Capacity Performance Initiative Comments of
The PSEG Companies

The PSEG Companies appreciate the opportunity to submit these comments in response to PJM Interconnection LLC’s (“PJM”) August 20, 2014 Capacity Performance Proposal (“CP Proposal”). In the CP Proposal, PJM states that it will not be able to meet its peak load requirements in the winter of 2015/2016 if the PJM region experiences similar cold weather temperatures that occurred during the most recent winter, coupled with scheduled generation unit retirements and a comparable rate of generation outages. While the PSEG Companies agree with PJM that its “capacity market has been highly successful … [ensuring] … adequate generation is committed to serve the region,” we also support PJM’s effort to address these perceived future reliability issues.

Even though we support the objectives PJM is seeking to achieve, we believe that the proposed timeframe for accomplishing these revisions is not adequate. We are concerned that the ramifications of the CP Proposal are not being fully considered by PJM and that PJM stakeholders do not have enough time to fully understand the impact of the CP Proposal and thus how to participate competitively in the upcoming auction. As such, the PSEG Companies suggest that PJM extend the timeframe for stakeholder consideration of the CP Proposal, implement a number of incremental changes that would achieve the desired goals of the CP Proposal and focus additional attention on the transition issues as an interim step. Taken together, this process would move the markets forward to achieve the goals of PJM without significant unwarranted expense and disruption to the markets. However, to the extent that PJM moves forward with the CP Proposal, the PSEG Companies believe that certain design features should be changed as further discussed below.

I. PJM Should Consider More Efficient Alternatives

First, PJM should implement provisions that provide greater flexibility for market participants to structure and modify their supply offers in the day-ahead and real-time energy markets similar to the market enhancements recently accepted by the Federal Energy Regulatory Commission (“FERC”) for the New England region¹ and that have been a feature of the NYISO markets for a number of years. This will allow unit owners to run their units in an economic manner instead of being faced with the conundrum of running the unit at a loss or taking a forced outage. The ability to update fuel costs will allow real-time energy prices to more accurately reflect the marginal cost of energy, which in turn will result in improved price formation, transparency and more importantly, unit availability and performance.

¹ See ISO New England Inc. and New England Power Pool, 145 FERC ¶ 61,014 (2013). As noted in the filing, ISO-NE proposed these changes to address emerging concerns over New England’s reliance on natural gas to generate electricity and over resource performance issues. We understand that these are some of the same concerns PJM is attempting to address with the CP Proposal.
Second, PJM should eliminate the Short-Term Resource Procurement Target (“the Holdback”). The Internal Market Monitor for PJM (“IMM”) has analyzed the impact of the Holdback each year and has presented evidence that the Holdback results in the suppression of prices in the Base Residual Auctions (“BRA”) and has acted as a barrier to efficient entry in capacity constrained regions. The IMM has further explained that Reliability Pricing Model (“RPM”) cannot serve its fundamental purpose of ensuring resource adequacy on the basis of competitive market principles and securing the confidence of ratepayers because the Holdback arbitrarily shifts the demand curve to the left and reduces demand.2

Finally, PJM should require all resources to be available on an annual basis and accordingly needs to eliminate the Limited and Extended Summer Demand Response products from the capacity market. The IMM has proposed this solution on numerous occasions and we believe that it is an important step towards simplifying the Loss of Load Calculation since PJM would not need to model these products as constraints in the BRA and only one product would be used to meet PJM’s reliability objective.

II. Assuming that the CP Initiative Goes Forward, It Needs To Be Modified

At its core, the CP Proposal is designed as a “carrot/stick” approach to improve generator availability and flexibility, particularly during times of system stress. However, as a general matter, the proposal leans too heavily on the “stick” and fails to provide an adequate “carrot.” If implemented as proposed, the proposal could be expected to result in either the premature retirement of some facilities otherwise needed for reliability or significantly higher costs to those facilities to participate as CP resources. Alternatively, resources may be forced to be base resources if they are unable to meet the CP resource requirements which could cause a shortage of CP resources. In either event, consumers could be expected to incur substantial amounts of unnecessary charges.

Fundamentally, the commercial risks associated with the proposed performance obligations and the “risk premium” are misaligned: the risk of loss greatly exceeds the allowed premium levels for many units. Further, costs associated with measures taken to reduce performance risk, such as capital improvements, are themselves placed at risk under the RPM design with little assurance of recovery. The commercial viability of many resources with higher than average EFORd levels will be greatly challenged by this structure. Further, imposing a construct that forces serviceable facilities out of the market because they do not meet highly idealized standards of performance and flexibility is inefficient and will impose unnecessary costs on consumers. Indeed, because many of the most affected units will be older coal and oil units, an

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unintended consequence of the CP Proposal could be to actually decrease reliability by undermining fuel diversity.

The PSEG Companies thus recommend four fundamental changes to the CP Proposal if PJM continues to move forward with it:

- First, the penalty level should be no more onerous than necessary to address the core problem, *i.e.*, unit unavailability at levels commensurate with their UCAP commitment during severe weather conditions. PJM should consider employing a lower penalty with the potential to recover “bonus” payments for superior performance as a means to incentivize generator availability.
- Second, the risk premium is deficient in relationship to the penalty risk being imposed on generation unit owners. A better balance will be achieved by allowing risk compensation to match the penalty risk exposure for specific units.
- Third, the proposal should be modified to facilitate the recovery of the increased capital and maintenance costs in meeting the new standards. Under the CP Proposal, generating facilities in need of substantial improvements will be faced with excessive recovery risks. These recovery risks need to be ameliorated.
- Fourth, PJM should eliminate its proposal to impose new flexibility requirements on generation capacity resources. Most of the proposed new flexibility standards are not necessary to address the core reliability deficiencies identified by PJM and, if the new flexibility standards are imposed, the level of costs and risks assumed by certain generators will be greatly compounded.

**III. PJM’s Proposed Penalty Structure Should Be Reevaluated**

PJM should reconsider its proposal to set the maximum penalty at two and one-half times a unit’s capacity revenues. Penalties should be high enough to incentivize robust performance needed for reliability, but not higher than necessary. If the penalties are too onerous, they will just result in the premature retirement of units or, at least, in the contraction of the universe of units that have the commercial capability to assume obligations as CP resources. While PJM proposes that penalties can be as high as two and one-half times the amount of the capacity payment it never explains why such a high potential penalty is needed. Consideration should be given to setting the penalty cap at a lower level such as the loss of a single year’s capacity payments. The receipt of capacity payments is essential for the economic viability of the vast bulk of generating units within the PJM footprint. Thus, the specter of losing the entirety of a unit’s capacity payments provides a powerful inducement to incent performance by generation owners.\(^3\)

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\(^3\) Further, setting the level of maximum penalty at the unit’s yearly capacity payment would also be consistent with PJM’s long-standing policies for incentivizing performance by Demand Resources that commit themselves as capacity. Thus, the maximum penalty that can be incurred by DR is the loss of a year’s capacity payment. In
Further, setting the penalty at a multiple of the capacity payment exacerbates the “tail” risk for CP resources that do not perform well in a given year. This increased “tail risk” is further compounded by PJM’s proposal to eliminate virtually all “out of management control” outage categories, including force majeure events such as hurricanes and floods. The proposed CP construct adds substantial financial and liquidity risks to generators, which could face the prospect of significant maintenance and repair costs associated with these types of events, at the same time that they would have to pay the proposed two and one-half times penalty.

Second, penalties should be measured against a unit’s UCAP commitment in RPM not its ICAP level as PJM proposes. Under PJM’s reliability construct, PJM is relying upon the UCAP commitments of generating resources to satisfy system-wide generation adequacy. Penalizing a unit for not satisfying a more onerous requirement than its commitment, i.e., its installed capacity rather than its unforced capacity, effectively constitutes a double penalty. The unit is penalized once by the reduction in its recognized capacity value through the EFORd mechanism so it must sell less capacity into the RPM market and then is penalized a second time if it operates in accordance with its committed level of capacity obligations. No justification is put forward in the CP Proposal for penalizing a unit’s real-time performance when it is contributing to reliability at the level it committed to as a capacity resource in RPM.

Third, units that perform above the level that satisfies their reliability commitment to PJM, i.e., the UCAP cleared through RPM, should be entitled as “bonus payments” to a share of the penalty amounts paid by CP resources that do not satisfy their commitment. Under the CP Proposal, only “uncommitted” MWs within the same generator portfolio as a non-performing resource can offset a penalty. The PSEG Companies propose that the penalty revenues be shared by resources that operate above their UCAP levels as follows: (i) calculate the ratio, for a given hour, equal to particular unit’s MW output above UCAP times the weighted hourly LMP at its generator bus, divided by the MW output of all units above their UCAP times the weighted average hourly LMP at all associated generator buses; and (ii) multiply the resultant ratio by the penalties incurred in the hour by units that did not perform at UCAP.

Stated as a formula:

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\text{(Bonus payment)} = ((\text{unit specific MWs} > \text{UCAP}) \times (\text{Bus LMP})/(\text{fleet MWs} > \text{UCAP}) \times (\text{weighted average LMP at all over-performing generator buses})) \times (\text{hourly penalties of underperforming units}).
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The calculation should be made on hourly basis so that “over-performance” by one unit will be a true substitute for the “under-performance” of another unit.

addition, because DR availability is not tracked by PJM through the EFORd mechanism, DR that fails to perform does not suffer a reduction in recognized available capacity in future RPM auctions.
Adopting this mechanism would also be expected to result in better real-time performance. Units will have financial incentives to operate above their ICAP commitment when they are capable of doing so. Even if a unit has reached the maximum level of penalties that may be incurred it would still have an incentive under this mechanism to operate to offset those penalties in the future. The contributions made towards reliability of generators that exceed their commitments during real-time operations should be recognized and performance above the level of committed service should receive compensation.

Fourth, there should be some retention of true force majeure events, e.g., force majeure under a pipeline tariff when the generator has obtained firm gas service or a natural disaster such as Superstorm Sandy. Placing these kinds of uncontrollable risks entirely on generators is unfair and may result in some generators seeking large risk premiums or being forced into premature retirement.

IV. The Risk Adder is Inadequate

In order for there to be efficient outcomes under the CP Proposal, generators need the ability to reflect the reasonable performance risks associated with the new requirements in their capacity market bids. The PJM proposal to set the risk adder at a level equal to the system-wide average EFORd multiplied by an average number of compliance hours multiplied by average LMPs during compliance periods, apparently is intended to reflect the likelihood that a generator will incur penalties during the deliver year. This methodology results in merely collecting revenues to recover expected costs for units that match the inputs. However, the proposal is clearly inadequate to compensate resources for the risks of not achieving the pool-wide EFORd, for variability in compliance hours or for LMP price differences. Many PJM generation resources are more likely to incur significant penalties even assuming that they make capital improvements to enhance operations because of these factors that, under the current proposal, are not allowed to be included in the cost of providing that service. The PJM proposal does not incorporate a true risk premium since it does not allow for the inclusion of any of the traditional elements of a risk calculation associated with the volatility of the inputs.

In order to reflect the actual risk that generation unit owners will wear, the CP Proposal needs several modifications. First, the use of average system EFORd in PJM’s proposed formula overstates risk for some technology types and understates it for others. It is not realistic to expect that the existing fleet of steam units or combustion turbines could consistently achieve EFORd comparable to those of nuclear plants or the generally much newer fleet of combined cycle generators even if capital improvements are made. Given the age of these units within

4 Nuclear plants may be able to achieve very low EFORd levels because they typically operate almost continuously except during maintenance and refueling outages. Yet other types of units typically exhibit higher forced outage rates. For example, based on data published by the IMM, nuclear units achieved EFORd levels of between 1.2% and 3.9% and combined cycle gas units achieved EFORd levels of between 3.5% and 4.6% over the past seven years. In comparison, combustion turbines averaged between 8.0% and 11.1% and steam units averaged between 8.2% and
PJM and the kind of operational challenges they face, it cannot be reasonably expected that they can operate at those levels. Older coal units that do not run for 6,000 hours per year and thus do not qualify as “base load” under the proposed flexibility requirements, will face particularly daunting challenges if they are required to cycle on a daily basis as the PJM proposal on unit flexibility would seem to expect.

Second, the PJM proposal effectively assumes that the EFORd will be the same as the level of performance over the compliance periods whereas, in reality, outages should be expected to occur more often during hot or cold weather alerts or during system emergency alerts when the system is under stress. Accordingly, the risk adder formula should focus on unit performance during compliance periods.

Third, PJM’s proposal does not capture “tail” risks that could result in the loss of a multiple (2 and one-half times) of the capacity payment under PJM’s whitepaper construct. Even if the PSEG Companies’ suggestion to consider reducing the maximum penalty is followed, units will still incur a significant “tail” risk of losing all their revenue. PJM proposal’s to base the risk adder on the EFORd of the entire PJM footprint and to use average values for run hours and LMPs, ignores this risk completely.

The PSEG Companies believe that the most efficient market outcomes will occur if generators can reflect the full panoply of operational and performance risks in their RPM bids. Competition will drive the risk adders down to the minimum level that plant owners can tolerate. However, if the allowed risk premiums are set too low, generators may be driven away from participating as CP resources entirely. The PSEG Companies thus submit three proposed modifications to PJM’s proposal for risk premiums that more realistically reflect the risk of meeting the new performance standards.

First, the risk adder should incorporate a unit specific risk factor based on the unit’s historic performance during past hot and cold weather events and during system emergency alerts. This provides a realistic assessment of a unit’s capability to perform without regard to speculation as to how it may perform in the future.

Second, we propose to use a 90/10 distribution of compliance hours based on experience over a long period of time – at least 10 years – in lieu of using an average of compliance hours. This would recognize at least some of the “tail” risks represented by a year of severe weather. Third, we believe that the LMP component of the PJM formula should reflect historic LMPs for hours in which the unit whose risk adder is being calculated did not operate. This calculation –

11.4% over the same period. Using the system-wide average of the ERORd of approximately 7% thus significantly understates the historical risk of these types of units.

5 See Attached Exhibit “PJM Capacity Performance: Probabilistic Weather Alert Analysis Proposal” that sets forth the probability of hot and cold weather alerts over approximately a thirteen year period.
especially for areas which experience significant congestion – will provide a much more realistic assessment of the unit’s exposure to high prices during times of system stress.

While we recognize that PJM has expressed concern that allowing units to include the full range of performance risks in RPM bids will reduce the unit’s incentives for robust real-time performance, we believe this concern is misplaced. The real-time performance penalties will incentive generation owners to maximize the availability of their units in order to retain as much of the capacity payments as possible. Moreover, the “bonus payment” mechanism proposed by the PSEG Companies would further bolster the incentives for real-time performance.6

Finally, a fundamental misconception that underlies the CP Proposal risk adder is that all resources should have availability factors that approach the system-wide average EFORd and, if units cannot currently achieve that standard, the unit owners should be required (or at least be incentivized) to repair or upgrade the units to meet them. In fact, there are clearly cases in which it would not make economic sense to upgrade or repair a unit so as to be capable of meeting (or even approaching) the system-wide EFORd. In some cases, the most efficient outcome for the market (that also achieves the most reliability) will be to allow the unit to operate at a higher EFORd and to reflect its unit specific EFORd in its capacity market bid.

For example, assume that a 30 year old, 500 MW coal unit has an EFORd of 30% and it will cost $300 M in capital costs for the unit to reach a 7% EFORd. Such a unit would have an APIR of more than $600 MW-day (a level in excess of the top of the VRR Curve) and thus would never be able to recover all of its costs through RPM. However, if the unit were permitted to bid a risk adder commensurate with its 30% EFORd, it could likely submit a lower bid in RPM. Admittedly, it would be submitting fewer MWs of CP resources at the higher EFORd than if the unit could operate at a 7% EFORd, but the assumption that it could reasonably achieve that level of performance is chimerical. Accordingly, subject to IMM approval, when the generation owner can demonstrate that it does not make economic sense to undertake upgrades or other improvements, it should be permitted to bid a risk adder into RPM commensurate with the unit’s current operating characteristics.

V. Capital/ Maintenance Costs Recovery Associated with Complying With The New Standards Pose Excessive Risk

In the CP Proposal, PJM proposes to add another category of the Avoidable Cost Rate (“ACR”) or Allowance for Project Investment Recovery (“APIR”) to account for additional costs such as costs incurred for natural gas delivery.7 However, recovering these costs through either the ACR

6 However, if PJM still perceives a need to include additional performance incentives in the risk premium, it could reduce the risk premium described supra by some percentage as an “incentive factor.” While we believe that this would not be appropriate or advisable, the proposed formula could easily be adjusted in this manner.

7 CP Proposal at 30.
or APIR mechanisms poses significant risks to resource owners because such costs are at risk given that they must be recovered over several RPM BRAs. Thus, unless prices reach a certain level for a number of consecutive auctions, resource owners will not be able to recover the investments that they may have made in order to qualify as a CP resource. Further, once costs are invested, resource owners may be forced to be price takers in subsequent auctions in order to cut losses. However, the CP Proposal can be modified so that unit owners can better mitigate investment risks.

First, the PSEG Companies suggest that PJM allow a price lock for a five year period for APIRs that are over a certain level (e.g., $450/Kw), but only for the upcoming BRA covering the 2018/2019 Delivery Year. We believe that this will provide an incentive for resource owners to make the investments necessary to achieve PJM’s reliability objectives. We further note that FERC has recently approved a temporary increase in the price lock in New England because of ISO-NE’s representation that the lock-in was necessary to compensate for lack of investor confidence in ISO-NE administered markets. As a general matter, the PSEG Companies do not support lock-in periods for prices. However, as in New England, the CP Proposal creates an uncertain investment environment and therefore a lock-in period will provide resource owners with some level of certainty that they will be able to recoup their investments associated with the enhanced performance standards. As such, it will support PJM’s goal of improving the performance of its generation fleet in an expedited manner.

In addition, the PSEG Companies believe that the following elements should be included in PJM’s final solution in order to reduce the risks associated with becoming a CP resource:

- Increase the Capital Recovery Factors used for Project Investments for CP resources;
- Allow “unrecovered” APIRs to be rolled forward for another amortization period;
- Provide clarification in the Tariff that bids up to a unit’s ACR are given a “safe harbor” from mitigation or claims of market manipulation;
- Adjust Gross CONE calculation to reflect winterization, firm fuel and unit parameter requirements; and
- Modify the Tariff to: (1) allow Project Investments for capital expenditures to improve “performance” for CP resources; and (2) allow inclusion of forward looking maintenance costs such as winterization within the scope of avoidable maintenance costs for CP resources.

VI. PJM Should Delay Implementation of Its Proposed Unit Flexibility Requirements

The CP Proposal, as augmented by other PJM pronouncements, appears to envision the following innovations to improve operational flexibility:
• Fossil units with excessively long lead times for notice or start-up will not qualify as CP resources.

• The creation of three classes of “flexibility requirements” for generators identified as “Base Load Asset Class,” “Interday Cycling Asset Class,” and “Intraday Cycling Class,” are not intended as qualification standards for CP status. However, PJM apparently intends that units failing to meet the standardized unit flexibility parameters will not be kept whole to their cost-based bids when run to meet PJM reliability requirements and may be penalized for nonperformance if their “inflexible” parameters result in the unit not being economically dispatched on a compliance day.

• The existing unit exception process for determining operating parameters (or something like it) will be maintained.

• Units will be allowed to include incremental capital and O&M costs in their ACRs related to making units more flexible.

With the exception of the first element, the PSEG Companies recommend that PJM delay implementation of these proposals. The PSEG Companies submit that PJM should not attempt to treat the detailed flexibility standards and categories as mandatory at this time, either as eligibility requirements for CP resources or as standards for imposing performance penalties on CP resources. The reliability concerns identified by PJM associated with severe weather conditions are related to generator availability. While PSEG understands PJM’s interest in seeking increased unit flexibility, this does not appear to be necessary to address the immediate reliability issue at hand. Rather, the flexibility issue seems to relate to PJM’s goal of reducing uplift payments. Further, the level of capital investments and expenditures will be substantial just to achieve the more robust availability standards. Trying simultaneously to increase both availability and flexibility levels will greatly complicate the effort required of generation owners and will increase the associated level of costs.

The proposed penalty structure for units that do not meet the flexibility standards, moreover, will further compound the risks associated with the operation of certain generators without due compensation. Most notably, coal generators that were originally designed to operate as base load units, but whose run hours have decreased due to displacement by gas fired combined cycle units will be severely affected. Under the PJM proposal, many of these units would be relegated to the “interday cycling asset” class and be required to cycle on a daily basis to avoid penalties. Not only would this require large capital investments in many cases, but operating the units in this manner would greatly increase the cost of maintenance due to the additional wear and tear. Given these operational risks as well as the risk of recovering investments associated with capital improvements, the economics of such plants – at least as CP resources – will be severely
challenged. Finally, the PJM risk adder proposal does not even purport to allow generators to reflect risks associated with unit flexibility in their bids.

We thus recommend that PJM pursue the elements of its proposal to improve unit flexibility in a separate stakeholder proceeding. While we agree that PJM should not allow fossil resources with excessively long notice or start-up periods to quality as CP resources, the other elements of the proposal should be deferred pending completion of a normal and fulsome stakeholder process.

However, if PJM does include the unit flexibility requirements within the CP construct, the following modifications are needed:

- PJM should clarify the ability of generation owners to include capital/maintenance costs needed to improve flexibility in ACRs and/or energy bids. This would appear to require revisions to the PJM tariff. The PSEG Companies believe that at least some of the increased maintenance costs should be recoverable in cost-based energy market bids since the higher maintenance expenses will be a function of the unit’s dispatch schedule and cycling duty.

- Consider a phase-in of the penalties associated with the flexibility requirements over time. A phase-in would at least ameliorate the impact on affected generators of trying to address both availability and flexibility improvements at the same time.

- If penalties are imposed now or phased-in, PJM should clarify the new test for flexibility exemptions and whether existing exemptions will be retained. We understand that PJM may be seeking to distinguish between operating characteristics related to the “physical” capabilities of a unit as opposed to “economic” restrictions. Such distinctions, however, may not always be clear: for example if the cost of meeting the flexibility standard causes the unit’s ACR to exceed the maximum allowed clearing price in a BRA, does this distinction make sense? In addition, PJM should clarify that units will not be penalized for using exempted flexibility parameters.

- PJM should better explain when units will be subject to penalties for failure to meet the stated flexibility requirements; in particular, how will PJM determine that a unit that was not dispatched would have been dispatched if it had more flexible parameters?

- If PJM retains the current penalty structure, at a minimum, it needs to change the definition of “base load” resources to remove the requirement that the unit operated for 6,000 hours in the previous recent past; this requirement pushes certain units that
were not designed to cycle into the “interday cycling” category; rather, units should be classified by design not by how economic they were over a previous year’s operations.

VII. Firm Gas Supplies

The PSEG Companies agree that PJM should not dictate the precise natural gas delivery arrangements that are necessary to meet the requirements for a gas-only CP resource. However, PJM must provide additional clarity regarding the certification requirement for the level of fuel security that should be met. As a concept, we believe that the “firm gas” available to a gas-only CP resource should provide a degree of reliability comparability to a dual-fuel gas/oil unit with a three day oil tank that can be refilled between periods when it is dispatched on oil.

VIII. Transition

We understand that PJM believes that significant reliability concerns may be presented as early as the winter of 2015/2016 and that PJM is considering holding an incremental auction to cover the 2015/2016 delivery year and other delivery years for which a BRA has already occurred. The PSEG Companies question the wisdom of this course of action and note that the CP Proposal fails to provide any details regarding the impact of the additional incremental auctions on units that have already cleared the BRA.

Rather than hold additional incremental auctions, PJM should develop a winter reliability program similar to ISO-NE for the initial years. This would entail payments for oil inventory, LNG inventory, firm gas supply arrangements, additional operations expenses (such as keeping coal piles from freezing) and similar efforts.