	152,743.30	67,931.90	11,225.00	4,791.70	33,144.50	1,612.40	8,350.80	4,491.10
			Resource Clearing Price	\$ 26.07	\$ 205.23	\$ 205.23	\$ 247.14	\$ 205.23	\$ 205.23	\$ 205.23	\$ 205.23
17	BASE	Increase PEPCO LDA Supply by 400 MW at \$0	Cleared MW	152,743.30	67,891.80	11,493.90	5,060.60	32,835.50	1,612.40	8,019.20	4,159.50
			Resource Clearing Price	\$ 26.07	\$ 208.11	\$ 208.11	\$ 208.11	\$ 245.00	\$ 245.00	\$ 245.00	\$ 245.00
18	BASE	Increase DPL-SOUTH LDA Supply by 400 MW at \$0	Cleared MW	152,743.30	67,931.90	11,225.00	4,791.70	33,144.50	2,012.40	7,950.80	4,091.10
			Resource Clearing Price	\$ 26.07	\$ 205.23	\$ 205.23	\$ 247.14	\$ 205.23	\$ 205.23	\$ 205.23	\$ 205.23
19	Simulation 19	Full Susquehanna-Roseland Line	Cleared MW	152,743.3	67,565.8	11,258.9	4,791.7	32,744.5	1,612.4	7,950.8	4,091.1
			Resource Clearing Price	\$ 27.73	\$ 229.86	\$ 229.86	\$ 247.14	\$ 229.86	\$ 229.86	\$ 229.86	\$ 229.86
20	Simulation 20	Full Susquehanna-Roseland Line & PATH	Cleared MW	152,743.3	66,172.0	10,515.2	4,455.5	32,266.6	1,206.2	7,905.1	4,065.6
			Resource Clearing Price	\$ 33.00	\$ 135.59	\$ 135.59	\$ 135.59	\$ 135.59	\$ 135.59	\$ 135.59	\$ 135.59
21	Simulation 21	Full Susquehanna-Roseland Line & PATH & Partial MAPP	Cleared MW	152,743.3	65,638.8	10,217.0	4,339.3	32,087.2	1,206.2	7,845.1	4,046.0
			Resource Clearing Price	\$ 37.51	\$ 114.63	\$ 114.63	\$ 135.59	\$ 114.87	\$ 114.87	\$ 114.87	\$ 114.87
22	Simulation 22	Full Susquehanna-Roseland Line & PATH & Full MAPP	Cleared MW	152,743.3	65,092.9	10,204.7	4,339.3	31,648.7	1,200.5	7,758.7	4,016.6
			Resource Clearing Price	\$ 38.10	\$ 100.00	\$ 100.00	\$ 135.59	\$ 100.00	\$ 100.00	\$ 100.00	\$ 100.00

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8	
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Updated: 5/17/2010 with Post-Clearing BRA Credit Rate

	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, \$/MW-Day (UCAP Price)	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$476.93	\$340.80	\$391.59	\$340.80	\$391.59	\$391.59	\$391.59	\$340.80
Point (b) UCAP Price, \$/MW-Day	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*(Asterisk) – LDA has adequate internal resources to meet the reliability criterion.

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	3,749.7	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	4,483.0	111%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	5,868.4	99%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	2,570.0	98%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	7,095.0	101%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	4,460.0	106%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	
Limiting conditions at the CETL for modeled LDAs									
LDA	Limiting Facility								
MAAC	Pleasant View 500/230 kV transformer.								
EMAAC	Elroy - Branchburg 500 kV line.								
SWMAAC	Pleasant View 500/230 kV transformer.								
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.								
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.								
PEPCO	Pleasant View 500/230 kV transformer.								

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.

2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.

3/1/10 Update: Adjusted for FRR Alternative elections and obligations

4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, \$/MW-Day (UCAP Price)	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$476.93	\$340.80	\$391.59	\$340.80	\$391.59	\$391.59	\$391.59	\$340.80
Point (b) UCAP Price, \$/MW-Day	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
Point (a) UCAP Level, MW	141,035.6	68,913.5	38,070.8	16,880.6	12,633.9	5,987.8	2,829.0	8,922.8
Point (b) UCAP Level, MW	146,239.0	71,451.0	39,472.3	17,501.5	13,098.8	6,208.0	2,933.0	9,250.4
Point (c) UCAP Level, MW	151,442.4	73,988.4	40,873.8	18,122.5	13,563.7	6,428.2	3,036.9	9,578.0
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

***(Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	3,749.7	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	4,483.0	111%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	5,868.4	99%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	2,570.0	98%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	7,095.0	101%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	4,460.0	106%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	
Limiting conditions at the CETL for modeled LDAs									
LDA	Limiting Facility								
MAAC	Pleasant View 500/230 kV transformer.								
EMAAC	Elroy - Branchburg 500 kV line.								
SWMAAC	Pleasant View 500/230 kV transformer.								
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.								
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.								
PEPCO	Pleasant View 500/230 kV transformer.								

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.

2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.

3/11/10 Update: Adjusted for FRR Alternative elections and obligations

4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	0.0%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net CONE, \$/MW-Day (UCAP Price)	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$476.93	\$340.80	\$391.59	\$340.80	\$391.59	\$391.59	\$391.59	\$340.80
Point (b) UCAP Price, \$/MW-Day	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
Point (a) UCAP Level, MW	146,086.1	71,238.9	39,346.9	17,433.3	13,052.3	6,181.9	2,918.0	9,196.3
Point (b) UCAP Level, MW	151,289.6	73,776.4	40,748.4	18,054.2	13,517.2	6,402.0	3,022.0	9,523.9
Point (c) UCAP Level, MW	156,493.0	76,313.8	42,149.9	18,675.2	13,982.1	6,622.2	3,125.9	9,851.5
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

***(Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	0.0	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	0.0	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	0.0	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	0.0	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	0.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	0.0	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	0.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	0.0	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	0.0	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	0.0	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	0.0	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	0.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	0.0	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	0.0	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	0.0	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	0.0	0.0	2,929.0
PEPCO	4,030	4,483.0	111%	6,690.0	7,094.0	1.06039	0.0	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	0.0	0.0	7,627.0
PS	5,950	5,868.4	99%	10,340.0	11,188.0	1.08201	0.0	0.0	11,188.0
PSNORTH	2,620	2,570.0	98%	NA	5,146.5	NA	0.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	0.0	0.0	444.0
EMAAC	7,050	7,095.0	101%	NA	34,273.0	NA	0.0	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	0.0	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	0.0	0.0	
MAAC	4,190	4,460.0	106%	NA	62,608.0	NA	0.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	0.0	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
SWMAAC	Pleasant View 500/230 kV transformer.
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.

2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.

3/11/10 Update: Adjusted for FRR Alternative elections and obligations

4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	0.0%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net CONE, \$/MW-Day (UCAP Price)	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$476.93	\$340.80	\$391.59	\$340.80	\$391.59	\$391.59	\$391.59	\$340.80
Point (b) UCAP Price, \$/MW-Day	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
Point (a) UCAP Level, MW	144,785.3	70,604.5	38,996.5	17,278.0	12,936.1	6,126.8	2,892.1	9,114.4
Point (b) UCAP Level, MW	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Point (c) UCAP Level, MW	155,192.1	75,679.5	41,799.5	18,520.0	13,865.9	6,567.2	3,099.9	9,769.6
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*(Asterisk) – LDA has adequate internal resources to meet the reliability criterion.

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	0.0	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	0.0	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	0.0	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	0.0	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	0.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	0.0	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	0.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	0.0	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	0.0	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	0.0	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	0.0	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	0.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	0.0	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	0.0	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	0.0	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	0.0	0.0	2,929.0
PEPCO	4,030	4,483.0	111%	6,690.0	7,094.0	1.06039	0.0	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	0.0	0.0	7,627.0
PS	5,950	5,868.4	99%	10,340.0	11,188.0	1.08201	0.0	0.0	11,188.0
PSNORTH	2,620	2,570.0	98%	NA	5,146.5	NA	0.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	0.0	0.0	444.0
EMAAC	7,050	7,095.0	101%	NA	34,273.0	NA	0.0	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	0.0	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	0.0	0.0	
MAAC	4,190	4,460.0	106%	NA	62,608.0	NA	0.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	0.0	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
SWMAAC	Pleasant View 500/230 kV transformer.
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.

2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.

3/11/10 Update: Adjusted for FRR Alternative elections and obligations

4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	16.2%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.44%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0872	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	174,641.3	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,708.6	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	150,932.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	3,773.3	1,701.7	931.5	400.0	304.1	139.9	63.4	192.8
Net CONE, \$/MW-Day (UCAP Price)	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$476.93	\$340.80	\$391.59	\$340.80	\$391.59	\$391.59	\$391.59	\$340.80
Point (b) UCAP Price, \$/MW-Day	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
Point (a) UCAP Level, MW	143,262.7	69,552.0	38,423.5	17,036.9	12,750.9	6,043.3	2,855.2	9,005.4
Point (b) UCAP Level, MW	148,458.3	72,069.8	39,814.1	17,653.1	13,212.2	6,261.7	2,958.3	9,330.4
Point (c) UCAP Level, MW	153,653.9	74,587.6	41,204.8	18,269.2	13,673.5	6,480.2	3,061.5	9,655.5
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.4%	69.8%	61.9%	67.5%	34.4%	64.3%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

***(Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	3,773.3	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	82.1	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.9	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	240.8	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	363.2	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	207.1	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	656.1	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.7	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	79.4	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	574.5	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	110.3	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.4	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	183.0	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	83.3	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	240.0	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.6	0.0	2,929.0
PEPCO	4,030	4,483.0	111%	6,690.0	7,094.0	1.06039	192.8	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	207.3	0.0	7,627.0
PS	5,950	5,868.4	99%	10,340.0	11,188.0	1.08201	304.1	0.0	11,188.0
PSNORTH	2,620	2,570.0	98%	NA	5,146.5	NA	139.9	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.1	0.0	444.0
EMAAC	7,050	7,095.0	101%	NA	34,273.0	NA	931.5	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	400.0	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	370.2	0.0	
MAAC	4,190	4,460.0	106%	NA	62,608.0	NA	1,701.7	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,497.1	21,807.0	
Limiting conditions at the CETL for modeled LDAs									
LDA	Limiting Facility								
MAAC	Pleasant View 500/230 kV transformer.								
EMAAC	Elroy - Branchburg 500 kV line.								
SWMAAC	Pleasant View 500/230 kV transformer.								
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.								
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.								
PEPCO	Pleasant View 500/230 kV transformer.								

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.

2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.

3/11/10 Update: Adjusted for FRR Alternative elections and obligations

4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, \$/MW-Day (UCAP Price)	\$276.09	\$176.44	\$212.50	\$176.44	\$212.50	\$212.50	\$212.50	\$176.44
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$414.14	\$264.66	\$318.75	\$264.66	\$318.75	\$318.75	\$318.75	\$264.66
Point (b) UCAP Price, \$/MW-Day	\$276.09	\$176.44	\$212.50	\$176.44	\$212.50	\$212.50	\$212.50	\$176.44
Point (c) UCAP Price, \$/MW-Day	\$55.22	\$35.29	\$42.50	\$35.29	\$42.50	\$42.50	\$42.50	\$35.29
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

***(Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	3,749.7	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	4,483.0	111%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	5,868.4	99%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	2,570.0	98%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	7,095.0	101%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	4,460.0	106%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	
Limiting conditions at the CETL for modeled LDAs									
LDA	Limiting Facility								
MAAC	Pleasant View 500/230 kV transformer.								
EMAAC	Elroy - Branchburg 500 kV line.								
SWMAAC	Pleasant View 500/230 kV transformer.								
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.								
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.								
PEPCO	Pleasant View 500/230 kV transformer.								

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.

2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.

3/11/10 Update: Adjusted for FRR Alternative elections and obligations

4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	99,999.0	99,999.0	99,999.0	99,999.0	99,999.0	99,999.0	99,999.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, \$/MW-Day (UCAP Price)	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$476.93	\$340.80	\$391.59	\$340.80	\$391.59	\$391.59	\$391.59	\$340.80
Point (b) UCAP Price, \$/MW-Day	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	-161.0%	-516.4%	-716.4%	-1684.3%	-3846.9%	-1181.5%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

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DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	3,749.7	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	99,999.0	7407%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
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PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	99,999.0	> 115%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	99,999.0	> 115%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	99,999.0	> 115%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	99,999.0	> 115%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	99,999.0	> 115%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	
Limiting conditions at the CETL for modeled LDAs									
LDA	Limiting Facility								
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2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
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Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	8,707.0	6,724.9	5,973.0	2,742.0	2,123.0	4,483.0
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Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
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Min % Int. Resources Req'd for FRR Load	NA	100.0%	85.6%	70.3%	61.5%	64.8%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

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LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
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ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	4,483.0	111%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	5,973.0	100%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	2,742.0	105%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	8,707.0	124%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	4,460.0	106%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	7,192.0	8,707.0	7,728.0	5,973.0	2,742.0	2,123.0	5,077.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, \$/MW-Day (UCAP Price)	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$476.93	\$340.80	\$391.59	\$340.80	\$391.59	\$391.59	\$391.59	\$340.80
Point (b) UCAP Price, \$/MW-Day	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	85.6%	64.0%	61.5%	64.8%	34.6%	57.0%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

* (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	3,749.7	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	5,077.0	126%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	5,973.0	100%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	2,742.0	105%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	8,707.0	124%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	7,728.0	135%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	7,192.0	172%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	8,018.0	8,707.0	8,126.0	5,973.0	2,742.0	2,123.0	5,158.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, \$/MW-Day (UCAP Price)	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Variable Resource Requirement Curve:								
Point (a) UCAP Price, \$/MW-Day	\$476.93	\$340.80	\$391.59	\$340.80	\$391.59	\$391.59	\$391.59	\$340.80
Point (b) UCAP Price, \$/MW-Day	\$317.95	\$227.20	\$261.06	\$227.20	\$261.06	\$261.06	\$261.06	\$227.20
Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	85.6%	61.5%	61.5%	64.8%	34.6%	55.9%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

* (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	3,749.7	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	5,158.0	128%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
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PS	5,950	5,973.0	100%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	2,742.0	105%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	8,707.0	124%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	8,126.0	142%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	8,018.0	191%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments		5/17/2010	573450v8					
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	RTO	Notes:						
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Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, \$/MW	\$34,816							
LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	8,768.0	9,555.0	8,126.0	5,973.0	2,742.0	2,406.0	5,158.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	23,560.3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
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Point (c) UCAP Price, \$/MW-Day	\$63.59	\$45.44	\$52.21	\$45.44	\$52.21	\$52.21	\$52.21	\$45.44
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Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	83.3%	61.5%	61.5%	64.8%	23.4%	55.9%
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, \$/MW	\$ 7,300.00	\$ 16,509.00	\$ 17,885.00	\$ 16,509.00	\$ 17,885.00	\$ 17,885.00	\$ 17,885.00	\$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

* (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	145,930.0	160,634.0	NA	3,749.7	0.0	138,827.0
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
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ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,406.0	178%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	5,158.0	128%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	5,973.0	100%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	2,742.0	105%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	9,555.0	136%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	8,126.0	142%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	8,768.0	209%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

**BEFORE THE
NEW JERSEY SENATE ENVIRONMENT AND ENERGY COMMITTEE**

**November 15, 2010
December 9, 2010**

**S-2381 (Smith, Bateman)
Assembly 3442**

***STATEMENT OF ROY J. SHANKER PH.D.
ON BEHALF OF COMPETITIVE SUPPLIERS COALITION***

1) My name is Roy J. Shanker. I am an independent consultant working principally in the electricity markets. I have been asked here today by Constellation NewEnergy, Inc. and Constellation Commodities Group, Inc., Exelon Corporation, Mirant Corporation, PPL Energy, RRI Energy, and Suez Energy (Competitive Suppliers Coalition) to comment on the proposed actions being considered by the New Jersey legislature in Senate Bill 2381/Assembly Bill 3442 (S-2318 or the Bill).

2) I have significant experience with both the PJM markets and with energy policy matters and associated regulation in New Jersey. I participated as part of the team that drafted the very first New Jersey State Energy Plan over thirty years ago, and have worked for a number of electric suppliers, utilities, and industrial customers in the state. I have over 37 years of experience, and have been an independent consultant for 30 years. During much of that period I worked with the same range of clients in

other matters related to PJM. In particular I have been very active in the PJM competitive electricity markets and the associated stakeholder processes since the very inception of the new ISO/RTO construct in the mid 1990's. I have attached a summary of my qualifications and relevant experience.

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS.

3) I have reviewed S-2381 and the revised version and amendments provided with ASM-3442 and have concluded that the proposal to enact new customer surcharges on all New Jersey customers in order to guarantee revenues and thereby induce construction of new in-state electric generation will increase New Jersey electricity costs in the long run, and impose risks on customers that should be borne by energy company shareholders. In reaching this conclusion, I have identified several major flaws with Bill.

4) First, there appears to be no need to use revenue guarantees to induce new generating capacity in New Jersey. The preponderance of indications are that current supplies, coupled with future transmission enhancements, are more than sufficient to serve New Jersey electricity customers reliably and the Bill does not reasonably identify anything to the contrary. Further, there is no indication that the underlying PJM capacity

market and transmission planning process is deficient in terms of meeting reliability goals.¹

5) Second, based on my review, the apparent reason for the proposal is the perceived “savings” in energy and capacity markets associated with the anti-competitive behavior of purchasing excess uneconomic supplies to suppress overall market prices.

6) In combination, these flaws fatally undermine any legitimate rationale for this Bill that would commit millions of consumer dollars to subsidizing select new electric generating capacity in New Jersey. Understanding the widespread harmful impact of this uneconomic initiative should clarify the public interest at issue.

7) This legislation would give discriminatory and preferential treatment to certain new generation capacity suppliers or undefined implementation of environmental upgrades, which would have the effect of shifting the risks of unnecessary new generation capacity and investment to New Jersey ratepayers from those generation developers. That subsidized generation then would be used to depress prices in the competitive market. This applies equally to new generation or out of market inducements related to environmental investment. Thus this Bill would have the effect in the market

¹ I do take issue with other elements of the PJM Reliability Pricing Model forward capacity market design.

of artificially depressing market prices using anti-competitive buyer market power. In the long run it would harm competitive capacity markets and cost customers more for generation capacity than otherwise.

8) Further, the use of rate-funded subsidies to support discriminatory investment would result in higher, not lower, overall costs to supply electricity. Although short-term wholesale market prices may be lower than they would have been without the subsidized new generation capacity, total societal costs are higher, because of both excess new capacity and uneconomic retirement of existing capacity. The subsidized entry is “unnecessary” and consumes resources that could be better used elsewhere in the economy. At the same time, the wholesale market price suppression will prompt uneconomic retirement, as some resources may be unable to continue to operate at artificially depressed prices. The uneconomic retirement can also increase the total costs of electricity as more costly new capacity replaces the capacity that was prematurely retired. Similarly, total employment may decrease, as the jobs lost at the older, otherwise economic generators that retire could exceed new jobs created.

9) New Jersey does not need new generation capacity. The argument for “energy independence” for New Jersey turns its back on more than half

a century of increasingly efficient coordination among Pennsylvania, Maryland and New Jersey utilities to share in the benefits of economic dispatch of baseload generation and the resulting integrated regional electric network. Further, to my knowledge there has been no demonstration of any real adverse reliability problems in New Jersey. In fact, as discussed below, the current and near future situations seem more indicative of a surplus market. Moreover, New Jersey has over 17,000 MWs of generation capacity in operation and significant demand response, none of which are subsidized by customers. Over the last decade alone, companies in New Jersey have built over 4,500 MWs of new generation, added nearly a 1000 MW of demand response, and upgraded dozens of existing plants, without relying on such subsidies.

II. BACKGROUND: EXPLANATION OF THE TERMS OF S-2381 AND ASSEMBLY 3442 (AS AMENDED)

10) If enacted as proposed, the Bill would establish a long-term capacity agreement pilot program to enable the construction or environmental improvements of at up to 1000 MW of generation facilities in certain locations within the state of New Jersey. The Bill would do so by creating a program in which eligible new generators will be awarded contracts to sell capacity to New Jersey utilities, with the price set at the higher of the PJM

Reliability Pricing Model (RPM) auction clearing price or a legislatively-set floor. Eligible generators would be required to bid and clear in the RPM auction in order to participate in the pilot. Effectively this would force them to bid as a price taker or at a zero offer price. But these select generators would be guaranteed a price of for their capacity that clears in the RPM auction based on the legislative price regardless of the actual auction results. (Originally this was proposed as \$232.75 per MW/day) If the RPM clearing price is below that guaranteed price, the generator would be paid the difference between the RPM clearing price and guaranteed price by the utility, with that guaranteed payment funded through a non-bypassable charge to all state utility customers. If the clearing price is above the guaranteed price, the generator will be paid the higher clearing price, or as now proposed refund this amount retaining the “locked in” floor. The stated purpose of the Bill is to avoid reliance on out-of-state at-risk power plants and to ensure that in-state generation will help the state reduce the cost and volatility of electricity prices. It is also intended to assist the state’s economic development through employment opportunities.

III. THE CURRENT RELIABILITY PROCEDURES ARE WORKING AND THERE IS NO RELIABILITY FAILURE.

11) The legislature has a reasonable concern that New Jersey residents continue to be provided with reliable electric service. But there is no indication that the current energy and capacity markets and transmission system operated by PJM are unreliable. To my knowledge, there has been no formal planning exercise, subject to the open participation of expert parties such as the BPU, FERC, PJM and others, as contemplated in PJM's tariff, which has reached any conclusion that generation is inadequate in New Jersey. Further, there is simply no factual basis developed anywhere for any concern there may be a reliability need justifying more "in state" supplies for New Jersey. In fact, as discussed below, it appears that many New Jersey "expert" bodies reached exactly the opposite conclusion.

12) PJM offered comments In The Matter of the New Jersey Board of Public Utilities Review of the State's Electric Power and Capacity Needs, Docket No. EO09110920, Technical Conference (June 24, 2010), related to overall reliability concerns as reflected by supply/demand balances and the associated pricing and functionality of RPM, which is used as the "engine" of the PJM capacity market. I have reviewed those comments, and while

PJM acknowledged the potential for decline in supply due to impending emission controls under EPA regulations that would result in some coal plant retirements, PJM also concluded that the general balance in supply and demand has been maintained over time, and that the RPM process complements continued reliability. Further, while some “vulnerability” was noted in northern New Jersey, this appears to be fully addressed by the timely addition of the Susquehanna-Roseland transmission facility. Thus, RPM is doing what it is intended to do, providing locational price signals tied to local capacity needs to complement the overall PJM planning processes, which assure reliability.

13) Potential changes in supply and demand are addressed in PJM’s multi-tiered reliability planning processes, which are designed to ensure adequate regional supplies. While the detail is extensive, one of the basic building blocks for reliability, in both the capacity market and in transmission planning, entails maintaining adequate supplies in the Local Deliverability Areas (LDAs) such as Eastern MAAC, PSEG and North PSEG.² In fact, any deficiency in these requirements (e.g. a projected

² While reliability requirements for PJM as a whole (and nationally) are based on one outage in ten years, within PJM the standard is one event in 25 years between each LDA and the remainder of PJM. This one event in 25 years criterion is used to assure reliability based on having sufficient transmission deliverability between internal LDA resources and supplies on a pool wide basis at levels that are consistent with the overall one event in ten years objective.

shortage of local resources or transmission limits into an LDA) mandates new transmission facilities for reliability, and also results in financial incentives for generation to be retained in any potentially deficient area.

The mandate is just that – it is incorporated in the formal reliability rules that PJM has adopted and *must* follow. Further, PJM also has incorporated backstop rules into its generation procurement should “normal” purchases not be enough due to unanticipated events. Thus while there may be “swings” in supply they are anticipated and the entire process is designed to ensure that no reliability shortage can persist.

14) To my knowledge no one has demonstrated that this process isn't working. Further, the New Jersey Board of Public Utilities, the Public Power Association of New Jersey and the New Jersey Department of the Public Advocate, Division of Rate Counsel joined in a formal complaint proceeding at FERC alleging that this process is too conservative and results in an unnecessarily high level of reliability and associated capacity. These three New Jersey parties were part of a group that challenged this entire reliability planning concept, seeking **lower** levels of reliability and planning standards than current PJM practices. They were advocating approximately a 3.5% reduction in installed capacity in the eastern regions

of PJM.³ Thus these parties, presumably the most knowledgeable parties in New Jersey with respect to electric utility matters, argued that there is too much, not too little, reliability under the status quo.

15) Empirically the results of the RPM auctions also seem to confirm this. As noted above, Mr. Wilson testified on behalf of New Jersey ratepayer interests that the cleared capacity for EMAAC was far in excess of what was appropriate during the initial RPM auctions. For PJM as a whole, quantities of capacity in excess of target requirements have cleared in all of the RPM auctions. For the EMAAC and New Jersey LDA's, this also has typically been the case. A summary of these results, initially compiled by

³ See *Maryland Public Service Comm'n, et al. v. PJM Interconnection, LLC*, Docket No. EL08-67, Complaint of the RPM Buyers (filed May 30, 2008) (Affidavit of James Wilson at 58-59, footnotes omitted, emphasis added). The RPM Buyers included the New Jersey Board of Public Utilities, the New Jersey Public Power Association and New Jersey Rate Counsel, sponsoring the following testimony of James Wilson:

PJM Used An Unreasonable Reliability Standard For LDAs.

In determining CETO and Reliability Requirements for LDAs, PJM applied a much more stringent planning resource adequacy standard than the traditional one-occurrence-in-ten years, thereby further increasing the Reliability Requirement in LDAs and, again, shifting the VRR curve to the right. PJM has reasoned that in order for the entire PJM region to be planned based on a single reserve margin reflecting the one-occurrence-in-ten years resource adequacy criterion, the PJM transmission system must be planned so that LDAs meet a much more rigorous criterion. While this standard may be reasonable for transmission planning, the manner in which PJM carried it over and applied it to establishing LDA Reliability Requirements during the transition period is not reasonable.

In setting the CETO and the Reliability Requirement for each LDA, PJM has chosen to apply a one-occurrence-in-25 years standard, *i.e.*, the LDA is expected to shed load due to insufficient internal generation plus import capability only once in 25 years. Earlier studies of the relationship between reserve margin and outage frequency suggest that this more stringent criterion applied to the calculation of LDA Reliability Requirements increases the capacity that must be provided by at least three percentage points, further shifting the VRR curve to the right and increasing the clearing price. By applying this overly conservative planning standard, PJM set Reliability Requirements for SWMAAC that correspond to installed reserve margins of more than 20 percent, *and the actual cleared capacity in EMAAC and SWMAAC corresponded to installed reserve margins of 19 percent or more in all four transitional BRAs – far above the 15.5 percent reserve that PJM deems adequate for system reliability and that it applies to the RTO Region as a whole.*

the PJM Market Monitor, appears below in Table A. The highlighted row shows the excess of the actual procured amount over the target values. New studies emphasize this as a continuing trend as new transmission facilities are added to the system. In fact, technical evaluations conducted by the Competitive Supplier Coalition by Charles River Associates indicate that after planned transmission improvements, prices will decline significantly in New Jersey, to a level approximately \$100 per MW/day lower than the original Senate proposal. This would result in locking in New Jersey customers for what was proposed to be 15 years of “out of the money capacity”.

BRA AUCTION RESULTS	PY '07/08	PY '08/09	PY '09/10	PY '10/11	PY '11/12	PY '12/13			PY '13/14	
	EMAAC	EMAAC	MAAC+APS	RTO	RTO	MAAC	EMAAC	PS-North	MAAC	EMAAC
Reliability Requirement	37,236.7	37,890.7	77,902.9	132,698.8	130,658.7	72,125.0	40,145.0	6,324.0	73,142.0	40,398.0
Total Cleared	30,797.8	30,231.3	72,547.7	132,190.4	132,221.5	65,452.4	31,080.2	3,521.9	67,653.9	32,849.4
CETL Total	5,845.0	7,930.0	4,941.0	N/A	N/A	6,377.0	9,079.0	2,755.0	4,460.0	7,095.0
Resources Short Term	36,642.8	38,161.3	77,488.7	N/A	N/A	71,829.4	40,159.2	6,276.9	72,113.9	39,944.4
Hold Back	N/A	N/A	N/A	N/A	N/A	1,673.9	922.8	136.8	1,691.0	925.7
Net Excess/(Deficit)	(593.9)	270.6	(414.2)	1,149.2	3,156.6	1,378.3	937.0	89.7	662.9	472.1
ILR Forecast	385.5	396.1	1,055.7	2,110.5	1,593.8	N/A	N/A	N/A	N/A	N/A
DR Offered	44.7	343.4	820.6	967.9	1,652.4	5,029.2	1,787.3	67.6	5,871.1	2,461.3
DR Cleared Resource	44.7	168.7	813.9	939.0	1,364.9	4,723.7	1,638.4	67.6	5,871.1	2,461.3
Clearing Price	\$197.67	\$148.80	\$191.32	\$174.29	\$110.00	\$133.37	\$139.73	\$185.00	\$226.15	\$245.00

TABLE A

16) Adopting S-2381/A-3224 would work against the existing reliability construct. Indeed, the reason developers pursue the type of revenue guarantee offered by the Bill is because market prices are signaling that new capacity is not needed. But guaranteeing a price for unneeded capacity simply makes matters worse. As discussed below, subsidizing uneconomic new capacity adds to the existing capacity surplus, suppresses prices for all other suppliers, deters competitive new entry, and likely forces some existing capacity to retire prematurely. It is a form of price discrimination, pure and simple. Essentially the Bill would result in a world where new entry can occur only via this type of discriminatory contract thereby undermining existing mechanisms in which utility and generation shareholders bear the bulk of the risk. The simple observation here is that the current system appears to be working, at least with respect to reliability (though prices may actually be too low),⁴ and it is a mistake to introduce a discriminatory mechanism that will distort prices and undermine the legitimate stated objective – reliability.

⁴ While reliability thus far has been maintained, there are legitimate arguments that several aspects of the current RPM design depress prices below truly competitive levels.

IV. THE UNDERLYING REASON FOR THE LEGISLATIVE PROPOSAL APPEARS TO BE THE ANTI-COMPETITIVE SUPPRESSION OF CAPACITY AND ENERGY PRICES.

A. AN “IN MARKET” COMPETITIVE BI-LATERAL AGREEMENT VERSUS BUYER MARKET POWER.

17) It certainly isn't unreasonable for New Jersey to consider entering into bi-lateral agreements for the purchase of energy and capacity on behalf of the state's electricity consumers. However, I would expect that such agreements would be competitive, economic, fuel-neutral, arms' length, and non-discriminatory bi-lateral contracts that would not differentiate between new and existing resources. Though the answer may be complicated, the question to determine whether such criteria are met is simple: on a *stand-alone* basis, do the economics of the transaction convey sufficient benefit to the buyer to justify the cost. If the answer is yes, then it is reasonable to proceed.⁵

18) Buyer market power is the ability of buyers to make discriminatory investments in uneconomic capacity resources that then flood the market with excess capacity, thereby artificially suppressing market prices for all capacity resources and allowing the buyers to recover their above-market expenditures by means of the portfolio savings. That is, the resource

⁵ This question is analogous to one of the FERC's considerations regarding whether a market action is appropriate versus potential market manipulation: does the transaction reflect a legitimate business purpose?

purchased is itself uneconomic, but the purchase results in “savings” based on artificially lowering all other prices. The ability to recover the uneconomic costs of the new resource through cost-of-service rate making or its equivalent makes such an anti-competitive strategy even more effective and destructive. Consumers are essentially guaranteeing that those exercising market power are both successful and profitable.

B. THE BILL WOULD RESULT IN UNECONOMIC ENTRY AND EXERCISE OF BUYER MARKET POWER.

19) In all the material I have reviewed, I have seen no analyses that support the view that the generation procurement proposed by the Bill makes economic sense. All information I have seen relates to the “portfolio effect” of the acquisition on total energy and capacity prices, not the stand-alone economics of any proposed transaction. To me this indicates that the real underlying rationale of the proposed procurement is not reliability, and that it does not further a legitimate business purpose. Rather, the proposed legislation is designed to exercise buyer market power to purchase uneconomic supplies in order to artificially suppress prices.

20) The Bill is proposing to discriminate among generation resources by guaranteeing a price to some, but not all, suppliers in order to attract only new uneconomic resources. These suppliers would be able to bid into the

capacity auction at a price below their long-term average cost because that cost would be paid by the non-bypassable surcharge subsidy. The purchasers of the uneconomic resource, i.e. the utilities, are protected from the direct out of market cost by the non-bypassable surcharge to consumers, and all purchasers benefit from the price suppressing impact of the excess. The only economic analyses that have been presented in this and related BPU proceedings address **only** these portfolio benefits of the exercise of market power. Nowhere is there any indication of the stand-alone value of the proposed bi-lateral agreements supported by the Bill. Presentations by LS Power indicate that energy prices as a whole may be depressed by \$98 million per year.⁶ Similarly, the New Jersey Rate Counsel submitted recent comments to the BPU estimating that capacity prices would be suppressed on the order of \$465 million by adding 500 MW of otherwise unneeded capacity.⁷ These are not true savings, however, they are just wealth transfers from unsubsidized, competitive sellers to buyers, realized via the exercise of the buyers' market power.

21) As I recently commented at FERC, market sellers could engage in analogous behavior by cooperating to uneconomically withhold supply from

⁶ LS Power Presentation, page 11. Note that this is likely a high side estimate as it is based on the absence of the significant new transmission being planned for the region. (Susquehanna Roseland)

⁷ BPU Docket No. EO09110920, Submission of New Jersey Rate Counsel, at 8 (July 2, 2010).

the market, such as by paying otherwise economic resources to retire from the market to realize increased prices for their remaining portfolio and that of remaining market participants. For example, using the Rate Counsel's estimate, if suppliers withheld 500 MW of capacity, the remaining participants would increase their revenues by approximately \$465 million dollars per year. This results in sufficient funds to "bribe" the 500 MW to retire, with the remaining market suppliers sharing excess. This isn't good economics, it is the symmetric application of inappropriate market power.

22) Finally, as I stated above, new studies sponsored by the Competitive Supplier Association now finally do provide at least a glimpse of a stand-alone evaluation, and show that after transmission improvements are in place the rate proposed in the Senate version of the Bill, New Jersey would initially be overpaying by approximately \$100 per MW day versus market priced capacity.

*C. THE EXERCISE OF SUCH BUYER MARKET POWER
ULTIMATELY HARMS THE PUBLIC INTEREST.*

23) A market cannot remain viable if it is subject to the exercise of market power, intentional or not, by either buyers or sellers. The Bill represents a classic example of monopsony or "buyer market power" that would artificially suppress market prices for the benefit of select suppliers who

have guaranteed subsidies outside the market. Under the declining demand curve design of the PJM capacity market, forcing excess supply into the market reduces all prices paid, and the cost of the inefficient excess can be offset by “savings” from reducing payments to others. While more entry and price suppression may seem like good things for customers, the reality is that uneconomic entry subsidized by ratepayers increases total electricity costs in the long run and is not compatible with efficient wholesale markets. Such market manipulation is harmful because it can (a) stimulate uneconomic demand for power and consequent inefficient consumption of resources; (b) increase total societal costs due to both excess new supply and premature retirement of resources that would be economic in a competitive market; and (c) discourage new competitive entry, including demand response, and add risk premiums to supplier costs. In other words, as I explain in more detail below, it can undermine the long-run viability of the entire competitive market model and ultimately result in higher total costs.

24) Consumers are harmed because lack of competition and distorted short term gains from market manipulation spawn inefficiencies in the supply of electricity. Some of this is even visible in the proposed legislation itself. For example, typically I would expect that since New Jersey rate

payers are bearing all of the capital risk of the new projects, they would also see the benefit of the energy margins earned when prices exceed the production cost of the underlying new facility. That is not the case here, since all energy margins accrue to the seller. Similarly in most such contracts the presence of a guaranteed capacity payment “fixes” the price, with any upside going to the buyer. Again that is not the case here. The proposed \$232 MW/day price is a floor, with all upside from the market going to seller. Because there is no competition in these arrangements, and the reliance on the anti-competitive price suppression effect is superficially attractive, such typical contract protections for the buyers are overlooked. This is exactly why we tried to avoid totally administrative solutions and introduce market mechanisms into procurement in the electric energy sector. In addition, the non-bypassable charge to consumers would especially penalize those customers who acted prudently on their own to hedge their exposure to market prices, as they already will have expended funds for the hedge positions, but then would be forced to pay a second time via the surcharge.

25) Suppliers are victimized by the price discrimination which effectively creates an unjustified two-tier market where all market participants provide the same reliability product or service, but certain individual new entrants

are paid a higher price and all other existing suppliers unjustifiably are paid a lower price. Ultimately no one will seek to enter the market other than by such subsidies, as a supplier without such protection would be victimized through the exercise of buyer market power. To compensate for that risk, any entrant would have to be compensated by ever increasing price levels, encouraging ever greater use of buyer market power. The increased risk shows up in all of the future bilateral contract costs and total costs to consumers are increased.

26) Both consumers and suppliers would be harmed by the effect of the market distortion on existing generation capacity. Because market prices would be artificially depressed, some resources that would have cleared in a competitive auction will fail to clear the market, and therefore will retire. This effect will inefficiently accelerate the “turn-over” of the entire capital generation stock and the associated premature loss of jobs, while increasing unnecessary investments.

27) These types of adverse effects are not news to either economists or regulators. The Federal Energy Regulatory Commission has explicitly rejected this type of discriminatory pricing in the ISO-NE, PJM and NYISO capacity markets. In accepting the NYISO demand curve design for capacity payments, the Commission explicitly rejected the argument that it

would be appropriate to price in such a manner so as to discriminate between new entrants and existing capacity, stating: “The Commission finds that all capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market. . . . The Commission does not see how [new] generators could receive ICAP revenues that were fundamentally different from those paid to other generators.”⁸ Any attempt to bypass such decisions via the exercise of market power would impair the function of the capacity market over time and as a result also lead to the need for existing suppliers to rely on cost-based Reliability Must Run contracts for the remaining capacity that otherwise would have been “in market” but for the price discrimination. This bill fosters the very harm the FERC has spent the last three years attempting to rectify in all three of the eastern RTO capacity markets.⁹

28) Thus I would expect that the Bill will exacerbate the very problem it purports to address. It will have a further chilling effect on future economic

⁸ *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 at P 81 (2003). Similarly, the Commission endorsed uniform market clearing prices for all participants, new entrant or existing. See *id.* at PP 77, 81.

⁹ See, e.g., *ISO New England Inc.*, 120 FERC ¶ 61,087 at P 2 (2007) (recounting history of FCM in New England, and highlighting “concerns regarding the number of generators seeking” RMR contracts “and the effect that widespread use of such contracts could have on the competitive market”); *Devon Power LLC.*, 103 FERC ¶ 61,082 at P 29 (2003) (“extensive use of RMR contracts undermines effective market performance”); *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, *order on reh’g*, 128 FERC ¶ 61,157 (2009); *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006), *order denying reh’g and approving settlement*, 117 FERC ¶ 61,331 (2006), *order on reh’g and clarification*, 119 FERC ¶ 61,318 (2007); *Devon Power LLC.*, 113 FERC ¶ 61,075 (2005), *order approving settlement*, 115 FERC ¶ 61,340 at P 7 (2006); *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, *reh’g denied*, 122 FERC ¶ 61,064 (2008); *New York Indep. Sys. Operator, Inc.*, 111 FERC ¶ 61,117, *reh’g denied*, 112 FERC ¶ 61,283 (2005); *New York Indep. Sys. Operator, Inc.*, 89 FERC ¶ 61,109 (1999).

capacity development, and may ultimately challenge the sustainability of the competitive market model. If utility funding of new entry creeps into the market construct, developers will not commit substantial capital to new merchant generation, because they will not take the risk that their investment could be “devalued” by regulatory guarantees.

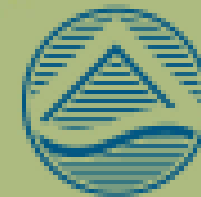
LS Power



New In-State Generation LS Power Energy Savings Analysis

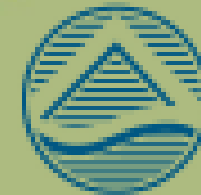
November 2010

Bringing Energy Forward



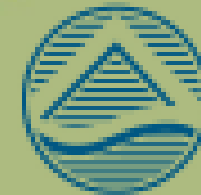
Energy Savings Impact of New, In-State Generation

- Developing new, efficient, combined cycle generation in NJ will reduce energy and capacity costs to NJ ratepayers
- Energy savings
 - LS Power estimates that energy savings would be approximately \$125 million/year
 - These savings are in addition to Rate Counsel's estimate of capacity savings
- Following is a discussion of the LS Power energy savings analysis
- Note on Capacity Market savings
 - NJ Rate Counsel provided comments in the June 24, 2010 BPU Technical Conference suggesting new, in-state generation could save NJ ratepayers approximately \$465 million/year in capacity payments. The analysis herein only considers the savings realized in the energy market



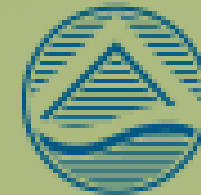
Analysis Model Description/Overview – Model Provider Overview

- Energy analysis model provided by Cambridge Energy Solutions (“CES”)
- CES is a software company with a mission to develop software tools for participants in deregulated electric power markets.
- CES provides information and tools to assist market participants in analyzing the electricity markets on a locational basis, forecast and value transmission congestion, and to understand the fundamental drivers of short- and long-term prices
- Additional information on CES is available on their website
 - <http://www.ces-us.com/>



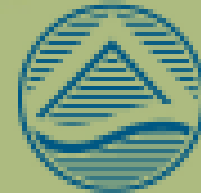
Analysis Model Description/Overview – Model Overview

- The energy analysis model is the Day-Ahead Locational Market Clearing Prices Analyzer (“DAYZER”) from CES
 - DAYZER is a tool that can forecast Day-Ahead hourly energy price using Locational Marginal Prices (“LMPs”) (Zonal or Nodal)
 - PJM calculates LMPs in clearing the PJM energy market
 - Simulates the operation of the electricity markets, RTO dispatch procedures and calculations made by the RTOs in solving for the security constrained, least-cost unit commitment and dispatch in the day-ahead markets.
 - Forecasts the day-ahead and hourly locational market-clearing prices and congestion costs
 - Updates using the most recently available data on fuel prices, demand forecast, unit & transmission line outages, emission permits costs
 - Incorporates all the security, reliability, economic and engineering constraints on generation units and transmission system components
 - See the website for additional information
 - <http://www.ces-us.com/products.html>



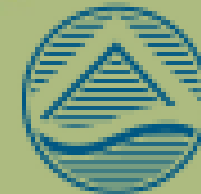
What is Locational Marginal Pricing (LMP)?

- The "Locational Marginal Price" ("LMP") is a market-pricing approach used to manage the efficient use of the transmission system when congestion occurs on the bulk power grid
 - Transmission system congestion occurs when available, low cost supply cannot be delivered to the demand location due to transmission system limitations
- Marginal pricing is the idea that the market price of any commodity should be the cost of bringing the last unit of that commodity - the one that balances supply and demand - to market
- In electricity, LMP recognizes that this marginal price may vary at different times and "locations" based on transmission congestion
- When the lowest-priced electricity can reach all locations, prices are the same across the entire grid (e.g., all of PJM)
- When there is heavy use of the transmission system, the lowest-priced energy cannot flow freely to some locations. In that case, more expensive electricity is ordered to meet that locational demand. As a result, the locational marginal prices are higher on the receiving end of the congestion (load) and lower on the sending end



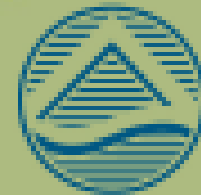
Location Marginal Pricing - PJM

- PJM Interconnection uses Locational Marginal Pricing (LMP) to establish the price of energy in the PJM wholesale electricity market
- Offers by generators to sell power are accepted in increasing price order
- Generators are selected (dispatched) by PJM with the lowest-priced offers committed and dispatched first
- Increasingly higher-priced generators are brought on-line as demand (load) increases
- Energy clearing price increases as higher-priced generators are bought on-line
 - Market-clearing prices are based on the last generating unit needed to meet demand
- With no congestion, all generators receive the same clearing price
- When congestion arise, generators receive the clearing price at their bus (node)



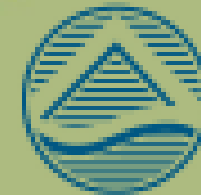
Sources of Model Input Data

- The energy analysis modeled the year 2013 (Jan 1, 2013 thru Dec 31, 2013) and the savings are for the entire year
- Long-term load forecast is based on historical load shape and forecasted peak demand by PJM
- Fuel prices (fuel oil and natural gas) from NYMEX
- Generator availability is based on the North American Electric Reliability Corporation ("NERC"), Generation Availability Data System ("GADS") database by unit types.
- The heat rates are based on EPA Continuous Emissions Monitoring Systems ("CEMS") data.
- Unit output is based on PJM Energy Information Agency ("EIA") data



Sources of Model Input Data

- Generation additions/retirements
 - All generation with interconnection agreements and in-service dates up to the analysis year (2013) are assumed to be in service
 - All transmission upgrades associated with the projects are also assumed to be in service
- Generation retirements are based on PJM's future deactivation list.
 - For example: Cromby 1 & 2 and Eddystone 1 are scheduled to be deactivated before 2013 and Eddystone 2 is scheduled to be deactivated on 12/31/2013
- Transmission upgrades
 - The model is similar to PJM's 2013 transmission system representation
 - All the planned projects are in service except MAPP, PATH & Branchburg-Roseland-Hudson 500 kV



Analysis Methodology

- The model was run for the year 2013 with the inputs discussed on prior pages and no new in-state generator
 - Energy costs for each Load Zone (including each NJ utility) were determined
- Then a new, efficient, combined-cycle, natural gas fired generator in southern NJ was included with the following parameters
 - Output – 640 MW (summer) / 725 MW (winter)
 - Heat Rate – 7100
- The energy costs for each Load Zone (including each NJ utility) was then determined with the new generator in-service
- The difference in the energy costs without the new generator and with the new generator is the annual energy savings NJ ratepayers can expect from a new, in-state generator in NJ

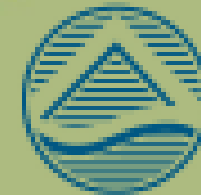


Results of Energy Savings Analysis

- The new generator operated ~61% of the year
- During this operating time, the new generator displaced more expensive units that, but for the new generator, would have cleared the energy market at a higher price
- **The total energy savings for NJ for the 2013 model year were found to be on the order of \$98 million**

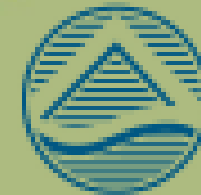
Zone Name	Load Savings
Atlantic Electric	\$39,884,810
JCP&L	\$20,378,254
PSEG	\$37,971,745
RECO	\$238,265
Total	\$98,473,074

Bringing Energy Forward



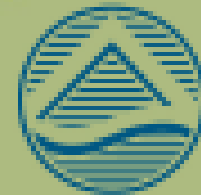
Additional Benefits from New, In-State Generation

- The new combined-cycle generator displaced approximately 1621 GWh of less efficient and less environmentally-advanced coal generation
- The new combined-cycle generator displaced approximately 567 GWh of less efficient and less environmentally-advanced peaking units (gas turbines)
- The new combined-cycle generator displaced approximately 1769 GWh of less efficient and less environmentally-advanced older combined-cycle and oil-fired generation



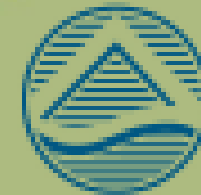
Summary of Benefits of New, In-State Generation

- **Total Energy-only savings to NJ ratepayers ~ \$98 million/year**
- In addition, a typical new, ~600 MW, combined-cycle plant would create
 - Up to **500 construction jobs** with a payroll of ~\$100 million
 - **25 permanent, skilled jobs** during operation
 - **Additional economic benefits to the community** through the purchase of local goods and services
 - **New tax revenues** to the local community of ~\$100 million over the life of the project



Worst Case Energy Savings Analysis

- The pending legislation calls for a capacity floor price of \$232.75/MW-Day fixed for the term of the contact
 - This represents a discount to the most recent wholesale capacity market clearing price
- The pending legislation would require a payment from the utilities to the generation owner ONLY in the event the wholesale capacity market clearing price fell below the floor price of \$232.75/MW-Day
- Assuming the wholesale capacity market clearing price was \$0.00/MW-Day (worst case), and therefore the utilities have to pay the generator the entire \$232.75/MW-Day, there is still an annual net savings to the ratepayers of \$43 million compared to the status quo of not building new combined-cycle generation. The savings are also in addition to the other benefits previously discussed



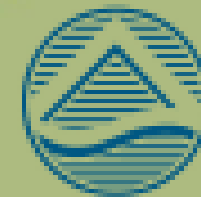
Contact Information

LS Power Development

2 Tower Center
11th Floor
East Brunswick, NJ 08816

Tom Hoatson
thoatson@lspower.com
732-867-5911

Bringing Energy Forward



NEW JERSEY LAW

[Fourth Reprint]

SENATE, No. 2381

STATE OF NEW JERSEY

214th LEGISLATURE

INTRODUCED OCTOBER 18, 2010

Sponsored by:

Senator BOB SMITH

District 17 (Middlesex and Somerset)

Senator CHRISTOPHER "KIP" BATEMAN

District 16 (Morris and Somerset)

Assemblyman UPENDRA J. CHIVUKULA

District 17 (Middlesex and Somerset)

Assemblyman JOHN F. MCKEON

District 27 (Essex)

Assemblyman JON M. BRAMNICK

District 21 (Essex, Morris, Somerset and Union)

Assemblyman LOUIS D. GREENWALD

District 6 (Camden)

Co-Sponsored by:

Assemblymen Giblin, Amodeo, Wisniewski, Connors and Assemblywoman Rodriguez

SYNOPSIS

Establishes a long-term capacity agreement pilot program to promote construction of qualified electric generation facilities.

CURRENT VERSION OF TEXT

As amended by the General Assembly on January 10, 2011.



(Sponsorship Updated As Of: 1/11/2011)

S2381 [4R] B. SMITH, BATEMAN

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1 **AN ACT** establishing a long-term capacity agreement pilot program
 2 to promote construction of qualified ²**[in-State]**² electric
 3 generation facilities, amending and supplementing P.L.1999,
 4 c.23.

5
 6 **BE IT ENACTED** *by the Senate and General Assembly of the State*
 7 *of New Jersey:*

8
 9 1. The Legislature finds and declares:

10 a. In 2007, PJM Interconnection, L.L.C., the firm that manages
 11 the regional electric power grid, changed the method of procuring
 12 capacity in the wholesale electricity market with the
 13 implementation of the reliability pricing model ¹**[**which, as
 14 estimated by the Board of Public Utilities, costs New Jersey
 15 ratepayers an additional \$1 billion per year for capacity**]**¹;

16 b. The PJM reliability pricing model ¹**[**created additional
 17 barriers to entry for new, efficient generators, by imposing a one to
 18 three year term requirement for contracts entered into by new
 19 entrants. The maximum three-year term is insufficient to support
 20 the project financing necessary to develop new, efficient generation
 21 within the State**]** sought to create enhancements to the previously
 22 ineffective capacity procurement mechanism which had resulted in
 23 projected capacity deficiencies in New Jersey and other areas of the
 24 regional power grid. While the reliability pricing model has
 25 resulted in significant capacity additions in the form of new demand
 26 response resources, new energy efficiency resources, reversals of
 27 generation unit retirements, upgrades of existing generating units
 28 and certain new peaking facilities ²**[in]** available to the region and²
 29 the State, the reliability pricing model has not resulted in large
 30 additions of peaking facilities or any additions of intermediate or
 31 base load resources ²**[in]** available to the region and² the State¹;

32 c. The PJM reliability pricing model ¹**[**continues to undergo
 33 structural changes that make it unreliable as an indicator of the true
 34 cost of capacity and therefore unreliable as an incentive for
 35 developing new generation**]** could, through structural changes,
 36 provide necessary incentives, such as the expansion of the “New
 37 Entry Price Adjustment” mechanism for the construction of new
 38 capacity, including new intermediate and base load plants, by
 39 allowing new resources to qualify and receive a guaranteed capacity
 40 price for a longer period of time. However, the implementation of
 41 similar structural changes ²**[were]** was² previously denied by
 42 FERC and any future implementation is uncertain at this time¹;

EXPLANATION – Matter enclosed in bold-faced brackets **[thus]** in the above bill is not enacted and is intended to be omitted in the law.

Matter underlined thus is new matter.

Matter enclosed in superscript numerals has been adopted as follows:

¹Senate SEN committee amendments adopted November 15, 2010.

²Assembly ATU committee amendments adopted December 13, 2010.

³Assembly floor amendments adopted January 6, 2011.

⁴Assembly floor amendments adopted January 10, 2011.

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1 d. To ¹[alleviate the cost burden and barriers to new entry
2 created by the PJM] address the lack of incentives under the¹
3 reliability pricing model, the construction of new, efficient ²[,in-
4 State]² generation must be fostered by State policy ¹[to avoid
5 higher electricity prices, higher congestion, and reliability
6 concerns] that ²[assures that] ensures sufficient² generation is
7 ²[constructed] available to the region, and thus the users² in the
8 State in a timely and orderly manner¹;

9 e. Due to PJM's lack of authority to order new generation as a
10 means to mitigate local electrical system reliability concerns and
11 solve other issues related to the lack of local generation, and since
12 only PJM has the authority to order transmission system upgrades
13 and expansions to mitigate electrical system reliability concerns
14 caused by transmission system overloads or the lack of local
15 generation being developed, ¹[New Jersey continues to send] New
16 ²[Jersey's] Jersey is experiencing an electric power² capacity
17 deficit ²and high power prices that² may result in the loss of¹ jobs
18 and investment ¹[out-of-state to] due to the necessity for the¹
19 upgrade ¹of¹ the transmission system to the west of New Jersey to
20 ensure a reliable supply of electricity and capacity from generators
21 located outside of New Jersey;

22 f. As a result of a lack of new, efficient ²[, in-State]² electric
23 ²[generating] generation² facilities, New Jersey has become more
24 reliant on ²[out-of-state]² coal-fired power plants;

25 g. The PJM State of the Market Report for 2009 by the PJM
26 Independent Market Monitor states that there ²are² over 11,000
27 megawatts ("MW") of coal-fired units at risk of retirement due to
28 their inability to cover their avoided costs;

29 h. ¹[Many of New Jersey's in-State generating facilities, as a
30 result of new emission reduction requirements, will need to have
31 installed new emissions control technology or retire them by April
32 30, 2015. In one instance, the rule will have a significant impact on
33 New Jersey's in-State fleet of electric generation facilities, as the
34 rule imposes nitrogen oxide ("NOx") emission limits that will likely
35 require the retirement of up to 102 combustion turbines,
36 representing approximately 2,800 MW, and five older New Jersey
37 steam electric generating units, representing approximately 800
38 MW, by April 30, 2015;

39 i.]¹ New Jersey's in-State fleet of electric generation facilities
40 ¹[are] is¹ aging, with over 50 percent of these facilities being more
41 than 30 years old and over 70 percent being more than 20 years old;
42 and

43 ¹[j.] i.¹ Fostering and incentivizing the development of ¹a
44 limited program for¹ new ²[in-State]² electric generation facilities
45 ²[¹, while potential enhancements to the reliability pricing model
46 and other PJM mechanisms are under consideration,¹]² will ²help

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1 ensure sufficient capacity to stabilize power prices to² assist the
2 State's economic development ²[by creating] and create²
3 '[numerous]'¹ opportunities for employment in the energy sector
4 while helping to reduce the cost and volatility of electricity prices in
5 New Jersey.

6

7 2. Section 3 of P.L.1999, c.23 (C.48:3-51) is amended to read
8 as follows:

9 3. As used in P.L.1999, c.23 (C.48:3-49 et al.):

10 "Assignee" means a person to which an electric public utility or
11 another assignee assigns, sells or transfers, other than as security,
12 all or a portion of its right to or interest in bondable transition
13 property. Except as specifically provided in P.L.1999, c.23
14 (C.48:3-49 et al.), an assignee shall not be subject to the public
15 utility requirements of Title 48 or any rules or regulations adopted
16 pursuant thereto;

17 ²"Base load electric power generation facility" means an electric
18 power generation facility intended to be operated at a greater than
19 50 percent capacity factor including, but not limited to, a combined
20 cycle power facility and a combined heat and power facility.²

21 "Base residual auction" means the auction conducted by PJM, as
22 part of PJM's reliability pricing model, three years prior to the start of
23 the delivery year to secure electrical capacity as necessary to satisfy
24 the capacity requirements for that delivery year;

25 "Basic gas supply service" means gas supply service that is
26 provided to any customer that has not chosen an alternative gas
27 supplier, whether or not the customer has received offers as to
28 competitive supply options, including, but not limited to, any
29 customer that cannot obtain such service for any reason, including
30 non-payment for services. Basic gas supply service is not a
31 competitive service and shall be fully regulated by the board;

32 "Basic generation service" or "BGS" means electric generation
33 service that is provided, to any customer that has not chosen an
34 alternative electric power supplier, whether or not the customer has
35 received offers for competitive supply options, including, but not
36 limited to, any customer that cannot obtain such service from an
37 electric power supplier for any reason, including non-payment for
38 services. Basic generation service is not a competitive service and
39 shall be fully regulated by the board;

40 "Basic generation service provider" or "provider" means a
41 provider of basic generation service;

42 "Basic generation service transition costs" means the amount by
43 which the payments by an electric public utility for the procurement
44 of power for basic generation service and related ancillary and
45 administrative costs exceeds the net revenues from the basic
46 generation service charge established by the board pursuant to
47 section 9 of P.L.1999, c.23 (C.48:3-57) during the transition period,
48 together with interest on the balance at the board-approved rate, that

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1 is reflected in a deferred balance account approved by the board in
2 an order addressing the electric public utility's unbundled rates,
3 stranded costs, and restructuring filings pursuant to P.L.1999, c.23
4 (C.48:3-49 et al.). Basic generation service transition costs shall
5 include, but are not limited to, costs of purchases from the spot
6 market, bilateral contracts, contracts with non-utility generators,
7 parting contracts with the purchaser of the electric public utility's
8 divested generation assets, short-term advance purchases, and
9 financial instruments such as hedging, forward contracts, and
10 options. Basic generation service transition costs shall also include
11 the payments by an electric public utility pursuant to a competitive
12 procurement process for basic generation service supply during the
13 transition period, and costs of any such process used to procure the
14 basic generation service supply;

15 "Board" means the New Jersey Board of Public Utilities or any
16 successor agency;

17 "Bondable stranded costs" means any stranded costs or basic
18 generation service transition costs of an electric public utility
19 approved by the board for recovery pursuant to the provisions of
20 P.L.1999, c.23 (C.48:3-49 et al.), together with, as approved by the
21 board: (1) the cost of retiring existing debt or equity capital of the
22 electric public utility, including accrued interest, premium and other
23 fees, costs and charges relating thereto, with the proceeds of the
24 financing of bondable transition property; (2) if requested by an
25 electric public utility in its application for a bondable stranded costs
26 rate order, federal, State and local tax liabilities associated with
27 stranded costs recovery or basic generation service transition cost
28 recovery or the transfer or financing of such property or both,
29 including taxes, whose recovery period is modified by the effect of
30 a stranded costs recovery order, a bondable stranded costs rate order
31 or both; and (3) the costs incurred to issue, service or refinance
32 transition bonds, including interest, acquisition or redemption
33 premium, and other financing costs, whether paid upon issuance or
34 over the life of the transition bonds, including, but not limited to,
35 credit enhancements, service charges, overcollateralization, interest
36 rate cap, swap or collar, yield maintenance, maturity guarantee or
37 other hedging agreements, equity investments, operating costs and
38 other related fees, costs and charges, or to assign, sell or otherwise
39 transfer bondable transition property;

40 "Bondable stranded costs rate order" means one or more
41 irrevocable written orders issued by the board pursuant to P.L.1999,
42 c.23 (C.48:3-49 et al.) which determines the amount of bondable
43 stranded costs and the initial amount of transition bond charges
44 authorized to be imposed to recover such bondable stranded costs,
45 including the costs to be financed from the proceeds of the
46 transition bonds, as well as on-going costs associated with servicing
47 and credit enhancing the transition bonds, and provides the electric
48 public utility specific authority to issue or cause to be issued,

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1 directly or indirectly, transition bonds through a financing entity
2 and related matters as provided in P.L.1999, c.23, which order shall
3 become effective immediately upon the written consent of the
4 related electric public utility to such order as provided in P.L.1999,
5 c.23;

6 "Bondable transition property" means the property consisting of
7 the irrevocable right to charge, collect and receive, and be paid
8 from collections of, transition bond charges in the amount necessary
9 to provide for the full recovery of bondable stranded costs which
10 are determined to be recoverable in a bondable stranded costs rate
11 order, all rights of the related electric public utility under such
12 bondable stranded costs rate order including, without limitation, all
13 rights to obtain periodic adjustments of the related transition bond
14 charges pursuant to subsection b. of section 15 of P.L.1999, c.23
15 (C.48:3-64), and all revenues, collections, payments, money and
16 proceeds arising under, or with respect to, all of the foregoing;

17 "British thermal unit" or "Btu" means the amount of heat
18 required to increase the temperature of one pound of water by one
19 degree Fahrenheit;

20 "Broker" means a duly licensed electric power supplier that
21 assumes the contractual and legal responsibility for the sale of
22 electric generation service, transmission or other services to end-use
23 retail customers, but does not take title to any of the power sold, or
24 a duly licensed gas supplier that assumes the contractual and legal
25 obligation to provide gas supply service to end-use retail customers,
26 but does not take title to the gas;

27 "Buydown" means an arrangement or arrangements involving the
28 buyer and seller in a given power purchase contract and, in some
29 cases third parties, for consideration to be given by the buyer in
30 order to effectuate a reduction in the pricing, or the restructuring of
31 other terms to reduce the overall cost of the power contract, for the
32 remaining succeeding period of the purchased power arrangement
33 or arrangements;

34 "Buyout" means an arrangement or arrangements involving the
35 buyer and seller in a given power purchase contract and, in some
36 cases third parties, for consideration to be given by the buyer in
37 order to effectuate a termination of such power purchase contract;

38 "Class I renewable energy" means electric energy produced from
39 solar technologies, photovoltaic technologies, wind energy, fuel
40 cells, geothermal technologies, wave or tidal action, and methane
41 gas from landfills or a biomass facility, provided that the biomass is
42 cultivated and harvested in a sustainable manner;

43 "Class II renewable energy" means electric energy produced at a
44 resource recovery facility or hydropower facility, provided that
45 such facility is located where retail competition is permitted and
46 provided further that the Commissioner of Environmental
47 Protection has determined that such facility meets the highest

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1 environmental standards and minimizes any impacts to the
2 environment and local communities;

3 "Co-generation" means the sequential production of electricity
4 and steam or other forms of useful energy used for industrial or
5 commercial heating and cooling purposes;

6 ²"Combined cycle power facility" means a generation facility
7 that combines two or more thermodynamic cycles, by producing
8 electric power via the combustion of fuel and then routing the
9 resulting waste heat by-product to a conventional boiler or to a heat
10 recovery steam generator for use by a steam turbine to produce
11 electric power, thereby increasing the overall efficiency of the
12 generating facility;²

13 "Combined heat and power facility" or "co-generation facility"
14 means a generation facility which produces electric energy, steam,
15 or other forms of useful energy such as heat, which are used for
16 industrial or commercial heating or cooling purposes. A combined
17 heat and power facility or co-generation facility shall not be
18 considered a public utility;

19 "Competitive service" means any service offered by an electric
20 public utility or a gas public utility that the board determines to be
21 competitive pursuant to section 8 or section 10 of P.L.1999, c.23
22 (C.48:3-56 or C.48:3-58) or that is not regulated by the board;

23 "Commercial and industrial energy pricing class customer" or
24 "CIEP class customer" means that group of non-residential
25 customers with high peak demand, as determined by periodic board
26 order, which either is eligible or which would be eligible, as
27 determined by periodic board order, to receive funds from the Retail
28 Margin Fund established pursuant to section 9 of P.L.1999, c.23
29 (C.48:3-57) and for which basic generation service is hourly-priced;

30 "Comprehensive resource analysis" means an analysis including,
31 but not limited to, an assessment of existing market barriers to the
32 implementation of energy efficiency and renewable technologies
33 that are not or cannot be delivered to customers through a
34 competitive marketplace;

35 "Customer" means any person that is an end user and is
36 connected to any part of the transmission and distribution system
37 within an electric public utility's service territory or a gas public
38 utility's service territory within this State;

39 "Customer account service" means metering, billing, or such
40 other administrative activity associated with maintaining a customer
41 account;

42 "Delivery year" or "DY" means the 12-month period from June
43 1st through May 31st ²[and shall be] ,² numbered according to the
44 calendar year in which it ends;

45 "Demand side management" means the management of customer
46 demand for energy service through the implementation of cost-
47 effective energy efficiency technologies, including, but not limited
48 to, installed conservation, load management and energy efficiency

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1 measures on and in the residential, commercial, industrial,
2 institutional and governmental premises and facilities in this State;

3 "Electric generation service" means the provision of retail
4 electric energy and capacity which is generated off-site from the
5 location at which the consumption of such electric energy and
6 capacity is metered for retail billing purposes, including agreements
7 and arrangements related thereto;

8 "Electric power generator" means an entity that proposes to
9 construct, own, lease or operate, or currently owns, leases or
10 operates, an electric power production facility that will sell or does
11 sell at least 90 percent of its output, either directly or through a
12 marketer, to a customer or customers located at sites that are not on
13 or contiguous to the site on which the facility will be located or is
14 located. The designation of an entity as an electric power generator
15 for the purposes of P.L.1999, c.23 (C.48:3-49 et al.) shall not, in
16 and of itself, affect the entity's status as an exempt wholesale
17 generator under the Public Utility Holding Company Act of 1935,
18 15 U.S.C. s.79 et seq.;

19 "Electric power supplier" means a person or entity that is duly
20 licensed pursuant to the provisions of P.L.1999, c.23 (C.48:3-49 et
21 al.) to offer and to assume the contractual and legal responsibility to
22 provide electric generation service to retail customers, and includes
23 load serving entities, marketers and brokers that offer or provide
24 electric generation service to retail customers. The term excludes an
25 electric public utility that provides electric generation service only
26 as a basic generation service pursuant to section 9 of P.L.1999, c.23
27 (C.48:3-57);

28 "Electric public utility" means a public utility, as that term is
29 defined in R.S.48:2-13, that transmits and distributes electricity to
30 end users within this State;

31 "Electric related service" means a service that is directly related
32 to the consumption of electricity by an end user, including, but not
33 limited to, the installation of demand side management measures at
34 the end user's premises, the maintenance, repair or replacement of
35 appliances, lighting, motors or other energy-consuming devices at
36 the end user's premises, and the provision of energy consumption
37 measurement and billing services;

38 "Electronic signature" means an electronic sound, symbol or
39 process, attached to, or logically associated with, a contract or other
40 record, and executed or adopted by a person with the intent to sign
41 the record;

42 "Eligible generator" means a developer of a ²[new, natural gas
43 fired, combined-cycle] base load² ⁴or mid-merit⁴ electric power
44 ²[generating] generation² facility ²[with a net summer output
45 rating of 100 megawatts or larger, that is physically located within
46 the State of New Jersey.] including, but not limited to, an on-site
47 generation facility that qualifies as a capacity resource under PJM

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1 criteria ⁴[but exclusive of a combustion turbine generation facility
2 that is directly interconnected with the electric public utilities'
3 transmission or distribution system,²⁴ and that commences
4 construction ⁴[²of new generation²]⁴ after the effective date of
5 P.L. , c. (C.) (pending before the Legislature as this bill);

6 "Energy agent" means a person that is duly registered pursuant to
7 the provisions of P.L.1999, c.23 (C.48:3-49 et al.), that arranges the
8 sale of retail electricity or electric related services or retail gas
9 supply or gas related services between government aggregators or
10 private aggregators and electric power suppliers or gas suppliers,
11 but does not take title to the electric or gas sold;

12 "Energy consumer" means a business or residential consumer of
13 electric generation service or gas supply service located within the
14 territorial jurisdiction of a government aggregator;

15 "Energy efficiency portfolio standard" means a requirement to
16 procure a specified amount of energy efficiency or demand side
17 management resources as a means of managing and reducing energy
18 usage and demand by customers;

19 "Energy year" or "EY" means the 12-month period from June 1st
20 through May 31st ²[and shall be] ² numbered according to the
21 calendar year in which it ends;

22 "Federal Energy Regulatory Commission" or "FERC" means the
23 federal agency established pursuant to 42 U.S.C. s.7171 et seq. to
24 regulate the interstate transmission of electricity, natural gas, and
25 oil;

26 "Financing entity" means an electric public utility, a special
27 purpose entity, or any other assignee of bondable transition
28 property, which issues transition bonds. Except as specifically
29 provided in P.L.1999, c.23 (C.48:3-49 et al.), a financing entity
30 which is not itself an electric public utility shall not be subject to
31 the public utility requirements of Title 48 or any rules or regulations
32 adopted pursuant thereto;

33 "Gas public utility" means a public utility, as that term is defined
34 in R.S.48:2-13, that distributes gas to end users within this State;

35 "Gas related service" means a service that is directly related to
36 the consumption of gas by an end user, including, but not limited to,
37 the installation of demand side management measures at the end
38 user's premises, the maintenance, repair or replacement of
39 appliances or other energy-consuming devices at the end user's
40 premises, and the provision of energy consumption measurement
41 and billing services;

42 "Gas supplier" means a person that is duly licensed pursuant to
43 the provisions of P.L.1999, c.23 (C.48:3-49 et al.) to offer and
44 assume the contractual and legal obligation to provide gas supply
45 service to retail customers, and includes, but is not limited to,
46 marketers and brokers. A non-public utility affiliate of a public
47 utility holding company may be a gas supplier, but a gas public
48 utility or any subsidiary of a gas utility is not a gas supplier. In the

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1 event that a gas public utility is not part of a holding company legal
2 structure, a related competitive business segment of that gas public
3 utility may be a gas supplier, provided that related competitive
4 business segment is structurally separated from the gas public
5 utility, and provided that the interactions between the gas public
6 utility and the related competitive business segment are subject to
7 the affiliate relations standards adopted by the board pursuant to
8 subsection k. of section 10 of P.L.1999, c.23 (C.48:3-58);

9 "Gas supply service" means the provision to customers of the
10 retail commodity of gas, but does not include any regulated
11 distribution service;

12 "Government aggregator" means any government entity subject
13 to the requirements of the "Local Public Contracts Law," P.L.1971,
14 c.198 (C.40A:11-1 et seq.), the "Public School Contracts Law,"
15 N.J.S.18A:18A-1 et seq., or the "County College Contracts Law,"
16 P.L.1982, c.189 (C.18A:64A-25.1 et seq.), that enters into a written
17 contract with a licensed electric power supplier or a licensed gas
18 supplier for: (1) the provision of electric generation service, electric
19 related service, gas supply service, or gas related service for its own
20 use or the use of other government aggregators; or (2) if a
21 municipal or county government, the provision of electric
22 generation service or gas supply service on behalf of business or
23 residential customers within its territorial jurisdiction;

24 "Government energy aggregation program" means a program and
25 procedure pursuant to which a government aggregator enters into a
26 written contract for the provision of electric generation service or
27 gas supply service on behalf of business or residential customers
28 within its territorial jurisdiction;

29 "Governmental entity" means any federal, state, municipal, local
30 or other governmental department, commission, board, agency,
31 court, authority or instrumentality having competent jurisdiction;

32 "Greenhouse gas emissions portfolio standard" means a
33 requirement that addresses or limits the amount of carbon dioxide
34 emissions indirectly resulting from the use of electricity as applied
35 to any electric power suppliers and basic generation service
36 providers of electricity;

37 ²"Incremental auction" means an auction conducted by PJM, as
38 part of PJM's reliability pricing model, prior to the start of the
39 delivery year to secure electric capacity as necessary to satisfy the
40 capacity requirements for that delivery year, that is not otherwise
41 provided for in the base residual auction;²

42 "Leakage" means an increase in greenhouse gas emissions
43 related to generation sources located outside of the State that are not
44 subject to a state, interstate or regional greenhouse gas emissions
45 cap or standard that applies to generation sources located within the
46 State;

47 ²"Locational deliverability area" or "LDA" means one or more of
48 the zones within the PJM region which are used to evaluate area

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1 transmission constraints and reliability issues including electric
2 public utility company zones, sub-zones, and combinations of
3 zones.²

4 “Long-term capacity agreement pilot program” or “LCAPP”
5 means a² [one-time]² pilot program established by the board that
6 ⁴[is limited to] includes⁴ participation by eligible generators, to
7 seek offers² [no later than February 4, 2011,]² for financially-
8 settled standard offer capacity agreements² [that extend for a term
9 of not less than 15 years, to quickly and safely construct new,
10 natural gas fired, combined-cycle electric power generating
11 facilities with a net summer output rating of 100 megawatts or
12 larger within the State] with eligible generators pursuant to the
13 provisions of P.L. _____, c. (C. _____) (pending before the Legislature as
14 this bill)]²;

15 "Market transition charge" means a charge imposed pursuant to
16 section 13 of P.L.1999, c.23 (C.48:3-61) by an electric public
17 utility, at a level determined by the board, on the electric public
18 utility customers for a limited duration transition period to recover
19 stranded costs created as a result of the introduction of electric
20 power supply competition pursuant to the provisions of P.L.1999,
21 c.23 (C.48:3-49 et al.);

22 "Marketer" means a duly licensed electric power supplier that
23 takes title to electric energy and capacity, transmission and other
24 services from electric power generators and other wholesale
25 suppliers and then assumes the contractual and legal obligation to
26 provide electric generation service, and may include transmission
27 and other services, to an end-use retail customer or customers, or a
28 duly licensed gas supplier that takes title to gas and then assumes
29 the contractual and legal obligation to provide gas supply service to
30 an end-use customer or customers;

31 ⁴"Mid-merit electric power generation facility" means a
32 generation facility that operates at a capacity factor between
33 baseload generation facilities and peaker generation facilities.⁴

34 "Net proceeds" means proceeds less transaction and other related
35 costs as determined by the board;

36 "Net revenues" means revenues less related expenses, including
37 applicable taxes, as determined by the board;

38 "Offshore wind energy" means electric energy produced by a
39 qualified offshore wind project;

40 "Offshore wind renewable energy certificate" or "OREC" means
41 a certificate, issued by the board or its designee, representing the
42 environmental attributes of one megawatt hour of electric
43 generation from a qualified offshore wind project;

44 "Off-site end use thermal energy services customer" means an
45 end use customer that purchases thermal energy services from an
46 on-site generation facility, combined heat and power facility, or co-
47 generation facility, and that is located on property that is separated

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1 from the property on which the on-site generation facility,
2 combined heat and power facility, or co-generation facility is
3 located by more than one easement, public thoroughfare, or
4 transportation or utility-owned right-of-way;

5 "On-site generation facility" means a generation facility, and
6 equipment and services appurtenant to electric sales by such facility
7 to the end use customer located on the property or on property
8 contiguous to the property on which the end user is located. An on-
9 site generation facility shall not be considered a public utility. The
10 property of the end use customer and the property on which the on-
11 site generation facility is located shall be considered contiguous if
12 they are geographically located next to each other, but may be
13 otherwise separated by an easement, public thoroughfare,
14 transportation or utility-owned right-of-way, or if the end use
15 customer is purchasing thermal energy services produced by the on-
16 site generation facility, for use for heating or cooling, or both,
17 regardless of whether the customer is located on property that is
18 separated from the property on which the on-site generation facility
19 is located by more than one easement, public thoroughfare, or
20 transportation or utility-owned right-of-way;

21 "Person" means an individual, partnership, corporation,
22 association, trust, limited liability company, governmental entity or
23 other legal entity;

24 "PJM Interconnection, L.L.C." or "PJM" means the privately-
25 held, limited liability corporation that is a FERC-approved Regional
26 Transmission Organization ², or its successor,² that manages the
27 regional, high-voltage electricity grid serving all or parts of 13
28 states including New Jersey and the District of Columbia, operates
29 the regional competitive wholesale electric market, manages the
30 regional transmission planning process, and establishes systems and
31 rules to ensure that the regional and in-State energy markets operate
32 fairly and efficiently;

33 "Private aggregator" means a non-government aggregator that is
34 a duly-organized business or non-profit organization authorized to
35 do business in this State that enters into a contract with a duly
36 licensed electric power supplier for the purchase of electric energy
37 and capacity, or with a duly licensed gas supplier for the purchase
38 of gas supply service, on behalf of multiple end-use customers by
39 combining the loads of those customers;

40 "Public utility holding company" means: (1) any company that,
41 directly or indirectly, owns, controls, or holds with power to vote,
42 ten percent or more of the outstanding voting securities of an
43 electric public utility or a gas public utility or of a company which
44 is a public utility holding company by virtue of this definition,
45 unless the Securities and Exchange Commission, or its successor,
46 by order declares such company not to be a public utility holding
47 company under the Public Utility Holding Company Act of 1935,
48 15 U.S.C. s.79 et seq., or its successor; or (2) any person that the

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1 Securities and Exchange Commission, or its successor, determines,
2 after notice and opportunity for hearing, directly or indirectly, to
3 exercise, either alone or pursuant to an arrangement or
4 understanding with one or more other persons, such a controlling
5 influence over the management or policies of an electric public
6 utility or a gas public utility or public utility holding company as to
7 make it necessary or appropriate in the public interest or for the
8 protection of investors or consumers that such person be subject to
9 the obligations, duties, and liabilities imposed in the Public Utility
10 Holding Company Act of 1935 or its successor;

11 "Qualified offshore wind project" means a wind turbine
12 electricity generation facility in the Atlantic Ocean and connected
13 to the electric transmission system in this State, and includes the
14 associated transmission-related interconnection facilities and
15 equipment, and approved by the board pursuant to section 3 of
16 P.L.2010, c.57 (C.48:3-87.1);

17 "Regulatory asset" means an asset recorded on the books of an
18 electric public utility or gas public utility pursuant to the Statement
19 of Financial Accounting Standards, No. 71, entitled "Accounting for
20 the Effects of Certain Types of Regulation," or any successor
21 standard and as deemed recoverable by the board;

22 "Related competitive business segment of an electric public
23 utility or gas public utility" means any business venture of an
24 electric public utility or gas public utility including, but not limited
25 to, functionally separate business units, joint ventures, and
26 partnerships, that offers to provide or provides competitive services;

27 "Related competitive business segment of a public utility holding
28 company" means any business venture of a public utility holding
29 company, including, but not limited to, functionally separate
30 business units, joint ventures, and partnerships and subsidiaries, that
31 offers to provide or provides competitive services, but does not
32 include any related competitive business segments of an electric
33 public utility or gas public utility;

34 "Reliability pricing model" or "RPM" means PJM's capacity-
35 market model, and its successors, that secures capacity on behalf of
36 electric load serving entities to satisfy load obligations not satisfied
37 through the output of electric generation facilities owned by those
38 entities^{2, 2 1} or otherwise secured by those entities through bilateral
39 contracts¹ ;

40 "Renewable energy certificate" or "REC" means a certificate
41 representing the environmental benefits or attributes of one
42 megawatt-hour of generation from a generating facility that
43 produces Class I or Class II renewable energy, but shall not include
44 a solar renewable energy certificate or an offshore wind renewable
45 energy certificate;

46 "Resource clearing price" or "RCP" means the clearing price
47 established for the applicable locational deliverability area by the
48 base residual auction¹ or incremental auction^{1 2}, as determined by

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1 the optimization algorithm for each auction,² conducted by PJM as
2 part of PJM's reliability pricing model;

3 "Resource recovery facility" means a solid waste facility
4 constructed and operated for the incineration of solid waste for
5 energy production and the recovery of metals and other materials
6 for reuse;

7 "Restructuring related costs" means reasonably incurred costs
8 directly related to the restructuring of the electric power industry,
9 including the closure, sale, functional separation and divestiture of
10 generation and other competitive utility assets by a public utility, or
11 the provision of competitive services as such costs are determined
12 by the board, and which are not stranded costs as defined in
13 P.L.1999, c.23 (C.48:3-49 et al.) but may include, but not be limited
14 to, investments in management information systems, and which
15 shall include expenses related to employees affected by
16 restructuring which result in efficiencies and which result in
17 benefits to ratepayers, such as training or retraining at the level
18 equivalent to one year's training at a vocational or technical school
19 or county community college, the provision of severance pay of two
20 weeks of base pay for each year of full-time employment, and a
21 maximum of 24 months' continued health care coverage. Except as
22 to expenses related to employees affected by restructuring,
23 "restructuring related costs" shall not include going forward costs;

24 "Retail choice" means the ability of retail customers to shop for
25 electric generation or gas supply service from electric power or gas
26 suppliers, or opt to receive basic generation service or basic gas
27 service, and the ability of an electric power or gas supplier to offer
28 electric generation service or gas supply service to retail customers,
29 consistent with the provisions of P.L.1999, c.23 (C.48:3-49 et al.);

30 "Retail margin" means an amount, reflecting differences in
31 prices that electric power suppliers and electric public utilities may
32 charge in providing electric generation service and basic generation
33 service, respectively, to retail customers, excluding residential
34 customers, which the board may authorize to be charged to
35 categories of basic generation service customers of electric public
36 utilities in this State, other than residential customers, under the
37 board's continuing regulation of basic generation service pursuant to
38 sections 3 and 9 of P.L.1999, c.23 (C.48:3-51 and 48:3-57), for the
39 purpose of promoting a competitive retail market for the supply of
40 electricity;

41 "Shopping credit" means an amount deducted from the bill of an
42 electric public utility customer to reflect the fact that such customer
43 has switched to an electric power supplier and no longer takes basic
44 generation service from the electric public utility;

45 "Social program" means a program implemented with board
46 approval to provide assistance to a group of disadvantaged
47 customers, to provide protection to consumers, or to accomplish a
48 particular societal goal, and includes, but is not limited to, the

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1 winter moratorium program, utility practices concerning "bad debt"
 2 customers, low income assistance, deferred payment plans,
 3 weatherization programs, and late payment and deposit policies, but
 4 does not include any demand side management program or any
 5 environmental requirements or controls;

6 "Societal benefits charge" means a charge imposed by an electric
 7 public utility, at a level determined by the board, pursuant to, and in
 8 accordance with, section 12 of P.L.1999, c.23 (C.48:3-60);

9 "Solar alternative compliance payment" or "SACP" means a
 10 payment of a certain dollar amount per megawatt hour (MWh)
 11 which an electric power supplier or provider may submit to the
 12 board in order to comply with the solar electric generation
 13 requirements under section 38 of P.L.1999, c.23 (C.48:3-87);

14 "Solar renewable energy certificate" or "SREC" means a
 15 certificate issued by the board or its designee, representing one
 16 megawatt hour (MWh) of solar energy that is generated by a facility
 17 connected to the distribution system in this State and has value
 18 based upon, and driven by, the energy market;

19 "Standard offer capacity agreement" or "SOCA" means a
 20 financially-settled transaction agreement, approved by board order,
 21 that provides for ¹[an] ¹eligible ¹[generator] generators ²[(1) ¹]²
 22 to receive ²[a payment] payments² from ²[one or more] the²
 23 electric public utilities ²[, in the event the SOCP is greater than the
 24 ¹base residual auction¹ RCP for any applicable delivery year, ¹and¹
 25 that ¹[provides for] ¹such payment ¹[to be] is¹ equal to the
 26 difference between the SOCP and the ¹base residual auction¹ RCP
 27 multiplied by the contract capacity ¹[, that provides] ; and (2) to
 28 remit a payment to one or more electric public utilities for the
 29 benefit of ratepayers, in the event the base residual auction RCP is
 30 greater than \$290 per megawatt day for any applicable delivery
 31 year, and that such payment is equal to the result of the difference
 32 between the base residual auction RCP and \$290 per megawatt day
 33 for the applicable delivery year multiplied by the contract capacity.
 34 The SOCA shall provide¹]² for a defined amount of electric
 35 capacity for ⁴[the term of the transaction of not less than] a term to
 36 be determined by the board but not to exceed 15 years,⁴ ²[15
 37 years.] ⁴[seven years or not more than 10 years,²]⁴ and ¹[that
 38 provides]¹ for ¹[such payment] ²such² payments ²[made pursuant
 39 to paragraph (1) ¹]² to be a fully non-bypassable charge, with such
 40 an order, once issued, being irrevocable;

41 "Standard offer capacity price" or "SOCP" means the capacity
 42 price that is fixed for the term of the SOCA and ²which² is the
 43 ²[minimum]² price to be received by ¹[an] ¹eligible ¹[generator]
 44 generators¹ under a board-approved SOCA;

45 "Stranded cost" means the amount by which the net cost of an
 46 electric public utility's electric generating assets or electric power

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1 purchase commitments, as determined by the board consistent with
2 the provisions of P.L.1999, c.23 (C.48:3-49 et al.), exceeds the
3 market value of those assets or contractual commitments in a
4 competitive supply marketplace and the costs of buydowns or
5 buyouts of power purchase contracts;

6 "Stranded costs recovery order" means each order issued by the
7 board in accordance with subsection c. of section 13 of P.L.1999,
8 c.23 (C.48:3-61) which sets forth the amount of stranded costs, if
9 any, the board has determined an electric public utility is eligible to
10 recover and collect in accordance with the standards set forth in
11 section 13 of P.L.1999, c.23 (C.48:3-61) and the recovery
12 mechanisms therefor;

13 "Thermal efficiency" means the useful electric energy output of a
14 facility, plus the useful thermal energy output of the facility,
15 expressed as a percentage of the total energy input to the facility;

16 "Transition bond charge" means a charge, expressed as an
17 amount per kilowatt hour, that is authorized by and imposed on
18 electric public utility ratepayers pursuant to a bondable stranded
19 costs rate order, as modified at any time pursuant to the provisions
20 of P.L.1999, c.23 (C.48:3-49 et al.);

21 "Transition bonds" means bonds, notes, certificates of
22 participation or beneficial interest or other evidences of
23 indebtedness or ownership issued pursuant to an indenture, contract
24 or other agreement of an electric public utility or a financing entity,
25 the proceeds of which are used, directly or indirectly, to recover,
26 finance or refinance bondable stranded costs and which are, directly
27 or indirectly, secured by or payable from bondable transition
28 property. References in P.L.1999, c.23 (C.48:3-49 et al.) to
29 principal, interest, and acquisition or redemption premium with
30 respect to transition bonds which are issued in the form of
31 certificates of participation or beneficial interest or other evidences
32 of ownership shall refer to the comparable payments on such
33 securities;

34 "Transition period" means the period from August 1, 1999
35 through July 31, 2003;

36 "Transmission and distribution system" means, with respect to an
37 electric public utility, any facility or equipment that is used for the
38 transmission, distribution or delivery of electricity to the customers
39 of the electric public utility including, but not limited to, the land,
40 structures, meters, lines, switches and all other appurtenances
41 thereof and thereto, owned or controlled by the electric public
42 utility within this State; and

43 "Universal service" means any service approved by the board
44 with the purpose of assisting low-income residential customers in
45 obtaining or retaining electric generation or delivery service.

46 (cf: P.L.2010, c.57, s.1)

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1 3. (New section) Notwithstanding any provisions of the
 2 “Administrative Procedure Act,” P. L. 1968, c.410 (C.52:14B-1 et
 3 seq.) to the contrary, the board shall ²[], within 10 days of the
 4 effective date of P.L. , c. (C.) (pending before the Legislature
 5 as this bill),² initiate ²and complete² a proceeding ²[on] in
 6 accordance with² the schedule set forth in this section ²[allowing
 7 such proceeding to be completed]² to support the commencement
 8 of the LCAPP ²[no later than January 31, 2011, and shall adopt,
 9 after notice, the opportunity for comment, and public hearing on the
 10 schedule set forth in this section, the following requirements for the
 11 LCAPP]²:

12 ²[a. the establishment of the LCAPP that allows for offering
 13 financially-settled SOCAs for the purpose of facilitating the
 14 development of eligible generators;

15 b. the establishment of the LCAAP on the following schedule:

16 (1) the board shall complete the process to develop the SOCA no
 17 later than January 1, 2011; and

18 (2) SOCAs resulting from this process shall be awarded,
 19 executed and approved by the board with a written board order no
 20 later than February 25, 2011;

21 c. the participation of selected eligible generators with board
 22 approved, executed SOCAs in and clearing of the base residual
 23 auction conducted by PJM and scheduled to commence on May 2,
 24 2011, as part of PJM’s reliability pricing model for the delivery
 25 year 2015;

26 d. that it be limited to eligible generators in order to maximize
 27 economic benefits and job creation in the State;

28 e. that electric public utilities shall procure at least 500
 29 megawatts and not more than ¹[1500] 1,000¹ megawatts of
 30 financially-settled SOCAs from the eligible generators;

31 f. ¹[that no single eligible generator or its affiliate may enter
 32 into more than 900 megawatts of financially-settled standard offer
 33 capacity agreements;

34 g.]¹

35 a. The board shall initiate ⁴[the proceeding within 30 days of
 36 the effective date of P.L. , c. (C.) (pending before the
 37 Legislature as this bill),]⁴ and allow such proceeding to be
 38 completed no later than ⁴[March 1, 2011] 60 days after the
 39 effective date of P.L. , c. (C.) (pending before the Legislature
 40 as this bill)⁴ to allow for the commencement of the LCAPP. The
 41 SOCA or SOCAs resulting from that proceeding shall be awarded
 42 ⁴[.] and⁴ executed ⁴[and approved by the board with a written
 43 board order]⁴ no later than ⁴[April 15, 2011] 30 days after the
 44 approval of the form of the SOCA or SOCAs⁴. The LCAPP shall
 45 require selected eligible generators with board approved and
 46 executed SOCAs to participate and be accepted as a capacity

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1 resource in the base residual auction conducted by PJM ⁴ [and
 2 scheduled to commence either on May 2, 2011, as part of PJM’s
 3 reliability pricing model for the delivery year 2015, or May 2012,
 4 as part of PJM’s reliability pricing model for the delivery year
 5 2016]⁴;

6 b. The board shall require ⁴ [, within 10 days of the effective
 7 date of P.L. _____, c. (C. _____) (pending before the Legislation as this
 8 bill)]⁴ that the electric public utilities within the State retain an
 9 agent ⁴, with the approval of the board,⁴ to administer the LCAPP.
 10 The agent retained in accordance with this section shall ⁴, on behalf
 11 of the board,⁴ be responsible for:

12 (1) assisting the board with the establishment of the LCAPP that
 13 allows for offering financially-settled SOCAs for the purpose of
 14 facilitating the development of eligible generators;

15 (2) prequalifying eligible generators for participation in the
 16 LCAPP through a showing of environmental, economic, and
 17 community benefits, and through demonstration of reasonable
 18 certainty of completion of development, construction and permitting
 19 activities necessary to meet the desired in-service date ⁴ [. Eligible
 20 generators must prequalify by April 1, 2011 and seek a SOCA by
 21 submitting an offer price and term by April 1, 2011]⁴ ; and

22 (3) recommending to the board the selection of winning eligible
 23 generators based on the net benefit to ratepayers of each
 24 prequalified eligible generator’s offer price and term. ⁴ [Eligible
 25 generators that are located in an “area in need of redevelopment” in
 26 accordance with the “Local Redevelopment and Housing Law,”
 27 P.L.1992, c.79 (C.40A:12A-1 et seq.) or a brownfield development
 28 area in accordance with the “Brownfield and Contaminated Site
 29 Remediation Act,” P.L.2005, c.223 (C.58:10B-1 et seq.), and
 30 eligible] Eligible⁴ generators that can enter commercial operation
 31 for delivery year 2015 ⁴ [, shall have] are to be provided with⁴ a
 32 weighted preference in addition to the net benefit ⁴ [to ratepayers
 33 ranking provided for in this subsection] ratepayer test⁴ . Eligible
 34 generators shall also indicate the amount of capacity they are
 35 offering in the LCAPP.

36 c. In the proceeding initiated by the board pursuant to this
 37 section, the board shall adopt, after notice, the opportunity for
 38 comment, and public hearing, an order addressing the following
 39 requirements for the LCAPP:

40 (1) that electric public utilities shall procure ³ [1,000] 2,000³
 41 megawatts of financially-settled SOCAs from eligible generators,
 42 which shall include new generation capacity ⁴ [for the 2015 or 2016
 43 delivery year]⁴;

44 (2)² that eligible generators participating in the LCAPP shall be
 45 required to offer ² [the maximum] a² quantity, in megawatts, ²offer
 46 a price per megawatt-day, and a term² of the SOCA ² [at the

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1 standard offer ¹capacity¹ price of \$232.75 per megawatt per day,
2 which represents a discount to the most recent clearing price
3 established by the base residual auction conducted by the PJM in
4 May, 2010 as part of the PJM's reliability pricing model] to be
5 evaluated by the agent and approved by the board²;

6 ¹[h.] ²[g. ¹] (3)² that ², taking into consideration the agent's
7 recommendation,² the board ²[select] approve the selected² ¹[an]¹
8 eligible ¹[generator] generators¹ from among the ²qualified²
9 eligible generators participating in the LCAPP for the award of
10 ²[a]² board-approved long-term financially-settled ²[SOCA]
11 SOCA² for a term ⁴[of not less than] to be determined by the
12 board but not to exceed 15 years⁴ ²[15 years] ⁴[seven years or
13 more than 10 years at the offer price and term of each selected
14 eligible generator²]⁴; ¹[.]¹

15 ²(4) that the board establish a method and the contract terms for
16 providing for selected eligible generators to receive payments from
17 the electric public utilities for the difference between the SOCP and
18 the RCP multiplied by the SOCA capacity in the event the SOCP is
19 greater than the RCP for any applicable delivery year and for
20 providing for electric public utilities to receive refunds from the
21 selected eligible generators for the difference between the SOCP
22 and the RCP multiplied by the SOCA capacity in the event the RCP
23 is greater than the SOCP for any applicable delivery year;

24 (5) that no single eligible generator or its affiliate may enter into
25 more than 700 megawatts of financially-settled standard offer
26 capacity agreements;

27 (6) that the board establish criteria associated with the
28 prequalification of eligible generators for participation in the
29 LCAPP through a showing of environmental, economic, and
30 community benefits, and through demonstration of reasonable
31 certainty of completion of development, construction and permitting
32 activities necessary to meet the desired in-service date;

33 (7) that the board establish a method for evaluating and
34 comparing the net⁴ [present]⁴ value⁴ to ratepayers⁴ of each eligible
35 generator's offer price and term;

36 (8) that the board establish a method for providing⁴ [for a
37 weighted preference for eligible generators in an "area in need of
38 redevelopment" in accordance with the "Local Redevelopment and
39 Housing Law," P.L.1992, c.79 (C.40A:12A-1 et seq.) or a
40 brownfield development area in accordance with the "Brownfield
41 and Contaminated Site Remediation Act," P.L.2005, c.223
42 (C.58:10B-1 et seq.), and]⁴ a weighted preference for eligible
43 generators that can enter commercial operation for delivery year
44 2015;²

45 ¹[i.] ²[h. ¹] that the selection of winning eligible generators give
46 preference to those eligible generators located in "areas in need of

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20

1 redevelopment” in accordance with the “Local Redevelopment and
 2 Housing Law,” P.L.1992, c.79 (C.40A:12A-1 et seq.), that based on
 3 the board’s determination, can provide the greatest environmental,
 4 economic, and community benefits, and can demonstrate certainty
 5 of completion of development and permitting activities necessary to
 6 meet the desired in-service date;

7 ¹[j.] ¹i. ¹(9)² that ¹[an]¹ eligible ¹[generator] generators¹
 8 ²[selected] approved² by the board, enter into a SOCA with each of
 9 the State’s four electric public utilities provided that each electric
 10 public utility shall pay ²or receive refunds pursuant to² ¹[a] an
 11 annually calculated¹ load-ratio share ²of the capacity² of the SOCA
 12 ²[price]² based upon each electric public utility’s annual forecasted
 13 peak demand as determined by PJM;

14 ¹[k.] ²[j.] ¹(10)² that the resulting SOCA shall bind the electric
 15 public utilities to the board approved SOCAs with ¹[a]¹ selected
 16 eligible ¹[generator] generators¹ for ²[not less than 15 years] the
 17 term of the SOCA²;

18 ¹[l.] ²[k.] ¹(11)² that the selected eligible generators with
 19 executed SOCAs shall offer the capacity, electricity, and ancillary
 20 services into the PJM wholesale markets as required by the PJM
 21 market rules; ²and²

22 ¹[m.] ²[l.] ¹(12)² that selected eligible generators with executed
 23 SOCAs shall participate in and clear the annual base residual
 24 auction conducted by the PJM as part of ²[PJM’s] its² reliability
 25 pricing model for each delivery year of the entire term of the
 26 agreement ²[;] ².

27 ¹[n.] ²[m.] ¹that the] d. The² board shall order the full recovery
 28 of all costs associated with the electric public utilities’ resulting
 29 SOCAs ², and the costs of the agent retained pursuant to subsection
 30 b. of this section,² from ratepayers through a non-bypassable,
 31 irrevocable charge;

32 ²[(1) notwithstanding] e. Notwithstanding² any other provision
 33 of law, each ²[LCAPP standard offer capacity agreement] SOCA²
 34 shall become irrevocable upon the issuance of such order
 35 ²approving a SOCA²; and

36 ²[(2) neither] f. Neither² the board or any other governmental
 37 entity shall have the authority, directly or indirectly, legally or
 38 equitably, to rescind, alter, repeal, modify or amend ²a SOCA or²
 39 an LCAPP cost rate order, to revalue, re-evaluate ²,² or revise the
 40 amount of LCAPP costs, or to determine that the LCAPP charges or
 41 the revenues to recover the LCAPP charges for such SOCAs are
 42 unjust or unreasonable ²[; and

43 ¹[o.] n.¹ that the board shall have complete discretion to
 44 approve any and all SOCAs resulting from the LCAPP]².

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21

1 ^{24.} (New section) If one or more provisions in P.L. ___,
2 c. (C.)(pending before the Legislation as this bill) are challenged
3 in an administrative or judicial proceeding, the board may suspend
4 the applicability of the challenged provision or provisions during
5 the pendency of those proceedings until final resolution of the
6 challenge and any appeals, and shall issue such orders and take such
7 other actions as it deems appropriate to ensure that the provisions
8 that are not challenged are implemented expeditiously to achieve
9 the public purposes of P.L. ___, c. (C.)(pending before the
10 Legislature as this bill).²

11

12 ^{25.} (New section) Notwithstanding the provisions of any other
13 law, rule, regulation, or order to the contrary, gas public utilities
14 shall not impose a societal benefits charge pursuant to section 12 of
15 P.L.1999, c.23 (C.48:3-60), or any other charge designed to recover
16 the costs for social, energy efficiency, conservation, environmental
17 or renewable energy programs, on natural gas delivery service or
18 commodity that is used to generate electricity that is sold for
19 resale.²

20

21 ^{2[4.] 6.}² This act shall take effect immediately.

MARYLAND RFP
(attachments omitted)

COMMISSIONERS

STATE OF MARYLAND



DOUGLAS R. M. NAZARIAN
CHAIRMAN

HAROLD D. WILLIAMS
SUSANNE BROGAN
LAWRENCE BRENNER
THERESE M. GOLDSMITH

PUBLIC SERVICE COMMISSION

December 29, 2010

In the Matter of Whether New Generating	*	
Facilities Are Needed to Meet Long-Term	*	Case No. 9214
Demand for Standard Offer Service	*	
	*	
	*	
	*	
	*	
	*	
	*	

**NOTICE OF COMMENT PERIOD ON
REQUEST FOR PROPOSALS FOR NEW GENERATING FACILITIES**

To: Parties of Record and Interested Persons

On September 29, 2009, the Commission issued Order No. 82936, which initiated this proceeding and invited parties to file proposals for Maryland-located new generating facilities by December 1, 2009. On October 9, 2009, Technical Staff (“Staff”) of the Public Service Commission (“Commission”) filed a letter asking that the Commission offer some clarification regarding the scope of proposals requested. In its letter, Staff provided a list of additional information that Staff recommended, should be contained in the proposals submitted pursuant to the Order for the Commission’s review. On October 15, 2009, the Commission set a comment period to allow parties and interested persons an opportunity to comment on Staff’s recommendations, or to provide any additional elements that any party or interested person believed would be helpful to the Commission’s review of the proposals. On November 10, 2009, the Commission issued a Notice tolling the date by which any proposals would be required to be filed in this matter.

After reviewing the comments made as a result of the Notice issued in the matter on October 15, 2009, the Commission determined that a more formal request for proposals (“RFP”) is required to seek offers for new generating facilities in or around Maryland, including the possibility that electric distribution companies (“EDCs”) could be required to enter into long term contracts with persons that construct a new generating facility in or around Maryland. The Commission has prepared a draft RFP, including form of contracts, to solicit offers from persons for new generating facilities in or around Maryland, a copy of which is attached to this Notice. In addition, the Commission anticipates that it will order the EDCs to submit proposals to construct, acquire, or lease, and operate new generation capacity resources in or around Maryland that meet the requirements of the RFP issued in this matter. Prior to issuing the RFP,

WILLIAM DONALD SCHAEFER TOWER • 6 ST. PAUL STREET • BALTIMORE, MARYLAND 21202-6806

410-767-8000 • Toll Free: 1-800-492-0474 • FAX: 410-333-6495

MDRS: 1-800-735-2258 (TTY/Voice) • Website: www.psc.state.md.us/psc/

Page 2

the Commission is setting a comment period to allow parties to the proceeding and interested persons to review the draft and provide any comments on, or suggested edits or revisions to, the draft RFP. The fact that the Commission issued this Notice or has prepared a draft RFP should not be construed as a finding by the Commission that new generation is required or that the Commission has decided to order any party to construct, acquire, lease or operate new capacity resources in or around Maryland.

Accordingly, any party or interested person shall file an original and seventeen paper copies, and an electronic version, of its comments to Terry J. Romine, Executive Secretary, Maryland Public Service Commission, William Donald Schaefer Tower, 6 St. Paul Street, Baltimore, Maryland 21202 by Friday, January 28, 2011. Five of the paper copies shall be three-hole punched. The Commission encourages persons to file the electronic public version of the comments via the Commission's "e-file" system which can be accessed via the Commission's website, www.psc.state.md.us.

By Direction of the Commission,

/s/ T. J. Romine

Terry J. Romine
Executive Secretary

**REQUEST FOR PROPOSALS
FOR
GENERATION CAPACITY RESOURCES
UNDER LONG-TERM CONTRACT**

**DATED
[DATE]**

DRAFT

**Request for Proposals
For
Generation Capacity Resources under Long-Term Contracts**

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DRAFT

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Attachment 4	Participation in Any Prior PJM Capacity Auction – Certification Form
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Attachment 6	Binding Offer Agreement
Attachment 7	Operating Data and Pricing Parameters Worksheet – Dispatchable Generation
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Attachment 9	Cost-of-Service Pricing Contract for Differences
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**Request for Proposals
For
Generation Capacity Resources under Long-Term Contracts**

1 INTRODUCTION

Pursuant to Sections 7-510(c)(4)(ii)1.B, 7-510(c)(4)(ii)2.A and 7-510(c)(6) (collectively, the “Customer Choice Act”) of the Maryland Public Utilities Article, *Annotated Code of Maryland* (“PUA”) the Maryland Public Service Commission (PSC or Commission) hereby directs Baltimore Gas and Electric Company (BGE), Delmarva Power and Light Company (DP&L), The Potomac Edison Company d/b/a Allegheny Power (AP), and Potomac Electric Power Company (Pepco) (collectively referred to as the Maryland electric distribution companies or “EDCs”) to issue this Request For Proposals (RFP) for Capacity, Energy, Ancillary Services, and, if applicable, Maryland Tier 1 Renewable Energy Credits (RECs) (collectively referred to as Products).¹ This RFP supplements other reliability initiatives undertaken by the Commission in Case 9149.²

The purpose of this RFP is to ensure the continued, long-term reliability of the electricity supply to Maryland customers. During the Commission’s Summer 2007 Electricity Planning Conference, PJM Interconnection L.L.C. (PJM) first reported to the Commission the possibility of power supply shortages on hot summer days beginning in 2011. More recently, as part of the Commission’s ongoing review of electricity supply and demand in Maryland, PJM updated its projections on Maryland’s potential capacity “gap.” In a March 2, 2010 presentation provided by PJM as part of Case No. 9149, PJM opined that the Capacity Emergency Transfer Limit (CETL) of the Mid-Atlantic area, which includes Maryland’s Eastern Shore and the Pepco load delivery area was limited

¹ PUA § 7-510 provides for the phased implementation of customer choice. PUA § 7-510(c) details the obligations of electric companies and the Commission in that regard. PUA § 7-510(c)(4)(ii)1.B provides that “Under the obligation to provide standard offer service ...the Commission, by regulation or order, and in a manner that is designed to obtain the best price for residential and small commercial customers in light of market conditions at the time of procurement, and the need to protect these customers from excessive price increases... may require or allow an investor-owned electric company to procure electricity for these customers directly from an electricity supplier through one or more bilateral contracts outside the competitive process.” PUA Article § 7-510(c)(4)(ii)2.A allows, at the Commission’s direction, an investor-owned electric company to solicit bids “to supply anticipated standard offer service load for residential and small commercial customers as part of a portfolio of blended wholesale supply contracts of short, medium or long terms and other appropriate electricity products and strategies, as needed to meet demand in a cost-effective manner.” PUA § 7-510(c)(6) permits the Commission to require an investor-owned electric company to construct, acquire or lease, and operate generating facilities in order to meet long-term anticipated demand in the State for standard offer service and other electricity supply.

² “In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland.”

by the Pleasant View 500/230 kV transformer. In a follow-up letter to the Commission, dated March 18, 2010, PJM reiterated its commitment to further analysis of the facilities limiting deliverability into the Pepco and Mid-Atlantic areas. PJM noted that removing the Pleasant View constraint would increase the CETL into these two areas. And at the April 14, 2010 Transmission Expansion Advisory Committee (TEAC) meeting, PJM reported that it had conducted preliminary load deliverability thermal and voltage analyses on selected Locational Deliverability Areas (LDAs) which include MAAC, Southwest MAAC (SWMAAC) and Pepco. The results show reactive deficiencies in 2015 with MAAC and the other areas being voltage limited.

The Pleasant View constraint is the most recent example of how resource and transmission limitations, often outside of Maryland, constrain the availability of resources to serve Maryland's needs. Although the Commission recognizes and appreciates PJM's role in planning regional transmission solutions, Maryland law directs this Commission to ensure an adequate and reliable supply of electricity to Maryland citizens. Where that supply may fall short, Public Utilities Article § 7-510(c)(6) authorizes this Commission to require investor-owned electric companies in Maryland to "construct, acquire or lease, and operate generating facilities in order to meet long-term anticipated demand in the State for standard offer service and other electricity supply." The reactive deficiencies PJM is predicting for 2015 would, if not cured, limit the amount of electricity available to import into Maryland. And that potential capacity shortage could be exacerbated further if new emissions regulations being considered by the United States Environmental Protection Agency were to cause coal-fired plants in PJM to cease operations. For all of these reasons, Maryland law requires this Commission to consider the impact of these potential constraints and shortfalls upon Maryland ratepayers and identify all possible mitigating solutions, including new generation. Because market forces have not produced new generation in our region, the Commission may need to invoke its authority under § 7-510(c)(6) if, after an evidentiary hearing, the record in this case demonstrates that a projected capacity shortfall in the Delivery Year may affect Maryland and that ordering the construction, acquisition, lease or operation of additional capacity resources would satisfy the long-term anticipated demand in Maryland for Standard Offer Service or other electricity supply.

Throughout this RFP, capitalized terms used but not defined herein have the meanings ascribed to such terms in PJM's Reliability Assurance Agreement (RAA) or PJM's Open Access Transmission Tariff (OATT), or in the model agreements (the "Agreements") for cost-of-service pricing or fixed/indexed pricing (see Section 4 below). This RFP is issued by and will be administered by the EDCs. The Commission will evaluate all proposals submitted hereunder and by the EDCs.

The Commission is solely responsible for determining contract awards under this RFP, and may authorize one or more of the Maryland EDCs to enter into a long-term Contract for Differences as Buyer, or may direct one or more EDCs to construct new generation, if and when it determines a need for additional generation in Maryland. The Commission will conduct an evidentiary hearing to evaluate these issues.

2 PRODUCTS REQUESTED

2.1 PRODUCT DEFINITION

The Commission is requesting proposals for Products, which must include Capacity, Energy and any available Ancillary Services and which may include Maryland Tier 1 RECs. The Products must be derived from Generation Capacity Resources (as defined in the PJM RAA) that will be located in or around Maryland so long as such Generation Capacity Resource is interconnected to the System such that the Generation Capacity Resource's output is infed to a node east of the Western Interface and deliverable to Maryland east of the Western Interface avoiding likely transmission congestion. Generation Capacity Resources may be conventional or renewable generation technology, but Generation Capacity Resources do not include demand resources or energy efficiency resources. Generation Capacity Resources may include new up-rates of existing generation resources, but only the incremental portion of such generation resources may be considered a Generation Capacity Resource.

Generation Capacity Resources offered can be either Dispatchable or Non-Dispatchable.

2.1.1 DISPATCHABLE GENERATION CAPACITY RESOURCE

The hourly Energy output from a Dispatchable Generation Capacity Resource will be dispatched in the PJM Day Ahead Market (DAM) or Real Time Market (RTM) based on an offering that reflects actual fuel costs plus non-fuel variable operation and maintenance (O&M) costs, and by the actual availability of the unit or units which make up the Dispatchable Generation Capacity Resource. Each such unit shall be offered into the DAM or RTM using the same definition of total variable cost as used to determine the Supplier's compensation for energy, as set forth in Article 6 of the Agreements. If appropriate, Supplier shall also offer relevant Ancillary Service products into the PJM markets so as to optimize net revenues.

2.1.2 NON-DISPATCHABLE GENERATION CAPACITY RESOURCE

The hourly Energy output from a Non-Dispatchable Generation Capacity Resource will be determined by the availability of a natural energy source (such as wind or solar) and the availability of the conversion unit or units that make up the Non-Dispatchable Generation Capacity Resource. Any ability to control the schedule of the energy output from a Non-Dispatchable Generation Capacity Resource is assumed to be very limited.

2.2 TERM OF AGREEMENT

Respondents may submit proposals to commit Generation Capacity Resources for an initial term of a maximum period of twenty years beginning no earlier than June 1, 2015 and no later than [TBD]. Generation Capacity Resources that can achieve a Commercial Operation Date (COD) on or around June 1, 2015 will be favored in this solicitation.

2.3 PRODUCT QUANTITY

Respondents may offer Products in any quantity from Generation Capacity Resources not to exceed 1,800 MW on an installed capacity basis. The quantity of Capacity offered by a Respondent must be constant over the contract term.

The Commission may award one or more contracts to one or more Suppliers for Products derived from Generation Capacity Resources or may direct one or more EDCs to construct new generation up to, but not to exceed, a total installed capacity of 1,800 MW. The Commission reserves the right to reject all submissions to this RFP and reject the EDCs' proposals if in its sole discretion the Commission determines that Respondents' submissions or the EDCs' proposals are not in the public interest.

3 CONTRACT STRUCTURE

The Supplier will own and operate the Generation Capacity Resource committed in response to this RFP. The Supplier will remain responsible for O&M of the Generation Capacity Resource, including offering and scheduling the Generation Capacity Resource in PJM's DAM and/or RTM. In accordance with Section 3.2 (Payment), the Buyer will enter into a financial arrangement with the Supplier in which the physical delivery to the EDC of the Capacity, Energy and Ancillary Services is not required. Rather, the obligation of physical delivery and related performance of the Capacity, Energy and Ancillary Services, including the Offer Requirements in the Reliability Pricing Model (RPM) and the DAM and/or RTM will be an obligation of the Supplier to PJM in accordance with the PJM RAA, the PJM Operating Agreement and OATT. The financial arrangement between the Buyer and a Supplier for Capacity, Energy and Ancillary Services will be a Contract-for-Differences (CfD). Hence, the delivery of Capacity, Energy and Ancillary Services will be settled financially rather than physically, thereby providing compensation to Supplier for Capacity, Energy and Ancillary Services. At Respondent's election, pricing for Capacity, Energy and Ancillary Services from Dispatchable Generation Capacity Resources may be offered on a cost-of-service basis, or, alternatively, based on a combination of a firm and indexed pricing basis, as described in Section 6.1, m. Pricing for Capacity, Energy and Ancillary Services from Non-Dispatchable Generation Capacity Resources shall not be offered on a cost-of-service basis but rather on a Fixed/Indexed price basis.

If the Products include RECs, the Buyer will pay the Supplier the contract price for RECs, and the Supplier will deliver RECs to the Buyer in accordance with the terms of the Agreements.

3.1 RESOURCE REQUIREMENTS

The Generation Capacity Resources provided must meet the following requirements:

- a. The Capacity from the Generation Capacity Resource(s) must not have cleared any prior PJM capacity auction;
- b. Capacity from the Generation Capacity Resources must meet all requirements to qualify for the BRA. The Supplier must offer the Capacity from the Generation Capacity Resource into the BRA for the Delivery Year that begins on the first

- June 1 following the target Commercial Operation Date of the Generation Capacity Resource and into any Incremental Auctions for a Delivery Year that occurs after the Commercial Operation Date but prior to the June 1 following the target Commercial Operation Date of the Generation Capacity Resource(s.) The Supplier must offer such Capacity into the PJM BRA so that it will clear and be committed, subject to the direction and timely notification of the Commission;
- c. The Supplier must keep separate in the PJM eRPM system the Generation Capacity Resources committed as a result of this RFP from other Generation Capacity Resources of the Supplier; and
 - d. The Supplier must provide the Buyer read-only access to its PJM eRPM system, Market Settlements Reporting System (MSRS), and Load Response system accounts for the Generation Capacity Resource(s) committed as a result of this RFP. Such accounts shall be used for the sole purpose of verifying contract performance.

3.2 PAYMENT

For the Supplier's Capacity and Energy, the financial arrangement between the EDC and the Supplier will be a CfD between a) the Supplier's contract Capacity price and the RPM LDA clearing price applicable to the Maryland EDC's service territory, and between b) the Supplier's contract Energy price and the hourly PJM nodal Locational Marginal Pricing (LMP) in the PJM DAM and/or RTM, as applicable, at the point of delivery into the EDC's service territory. If applicable, similar determinations of differences for Ancillary Services will be defined. If applicable, payments to Supplier for RECs will be based on the REC price set forth in the Agreements between the Supplier and the Buyer. *For illustration purposes only*, a sample CfD transaction for Capacity, Energy, and Ancillary Services from a Dispatchable Generation Capacity Resource is shown in Attachment 1, Example 1. Example 2 in Attachment 1 illustrates a transaction for Capacity, Energy and RECs from a Non-Dispatchable Generation Capacity Resource. The schedule for billing net amounts of CfD obligations due to either party will be monthly.

3.3 NON-PERFORMANCE PENALTIES

Penalties for failure to provide proposed Products or to meet proposed heat rate and availability standards are defined in the Agreements (Attachments 9 and 10).

3.4 CREDIT REQUIREMENTS

All Respondents must provide financial information as described in Section 6.1 below. The Commission will determine if a Respondent and its Guarantors meet minimum standards of financial integrity.

General requirements for construction and operating phase security are described in Attachment 2. Specific preferred terms are presented in the Agreements (Attachments 9 and 10).

4 AGREEMENTS

Two model Agreements to be executed as a result of this RFP are provided as Attachment 9 (for cost-of-service pricing) and Attachment 10 (for Fixed/Indexed pricing). The Agreements contain the parties' rights and obligations for providing and receiving Capacity, Energy, Ancillary Services and, if applicable, RECs. While suggested changes to the model Agreements will be considered, offers which conform to all major terms will receive preference in evaluation.

5 ELIGIBILITY OF RESPONDENTS

5.1 ELIGIBILITY REQUIREMENTS

A Respondent is eligible to offer a proposal if, in a timely and complete fashion, the Respondent submits the following Eligibility Documents by the respective due dates indicated in Section 8:

- a. A non-binding Expression of Interest Form, provided as Attachment 3;
- b. An executed copy of the certification that the Generation Capacity Resource which the Respondent plans to commit under this RFP did not clear any prior PJM capacity auction, provided as Attachment 4;
- c. An executed copy of the certification that the Respondent meets the PJM membership requirements, provided as Attachment 5;
- d. An executed copy of the Binding Offer Agreement, provided as Attachment 6; and
- e. An executed copy of the Confidentiality/Non-disclosure Agreement, provided as Attachment 11. A Respondent and the EDC issuing the RFP will be required to execute the Confidentiality/Non-disclosure Agreement. Once the agreement is received from the Respondent, the EDC will complete the execution of the agreement and send a copy of the fully executed agreement to the Respondent and to the Commission by mail, courier service, or appropriate electronic means.

5.2 AFFILIATE PARTICIPATION

An unregulated affiliate of an EDC may participate as a Respondent in this RFP process. The unregulated affiliate and its affiliated EDC will be subject to the provisions of the Code of Maryland Regulations, Title 20, Subtitle 40- Electric and Gas Companies-Affiliate Regulations.

6 PROPOSAL

6.1 PROPOSAL CONTENT

Proposal content must include:

- a. Summary description of the Respondent, including:
 - Name

- Legal form (*e.g.*, sole proprietorship, partnership, limited partnership, joint venture, corporation, etc.)
- Principal contact information (name, mailing address, telephone number, fax number, and email address)
- Date of establishment
- State of incorporation
- Residency of organization
- Organization chart of the Respondent's company showing parent company, subsidiaries, and affiliates
- If the Respondent proposes to have a Guarantor guarantee its obligations, then the above information also must be provided for that Guarantor
- If the Respondent is a joint venture or consortium, the above information must be provided for each member of the venture or consortium
- Description of technical and managerial experience and qualifications in the areas of permitting, development, financing, construction, and operation of electric generating facilities, including experience in the control of cost overruns
- Description of familiarity and experience with PJM markets and requirements for membership status with PJM
- Description of financial condition and evidence of creditworthiness, including senior unsecured long-term debt credit ratings from major rating agencies and the most recent two years' audited financial statements for Respondent and Guarantor, if applicable
- Description of other generation owned or under contract within the State of Maryland, including resources currently under development or construction
- Description of other principal team members, such as Engineering, Procurement, and Construction (EPC) and Operations and Maintenance Contractors, if any, and relevant experience of those entities
- Description of defaults, non-compliance, fraud or criminal misconduct by a Respondent or any of its officers, directors, partners, guarantors, or affiliates with any obligations relating to power or natural gas sales or purchases or transmission obligations
- Description of instances in which a Respondent or any of its officers, directors, partners, guarantors or affiliates was the subject of an investigation or a proceeding relating to conversion, fraud, misrepresentation, false statements, unfair or deceptive business practices, business theft, anti-competitive acts or omissions or collusive offering or other procurement- or sale-related irregularities

- Description of any instances in which a Respondent or any of its officers, directors, partners, guarantors or affiliates was convicted of any felony, or any crime relating to the sale of power, natural gas or transmission, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions or collusive offering or other procurement or sale-related irregularities
- b. Summary description of the proposed Generation Capacity Resource, including:
- Description of site and surroundings, including description of site control (ownership, contractual arrangements, etc.)
 - Map showing location of site and interconnection facilities
 - Electric interconnection point with transmission system
 - Interconnection status and cost estimates
 - Copies of transmission interconnection studies conducted
 - Nominal capacity
 - Technology type
 - Size of unit(s)
 - Number of unit(s)
 - Site plan drawing showing layout of major equipment and structures
 - Description of Ancillary Services capability
 - Commercial Operation Date and detailed critical path schedule, including timelines for permitting, engineering, procurement, construction, startup, and commercial operation
 - PJM market participation eligibility
 - Proposed contract term
- c. Fuel Supply Plan / Energy Resource Assessment
- Fuel type and secondary fuel, if applicable
 - Liquid fuel storage capacity on-site or contracted for, fuel replenishment rate, and oil tankage refill logistics
 - Natural gas interconnection points, source of supply, interstate and local transportation arrangements
 - Character of service on interstate pipelines, including definition of primary firm, secondary firm, and/or interruptible transportation rights with specific designation of receipt and delivery points on each pipeline segment on which Supplier has an entitlement

- Imbalance resolution arrangements with a gas utility, marketer or third party
 - Identification of storage, Park & Loan, other arrangement providing for natural gas scheduling flexibility
 - Other fuel supply and transportation arrangements (*e.g.*, supply plan for biomass fuel, landfill gas, or other if applicable)
 - For Generation Capacity Resources using wind, solar, or other Non-Dispatchable sources of energy, a detailed assessment of the available resource, including expected P50 (50% probability estimate) annual seasonal and daily profiles, and upper and lower expectations, *e.g.*, P10, P90, (10% and 90% probability estimates) for annual energy potential
- d. Permitting Plan
- List of any applicable federal, state, and local permits, certifications, and approvals required to construct and operate the Generation Capacity Resource and a projected timeline for securing any applicable federal, state and local permits
 - Current status of all permits, certifications, and approvals required to construct and operate the Generation Capacity Resource including electric and gas interconnections
 - Documentation of community support for Generation Capacity Resource
- e. Capital Cost Estimate: If the proposed Generation Capacity Resource is offered on a cost-of-service basis, a detailed capital cost estimate must be provided. Additional detail must be provided in the form of a narrative supporting the scope of and level of confidence in the estimate.
- f. Pass-Through Component: If the proposed Generation Capacity Resource is offered on a Fixed/Indexed basis, Respondents may offer certain components of capital costs on a “pass-through” basis from the Respondent if such costs can not be determined until after the completion of certain analyses, such as gas or electric interconnection studies. In this case, the estimated capital cost of the items to be passed through must be provided in detail, along with a description of all assumptions regarding scope, level of confidence and other factors.
- g. Operating Cost Estimate: If the proposed Generation Capacity Resource is offered on a cost-of-service basis, a detailed operating cost estimate must be provided. The estimate should be summarized and narrative detail must be provided supporting the scope and level of confidence in the estimate.
- h. Financing Plan: Description of plan and demonstration that the proposed Generation Capacity Resource can be financed. The sources of debt and equity investment must be provided. Anticipated usage of federal loan guarantees and/or production or investment tax credits available under federal programs must be identified, if applicable. Other sources of tax benefits attributable to accelerated depreciation benefits for specific Generation Capacity Resource technology types

- must be stated. The Financing Plan shall include a detailed *pro forma* cash flow statement showing the financial viability of the Generation Capacity Resource.
- i. Ratepayer Benefits: Description of the reliability and economic benefits which are likely to be realized by Maryland ratepayers as a result of the Generation Capacity Resource.
 - j. State of Maryland Benefits: Description of other reliability, economic, socioeconomic and, if applicable, environmental benefits that are likely to be realized in Maryland as a result of the Generation Capacity Resource, *e.g.*, construction jobs, permanent employment during the operating period, tax effects, community improvements, other.
 - k. Contract: State any exceptions to the contract terms appearing in the Agreements (Attachments 9 and 10) or state that contract terms are acceptable in their entirety.
 - l. Detailed Operating Parameters
 - For Dispatchable Generation Capacity Resources: Complete the worksheets appearing in Attachment 7 and provide any narrative that will facilitate the Commission's analysis of Generation Capacity Resource performance.
 - For Non-Dispatchable Generation Capacity Resources: Complete the worksheets appearing in Attachment 8 and provide any narrative that will facilitate the Commission's assessment of Generation Capacity Resource performance. Specific information such as estimated monthly and hourly energy outputs from the project for a typical calendar year should be provided as well as a statement as to the certainty and probability of the energy projections. For solar projects, the manufacturer's guaranteed availability as well as climate shut-down constraints such as snow or ice storms should also be provided.
 - The Commission reserves the right to seek additional information from Respondents to support its technical assessment of the Generation Capacity Resource submissions.
 - m. Pricing Proposal
 - Respondents are invited to submit multiple pricing options for the same Generation Capacity Resource. Provide a narrative description of each separate pricing option offered with respect to the Generation Capacity Resource. The pricing option for each should include the total pricing provisions for the Capacity, Energy, Ancillary Services, and, if applicable, RECs produced by the Generation Capacity Resource over the contract term. Respondents are encouraged to provide pricing options that may also include contract extensions unilaterally exercisable by the Buyer. Principles for Fixed/Indexed pricing are described in detail in Exhibit G of Attachment 10 and on the pricing worksheets in Attachment 7 (Dispatchable Generation Capacity Resource) and Attachment 8 (Non-Dispatchable Generation Capacity Resource). Respondents offering a Dispatchable Generation Capacity Resource may choose to offer cost-of-service based pricing, as

described in Exhibit E of Attachment 9. Pricing parameters under the cost-of-service option may only be provided in Attachment 7.

- Pricing may be specified for Capacity in either of the following forms:
 - 1) A Fixed/Indexed offer based on principles defined in Exhibit G of Attachment 10, as a combination of:
 - A schedule of firm, fixed prices expressed as \$/MW-day of Unforced Capacity (“UCAP”) provided, for each Delivery Year (June 1 to May 31) of the contract term;
 - A fixed base price, expressed as \$/MW-day of UCAP provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator;
 - A “pass-through” component, expressed as \$/MW-day of UCAP provided, based on the actual capital cost of such items as electrical interconnection and natural gas interconnection costs, multiplied by a specified annual recovery factor and divided by a specified MW-day per year of UCAP.
 - 2) A cost-of-service based Unit Annual Fixed Revenue Requirement, based on the principles defined in Exhibit E of Attachment 9 and applicable to Dispatchable Generation Capacity Resources only. A cost-of-service pricing proposal must include a proposed debt-to-equity ratio and a proposed return on equity (ROE), expressed as a basis point adder or deduction relative to the weighted average ROE authorized from time to time by the Commission for one or more Maryland EDCs that will enter into an Agreement pursuant hereto.
- Pricing for energy from a Non-Dispatchable Generation Capacity Resource must be specified as a combination of:
 - A schedule of firm, fixed prices expressed as \$/MWh of energy delivered, for each Delivery Year (June 1 to May 31) of the contract term; and/or
 - A fixed base price, expressed as \$/MWh of energy delivered, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator.
 - The index-adjusted fixed base price multiplied by a table of price factors for on-peak and off-peak hours in the summer (June-September) and non-summer (October-May) months.
- Pricing for Energy from a Dispatchable Generation Capacity Resource offered on a Fixed/Indexed basis as described in Exhibit G of Attachment 10 shall consist of a heat rate call option with any or all of the following components:

- 1) A non-fuel variable component expressed as:
 - A schedule of firm, fixed prices expressed as \$/MWh of energy delivered, for each Delivery Year (June 1 to May 31) of the contract term, and/or;
 - A fixed base price, expressed as \$/MWh of energy delivered, and a formula for adjustment for each capacity Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator.
- 2) A fuel component expressed as the product of:
 - a defined heat rate (MMBtu {Higher Heating Value (HHV)}/MWh) as a function of fuel, load, ambient temperature, and output degradation factor, and;
 - a fuel price (\$/MMBtu) based on a published daily index plus defined adjustments for transportation and local delivery service adder(s), which is applied to energy output in each hour.
- 3) A start-up component consisting of:
 - A fixed base price, expressed as \$/unit start, with a formula for adjustment for each capacity delivery year, based on a broad-based, published inflation index such as CPI or GDP deflator, and;
 - A fuel component defined as the product of a specified start-up fuel amount in MMBtu/unit start and a fuel price (\$/MMBtu) based on a published daily index plus specified adjustments for transportation and delivery services.
- Pricing for Energy from a Dispatchable Generation Capacity Resource offered on a cost-of-service basis shall be priced in accordance with the provisions of Exhibit E of Attachment 9.
- If offered, a Black Start Service Price shall be specified as either:
 - 1) A Fixed/Indexed offer based on principles defined in Attachment 10, as a combination of:
 - A schedule of firm, fixed prices expressed as \$/MW of Black Start Capacity provided, for each Delivery Year (June 1 to May 31) of the contract term;
 - A fixed base price, expressed as \$/MW of Black Start Capacity provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator; or
 - 2) A cost-of-service based Unit Annual Fixed Revenue Requirement for Black Start Service, based on the principles defined in Exhibit E of

Attachment 9 and applicable to Dispatchable Generation Capacity Resources only.

- If offered, a Regulation Service Floor Price shall be specified as either:
 - 1) A Fixed/Indexed offer based on principles defined in Exhibit G of Attachment 10, as a combination of:
 - A schedule of firm, fixed prices expressed as \$/MW-hour of Regulation Service provided, for each Delivery Year (June 1 to May 31) of the contract term;
 - A fixed base price, expressed as \$/MW of Regulation Service provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator, and;
 - 2) A cost-of-service based Unit Annual Fixed Revenue Requirement for Regulation Service, based on the principles defined in Attachment 9 and applicable to Dispatchable Generation Capacity Resources only.
- If offered, a Synchronized Reserve Service Floor Price shall be specified as either:
 - 1) A Fixed/Indexed offer based on principles defined in Exhibit G of Attachment 10, as a combination of:
 - A schedule of firm, fixed prices expressed as \$/MW-hour of Synchronized Reserve Service provided, for each Delivery Year (June 1 to May 31) of the contract term;
 - A fixed base price, expressed as \$/MW of Synchronized Reserve Service provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator, or;
 - 2) A cost-of-service based Unit Annual Fixed Revenue Requirement for Synchronized Reserve Service, based on the principles defined in Attachment 9 and applicable to Dispatchable Generation Capacity Resources only.
- If offered, a Day-Ahead Scheduling Reserve Service Floor Price shall be specified as either:
 - 1) A Fixed/Indexed offer based on principles defined in Exhibit G of Attachment 10, as a combination of:
 - A schedule of firm, fixed prices expressed as \$/MW-hour of Day-Ahead Scheduling Reserve Service provided, for each Delivery Year (June 1 to May 31) of the contract term;
 - A fixed base price, expressed as \$/MW of Day-Ahead Scheduling Reserve Service provided, and a formula for

adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator; or

- 2) A cost-of-service based Unit Annual Fixed Revenue Requirement for Day-Ahead Scheduling Reserve Service, based on the principles defined in Exhibit E of Attachment 9 and applicable to Dispatchable Generation Capacity Resources only.
- If offered, REC prices may be fixed over the contract term or may include a formula for adjustment for each delivery year, based on a broad-based, published inflation index such as CPI or the GDP deflator, or indexation to energy prices in the PJM DAM.

6.2 SUBMITTAL OF PROPOSALS

Proposals from Respondents are due no later than 5:00 p.m. Eastern Prevailing Time (EPT), on September 15, 2011. Submit five (5) hard copies of the proposal through express mail (*e.g.*, FedEx, UPS, etc.) to the following name and address:

Name: Don Eveleth
Address: 6 St. Paul Street, 16th Floor, Baltimore, MD 21202
Phone: 410-767-8057
Fax: 410-333-3802

In addition to the hard copy submittal, submit electronic versions of the proposal to the following address:

develeth@psc.state.md.us

6.3 PROPOSAL CONFIRMATION

The Commission will confirm receipt of a Respondent's proposal by phone. As indicated in each proposal, the Respondent will provide a contact name and phone number which will be used for the receipt confirmation.

6.4 EXPIRATION OF PROPOSALS

Proposals shall expire the earlier of the time Commission notifies the Respondent that its proposal has been rejected in full or part, or at midnight EPT on March 1, 2012. All Product pricing submissions must remain binding until midnight EPT on March 1, 2012.

6.5 EVALUATION OF PROPOSALS

The Commission will evaluate the Generation Capacity Resource proposals and proposals from the EDCs to determine whether the proposals will enhance electric service reliability and are in the best interests of ratepayers. The Commission will evaluate all responsive proposals and proposals from the EDCs based on quantitative as

well as qualitative evaluation criteria. After the proposals are submitted, the Commission may request additional information from Respondents or the EDCs in furtherance of the Commission's technical evaluation. A Respondent's failure to provide additional information on a timely basis may cause the Commission to reject such Respondent's proposal.

6.5.1 MINIMUM THRESHOLD CRITERIA

In submitting proposals for the Commission's evaluation, Respondents must demonstrate that the proposed Generation Capacity Resource meets certain minimum threshold criteria related to the Respondent's managerial, technical, and financial capabilities. The minimum threshold criteria are those factors that are either explicitly mandated in this RFP or are otherwise deemed by the Commission to be integral to the successful development of the Generation Capacity Resource, in particular, the delivery of reliability and economic benefits for Maryland ratepayers. The minimum threshold criteria are designed to be straightforward factors that can be assessed by the Commission in an initial review of the proposals and therefore do not require extensive economic, commercial, or engineering analyses. Proposed Generation Capacity Resources that do not comply with each of the minimum threshold requirements will not be considered by the Commission for further evaluation.

The minimum threshold criteria are as follows:

1. The proposal includes all of the Eligibility Requirement documentation described in Section 5.1.
2. The Respondent possesses sufficient technical, managerial, and financial capability to implement the proposal in accordance with the Commission's requirements.
3. Proposals from an affiliate of a Maryland EDC must demonstrate that the Generation Capacity Resource will not receive any form of cross-subsidization by the EDC or other regulated affiliated entity.
4. Proponents must demonstrate a legal entitlement to each site on which a Generation Capacity Resource is proposed. Proof can be in the form of current ownership of the property, a current long-term lease on the property, or an option to lease or buy the property that can be exercised at any time until the Commission issues its final decision on the proposal and a contract is executed. Respondents must also demonstrate a legal entitlement to any required right-of-way to access electrical and fuel interconnection points.
5. The proposed Generation Capacity Resource must be interconnected to the System such that the Generation Capacity Resource's output may be infed to a node east of the Western Interface and deliverable to Maryland east of the Western Interface avoiding likely transmission congestion.
6. Respondents must provide proposals for building new Generation Capacity Resources. Existing generation capacity does not satisfy threshold procurement criteria set forth in this RFP. However, proposals for uprated capacity at existing

- generation facilities or new units to be constructed at existing facilities will be considered in accord with the minimum threshold requirement set forth in this RFP, but only for the incremental capacity associated with the uprate or new unit at the existing facility. Any proposal for an uprate to an existing facility must include an explanation how the Products ascribable to the uprated capacity will be distinguishable from existing capacity.
7. Respondents must submit proposals that commit Generation Capacity Resources beginning no earlier than June 1, 2015 and no later than June 1, 2017.
 8. Respondents or their guarantors must demonstrate a minimum investment grade credit rating, as defined in Attachment 2, if available. Absent an investment grade credit rating from Standard and Poor, Moody, or Fitch, comparable alternative credit support, including a Letter of Credit from a Qualified Institution as defined in Attachment 2 shall be provided.
 9. While suggested changes to the model Agreements (Attachments 9 and/or 10) will be considered, offers which conform to all major terms will receive preference in evaluation.

6.5.2 COSTS AND BENEFITS TO RATEPAYERS

Each proposed Generation Capacity Resource which meets the minimum threshold criteria will be evaluated with respect to the enhancement to reliability and the costs and benefits of the Products offered from the standpoint of Maryland's ratepayers.

For Generation Capacity Resources seeking cost of service pricing, Respondents must provide sufficient information to allow the Commission to conduct the requisite technical analysis to determine if the delineation of Generation Capacity Resource costs is reasonable. The Commission reserves the right to incorporate adjustments and modifications to account for missing or uncertain cost components. The Commission may seek clarification from Respondents regarding costs and technical operating parameters.

Respondents who propose Fixed/Indexed pricing must estimate costs for all pass-through items, *e.g.*, electric interconnection and transmission upgrade costs, natural gas interconnection costs to a pipeline or local distribution company, other facility improvements assignable to the Generation Capacity Resource, as well as "soft" costs including architectural, [engineering](#), [financing](#), and [legal fees](#). The Commission may seek clarification from Respondents regarding such cost estimates. The Commission reserves the right to incorporate adjustments and modifications to pass-through cost data submitted by Respondents.

The Commission will evaluate the size and quality of the reliability enhancement and economic benefits associated with each proposal from Respondents and the EDCs that satisfies the minimum threshold criteria. Subject to the 1,800 MW limit available for long term contracts, the Commission also will consider the impact of different Generation Capacity Resource portfolios on the expected net benefits realized by the ratepayers of Maryland's EDCs.

6.5.3 QUALITATIVE FACTORS

Each proposal that meets the threshold criteria will also be subject to a qualitative evaluation based on an overall assessment of its merits. If the Commission determines that there is not a substantial difference in the costs to ratepayers of two or more proposals (including proposals from an EDC), the Commission will give proposals containing the following attributes (not necessarily listed in order of importance) more favorable consideration in determining which Generation Capacity Resources, if any, are in the best interest of ratepayers:

1. Early Commercial Operation Date (*i.e.*, on or around June 1, 2014) and low risk of project delays, certainty of achieving key project development milestones, including securing permits and interconnection agreements;
2. Low risk of cost increases to ratepayers resulting from factors such as electric transmission and fuel interconnection costs, payment in lieu of taxes (PILOT), and technical attributes of Generation Capacity Resource, cost of equipment and materials, etc.;
3. The Respondent's project development experience and managerial, technical, and financial capability in developing and operating generation projects;
4. Environmental benefits, including net reduction in emissions of air pollutants and greenhouse gases and reuse of existing generation or brown field sites;
5. Creation of construction and permanent jobs in Maryland.

The Commission will apply these criteria to all proposals that satisfy the minimum threshold criteria and include the analysis in the selection of a final award group, if any.

7 COMMUNICATIONS

This RFP, updates to this RFP, and other relevant information will be posted on the Maryland Public Service Commission's website at www.psc.state.md.us.

Questions regarding this RFP may be submitted to the Commission until the deadline indicated in Section 8. All questions regarding this RFP must be directed to:

Donald P. Eveleth
Deputy Executive Secretary
Maryland Public Service Commission
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

The Commission will respond to questions as soon as practicable. Questions and responses will be posted on the Maryland Public Service Commission's website. Questions will be redacted as necessary to preserve the confidentiality of Respondents.

8 SCHEDULE FOR RFP PROCESS

In order to preserve a possible offering into the May, 2012 Base Residual Auction (“BRA”) for the 2015-2016 delivery year, the RFP schedule is as follows:

<u>Activity</u>	<u>Date</u>
RFP issued	March 18, 2011
Solicitation for Expressions of Interest	April 8, 2011
Pre-offer conference	April 15, 2011
Eligibility Documents due	May 1, 2011
Issue Respondents' eligibility status	June 17, 2011
Deadline for receipt of Respondents' questions	July 1, 2011
Proposal Due Date	July 29, 2011
Staff/Consultant evaluation filed with Commission	December 2, 2011
Public comments due to Commission	December 30, 2011
Commission hearing	[TBD]
Commission selects and approves any winning offers	[TBD]
EDC(s) execute Commission-approved agreements	February 10, 2012
Advance notification of intent to offer due to PJM	March 1, 2012
Executed system impact study agreement in place	April 13, 2012

9 RESERVED RIGHTS

9.1 RESPONDENT ELIMINATION RIGHT

If, in the course of the RFP process, a Respondent is found to provide faulty information, misrepresent itself, or omit any pertinent information, the Commission reserves the right to eliminate such Respondent from the RFP process. The Commission also reserves the right to reject any proposal that does not comport with the requirements set forth in the RFP.

9.2 CONTRACT TERMINATION RIGHT

If a Respondent who engages in any conduct described in Section 9.1 (Respondent Elimination Right) is awarded an offer and executes the contract, the Commission reserves the right to terminate the contract and pursue remedies as outlined in the Agreements.

9.3 WITHDRAWAL AND REJECTION RIGHT

The Commission reserves the right to order the EDCs to withdraw, modify, or cancel this RFP at any time and the Commission may accept or reject any or all proposals received as a result of this RFP.

To the extent practicable, the Commission will inform Respondents that have filed an Expression of Interest form of any such change. The Commission further reserves the

right to waive, in its sole discretion, any irregularity or defect in proposals received and to consider alternatives outside of this solicitation.

Nothing in this RFP limits the Commission's authority, and the Commission expressly reserves its authority to reject all submissions received under this RFP.

10 MISCELLANEOUS

10.1 WARRANTY ON INFORMATION

The information provided in the RFP has been prepared to assist Respondents in evaluating the RFP. It does not purport to contain all the information that may be relevant to a Respondent in satisfying its due diligence efforts. The Commission makes no representation or warranty, express or implied, as to the accuracy or completeness of the information in the RFP, and shall not be liable for any representation expressed or implied in the RFP or any omissions from the RFP, or any information provided to a Respondent by any other source.

Neither the RFP nor any other related correspondence from the Commission or its employees, agents, or consultants shall be considered legal, financial or other advice and does not establish a contract or any contractual obligations.

10.2 HOLD HARMLESS

Respondents shall hold the Commission and its employees, agents and consultants harmless of and from all damages and costs, including but not limited to legal costs, in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a offer pursuant to this RFP.

Each Respondent is responsible for its costs incurred in responding to this RFP.

10.3 PROPOSALS BECOME COMMISSION PROPERTY

All proposals submitted by each Respondent pursuant to this RFP shall become the exclusive property of the Commission.

10.4 RESPONDENT'S ACCEPTANCE

The submission of a proposal to the Commission shall constitute a Respondent's acknowledgment and acceptance of all the terms, conditions and requirements of this RFP and the Agreement(s) that are a result of this RFP.

The Respondent and its representatives irrevocably agree to submit to the personal jurisdiction of any State or Federal court located in the State of Maryland and any appellate court thereof in respect of any action, dispute or proceeding arising out of this RFP process, including but not limited to the execution, implementation and performance of an Agreement.

10.5 PERMITS, LICENSES AND COMPLIANCE WITH THE LAW

Respondent shall obtain all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to respond to this RFP. Subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

10.6 REGULATORY APPROVALS

As indicated in Section 8 (Schedule for RFP Process) and as set out in the Agreements, the executed Agreements will be contingent upon the EDC's receipt of Commission approval. Respondent agrees to cooperate, to the fullest extent necessary, to obtain any and all required State, Federal or other regulatory approvals of the Agreement(s) resulting from its proposal(s).

10.7 NON-DISCRIMINATION POLICY

Throughout the RFP evaluation, the Commission will not discriminate between, or grant preferences to, any Respondent based on race, gender, ethnic origin, creed or religion, in accordance with legal requirements. The Commission's consideration, evaluation and selection of proposals shall be entirely based on the merits of each proposal and not upon unrelated factors.

PLATT'S ELECTRIC POWER DAILY ARTICLE

Electric Power Daily

Thursday, February 24, 2011

New Hampshire House votes to quit RGGI; group to push N.J. next

New Hampshire's House of Representatives approved a bill Wednesday to withdraw from the Regional Greenhouse Gas Initiative, following lobbying by a Washington-based group also pushing New Jersey to withdraw.

RGGI, established in 2009, is a binding agreement among 10 states in the Northeast and Mid-Atlantic to reduce CO2 emissions from power plants 10% by 2018.

The 246-104 vote came as little to surprise to statehouse insiders, who said they expected the Republican majority in the House to favor repeal of New Hampshire's involvement in the nation's only mandatory greenhouse gas cap and trade program.

"We sort of knew how the majority in the House was going to vote. But it is disappointing," said Jim O'Brien, executive director of Conservation New Hampshire. "There wasn't much discussion of economics; it was an ideological push."

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PUC derails Duke Energy Ohio's move to market-based rates

Duke Energy Ohio's planned two-year move to market-based generation rates was routed to an off-ramp Wednesday by the Public Utilities Commission, which ruled the proposal failed to comply with state law.

In voting unanimously to reject the company's November request, the commission "thoroughly reviewed Duke's application and the case record, and found that the company did not comply with the statute for the filing of a market-rate offer," said interim PUC Chairman Steven Lesser. Republican state Representative Todd Snitchler, appointed PUC chairman earlier this month by Governor John Kasich, is expected to become chairman in early March.

The PUC staff in late January recommended the plan be denied "in its entirety," calling it deficient. In particular, staff said Duke was proposing to fully transition to market-based rates in only two years, not the five years required under S.B. 221, the state's 2008 electric restructuring law. The longer period was intended by

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New Jersey gets proposals for more than 6,400 MW

The New Jersey Board of Public Utilities will review 34 submissions for more than 6,400 MW in response to its fast-track solicitation to support a new state law that would subsidize 2,000 MW of new generation.

"This is what we had hoped for — a very enthusiastic turnout from prominent generators," Richard Levitan, president of Levitan & Associates, the BPU's agent in charge of the solicitation, said Wednesday in an interview.

The vast majority of proposed projects received by a Tuesday deadline are located in New Jersey and are natural gas-fired, but a number of other technologies, including synthetic gas, nuclear upgrades and wind were submitted. Projects proposed outside the state also were submitted, Levitan said.

Projects that can be bid into the PJM Interconnection's May capacity auction will be favored, Levitan said. Only projects that had not begun construction at the end of January qualify, however. Projects also will be rated based on the economic

EPA releases final pollutant rules for industrial boilers

The Environmental Protection Agency released final rules Wednesday for controlling hazardous air pollutants from industrial boilers that the agency says are "significantly" different from its proposal and will be seeking public comment on the changes.

"These final standards are based on the best and latest science," Gina McCarthy, assistant administration for EPA's Office of Air and Radiation, said in a call with reporters Wednesday. "They are based on feedback we received and will reduce emissions at a lower cost."

EPA put the projected costs of complying with the final rules at about \$1.8 billion, or about half of what had been estimated under the proposed rule. The agency also increased the estimated health benefits from the standards, which will avoid between 2,600 and 6,600 premature deaths, prevent 4,100 heart attacks and avert 42,000 asthma attacks per year in 2014.

EPA was under a 2006 court order to
(continued on page 7)

Los Angeles Basin reliability under scrutiny by task force

This much is clear: When seven coastal power plants totaling 7,600 MW decide this year whether or not they are going to keep operating in Southern California, there could be a reliability crisis looming in the Los Angeles Basin.

What is less clear: how much of a threat to reliability will actually result and if immediate backup action should be taken.

The fossil-fueled plants must comply with a statutory ban on once-through cooling at coastal power plants, and while equipment replacement or repowering are options, the operators also may decide to simply shut down rather than make the economic investment in retrofits.

Should they go out of service, power projects that could serve as replacements also face a murky situation, in that emission reduction credits, or ERCs, needed for construction permits are at a premium.

At a public workshop earlier this month in Diamond Bar, California, south of Los

(continued on page 8)

benefits they add to the state, he said. "While projects located in New Jersey are more likely to confer economic benefits to the state, others will be fully and fairly considered," he said. Price and environmental issues also are among the checklist of issues that will be used to rate projects, Levitan said.

Levitan would not name the companies that submitted proposals, but he said there was an enthusiastic turnout and spirited competition among rival bidders. However, he confirmed a news report that Public Service Enterprise Group, Exelon, Competitive Power Ventures, Hess, NRG and LS Power submitted proposals.

"This is a good indication that the market is taking this seriously even with the outstanding challenges at [the Federal Energy Regulatory Commission] and federal court," Levitan said. A group of suppliers within PJM's footprint recently asked FERC to establish rules that would protect the market from subsidized projects. Also, seven power companies in early February filed a complaint in federal court claiming the New Jersey law violates the Constitution's Supremacy and Commerce Clauses.

The solicitation is on a fast track. Pre-qualifications were due Tuesday, which included the scope of the proposed project, including technology, fuel, location, and other information, Levitan said. Projects selected to receive a subsidy are limited to 700 MW by law.

"There is a tremendous effort to conduct as much technical due diligence as can be done in a compressed time schedule," Levitan said.

Bidders will submit a fixed price for their projects on March 7.

A standard contract for the projects is being developed on a parallel track. Levitan posted the BPU's draft capacity agreement Wednesday with comments due from bidders on Friday. The contracts are for capacity only and do not include energy or ancillary services, Levitan said.

Selected projects must be bid into and clear PJM's capacity auction in May in order to receive a subsidy, Levitan said.

The BPU is scheduled to make a final selection on March 30.

— Mary Powers

States, utilities urge flexibility in EPA GHG rules

State clean air regulators, utility lawyers and university think tanks on Wednesday urged the Environmental Protection Agency to find ways to consider market-based approaches that keep costs in check and work with state emissions trading programs as the agency drafts greenhouse gas standards for existing power plants and refineries.

EPA Assistant Administrator Gina McCarthy told the gathering at the agency's Washington headquarters that the federal regulators will "take great care" to get GHG reductions from the energy sector and find the right program design while meeting legal challenges. EPA has "no intention of undermining" state programs, she said.

State and industry coalitions suggested EPA provide ample flexibility — including emission offsets, averaging and credit for renewable energy and early plant retirements — in its pending GHG rules and build off existing state and regional programs to curb emissions linked to climate change.

"There is a real opportunity here for federal and state partnerships," said Greg Wannier, deputy director of the Center for Climate Change Law at Columbia University.

EPA could aggregate emission reductions across sources, include offsets, banking and borrowing of emission reduction and even provide guidance to limit the cost of emission reductions as a means to reap cost savings for compliance, he said.

Jared Snyder, assistant commissioner for air resources, climate change and energy in the New York State Department of Environmental Conservation, said states should be allowed to use market-based programs like the Northeast's Regional Greenhouse Gas Initiative. The RGGI emissions trading program "reduces costs and reduces emissions more than command and control" regulations would, Snyder said.

EPA, under a court agreement with environmental organizations, will propose "new source performance standards" for GHG emissions in July for existing power plants and in December for oil refineries. EPA must finalize the power plant GHG standards in May 2012 and in November 2012

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Chief Editor
Rod Kuckro

News Desk
202-383-2254, electric@platts.com
Amy Fickling, Editor
Paul Ciampoli, Editor

Staff Reporters

Paul Carlsen, Catherine Cash, Jason Fordney, Jeffrey Ryser, Tom Tiernan, Lisa Weinzimer

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To reach Platts

E-mail: support@platts.com

North America

Tel: 800-PLATTS-8 (toll-free)+1-212-904-3070 (direct)

Latin America

Tel: +54-11-4804-1890

Europe & Middle East

Tel: +44-20-7176-6111

Asia Pacific

Tel: +65-6530-6430

Manager, Advertisement Sales

Ann Forte

Advertising

Tel: +1-720-548-5479

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