EXHIBIT J

PJM Capacity Performance Proposal

PJM Staff Proposal

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Executive Summary - Defining Capacity Performance

Last winter's generator performance—when up to 22 percent of PJM capacity was unavailable due to cold weather-related problems—highlighted a potentially significant reliability issue. PJM's analysis shows that a comparable rate of generator outages in the winter of 2015/2016, coupled with extremely cold temperatures and expected coal retirements, would likely prevent PJM from meeting its peak load requirements.

PJM Interconnection's capacity market has been highly successful, attracting more than 35,000 megawatts of new physical generation to the system since its inception in 2007. Our capacity auctions ensure that adequate generation is committed to serve the region three years in advance of the need. The capacity market also has eased impacts from the major fuel switch that is occurring as coal generators retire and new natural gas generators replace them. However, this rapid transition is contributing to concerns about the performance of the generation fleet—particularly during extremely cold weather, like last January's.

PJM, therefore, is seeking to develop a more robust definition of Capacity Resources that provides stronger performance incentives and more operational availability and diversity during peak power system conditions. To do so, PJM is proposing to add an enhanced capacity product – Capacity Performance – to its capacity market structure and to reinforce the existing definition of the Annual Capacity product to ensure that the reliability of the grid will be maintained through the current industry fuel transition and beyond.

Capacity providers—including physical generators, demand response and energy efficiency providers—that offer and are committed to provide the Capacity Performance product will be required to meet additional eligibility qualifications and obligations designed to ensure better performance.

Under this enhanced structure, there will be four products – Capacity Performance, Annual Capacity, Extended Summer and Limited Demand Response.

Objectives

The objectives for the Capacity Performance product are to provide PJM with:

- Fuel security through a dependable fuel source
- Enhanced operational performance during peak periods
- High availability of generation resources
- Flexible unit operational parameters
- Operational diversity

Eligibility

Under the proposal, eligible resources for Capacity Performance will be generators capable of sustained, predictable operation for 16 hours per day for three consecutive days; Annual Demand Response capable of sustained curtailment for 72 hours; and Energy Efficiency. To be eligible as a Capacity Performance resource, an officer of the generation resource's owner would have to certify that four specific requirements have been met:

- A generator must have on-site fuel (or dual-fuel backup capability) for at least 16 hours of continuous operation per day for three consecutive days at an output equal to its quantity of committed Installed Capacity.
- Generators that burn gas only must have a secured fuel supply with some combination of firm transport, firm commodity and access to storage or equivalent to provide flexible operation during peak gas-usage conditions.
- Energy efficiency plans must be determined by PJM to be complete in order to be able to offer into RPM auctions, and must demonstrate the committed level of reduction for the entirety of the Delivery Year for which they are committed.
- Annual Demand Response must be available 24 hours a day, 365 days per year, and for 72 continuous hours such that it is capable of reducing demand at least in the amount of the committed quantity for the 16 peak hours of three consecutive days.

Performance Assurance

To ensure performance, a Capacity Performance resource must deliver energy in all hours if scheduled by PJM or if self-scheduled when PJM has declared a Hot Weather or Cold Weather Alert and/or declared a Maximum Emergency Generation Alert. A resource also must offer into the Day-Ahead Market as available on a non-emergency schedule (economically for Demand Response resources). Limited exemptions would be provided only for resources not scheduled by PJM. A penalty would be applied for every hour that energy is not delivered, with a provision that failure to perform by one generator could be offset by energy produced by a non-capacity resource in the generation owner's portfolio.

High Availability and Flexibility

High availability would be defined as the capability to run for a minimum number of hours over a three consecutive day period while being offered as a non-emergency resource and with no energy limitations. Flexibility parameters would be defined for each class of resource.

Annual Capacity Product

Proposed changes to the requirements for the Annual Capacity product would eliminate many current restrictions on offers, define performance standards for peak periods and set penalties for not meeting them. They would also define rules for energy storage eligibility, and set minimum standards for environmentally limited resources.

Impact on Installed Reserve Margin

The new Capacity Performance product would not have an immediate impact on the Installed Reserve Margin calculation. This reflects the fact that the existing IRM calculations already assume higher capacity performance than is occurring, meaning that the new product should produce performance that already is factored in to the IRM calculation.

I. Introduction

The purpose of this document is to provide details regarding PJM's proposed initial solution to the issues that were described in PJM's August 1, 2014 whitepaper entitled "Problem Statement on PJM Capacity Performance Definition." PJM is proposing this initial solution to begin detailed dialogue with stakeholders on these important issues. PJM expects the solutions detailed in this paper will be adapted through the process of discussion with stakeholders.

As described in PJM's August 1 whitepaper, the issues indicate a more robust capacity product definition is required that provides enhanced performance incentives and provides more operational availability and diversity during peak conditions. Therefore, within the existing RPM structure, PJM proposes to add an enhanced product, called the Capacity Performance product, which is based on winter peak load requirements. As described below, this enhanced product includes additional eligibility requirements and obligations on resources that elect to commit in this product category. PJM also proposes enhancements and clarifications to the existing annual capacity product definition.

The overall design objectives for the Capacity Performance product are to address the concerns highlighted in the PJM whitepaper including the observed generation performance issues, winter peak operations issues and the operational characteristics of resources that are needed to ensure that system reliability will be maintained throughout the current industry transformation and beyond. The design objectives include mechanisms to incent or require the following characteristics:

- Enhanced operational performance requirement in peak periods
- Fuel security – dependable fuel source
- High availability resources
- Flexible unit operational parameters
- Operational diversity

The following sections of this document provide a detailed description of the PJM proposal. Specifically, the sections below are organized as follows:

- **Section II - Capacity Products:** The capacity products PJM proposes to be eligible to offer into Reliability Pricing Model (RPM) auctions or commit to an Fixed Resource Requirement (FRR) Capacity Plan, including a new Capacity Performance product and enhancements to the current definitions of the existing products;
- **Section III - Methodology for Establishing Maximum Product Quantities:** The analysis PJM will conduct in order to establish the required quantity of the new Capacity Performance product to be procured;
- **Section IV - Unforced Capacity (UCAP) Calculations and Installed Reserve Margin:** Description of the Unforced capacity calculation, the relationship with the new product, and the impact to the calculation of PJM's Installed Reserve Margin (IRM);

- **Section V - Capacity Performance Availability and Flexibility Requirements:** The eligibility, performance, availability and flexibility requirements for the new and existing capacity products;

- **Section VI – Changes to Base Capacity Requirements:** The changes to existing Annual Capacity requirements, which PJM proposes to rename "Base Capacity";

- **Section VII - Peak Period Performance Assurance:** The penalties PJM proposes to apply to the new and existing capacity products;

- **Section VIII - Product Offer Requirements:** The rules PJM proposes with respect to offers to provide the new Capacity Performance product in RPM auctions;

- **Section IX - Cost Allocation:** Options as to how the costs of the new Capacity Performance product could be allocated; and

- **Section X - Previously Proposed RPM Changes:** PJM's recommendations regarding the incorporation into the Capacity Performance proposal some of the other changes recently filed at FERC as part of the Replacement Capacity proposal.

- **Section XI - Transition Auction Mechanism for Delivery Years 2015/16, 2016/17, 2017/18:** Description of a transitional mechanism to address reliability requirements for Delivery Years 2015/16, 2016/17, 2017/18

II. Capacity Products

The four capacity products proposed to participate in the PJM RPM include: Capacity Performance product, Base Capacity product (which includes Annual Demand Response), Extended Summer Product, and Limited Demand Response.

Capacity Performance Product

Generation Capacity Resources, Demand Resources, and Energy Efficiency (EE) Resources may be eligible to be considered a Capacity Performance Product so long as the resource in question meets the following criteria.

1. Generation Capacity Resources are able to operate at their Capacity Performance Installed Capacity (ICAP) value for at least 16 hours per day for three consecutive days throughout the delivery year.

   In order to satisfy this criterion, it is expected that Generation Capacity Resources will have fuel on-site in the case of coal, or oil backup for gas-fired resources. In the case of gas-fired resources it is assumed appropriate transportation arrangements to ensure delivery of fuel when it is needed through any combinations of firm transportation, storage, balancing agreements, use of park and loan service, either directly or through a third party via asset management agreement. The Capacity Performance Product does not mandate how fuel availability is ensured, but rather the decisions are left up to the individual resource owner on how to best manage fuel availability risks.

Moreover, it is expected that resource owners will have made the appropriate investments in O&M and weatherization to ensure that the unit can operate as required above through extreme hot or cold weather conditions. Examples of such investments include but are not limited to ensuring stored fuel on-site does not freeze up, conveyors do not freeze, or valves and piping operate properly.

2. Generation Capacity Resources are capable of operating according the minimum flexibility requirements defined in Section V.

   Generation Capacity Resources that have long notification and start times or have inflexible operating parameters run the risk of not being available when the system needs them most and should not be eligible to be committed as the Capacity Performance product. Moreover, in order to ensure these resources are available, PJM may need to commit such inflexible resources out of economic merit order and incur operating reserve (uplift) costs to ensure the resources are available when needed. Consequently, to ensure availability at the least cost to the system, Capacity Performance resources will be required to meet minimum flexibility requirements.

3. Demand Resources (DR) that are able to achieve load reductions to their reduction ICAP value, for at least 16 hours per day for three consecutive days when called upon by PJM and must be available 24 hours per day for each day of the Delivery Year.

   Demand Resources that qualify as the Capacity Performance Product are being treated identically to Generation Capacity Resources that qualify. Effectively, DR must be capable of providing load reduction over all 16 hours of operation during any day. This requirement effectively means DR must be present summer and winter.

   The Annual DR nominated value determined using a non-summer-period Peak Load Contribution (PLC) value will not be less than that determined using a summer PLC. PJM proposes to define the non-summer-period PLC as calculated in the same manner as the current summer PLC, with the exception of utilizing the five highest coincident peak load values from the months of January and February. Alternately, Annual DR may comply as the Guaranteed Load Drop (GLD) category during the non-summer period without the requirement to reduce below the summer period PLC value.

Energy Efficiency plans that meet all current requirements in M-18, M18B, and OATT can qualify as the Capacity Performance product as long as Measurement & Verification Plan & Post-Installation Measurement & Verification Report meet an additional M&V requirement to demonstrate that the EE resource provides load reduction during winter performance hours. The demand reduction determined based on winter performance hours must be not less than the Nominated EE Value in summer EE Performance Hours. EE resources based on load reductions not realized during non-summer periods are ineligible to offer as the Capacity Performance product but will be able to clear as Extended Summer Capacity resources. Examples may include HVAC and measures that optimize building controls that impact only the summer period. Additionally, augmentation of nominated Installed Capacity (ICAP) value by use of interactive factors would not be applicable for non-summer load reductions. Interactive factors are secondary impacts of EE installations that serve to further increase the demand reduction impact of those installations during the summer months. For example, the fact that more efficient lighting that generates less heat is installed in a building may also reduce the air conditioning needs of the building and further reduce the electrical load. Such interactive factors do not apply in the winter.

4. Environmentally Limited Generation Capacity Resources and Demand Resources must be able to perform to the equivalent of at least a 10 percent capacity factor over the entire Delivery Year.

   Not all Generation Capacity Resources have unlimited run hours in a year. Many peaking units such as combustion turbines (CTs) or gas and oil steam units are subject to an air permit or regulation determined number of run hours or fuel-throughput that effectively limits operation. Historically, such limits have rarely been binding since CTs and gas and oil steam units operate at low capacity factors based on economic dispatch over the year. While such resources may be run time limited, they may otherwise be capable of meeting all the other criteria to be a Capacity Performance Product. A 10 percent capacity factor was chosen based upon the fact that historically the number of hours in a year for which Cold and Hot Weather Alerts have been called has never exceeded 876 hours.

   Demand Resources, could also face direct permit or regulatory limitations if they are based on backup generation. All DR must be capable of responding to the equivalent of at least a 10 percent capacity factor to ensure they can be available during all potential hours in which Cold and Hot Weather Alerts are in place.

5. An external Generation Capacity Resource must meet all criteria for an exemption from the Capacity Import Limits as well as the criteria that apply to Generation Capacity Resources described above to qualify as a Capacity Performance product. External Generation Capacity Resources that do not qualify for an exemption to the Capacity Import Limits may qualify as Base Capacity resources but not as Capacity Performance resources.

   The fifth criterion simply requires any resources that are physically external to the PJM footprint to effectively be electrically a part of PJM in the same way an internal resource is.

An Officer Certification will be required at the time of the Base Residual Auction or Incremental Auction for the Delivery Year in which the resource is to be committed attesting that the resource in question will satisfy the above five criteria to be a Capacity Performance product. Moreover, three months prior to the Delivery Year a second Officer Certification will be required to confirm that the committed Capacity Performance product meets the above five criteria and confirmation that all required permits allow the resource to respond to the equivalent of at least a 10 percent capacity factor over the Delivery Year.

In addition to the above Capacity Performance criteria, resources committed as the Capacity Performance Product have the following obligations:

1. Generation Capacity Performance resources must provide market-based and cost-based non-emergency energy offers into the PJM Day-Ahead Energy Market up to the committed ICAP value of the resource every day during the Delivery Year unless the resource is unavailable due to a forced or scheduled outage. Demand Response Capacity Performance resources must submit non-emergency offers into the PJM Day-Ahead Energy Market up to the committed ICAP value of the resource every day during the Delivery Year unless the resource is unavailable due to a forced or scheduled outage.

2. To the extent the resource has operational run-time limitations; it may not make itself available as emergency only but must use the Energy and Environmentally Limited Opportunity Cost to make economic offers in a way that best

allocates available run hours. Availability as emergency only will be treated for performance measurement purposes as a forced outage.

3. In the case of a Generation Capacity Performance resource, the ability to deliver energy to load on the PJM system at all times, especially during system peak and emergency conditions, as demonstrated through a generation deliverability analysis.

4. Provide energy output or load reductions to PJM if needed to maintain reliable operations during emergency conditions, which include PJM recall rights for off-system energy sales for committed resources.

5. Avoiding scheduled outages during specified peak load periods and providing outage data to PJM.

Capacity resources that satisfy the Capacity Performance product performance criteria are eligible to offer into the RPM auctions and be committed as a Capacity Performance product and receive the Capacity Performance product resource clearing price.

Base Capacity Product

Capacity resources that satisfy the current Annual resource product requirements as defined in the PJM Tariff and Manuals would generally qualify as Base Capacity with the proposed enhancements discussed below. Base Capacity products may include generation, Annual DR and EE resources.

Generation

Generation meeting the RPM eligibility requirements as defined in the PJM Tariff and Manuals but not meeting those of the Capacity Performance product above would qualify as Base Capacity.

Annual Demand Resources

Annual DR is available for an unlimited number of interruptions during the Delivery Year, and must be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00 a.m.to 10:00 p.m. Eastern Prevailing Time for the months of June through October and the following May, and 6:00 a.m. through 9:00 p.m. Eastern Prevailing Time for the months of November through April unless there is PJM approved maintenance outage during October through April.

PJM proposes to enhance the current definition of the Annual DR product such that the Annual DR nominated value determined using a non-summer-period PLC value (determined as described above) must not be less than that determined using a summer PLC. Alternately, Annual DR may comply as the Guaranteed Load Drop category during the non-summer period independent of the summer period PLC value.

Energy Efficiency

An EE Resource involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then-current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of Schedule 6 (section M) of the Reliability Assurance Agreement. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site (during the defined EE Performance Hours[1]) that is not reflected in the peak load forecast used for the Base Residual Auction for the Delivery Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention.

The demand reduction at winter peak load forecast must not be less than the Nominated EE Value in summer EE Performance Hours for EE to qualify as the Base Capacity product. EE for which the demand reduction in the winter is less than the Nominated EE Value in summer EE Performance Hours may qualify as Extended Summer product.

Extended Summer Product

Extended Summer DR is available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00 a.m. to 10:00 p.m. Eastern Prevailing Time.

PJM proposes that EE resources based on load reductions not realized during non-summer periods will be treated as Extended Summer product. Examples may include HVAC and measures that optimize building controls that impact only the summer period.

Limited DR

Limited DR is available for interruption at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than North American Electric Reliability Corporation (NERC) holidays, from 12:00 p.m. (noon) to 8:00 p.m. Eastern Prevailing Time.

[1] The EE Performance Hours are between the hour ending 15:00 Eastern Prevailing Time (EPT) and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday.

Summary of Capacity Products

Category	Availability Expectations	Limitations	Penalties	Penalty Window
Capacity Performance	All hours of the year	none	Real-Time LMP Charge	Year Round – Hot Weather Alert / Cold Weather Alert / Max Emergency Alerts
Base Capacity	All hours of the year	none	Real-Time LMP Charge for generators / Current DR Penalties for DR	For Generators – Max Emergency Generation Loaded in summer or winter; Current rules for DR
Summer Extended DR	May through October	10 hours per day	Current DR Penalties	Summer - DR activations
Limited DR	June through September	10 x 6	Current DR Penalties	Summer - DR activations

Storage Resources

Storage resources, including pumped storage hydro plants, battery resources, flywheels, etc. can qualify as the Capacity Performance product only if they are able to deploy technology to allow them to meet the requirements for the product, i.e. must be able to produce energy at rated capacity output continuously for periods of at least 16 hours on three consecutive days. With respect to qualification as the Base Capacity product, PJM proposes that storage resources qualify to provide that amount of Installed Capacity for which they can provide energy for ten continuous hours. For example, if a given storage resource has the ability to produce a peak energy output of 10 MW; it would qualify to provide 10 MW of Base Capacity only if it had the ability to produce 100 MWh of energy without the need to recharge. If the same resource could only produce 75 MWh of energy without recharging, then the resource would be able to qualify to provide 75 MWh divided by 10 hours, or 7.5 MW of Installed Capacity.

PJM recognizes that storage resources can provide flexibility to the system. However, the purpose of RPM is to ensure that sufficient aggregate quantities of resources are available to PJM to efficiently meet the peak demand requirements of the system on a year-round basis. If storage resources could be dispatched with perfect foresight in actual operations such that they are operated in an optimal manner, then there could be a basis for qualifying storage resources to provide a greater level of capacity than for which they would otherwise qualify under the above calculation on the basis that they can follow the load shape or otherwise be dispatched for optimal benefit. However, this assumption is not realistic, nor does it necessarily reflect what occurs in actual operations. These storage resource units can be self-scheduled by the owners or may be operated under direction by PJM in a manner that does not follow the load shape if necessary due to the system conditions materializing on any given peak day.

Qualifying Transmission Upgrades (QTUs)

PJM proposes that Qualifying Transmission Upgrades (QTU) can offer into the RPM auctions only as the Capacity Performance product. The reasoning behind this proposal is that the MW quantity of capacity provided by a Qualifying Transmission Upgrade is based directly upon the increase in the Capacity Emergency Transfer Limit (CETL) into a

Locational Deliverability Area (LDA). Such a CETL increase can only be implemented such that it impacts the Capacity Performance requirement for the LDA in question but at the same time reduces the Base Capacity and more limited capacity requirements , as described in more detail below. Therefore, the only way to incorporate Qualifying Transmission Upgrades is to offer them as the Capacity Performance product.

Resource Coupling

A Demand Resource with the potential to qualify as two or more RPM product types may submit separate but coupled Sell Offers for each product type for which it qualifies at different sell offer prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Separate resources will be modeled in the eRPM system for each product type. Under the current RPM rules, for coupled Demand Response Sell Offers, the offer price of the Annual Demand Resource offer must be at least $0.01/MW-day greater than the offer price of the coupled Extended Summer Resource offer, and the offer price of an Extended Summer Resource must be at least $0.01/MW-day greater than the offer price of the coupled Limited Demand Resource offer. PJM proposes to extend the concept of coupled offers to the proposed new Capacity Performance and Base Capacity products as well, such that a single resource could offer to be committed as either the Capacity Performance or Base Capacity product depending on the resulting clearing prices for each product. Under this proposal, the offer price of the Capacity Performance product resource would need to be at least $0.01/MW-day greater than the offer price of the coupled Base Capacity offer.

Limited Resource, Sub-Annual Resource and Base Capacity Resource Constraints

In the current RPM Auction clearing algorithm, the greater reliability value associated with the less limited demand resources and Annual Capacity Resources are recognized by establishing and enforcing a maximum quantity on the commitment of more limited products. The Limited Resource Constraints set the maximum level of Limited Resources to be procured in RPM Auctions for the Delivery Year. The Sub-Annual Resource Constraints set the maximum level of Limited Demand Resources and Extended Summer Resources to be procured in RPM Auctions for the Delivery Year.

PJM proposes to continue to set Limited Resource Constraints and Sub-Annual Resource Constraints for each RPM auction, and also add Base Capacity Resource Constraints for the RTO and each modeled LDA. The process by which PJM proposes to establish these maximum quantities is described in Section III of this document. The auction clearing process can select more expensive Capacity Performance products, Base Capacity Resources or Extended Summer in lieu of more limited products with lesser priced offers, if necessary, to enforce Base Capacity Resource Constraints, Sub-Annual Resource Constraints or Limited Resource Constraints. In those cases where one or more of the resource constraints bind in the auction solution, Limited Demand Resources and/or Extended Summer Resources and/or Base Capacity Resources selected will receive a decrement to the system marginal price of capacity (in addition to any locational price adder(s) received to resolve locational constraints).

For the RTO, the Limited Resource Constraint is equal to the Limited Demand Resource Reliability Target for the RTO in Unforced Capacity minus the Short-term Resource Procurement Target for the RTO. For an LDA, the Limited Resource Constraint is equal to the Limited Demand Resource Reliability Requirement for the LDA in Unforced Capacity minus the Short-term Resource Procurement Target for the LDA. The Limited Demand Resource Reliability Target for the PJM Region or an LDA is the maximum amount of Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability as more fully described in the PJM Manual for Reserve Requirements (M-20).

For the RTO, the Sub-Annual Resource Constraint is the equal to the Sub-Annual Resource Reliability Target for the RTO in unforced capacity minus the Short-term Resource Procurement Target for the RTO. For an LDA, the Sub-Annual Resource Constraint is equal to the Sub-Annual Resource Reliability Target for the LDA in unforced capacity minus the Short-term Resource Procurement Target for the LDA. The Sub-Annual Reliability Target (formerly known as the Extended Summer Reliability Target) for the PJM Region or an LDA is the maximum amount of the combination of Extended Summer Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability as more fully described in the PJM Manual for Reserve Requirements (M-20).

For the RTO, the Base Capacity Resource Constraint is the equal to the Base Capacity Resource Reliability Target for the RTO in Unforced Capacity minus the Short-term Resource Procurement Target for the RTO. For an LDA, the Base Capacity Resource Constraint is equal to the Base Capacity Resource Reliability Target for the LDA in Unforced Capacity minus the Short-term Resource Procurement Target for the LDA. The Base Capacity Reliability Target for the PJM Region or an LDA is the maximum amount of the combination of Base Capacity Resources (including Annual DR), Extended Summer Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability.

Auction Clearing Mechanism

The Auction clearing software is an optimization algorithm. This algorithm has the objective of minimizing capacity procurement costs given the supply offers, Variable Resource Requirement Curve(s), Locational Constraints, Base Capacity Resource Constraints, Sub-Annual Resource Constraints and Limited Resource Constraints.

The Base Residual Auction (BRA) resource clearing price for each LDA is determined by the optimization algorithm. As more fully described in Section III of this document, PJM proposes to enhance the methodology by which the Sub-Annual Resource Constraint is both established and incorporated into the RPM auctions. Specifically, PJM proposes to more completely recognize the interactions between the commitments of the two limited resources on the resulting Loss of Load Expectation (LOLE). As the commitment of Limited Demand Response increases, the maximum value of Extended Summer resources that maintains the same LOLE decreases. Similarly, as the commitment of Extended Summer resources increases, the maximum value of Limited resources that maintains the same LOLE decreases. In order to more completely capture this interaction, PJM proposes to fix the maximum quantity of Base Capacity resources that can be procured in RPM auctions, but allow the optimization algorithm to select the most optimal set of Limited and Extended Summer resources given the total Sub-Annual Resource Constraint, the interaction between the procured quantities, and the submitted offers.

The Resource Clearing Price within each LDA is the sum of:

- The marginal value of system capacity;
- Base Capacity Resource Price Decrement, if any;
- Sub-Annual Resource Price Decrement, if any;

- Limited Demand Response Price Decrement, if any; and
- Locational Price Adder(s), if any, relevant to such LDA.

The marginal value of system capacity is the clearing price for the Capacity Performance product resources in the unconstrained area of the PJM region.

The Resource Clearing Price within an external source zone is the sum of:

- The marginal value of system capacity; and
- Locational price decrement(s), if any, relevant to the external source zone.

A locational price decrement is applicable when a region-wide Capacity Import Limit or Capacity Import Limit for an external source zone is binding.

In the event that the Sell Offers forming the supply curve do not result in an intersection with the Variable Resource Requirement Curve, the marginal value of system capacity will be set along the Variable Resource Requirement Curve by extending the supply curve vertically from its end point until it intersects the Variable Resource Requirement Curve.

III. Methodology for Establishing Maximum Product Quantities

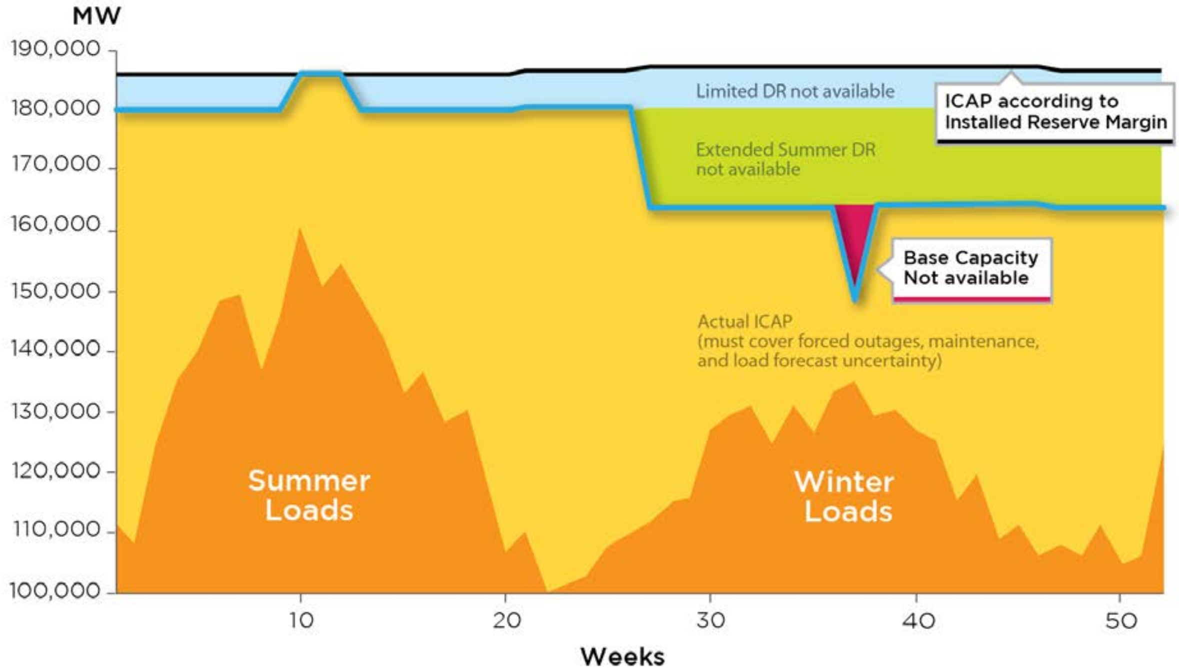
PJM proposes that all capacity products other than the Capacity Performance product be subjected to a restriction on the maximum quantity of the product that can clear in the RPM auctions. The rationale for setting this restriction is the limitation in the availability of these products in comparison with the Capacity Performance product. Since the calculation of the reliability requirement (to be procured in the RPM auctions) assumes that all resources are available on an annual basis (as is the Capacity Performance product), it is necessary to establish the maximum amount of the non-annual products that can be procured while being consistent with the reliability requirement.

In the past, PJM has set a similar maximum quantity restriction for the Extended Summer and Limited DR products. In particular, the maximum quantity allowed for the Extended Summer product has been calculated by determining the amount of annual capacity resources that can be displaced by the Extended Summer product until there is a 10 percent increase in the Loss of Load Expectation (LOLE) for the RTO (the restriction also applies to LDAs that are modeled separately in an RPM auction). This method, as it is currently applied, does not take into consideration that the Limited DR product can also displace annual resources, further increasing the LOLE risk. In other words, PJM's current procedures do not assess the combined LOLE impact of products with availability limitations[2].

[2] PJM has implemented the Extended Summer maximum quantity restriction in RPM by ensuring that the sum of Limited and Extended Summer products is less than or equal to the Extended Summer maximum quantity. However, this is not the same as assessing the combined LOLE impact of Limited and Extended Summer products when the sum of both is the Extended Summer maximum quantity (the impact is likely to be greater than a 10% increase in LOLE since the Limited product is less available than the Extended Summer product).

With the introduction of the new Base Capacity product, PJM is proposing to address this shortcoming and establish maximum product quantities for the Limited DR, Extended Summer and Base Capacity products based on their *combined* reliability impact. This method will calculate the amount of Capacity Performance resources that can be displaced by the sum of Limited DR, Extended Summer and Base Capacity products until there is a 10 percent increase in the LOLE. By applying such a method, PJM will allow resources with availability limitations to clear in RPM auctions only up to maximum quantities which do not significantly increase reliability risk.

The figure below illustrates the general approach that will be used to establish the maximum product quantities for the three limited products. The top black line represents the total ICAP procured in the RPM auction and is assumed to be equal to the IRM. (The black line is slightly higher in the non-summer periods to reflect the slightly higher unit ratings in the spring, fall and winter seasons.) The blue area represents the weeks during which Limited DR is unavailable, the green area the weeks during which Extended Summer DR is unavailable, and the red area the peak winter week during which some portion of the Base Capacity Product is unavailable. The remaining yellow area is the amount of actual ICAP reserves that are available each week of the Delivery Year. The purpose of the analysis is to determine the size of the blue, green and red areas such that the PJM system maintains an LOLE of 0.11 events/year (or a 10 percent increase in the target LOLE of 0.1 events/year).

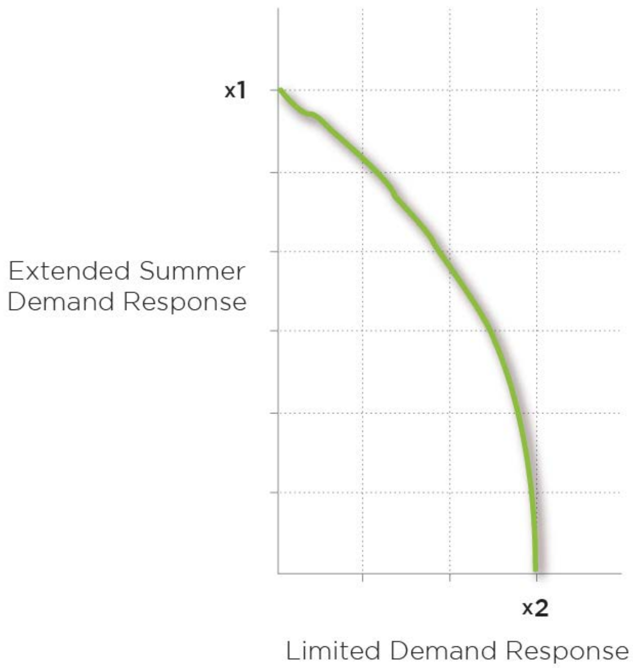


To perform the analysis, PJM will use its LOLE software, PRISM, which compares probabilistic distributions of load and available capacity on a weekly basis. The Limited DR, Extended Summer and Base Capacity products will be modeled based on their availability requirements.

Although the Limited DR product is available for interruption over the four month summer period, it is required to perform only up to ten times and for no more than six hours per interruption. Therefore, in addition to performing the above proposed methodology to compute maximum quantity restrictions, PJM will continue to compute the maximum quantity restriction for the Limited DR product based on the current 6 hour and 10 interruption performance limitation tests. The RPM auction will then use the lowest cap on the Limited DR product that is produced by the three tests. The three tests are required due to the three restrictions associated with the Limited DR product: no more than ten interruptions per year, no longer than six hours per interruption and available only from June - September.

PJM will first compute the maximum quantity restriction on the Base Capacity product and its impact on reliability as measured by a percentage increase in the PJM LOLE. The difference between a 10 percent increase in LOLE and the percentage increase in LOLE attributed to the Base Capacity product alone will be allocated to the Limited DR and Extended Summer products. PJM will then compute the allowable amount of the two DR products that can clear in the RPM auction without increasing the PJM LOLE beyond this allocated percentage. This computation will produce a graph similar to the one below:

Figure 1: Limited Demand Response and Extended Summer Product Cap



The graph shows that, if zero Limited DR clears in the auction, the cap on the Extended Summer product would be x1. If zero Extended Summer clears in the auction, the cap on the Limited product would be x2. The curve shows the various combinations of these two products that could clear in the auction while maintaining reliability at an acceptable level. Preliminary study results indicate that the RTO cap on the aggregate amount of the Base Capacity, Limited DR and Extended Summer products will be in the 10-15 percent range (expressed as a percentage of the forecasted summer 50/50 peak load). The key to this methodology is that it would ensure that the combined impact of the Base Capacity, Limited DR and Extended Summer products does not degrade the PJM LOLE by more than 10 percent.

PJM will also compute maximum product quantities for the sub-annual products for any individual LDA that is modeled separately in an RPM auction. The methodology for this computation will be similar to the methodology described above for the RTO. A base LOLE will be established for the LDA based on an LDA reserve margin equal to the sum of the LDA's internal generation and its capacity emergency import limit under peak conditions. The LDA limits on the sub-annual products will then be computed such that the LDA's LOLE does not increase by greater than 10 percent of its base LOLE. Thus a graph such as the one above indicating the allowable amounts of the Limited and Extended Summer products will be produced for each LDA modeled separately in an RPM auction. PJM will continue to compute the LDA maximum quantity restriction for the Limited product based on the current 6 hour and 10 interruption performance limitation tests. The RPM auction will then use the lowest LDA cap on the Limited product that is produced by the three tests.

IV. Unforced Capacity (UCAP) Calculations and Installed Reserve Margin

Installed Capacity vs. Unforced Capacity and Calculation of Unforced Capacity

Generating Unit

Installed Capacity (ICAP) can be thought of as the "nameplate" capability of a generating unit. ICAP represents the summer net capability of a unit, meaning the output level the unit can dependably achieve during summer conditions. Unforced Capacity (UCAP) is the ICAP value of the unit reduced by its recent actual forced outage rate (EFORd). As an equation, UCAP is calculated as:

$$\boxed{UCAP = ICAP * (1 - EFORd)}$$

EFORd is based on forced outage data for the October through September period that occurs immediately prior to the Delivery Year. See M-18, Section 4.2.5.

Historically, PJM has allowed generating units to remove forced outages that were defined as Outside Management Control from the forced outage rate that determined the amount of UCAP that could be sold into RPM auctions. As part of this Capacity Performance proposal, PJM proposes that exclusion of Outside Management Control outages no longer be allowed in calculations for the purposes of RPM UCAP. The performance penalties ultimately adopted as part of this proposal will apply to generation resources regardless of the reason for a forced outage, and therefore it would be inconsistent to remove Outside Management Control outages from the EFORd calculation utilized to determine UCAP capability and therefore RPM Capacity capability.

Intermittent Generation (No Change)

EFORd is not applicable to intermittent generation such as wind and solar. UCAP value is based on average of June through August peak hour output over three calendar years. See Manual 21.

Qualifying Transmission Upgrades (no change)

UCAP value is equal to the incremental import capability certified by PJM.

Demand Resources

Prior to RPM: Active Load Management (ALM, the PJM precursor to the current Demand Response products) was modeled such that the PJM Unforced Capacity Requirement was reduced by ALM (in MWs) * ALM Factor * Forecast Pool Requirement (FPR). See the calculation below:

$$\text{PJM Capacity Requirement} = \left[\text{Unrestricted PJM Peak Load Forecast} - \text{ALM} * \text{ALM Factor}\right] * \text{FPR}$$

Forecast Pool Requirement = FPR

When ALM was treated on the demand side as a reduction to the peak load forecast, ALM had an implicit capacity value of ALM * ALM Factor * FPR because the ALM quantity reduced the PJM Capacity Requirement by a value equal to ALM*ALM Factor*FPR.

Under RPM: PJM Capacity Requirement is replaced by PJM Reliability Requirement in UCAP terms. ALM is called DR and ALM Factor is called DR Factor. DR is offered as a supply resource and is not modeled to reduce PJM Reliability Requirement. See the calculation below:

$$\text{PJM Reliability Requirement} = \text{Unrestricted PJM Peak Load Forecast} * \text{FPR}$$

Under RPM, unrestricted peak load forecast is not reduced by DR and PJM Reliability Requirement is not reduced by DR (in MWs) * DR Factor * FPR. However, UCAP value of DR as a resource is still being calculated as DR MW * DR Factor * FPR.

DR Factor is determined assuming DR MW to be constant at any load level (basically assuming Guaranteed Load Drop type of DR). The fact that DR is constant even at a load higher than the load forecast results in a DR (discount) Factor of about 95 percent. The changes made in DR compliance effective 2012/2013 Delivery Year require load to be reduced to below PLC to meet the Nominated DR Value. This means demand reduction associated with Guaranteed Load Drop type DR would be higher at loads higher than the load forecast to comply with a DR event (similar to Firm Service Level type of DR). DR (discount) Factor is not justified with this compliance requirement for Guaranteed Load Drop and for Firm Service Level type DR and DR Factor should be eliminated. PJM further proposes to also change the compliance of Direct Load Control (DLC) programs to Firm Service Level type of compliance.

Also, FPR multiplier should not be applied in calculating UCAP value of DR because the PJM Reliability Requirement is not reduced by load reduction times FPR. RPM auctions are conducted to procure the Reliability Requirement based on 100 percent peak load forecast. When DR is treated as a supply side resource like generation, there is no difference between them in operations. In an emergency, effect of starting 100 MW generation and reducing 100 MW demand are the same. Implementing 100 MW DR does not produce "100 MW times FPR" amount of demand reduction.[3]

Energy Efficiency

To ensure treatment similar to DR resources, DR Factor and FPR multiplier were used to determine the UCAP value of EE when EE was defined as a product in RPM. The reasons provided above to eliminate these factors to value DR are applicable to EE also. The DR Factor and FPR multiplier used to determine the UCAP value of EE should be eliminated.

Implications of PJM Proposal on Installed Reserve Margin (IRM)

PJM anticipates that some stakeholders may question whether strengthening the performance requirements for Capacity Resources in PJM should enable PJM to reduce the Installed Reserve Margin due to the increased level of resource performance that can be assumed in the IRM calculation. However, calculation of the IRM already assumes an average forced outage rate. As recent history has shown, the actual forced outage rate of PJM Capacity Resources can be, and actually has been, much worse than the average on peak days. Therefore, because the IRM assumes a better level of performance by Capacity Resources than has actually been observed, the current IRM calculation is expected to better align with actual operating conditions during the most stressed times of the year via the PJM proposal. Improving Capacity Resource performance during the peak periods in actual operations, which is the goal of the PJM Capacity Performance proposal, will bring the actual resource performance more in line with the assumption utilized in the IRM calculation, meaning no change to the current calculation would be required.

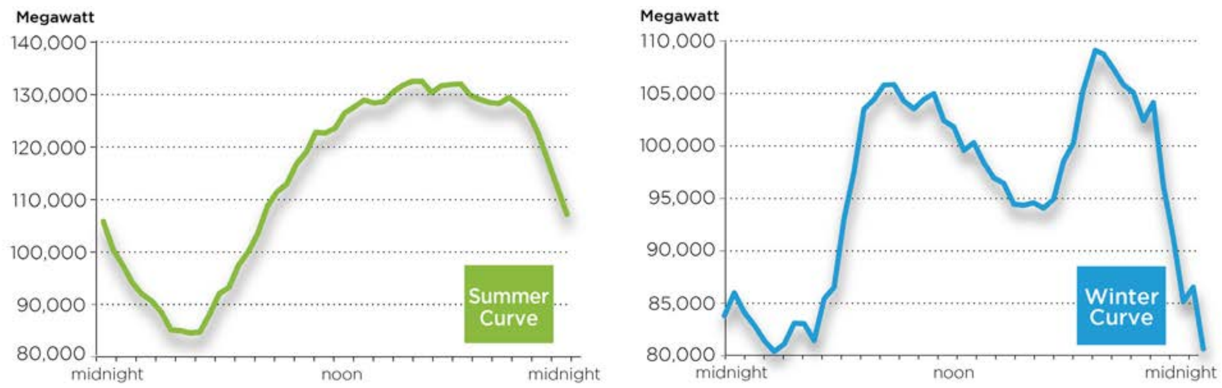
V. Capacity Performance Availability and Flexibility Requirements

General

The proposed operational requirements of committed Capacity Performance resources are described in this section. These proposed requirements are based on the operational flexibility PJM needs from supply and demand resources to most efficiently meet system needs on a peak load day. More specifically, winter peak load days pose a unique operational challenge as they have two daily peaks whereas a summer day only has one. This additional complexity is represented in the resource performance parameters and the asset classes proposed.

[3] FERC accepted a filing by ISO-NE/NEPOOL to eliminate the Reserve Margin Gross-Up for demand resources from ISO-NE market rule regarding the Forward Capacity Market (FCM) effective 2012/2013. (Order dated Dec 23, 2008; Docket No. ER09-209-000). The purpose of Reserve Margin Gross-Up has been to reflect the reserve that would not be needed if system peak load can be reduced with a perfectly available resource. Historically, vertically integrated utilities employed this approach in cost-benefit analysis of generation vs. demand–side management, but as explained above it is not applicable to RPM because DR is modeled as a supply side resource.

Figure 2: Summer vs. Winter Load Shape



Supplemental to the individual asset class requirements described in the next section, the following requirements are common to all Capacity Performance resources.

- EFORd less than 50 percent

- Must be able to operate continuously for periods of at least 16 hours on three consecutive days. This includes:

  - Generation resources with onsite fuel storage with the necessary delivery arrangements;
  - Annual DR able to fully curtail their load;
  - EE projects that achieve a consistent year-round reduction; and
  - Other resources capable of meeting the performance criteria.

- The cleared ICAP amount of the resource must be offered into the Day-Ahead Energy Market as economic excluding periods where the resource is on an outage for which a ticket was submitted and approved.

- Offer parameters submitted with a Day-Ahead Energy Market offer must be based solely on the physical limitations of the resource. This requirement applies for all schedules, regardless of whether they are price-based schedules or cost-based schedules, submitted for a given unit. PJM proposes to include in the Tariff the acceptable levels of these parameters by unit class, and also proposes to maintain the exception process such that unit operators may reflect physical conditions at individual units that may deviate from these parameters. These parameters include:

  - economic minimum
  - economic maximum
  - startup time
  - notification time
  - minimum run time
  - minimum down time
  - maximum run time

A Capacity Performance resource is expected to be staffed and ready to be operated at all times except during a planned outage. If at any point the resource's offer parameters deviate from the physical limitations of the resource it may receive a capacity penalty and will forfeit any Operating Reserves credits when operating based on non-physical parameters. (See Section VI below for additional details regarding capacity penalties.)

Flexibility Requirements

Due to the dual-peaked nature of the winter load curve, PJM values resource flexibility especially on peak winter days. The goal on a winter day is to schedule resources to meet the morning peak, either cycle them or reduce them to their minimum output during the afternoon valley, and then be able to re-start them or increase their output back up to their maximum output for the evening peak. The ability for resources to be flexible throughout an operating day is integral to efficiently dispatching the system and minimizing uplift.

There are three general classes of resources that PJM uses to manage system needs each day. The first is a base load asset class. The base load asset class would include resource types that are typically operating any time that they are not on an outage. The base load asset class includes resources such as a nuclear generation resources that cannot be operated flexibly throughout the operating day but have a high amount of run hours over the course of the year indicating that when they are available to run they are typically operating. The second class is the interday cycling asset class which consists of resources that provide the next level of flexibility but still have some restrictive parameters. These resources are defined as those that have startup and notification times that require these resources to be committed in the Day-Ahead Energy Market in enough time to meet the winter morning peak the next day and are dispatchable throughout the operating day such that PJM can reduce or increase their output as system conditions require. This interday cycling asset class also has the capability to cycle during the overnight period between contiguous days. The third asset class is the intraday cycling asset class. This class is characterized by its ability to quickly turn on and off to meet system operational needs. These resources are required to have at least two starts per day and must be able to quickly come off and re-start.

With those concepts in mind, PJM proposes the following criteria as qualification standards for committed Capacity Performance generation capacity resources.

- Base Load Asset Class
    - Resources with more than 6,000 run hours per year
    - Startup + notification time exceeds 12 hours
    - Minimum run time exceeds 18 hours
    - Minimum down time exceeds 8 hours
- Interday Cycling Asset Class
    - Startup + notification time less than or equal to 12 hours
    - Minimum run time is less than or equal to 18 hours
    - Minimum down time is less than or equal to 8 hours
    - Economic minimum is less than or equal to 50 percent of the economic maximum

- Intraday Cycling Asset Class

  - Startup + notification time less than or equal to 1 hour
  - Two or more starts per day
  - Minimum run time is less than or equal to 5 hours
  - Minimum down time is less than or equal to 2 hours
  - Economic maximum is greater than or equal to economic minimum

Energy Efficiency, Demand Resources, Storage Technologies and External Capacity may also qualify as Capacity Performance resources. The requirements for those resources are as follows:

1. Energy Efficiency

   - Full reduction must be achieved 365 days per year.

2. Demand Response

   - Must be available to achieve full reduction 365 days per year, and able to achieve full reduction continuously for at least 16 hours per day for three consecutive days
   - Shutdown + notification time less than or equal to 1 hour
   - Minimum down time less than or equal to 1 hour

3. Storage Technologies

   - Must be available to achieve full capacity output 365 days per year, and able to achieve full output continuously for at least 16 hours per day for three consecutive days
   - Startup + notification time less than or equal to 1 hour
   - Minimum down time less than or equal to 1 hour

4. External Capacity

   - External capacity resources must meet the established requirements for an exemption to the Capacity Import Limits for RPM Auctions effective with 2017/2018 Delivery Year documented in PJM Manual 18, Section 2.3 in addition to qualifying as one of the aforementioned asset classes.

VI. Changes to Base Capacity Requirements

Changes to Current Capacity to Meet Base Capacity Requirements

Flexibility

Annual capacity resources should have a startup and notification time of less than 48 hours. Units that are unable to achieve a 48 hour notice must be made unavailable and put on forced outage until they can achieve the 48 hour startup time.

Resources that are annual resources must have operational availability of a minimum of 100 run hours per year to be considered an annual resource. This minimum is regardless of any emissions or environmental limitations.

Storage Resource Eligibility

Storage resources such as pumped storage hydro plants, batteries and flywheels must be able to run for at least 10 hours per operating day at the annual capacity output but can be split into two 5 hour blocks. In addition, the unit must have a min down time of less than 3 hours between blocks. For example, a unit can come online and run for 5 hours over the morning peak at full output and then can run for 5 hours at full output for the evening peak. However, the unit must be able to do so without the need to charge in between the run hours.

VII. Peak Period Performance Assurance

Proposed Performance Requirement

PJM proposes that all units with a Capacity Performance commitment must offer into the Day-Ahead Energy Market with at least the committed quantity of ICAP available as non-emergency. In other words, a Capacity Performance committed generating unit must offer into the PJM Day-Ahead Energy Market with an economic maximum quantity at least as great as the ICAP equivalent of the committed UCAP value. Annual DR with a Capacity Performance commitment must submit an economic Day-Ahead Energy Market and Real-Time Energy Market offer in a quantity at least as great as the committed Capacity Performance MW quantity. As detailed in other sections of this paper, for generators, the parameters associated with these offers must be at least as flexible as the physical capabilities of the unit class. The expectation for the Capacity Performance product is that it will be available to provide energy at all times that resources are needed to ensure system reliability regardless of the time of year. PJM proposes that the definition of these times be all hours of those days when either a Hot Weather Alert or Cold Weather Alert is in effect, or for which PJM declares a Maximum Emergency Generation Alert, in either the entire RTO or for the portion of the PJM Region in which the resource is located.

This performance standard would require delivery of energy during all such hours if a unit was scheduled by PJM or self-scheduled to operate. The only exception from application of the penalty would be those instances when PJM did not schedule a unit, or when the unit was on line but dispatched down by PJM. The reasons PJM would dispatch a unit down could include dispatch to provide ancillary services or to control power balance or transmission constraints. It is also possible for PJM to not schedule a resource entirely because of transmission constraint, in which case the unit would not be subject to performance penalties under this proposal.

Non-Performance Penalty Calculation

The penalty calculation PJM proposes is intended to be straightforward such that it is transparent and predictable, lending itself to ready valuation by market participants and their counterparts for the purposes of developing RPM offers and financing resource development in PJM. The calculation is also based upon the ISO-NE model which has already been accepted by the FERC.

The non-performance penalty would apply for each hour when energy is scheduled as described above, and not delivered. The hourly penalty would be calculated as follows:

Hourly Energy Penalty = MW Not Delivered * Locational Marginal Price

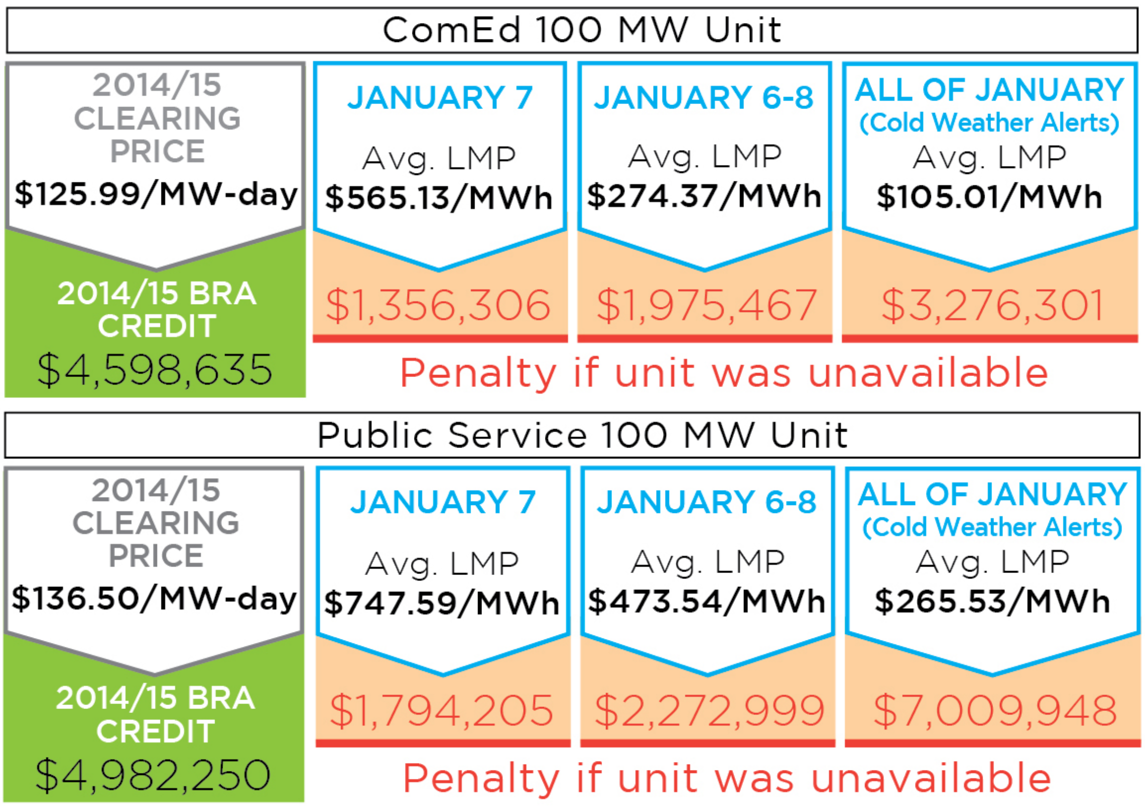
PJM proposes that the penalty apply to the lower of the quantity of MWs scheduled by PJM, or the unit's ICAP equivalent of the Capacity Performance committed UCAP value. For example, assume a unit with a 100 MW ICAP commitment is scheduled to operate by PJM and dispatched by PJM to 75 MW for a given hour. If the unit produces only 25 MW then the penalty would be the 50 MW difference between the scheduled quantity and the amount produced, times the hourly integrated LMP at the unit's bus for that hour. Assuming the same unit with the 100 MW ICAP commitment was scheduled by PJM to produce 100 MW in a given hour and the unit produced no megawatts, the penalty would be calculated as the full 100 MW Installed Capacity commitment times the hourly integrated LMP at the unit's bus for that hour.

For units that were scheduled to operate by PJM but were not on line for a particular hour and therefore did not have an economic dispatch calculated in the PJM Security Constrained Economic Dispatch (SCED) system, but were on line as scheduled by PJM for other hours of the same operating day, the scheduled quantity for any given hour will be determined by applying the hourly integrated LMP for that hour to the unit's applicable offer curve. For units that would have been scheduled to operate by PJM but were forced out for the operating day, the penalty that would apply would be for the entire 24-hour period of the day for which the Hot or Cold Weather Alert was issued. A generating unit with a Capacity Performance commitment that would have been scheduled for a given Hot or Cold Weather Alert day, and physically could have been scheduled within the timeframe necessary, but was not scheduled by PJM because its startup and notification time was longer than physically required, will incur the above performance penalty for its entire committed ICAP value for all 24 hours of the day.

PJM proposes that the penalty also apply for self-scheduled resources. For resources that are self-scheduled at a fixed output quantity, the penalty for any hour will be calculated as the committed ICAP quantity minus the unit's actual output (not less than zero MW) times the hourly integrated LMP at the unit's bus for that hour. For units that are self-scheduled at a minimum output value and then dispatchable by PJM above that value, the penalty for any given hour will be calculated the same as for units scheduled by PJM as described above.

Figure 3 below illustrates an example of how this penalty would have been calculated had it applied during January of 2014. The example supposes two 100 MW units, one in the ComEd zone in northern Illinois and one in the Public Service zone in northern New Jersey. Using the 2014/2015 RPM Base Residual Auction Resource Clearing Prices as the basis for their annual Capacity revenue, the ComEd zone unit would have received $4,598,635 in Capacity revenue for the year (the $125.99/MW-day Resource Clearing Price applicable to the ComEd zone times 100 MW times 365 days). Similarly, the Public Service zone unit would have received $4,982,250 in Capacity revenue (the $136.50/MW-day Resource Clearing Price applicable to the Public Service zone times 100 MW times 365 days). If the ComEd zone unit would have been forced out of service on the peak day, January 7, the penalty that would have applied under this proposal would have been the 24-hour average LMP of $565.13/MWh times 100 MW times 24 hours or $1,356,306. If the ComEd zone unit would have been forced out of service for the three-day period from January 6 through January 8, the penalty that would have applied under this proposal would have been the $274.37/MWh average LMP for the 72-hour period, times 100 MW times 72 hours or $1,975,467. If the ComEd zone unit would have been forced out of service for the entire month of January, the penalty that would have applied under this proposal would have been the $105.01/MWh average LMP for the days in January when Cold Weather Alerts were issued, times 100 MW times the 312 hours for the 13 days when Cold Weather Alerts were issued in the ComEd zone, or $3,276,301. In the same three sets of conditions for the 100 MW Public Service zone unit, applying the PS zone LMPs in the same manner[4], the penalties that would have been calculated under this proposal are $1,794,205, $2,272,999 and $7,009,948, respectively.

Figure 3: Example Self –Schedule Resource Penalty



[4] On January 6 and 21 the Cold Weather Alerts excluded the Mid-Atlantic region and the Dominion zone. Therefore, in the second example the Public Service zone unit's penalty was calculated based on the 48-hour period of January 7 and 8, and in the third example the 264-hour period that was the same as for the ComEd zone unit excluding January 6 and 21.

Non-Performance Penalty Offset

PJM proposes that a Capacity Market Seller may offset the penalties applied to its Capacity Resources via energy production from uncommitted units. An uncommitted unit would be defined as a unit for which all or part of the unit's capability does not have an RPM commitment for either the Capacity Performance or Base Capacity products for the Delivery Year. Energy produced by uncommitted units or portions of uncommitted units during periods when the above described penalty applies to committed units in the Generation Owner's portfolio would be used to net against those penalty amounts. The exact offset would be determined based on the product of the megawatt-hours of output from each such uncommitted unit or partially uncommitted unit and the LMP at the uncommitted unit's bus. Therefore, the penalty offset for a given Generation Owner would be the megawatt-hours of output from each unit over and above its committed Installed Capacity quantity, times the LMP at that unit's bus, summed for all such units with uncommitted megawatt. The sum of these penalty offset values would not be allowed to exceed the total penalties applied to a given Generation Owner's portfolio such that the net penalty applied cannot be less than zero.

Deficiency Penalty vs. Non-Performance Penalty

In the event that a given unit has a Capacity Performance commitment but does not achieve commercial operation by the beginning of a Delivery Year, the total penalty applied for the period until such time as commercial operation is achieved will be the greater of the Capacity Deficiency Penalty or the Non-Performance Penalty. The application of the higher of these two penalty amounts is necessary in order to ensure that resources owners do not choose to remain in a deficiency as opposed to achieving commercial operation to avoid the risk of a Non-Performance Penalty.

Capacity Performance Demand Resources and Energy Efficiency Resources

Annual DR that meets the specific qualifications, as well as EE resources that meet their specific qualifications, may offer and clear as Capacity Performance resources. Annual DR committed as Capacity Performance resources will face the same hourly energy penalty applied to Generation Capacity Performance resources. Similarly, EE resources committed as Capacity Performance resources and that either fail to achieve installation by the start of the Delivery Year or fail to achieve the required level of load reduction will be charged the hourly energy penalty applied to Capacity Performance Generation Capacity Resources for the Delivery Year.

Base Capacity Resource Penalties

PJM proposes to maintain the current penalty structure for Base Capacity Annual DR resources as well as Extended Summer and Limited DR resources. For Base Capacity generation resources, PJM proposes to apply the hourly energy penalty described above for non-delivery, but limited to those periods when PJM has loaded Maximum Generation or any more severe emergency procedure during the months of May through October. PJM proposes the elimination of the current Peak Hour Availability penalty and associated "EFORp" calculations.

Penalty Cap

PJM proposes that the total penalty applied to any individual, committed Capacity Performance resource for any Delivery Year not exceed 2.5 times the Delivery Year Resource Clearing Price credit applicable to the resource as a result of clearing in the RPM auctions applicable to that Delivery Year. Similarly, PJM proposes that the penalty applied to any individual, committed Base Capacity resource not exceed 1.5 times Resource Clearing Price credit the resource received as a result of clearing in the RPM auctions applicable to that Delivery Year. For resources acquired via bilateral transactions that did not clear in an RPM auction, the penalty caps would be based upon the RPM revenue the resource would have received had it cleared in the RPM Base Residual Auction for the applicable Delivery Year. PJM proposes these caps in order to ensure that there is some upper bound on the level of the penalty in order to allow for its valuation by prospective resources offering into RPM auctions, but maintain a maximum level of penalty that will incentivize the desired level of resource performance.

Credit Requirements

Given that PJM proposes to eliminate the current EFORp penalty and replace it with the non-performance penalties described above, PJM would propose to change the billing process by which penalties are assessed to market participants. Rather than billing penalties well after the conclusion of a Delivery Year, as is currently done given the timing of the completion of EFORp calculations, PJM would be able to begin billing penalty amounts during the Delivery Year, very shortly after non-performance actually occurred. Therefore, PJM would be able to withhold any remaining RPM revenues, and if necessary other revenues, to offset penalty charges as the Delivery Year progressed. As a result, while the potential magnitude of the penalties will increase under PJM's proposal, most significantly for Capacity Performance resources, PJM does not propose to change RPM-related credit requirements from today's levels due to the offsetting impacts of the change in the timing with which those penalties could be assessed.

VIII. Product Offer Requirements

There are three main issues with respect to offers into the capacity market: 1) The ability to reflect all costs associated with improving availability and performance during peak periods; 2) The question of must-offer requirements for the Capacity Performance product; and 3) The ability to reflect performance risk in capacity offers up to a threshold level so as to make symmetric the risk and reward for making investments to ensure performance while accounting for the fact that outages and non-performance may occur up to a certain level.

First, resource owners must be able to reflect in their capacity market offers, specifically with the Market Seller Offer Caps for Generation Capacity Resources, the costs of ensuring performance during system peaks. In general, investments and costs related to improved O&M practices are already accounted for with the Avoidable Cost Rate that goes into determining Market Seller Offer Caps under Section 6.8 of Attachment DD. Investment related to dual fuel capability and weatherization can already be accounted for within the Allowance for Project Investment Recovery, while the carrying costs associated with holding fuel inventories are accounted for in Avoidable Cost Rate. Currently the Tariff is silent on the ability to reflect the cost of firm gas pipeline transportation and other costs associated with ensuring natural gas availability and delivery which could also include storage, the cost of balancing agreements with the pipeline that allow for flexibility in takes from the pipeline, and/or park and loan services. PJM proposes to add another category into the Avoidable Cost Rate or Allowance for Project Investment Recovery to specifically account for the aforementioned pipeline services.

The ability to reflect natural gas delivery costs such as firm transportation is a necessary condition to provide the right incentives to ensure performance during system peaks. There are many different ways to secure firm delivery of gas during peaks. One is for the resource owner to directly purchase firm transportation from the pipeline. Another is to contract with a third party such as a marketer or asset manager to ensure firm commodity purchase and delivery of gas, where these costs have historically been reflected in the total gas charge on a volumetric basis. PJM is not mandating a method as to how a resource owner must ensure fuel delivery, but simply to allow these costs to be reflected in capacity market offers.

However, if a resource owner would choose to reflect the costs of firm delivery in its capacity market offer, but yet rely on a marketing or asset management agreement which states costs on a volumetric basis, those same costs should not be permitted in energy market offers as this would result in a double counting of costs. By the same token, should a resource owner choose not to reflect the costs gas delivery in the Market Seller Offer Caps and rely on volumetric recovery of costs, it would be permitted to reflect those costs in the cost-based energy market offers.

Second, there is an open question from the perspective of market power mitigation as to whether or not there should be a must offer requirement for the Capacity Performance product. If all capacity were required to satisfy the criteria for the Capacity Performance product, then the current must offer requirement would make sense. However, if there are multiple products, it is not clear how the must offer requirement should apply. At a minimum the must offer requirement to offer into the capacity market as one type of product or another should apply. But with multiple products, market incentives and competitive forces should then take over with resources offering in the product area that will result in the most surplus (clearing price minus the cost of providing the product), and assuming the design of the Capacity Performance product works as intended, there should be a sufficient incentive for most, if not all resources to offer the Capacity Performance product.

Third and finally, resource owners should have the ability to reflect performance risk, up to some threshold level, during peak periods in their offers so that there is some symmetry between risk and reward of being committed as a Capacity Performance product. To date, the Avoidable Cost Rate in Market Seller Offer Caps in the PJM capacity market includes a 10 percent adder which accounts for hard to quantify costs, which could be said to already incorporate risk along with other hard to quantify costs such as the imperfect measurement of costs in advance, or the possibility of additional costs that may be incurred from the time the capacity commitment is made to the time the capacity is delivered 3 years later.

Rather than relying entirely on the 10 percent cost adder to reflect such hard to quantify costs, resource owners should be able to reflect the risks of performance. However, in allowing such performance risk in capacity market offers, it is important to provide strong incentives for resources to make investments and incur costs to improve performance. Resource owners will only take on a commitment as a Capacity Performance product if the expected surplus from taking on that commitment (capacity price less the costs of O&M and other investments to enhance performance) is greater than the expected performance penalties to incurred if the resource does not perform at peak, where expected performance penalties are a function of the expected forced outage rate (EFORd).

So, if a resource with an EFORd of 0.25 (25 percent) were allowed to reflect the entirety of is probability of forced outage in its offer; there would be no incentive to make O&M and other investments to improve performance and reduce the EFORd because the resource would have already recovered this expected penalty from the capacity market price. If the expected penalty is completely recovered from capacity market price, the generation owner simply has an incentive to minimize costs. Consequently, performance risk should only be reflected in offers up to a target or benchmark EFORd that is assumed in the LOLE studies: the pool-wide EFORd, approximately at 0.07 (7 percent). If the pool-wide EFORd were to be used as the limit to which risk could be reflected, then resource owners in order to take on a Capacity Performance product commitment, have the incentive to incur O&M and other investments to achieve significantly better performance than PJM has historically observed during peak periods, particularly in the winter.

The proposed is a function of the pool-wide EFORd, average historic number of hours of Hot and Cold Weather Alerts, and the average Real-Time LMP the specific generation bus during those Hot and Cold Weather Alert hours:

$$\text{Risk Premium} = (\text{Pool-Wide EFORd})*(\text{Historic Hours of Hot and Cold Weather Alerts})*(\text{Average Real-Time LMP during Hot and Cold Weather Alerts})$$

IX. Cost Allocation

Current Methodology

Currently capacity costs are allocated to LSEs as Locational Reliability Charges. The LSE Locational Reliability Charge is calculated as the LSE Daily Unforced Capacity Obligation times the Final Zonal Capacity Price.

The LSE Daily Unforced Capacity Obligation is an allocation of the Zonal Unforced Capacity Obligation to LSEs based on the LSE Obligation Peak Loads. The Zonal Unforced Capacity Obligations are allocations of capacity procured in the RTO to zones pro rata based on zonal summer peak load forecasts. See M-18, Section 7.

The Zonal Capacity Price is calculated as the sum of (System Marginal Price + Locational Price Adder) for annual capacity, adjusted for (Limited DR and Extended Summer) product price decrements, price decrements for external capacity resources, and make-whole payments.

Cost Allocation Option 1 – Extension of Existing Method

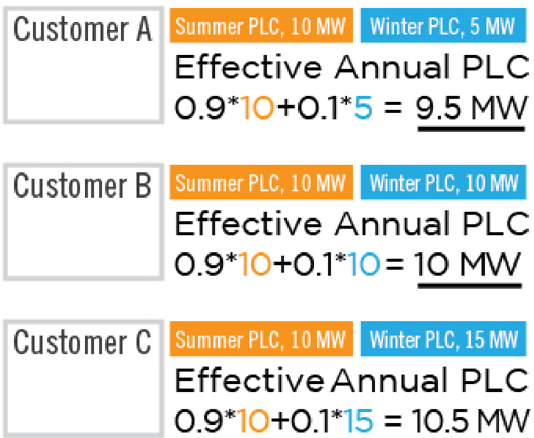
The proposed changes to create a Capacity Performance product are primarily to assure better availability of capacity in winter. However, the concept of “critical period” penalty should assure better availability of capacity in summer also. One option to cost allocation is to use the existing method. There would not be any change in calculating the Unforced Capacity Obligations. The Zonal Capacity Price would be calculated as the sum of (System Marginal Price + Locational Price Adder) for the Capacity Performance Product, adjusted for (Limited DR, Extended Summer, and Base Capacity) product price decrements, price decrements for external capacity resources, and make-whole payments.

Cost Allocation Option 2 – Winter Peak Allocation

An alternate method would be to allocate the additional cost of the Capacity Performance product in each LDA to zones based on zonal winter peak load forecasts. A Capacity Performance product cost component would be calculated as the additional cost allocated to the zone divided by the Zonal Unforced Capacity Obligation. This Capacity Performance product cost component would be added to the Zonal Capacity Price calculated without the additional Capacity Performance product cost. The allocation of Premium Capacity cost in Option 2 can be implemented by PJM up to the zonal level.

While under this second option the additional cost of the Capacity Performance product would be allocated to zones based on the winter peak load forecast, Electric Distribution Companies (EDCs) may continue to provide PJM the current summer based Obligation Peak Loads to calculate LSE Unforced Capacity Obligations for the purpose of allocating the total zonal Locational Capacity Charges to individual LSEs. PJM would apply the Zonal Capacity Price to the LSE Unforced Capacity Obligation to determine the LSE Locational Reliability Charge based on the individual LSE PLCs as submitted by the EDCs. EDCs would have an option of modifying the Obligation Peak Load as a summation of summer peak and a fraction of winter peak. This approach would recognize the risk due to higher winter peak loads in the cost allocation.

Figure 4: Example: Assume the summer/winter risk ratio = 0.9/0.1.



X. Previously Proposed RPM Changes

In March 2014, PJM had proposed several other changes to the RPM processes, in particular related to the RPM Incremental Auctions[i]. PJM believes that enhancing the definition of the PJM Capacity product as detailed in this document will achieve the objectives of some of those previously proposed changes. PJM further believes that the remainder of those changes should be postponed until the instant proposal is implemented to evaluate its effects.

PJM had proposed to include several changes to the Incremental Auction processes considered during the Replacement Capacity stakeholder discussions. Specifically, PJM proposed to eliminate the first and second Incremental Auctions from the RPM process, to implement the Incremental Auction Settlement Adjustment, and to implement the changes to the offer price at which PJM offers excess capacity into the remaining Incremental Auction due to decreases in the load forecast.

PJM believes that given the much more explicit definition of the Capacity products provided by this proposal, as well as the more specifically delineated responsibilities of committed Capacity Resources and the more straightforward penalty structure, Capacity Market Sellers should have a much clearer picture of the capability of their resources prior to offering into the Base Residual Auction. PJM therefore suggests evaluating the remainder of the Replacement Capacity proposal items in light of the changes proposed in this document.

Other clarifications and/or revisions that PJM may need to make in order to comprehensively incorporate the new capacity product into RPM are clarifying the definition of planned versus existing resources; clean up to force majeure provisions;

Day-ahead Energy Market must offer requirement clarification regarding offering available ICAP (related to defining obligations of Capacity Resources); applicability to external resources; applicability to FRR entities; revisions to modify Qualifying Transmission Upgrades Deficiency Charge and Credit Rate; and any revisions to RPM Must Offer requirements (related to defining obligations of Capacity Resources)

XI. Transition Auction Mechanism for Delivery Years 2015/16, 2016/17, 2017/18

Based on the reliability analysis PJM has performed and reported in the Capacity Performance problem statement whitepaper posted on August 1, 2014, PJM's analysis shows that a comparable rate of generator outages in the winter of 2015/2016, coupled with extremely cold temperatures and expected coal retirements, would likely prevent PJM from meeting its peak load requirements. Therefore, PJM believes it is necessary to address fuel security, winter availability and resource performance incentives/penalties beginning in the 2015/16 Delivery Year.

In order to address the reliability shortfall caused by fuel security, winter availability limitations and performance shortfalls, PJM proposes to hold an incremental auction for the 2015/16, 2016/17 and 2017/18 Delivery Years to incrementally procure a sufficient amount of capacity that adheres to the performance standards and requirements of the Capacity Performance product described in the preceding sections of this document. The incremental auction process will establish a required amount of Capacity Performance product that must be procured and the procurement auction will provide opportunity for resources with an existing capacity commitment and resources with no capacity commitment for the applicable Delivery Year to compete to provide the required amount of Capacity Performance product for which they would receive an incremental payment.

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[i] See PJM's "Replacement Capacity" filing in docket No. ER14-1461.