Capacity in the PJM Market

This report is in response to letters from five state commissions as well as a resolution passed on December 1, 2011, by the Organization of PJM States, Inc. (OPSI) seeking further information about issues which had been raised by the Independent Market Monitor (IMM) regarding PJM's capacity market.

The core matter underlying these issues is the definition of capacity and the obligations of capacity resources. Other issues addressed in this report stem from this fundamental question.

The IMM and PJM staff discuss these issues in separate whitepapers within this document.

August 20, 2012

IMM White Paper
Selected RPM Issues

The Independent Market Monitor for PJM

August 20, 2012

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Introduction

The Independent Market Monitor for PJM (IMM or MMU) has raised a number of issues related to the design of the capacity market since the introduction of the Reliability Pricing Model (RPM) for the 2007/2008 Delivery Year. Four state commissions requested by letter of November 3, 2011, that PJM respond to the issues raised by the IMM. The Ohio PUC letter of November 9, 2011, to the PJM Board requested that PJM address specific issues raised by the IMM. The Organization of PJM States, Inc. (OPSI) Board Resolution of December 1, 2011 requested that PJM address the issues raised by the IMM.[1] The letters are attached as Attachment A.

The Ohio PUC letter of November 9, 2011 listed four issues: that capacity resources required offers in the day-ahead energy market be competitive; that units take forced outages when they cannot meet their day-ahead energy offer; that OMC outage rules be made transparent and that fuel be eliminated as an OMC outage cause; and that capacity resources be paid based on whether they produce energy during the defined critical hours.

The most fundamental issues underlying the IMM issues and the OPSI requests are the definition of capacity and the obligations of capacity resources. The other issues addressed in this report all stem from the answers to these questions.

MMU Recommendations

The MMU made a series of recommendations related to the capacity market in the 2011 State of the Market Report for PJM.[2] The full recommendations are in Attachment B to this report. The MMU has also published multiple reports on the PJM Capacity Market. A list is included in Attachment C.

The recommendations included here are the recommendations made to date which are most relevant to the requests of OPSI:

- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.

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1 See MD, DE, NJ and DC Commissions' Letter Regarding RPM Performance Assessment, (November 3, 2011), See Ohio Commission Letter Regarding RPM Performance Assessment, (November 9, 2011), See OPSI Letter to the Board Regarding RPM Performance Assessment, (December 1, 2011).

2 See the *2011 State of the Market Report for PJM*, Volume 2, Section 1: Introduction, p 8.

- The MMU recommends that there be an explicit requirement that capacity unit offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.

- The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification.

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.

    - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

    - The MMU recommends that PJM eliminate all Out of Management Control (OMC) outages from use in planning or capacity markets. PJM recommends that pending elimination of OMC outages, that PJM review all requests for Out of Management Control (OMC) carefully, implement a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage.[3]

Additional recommendations which result from the analysis done for this report are included in the list of relevant recommendations in the conclusion to this report.

Capacity Market

The Reliability Pricing Model (RPM) Capacity Market is a three year forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives,

[3] This recommendation differs from the recommendation in the *2011 State of the Market Report for PJM*, but is a recommendation in the *2012 State of the Market Report for PJM: January through June*.

that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

The MMU has found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[4]

What is Capacity?

Generating resources provide both energy and capacity, and, in some cases, ancillary services. Capacity, measured in MW, is sometimes referred to as the ability to produce energy while energy, measured in MWh, is what is actually produced and consumed. Customers use energy to power air conditioners and motors. Customers do not use capacity to power air conditioners and motors.

Capacity is fundamentally an economic concept rather than a physical concept in the PJM market design, although capacity resources must be physical resources. The capacity market exists in its current form because revenues from the PJM market design, which included an energy market and a daily capacity market, were not adequate to provide an incentive to build and maintain the generating resources required to meet defined reliability requirements. While, in theory, an energy only market could be designed to produce adequate revenues, such an energy market design would require that the definition of scarcity be modified and that there be very high energy prices for a significant number of hours per year. PJM chose to implement a capacity market as a solution to the revenue adequacy problem. Both the capacity market solution and the scarcity pricing solution are administrative constructs designed to address the same issue of revenue inadequacy.

In the PJM market design, capacity markets and energy markets are inextricably intertwined. Generating units do not have capacity components and energy components. A unit is viable based on its total revenues without regard to whether they come from the capacity market or the energy market.

4 See Attachment C.

Capacity market revenues are not payments for one type of output from a unit and energy market revenues are not payments for another type of output from the same unit. The energy market requires energy for all 8,760 hours in the year. Not all units have to produce energy in all hours of the year but many base load units do so. Mid merit units produce energy for fewer hours and peaking units produce energy for fewer hours than mid merit units. But the capacity payments to each type of unit are not to reserve access to energy from those units for only a few on peak hours of the year and the capacity payments are not to reserve capacity only from peaking units. The capacity payments to each type of unit are an essential contribution to the viability of each unit type. In return for capacity market revenues, each unit type must be available at any time during the year that they are needed to meet the demand for energy from PJM customers.

Generating units that are capacity resources, as part of the obligations they take on in return for capacity payments, are required to provide a call on their energy at any time during the year, at the market price. The capacity market is designed to ensure that capacity resources cover their fixed and variable costs from a combination of energy and ancillary market net revenues and capacity market revenues. The capacity market is an annual construct. Generation owners sell capacity for a year and customers pay for capacity for a year. Net revenues and costs are evaluated for a year. The obligations of capacity resources are for a year. The relevant year in the capacity market is termed the Delivery Year, which is three years forward from the date of the capacity market base auctions.

The RPM Capacity Market design provides that there are only about 500 critical hours on which the performance incentives of capacity resources are based. In fact, it is essential that capacity resources be available to produce energy for all 8,760 hours per year in order to provide reliable service. During the shoulder period, when as much as a third or more of the PJM generation fleet may be on planned outage, it is just as critical that the remaining units provide energy as during higher demand periods when PJM does not permit units to be on planned outages. It is just as critical that capacity resources produce energy during an hour which is not a peak period hour as during a peak period hour.

Capacity resources are not committed to providing energy only during system peaks, or only during emergency conditions. If that were correct, scarcity pricing would be a more effective and cost effective way of providing an incentive to provide energy for those limited hours.

The suggestion that capacity resources are only required in order to meet loads during system peaks, or emergency conditions, derives from the pre market period in PJM history. During that period, regulated utilities built generation in order to meet load and were compensated under rate base rate of return regulation by state public utility commissions. Each utility built generation based on system planning concepts that defined the least cost type of capacity derived from forecast load duration curves and the costs of energy and capacity from different unit types. Capacity was not built just to meet peak load. Base load units were built when they were the economic choice and mid merit and peaking units were built when they were the economic choice. The capacity construct in the PJM Interconnection Agreement prior to the introduction of markets was designed to provide an incentive to each individual utility to build enough capacity to meet its individual load and to provide a rudimentary market mechanism to shift the cost of capacity at the margin if the lumpiness of capacity additions meant that one utility was short and another long capacity for a brief period of time. In effect it was an accounting mechanism to permit the exchange of money among members of the power pool when one member was temporarily short and another was temporarily long capacity compared to the individual utility reliability targets. The capacity construct during the pre market period did not serve as the source of an essential component of market revenue, as it does in the current RPM Capacity Market.

While the target amount of capacity that must be built is based on the forecasted peak load plus a reserve margin, that does not mean the capacity is only needed for peak hours. Such a conclusion would be illogical. Base load nuclear power plants are capacity resources but they are needed year round. Base load coal units are capacity resources but they are needed year round. The markets would not function if capacity resources were only needed for short periods of peak demand. Customers would not receive the service they paid for when they paid for capacity if capacity were only needed for short periods of peak demand.

The fact that the capacity price is a function of the cost of a peaking unit does not mean that only peaking units are relevant to capacity or that only peak hours are relevant to capacity. The reason that the capacity price is a function of the cost of a peaking unit is rooted in the need for a capacity market. Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity.[5] The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, capacity markets, or energy markets with administrative scarcity pricing. Regardless of the enforcement mechanism, the requirement to construct

[5] The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone, without administrative intervention. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices.

The revenue shortfall which results affects all units and all unit types. Nuclear power plants, coal plants, combined cycle plants and peaking plants all rely on the capacity market for revenue adequacy. If the energy price is too low, that affects all unit types and creates a revenue issue for all unit types.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason. But a capacity market is not the only market mechanism that can work in this situation. An energy only market with an administrative scarcity pricing can also work. In fact, such an energy only market should be the model when thinking about incentives in the capacity market design.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units.

Capacity resources commit to a firm energy product on an 8,760 hour basis. This is not a commitment for peak hours only. The expected equilibrium price in the capacity market is the full cost of new capacity, gross cost less net revenues, and not a price based on the marginal cost of existing capacity. The position that the capacity market is associated with peak hours only is not consistent with the basic design of the capacity market or the reasons for creating the capacity market.[6]

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6 This is the case regardless of the definition of peak hours used, including peak load, all on peak hours, high load hours or emergency hours.

In addition to these basic facts about the capacity market construct, the fact that capacity is an annual product is also evident from the fact that capacity is defined to include the obligation to offer energy in every hour in the year.

Many of the disagreements about the capacity market are based on a difference of opinion about what capacity is. The IMM's position is internally consistent and consistent with the actual operation of the capacity market as well as its conceptual basis and tight integration with the energy market and ancillary services market.

Obligations of Generation Capacity Resources

The sale of a generating unit as a capacity resource within PJM entails obligations for the generation owner. The first four of these requirements, listed below, are essential to the definition of a capacity resource and contribute directly to system reliability.

- **Day-Ahead Energy Market Offer Requirement.** Market sellers owning or controlling the output of a generation capacity resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in any RPM Auction, or designated as replacement capacity, and that is not unavailable due to an outage are required to offer into PJM's Day-Ahead Energy Market.[7] When LSEs purchase capacity on behalf of customers, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, PJM capacity resource owners must provide the offered energy at the offered price if the offer is accepted in the Day-Ahead Energy Market. This energy can be provided by the specific unit offered, by a bilateral energy purchase, or by an energy purchase from the Real-Time Energy Market.

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in PJM. Capacity resources must be deliverable, consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency.[8] In addition, for external capacity resources used to meet an obligation within PJM, capacity and energy must be delivered to the metered, PJM boundaries through firm transmission service.

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7 OA Schedule 1, § 1.10.1A (d).

8 Deliverable per PJM. "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Schedule 10.

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity from a generating unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures. The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load. When PJM invokes the recall right, the energy supplier is paid the PJM Real-Time Energy Market price. The sale of capacity provides the obligation of the capacity resource to provide the physical energy to PJM when it is recalled in an emergency.

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 11 of the Reliability Assurance Agreement among Load Serving Entities (RAA).

While all of these obligations are critical for the definition of the capacity product, the MMU recommendations referenced by OPSI relate primarily to the first one, the obligation to make offers in Day-Ahead Energy Market. This obligation is meaningless without a corresponding obligation to offer energy at a competitive price. This obligation is also meaningless if an emergency only (Max Emergency) offer is considered an acceptable offer because such an offer is not an actual offer of energy, but a statement that energy can only be provided for as few as one event per year.[9]

In the absence of an enforceable rule requiring competitive offers, customers who pay for capacity cannot be assured of getting what they pay for. To date, competitive pressures in the PJM energy market have resulted in only a small number of offers at prices substantially in excess of their competitive level and have resulted in energy market outcomes that reflect offers at or very close to short run marginal costs. This means that the risk to generation owners of having to offer at marginal costs is slight. This risk is further reduced by the introduction and recent substantial modification of scarcity pricing rules in PJM, which result in high prices in the energy market that are administratively determined and that do not depend on high offers for individual units.

It has also been suggested that it is too difficult to define short run marginal cost. But that assertion is demonstrably incorrect. The current local market power mitigation rules

[9] This assumes that there is one four hour emergency in a year. The number could also be zero or somewhat higher than four hours depending on actual emergencies in a year.

depend on the submission of offers equal to short run marginal costs, which are well defined in Manual 15.[10]

The risk of not having such a requirement is illustrated by the recent discussions regarding the potential import of capacity from MISO, what has been termed capacity portability. Capacity from MISO could, under a literal reading of the current rules, sell capacity in the PJM Capacity Market but make offers in the Day-Ahead Energy Market at $999 per MWh. This would permit such resources to receive revenues from the PJM Capacity Market but not effectively meet their obligation to offer energy to the PJM customers who paid for their capacity. This would permit MISO units to collect PJM Capacity Market revenues but not change their behavior in the energy market and continue to sell energy in the MISO market. The fact that MISO units are not an integrated part of the PJM markets means that, unlike PJM units, MISO units do not have an incentive to make competitive offers into the PJM Energy Market. To the contrary, MISO units have an incentive to make non-competitive offers into the PJM Energy Market because such offers permit receiving capacity market payments while not changing energy market operations.

Similarly, the obligation to make an offer into the Day-Ahead Energy Market is meaningless without the requirement that outages be taken when a unit is not able to produce energy, except in an emergency. A unit which is able to produce energy only in an emergency is not the same as a unit that is able to produce energy whenever called on. Outage status matters because outage status affects payments to capacity resources both through availability incentive payments and through the impact on the amount of unforced capacity that a unit may sell in the capacity auctions. It is essential that the outage status of units be reported and recorded accurately. Such reporting is a requirement for generation capacity resources.

The recommendation related to the definition of out of management control outages (OMC) is related to the accurate reporting of outages. It is inappropriate that units on outage do not have to reflect that outage in their outage statistics, which affect their performance incentives and the level of unforced capacity and therefore capacity sold. No outages should be treated as OMC because when a unit is not available it is not available, regardless of the reason, and the data and payments to units should reflect that fact. In addition, given that there currently are OMC rules, there should be transparent, written definitions and enforcement of OMC rules. While PJM's OMC rules currently permit fuel related issues to be classified as OMC, this should be immediately eliminated as an acceptable OMC cause. The quality and availability of fuel are causes of

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10 PJM. "Manual 15: Cost Development Guidelines," Revision 19 (June 1, 2012).

outages but these should be included as recorded outages and not be treated as nonexistent for purposes of evaluating unit performance. If a unit regularly does not have fuel because of its location or access to fuel, its outage statistics should reflect that. Similarly, the tariff provision that exempts single fuel gas units from reporting outages in the winter if they do not have access to gas should be eliminated. Such an exemption results in inaccurate and misleading outage information, which is of special concern as PJM's reliance on gas fired generation for reliability increases.

The obligation to offer into the Day-Ahead Energy Market carries with it a corresponding obligation to produce energy in real time if called on. If capacity resources do not produce energy when called on, their capacity payments should reflect that failure to perform through reported outages. Given the tight integration of the energy and capacity markets in the PJM design, the incentives to perform in the capacity market should reflect the incentives that would exist in an energy only market. Units should not be paid if they do not produce energy when they are needed.

Capacity Performance Incentives

The performance incentives in the capacity market are intended to provide incentives for capacity resources to be fully available to provide energy when needed. The goal of the performance incentives should be to match the incentives that would result from a competitive all energy market with administrative scarcity pricing.

The capacity market performance incentives use metrics based on forced outage rates and on the requirements of capacity resources to pass tests related to their committed installed capacity (ICAP) levels.

Outages

There are multiple types of outages taken by generating units, including maintenance outages, planned outages and forced outages. It is assumed that because maintenance outages and planned outages are largely under the control of the generating unit owner, must be coordinated with PJM, and cannot be taken during peak periods, such outages are less relevant to the level of capacity required to reliably operate the wholesale power market, although there is an explicit performance incentive related to taking maintenance outages during peak periods without PJM's permission. Forced outages are unpredictable and therefore must be accounted for when determining the level of installed capacity required to reliably operate the system.

The physical capability of a unit is referred to as installed capacity (ICAP) or nameplate capacity.[11] The physical capability of a unit, adjusted for its forced outage rate, is referred to as unforced capacity (UCAP). UCAP is equal to ICAP reduced by the forced outage rate. There are multiple metrics for the forced outage rate, but the best such metric is the Equivalent Demand Forced Outage Rate, or EFORd. Thus, if ICAP is 100 MW and the forced outage rate is 10 percent, then UCAP is 90 MW. This can also be expressed as UCAP = ICAP * (1 – EFORd). UCAP is the commodity that is directly bought and sold in the PJM Capacity Market, but the link to the underlying ICAP is essential.

As a result, the forced outage rate is a capacity performance incentive. The higher the forced outage rate, the less capacity can be sold from a generating unit in the capacity market and the lower are the capacity market revenues for that unit. The capacity market creates an incentive to have low forced outage rates in this direct way. The forced outage rate also affects the level of payment actually received for the level of capacity sold in the RPM Auctions. If the actual forced outage rate during peak periods is greater than the forced outage rate on which the sale of UCAP is based, net payments to the capacity resource are correspondingly reduced. This is also a direct incentive to have low forced outage rates.

Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp.

The unadjusted forced outage rate of a generating unit is measured as the Equivalent Demand Forced Outage Rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours,[12] service hours, average forced outage duration, average run time, average time between unit starts, available

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11 The ICAP value of a generation resource under RPM is based on the net dependable summer capability of a unit.

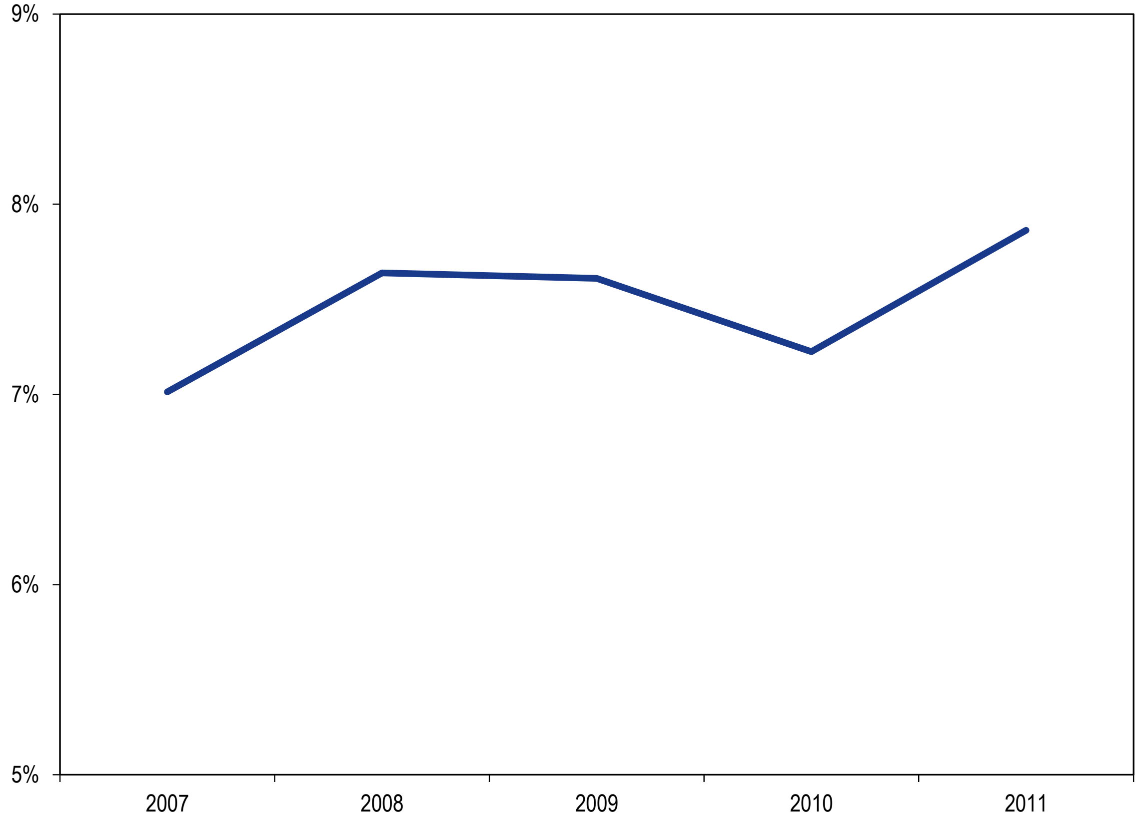
12 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

hours and period hours.[13] The EFORd metric includes all forced outages, regardless of the reason for those outages.

EFORd

Figure 1 shows the average EFORd since 2007 for all units in PJM.

Figure 1 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2011



The average EFORd results do not show the underlying pattern of EFORd rates by unit type. The distribution of EFORd by unit type is shown in Figure 2. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Steam and combustion turbine units have the greatest variance in EFORd values, while nuclear and combined cycle units have the lowest variance in EFORd values.

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13 See "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Equations 2 through 5.

Figure 2 PJM 2011 distribution of EFORd data by unit type

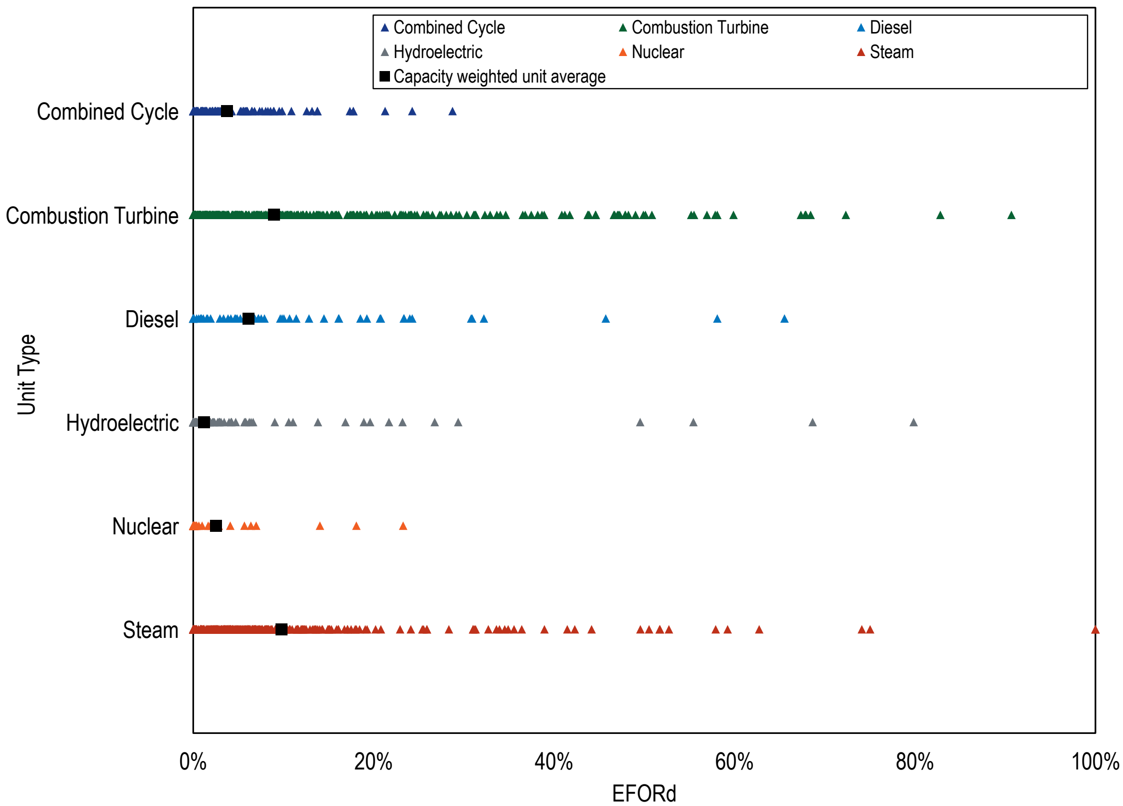

Table 1 compares PJM EFORd data by unit type to the five year North American Electric Reliability Council (NERC) average EFORd data for corresponding unit types.[14] In PJM in 2011, all unit types had EFORd rates less than the five year NERC averages, except steam units.

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[14] NERC defines combustion turbines in two categories: jet engines and gas turbines. The EFORd for the 2006 to 2010 period are 9.6 percent for jet engines and 9.6 percent for gas turbines per NERC's GADS "2006-2010 Generating Unit Statistical Brochure – Units Reporting Events," <http://www.nerc.com/files/2006-2010_Generating_Unit_Statistical_%20Brochure%20-%20Units_%20Reporting_%20Events%20only.zip>. Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM values are weighted by capability for each calendar year.

Table 1 PJM EFORd data comparison to NERC five year average for different unit types: Calendar years 2007 to 2011

	2007	2008	2009	2010	2011	NERC EFORd 2006 to 2010 Average
Combined Cycle	3.7%	3.8%	4.2%	3.8%	3.2%	5.0%
Combustion Turbine	11.0%	11.1%	9.9%	8.9%	7.8%	9.6%/9.6%
Diesel	11.9%	10.4%	9.3%	6.1%	9.0%	15.8%
Hydroelectric	2.1%	2.0%	3.1%	1.2%	2.2%	5.2%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	3.0%
Steam	9.1%	10.1%	9.4%	9.8%	11.2%	7.6%
Total	7.0%	7.6%	7.6%	7.2%	7.9%	NA

Other Forced Outage Rate Metrics

There are two additional primary forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours.

The PJM Capacity Market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit's ICAP, rather than one minus EFORd.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations of XEFORd, which are used to determine the level of unforced capacity for specific units in PJM's Capacity Market.

Thus the PJM Capacity Market rules, as currently written, create an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[15] [16] An outage can be classified as an OMC outage only if

15 Generator Availability Data System Data Reporting Instructions state, "The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control… There are a number of

the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[17] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per the NERC directive.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market. That choice was made by PJM and can be modified without violating any NERC requirements.[18] It is possible to have an OMC outage under the NERC definition, which PJM does not define as OMC for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

At present, PJM does not have a clear, documented, public set of criteria for designating outages as OMC.

Table 2 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 11.6 percent of all forced outages. The largest contributor to OMC outages, lack of fuel, was the cause of 47.3 percent of OMC outages and 5.5 percent of all forced outages in 2011. This understates the role of fuel related OMC outages because

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outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/files/2009_GADS_DRI_Complete_SetVersion_010111.pdf>.

16 See GADS Data Reporting Instructions – January 2012, Appendix K – Outside Management Control. North American Electric Reliability Corporation, <http://www.nerc.com/files/Appendix_K_Outside_Plant_Management_Control.pdf>.

17 For a list of these cause codes, see the *MMU Technical Reference for PJM Markets,* at "Generator Performance: NERC OMC Outage Cause Codes."

18 It is unclear whether there were member votes taken on this issue.

there were substantially more natural disaster related OMC outages in 2011 than prior years. The largest contributor to OMC outages, lack of fuel, was the cause of 66.6 percent of OMC outages and 7.0 percent of all forced outages in 2010. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels." Of the OMC lack of fuel outages in 2011, 97.5 percent of the outage MW were submitted by units operated by a single owner.

Table 2 OMC Outages: Calendar year 2011

	% of OMC Forced Outages					% of all Forced Outages				
OMC Cause Code	2007	2008	2009	2010	2011	2007	2008	2009	2010	2011
Lack of fuel	43.3%	70.3%	87.1%	66.6%	47.4%	3.0%	9.3%	8.6%	7.0%	5.7%
Earthquake	0.0%	0.0%	0.0%	0.0%	31.3%	0.0%	0.0%	0.0%	0.0%	3.8%
Tornados	0.0%	0.0%	0.0%	0.0%	4.1%	0.0%	0.0%	0.0%	0.0%	0.5%
Switchyard transformers and associated cooling systems external	0.4%	0.3%	0.0%	0.1%	3.3%	0.0%	0.0%	0.0%	0.0%	0.4%
Transmission system problems other than catastrophes	7.8%	3.9%	1.6%	1.4%	3.3%	0.5%	0.5%	0.2%	0.1%	0.4%
Flood	0.6%	0.7%	3.0%	11.6%	3.3%	0.0%	0.1%	0.3%	1.2%	0.4%
Other switchyard equipment external	0.8%	1.2%	3.0%	1.5%	1.3%	0.1%	0.2%	0.3%	0.2%	0.2%
Other miscellaneous external problems	9.3%	1.2%	0.5%	0.6%	0.9%	0.6%	0.2%	0.0%	0.1%	0.1%
Switchyard system protection devices external	1.6%	0.6%	0.6%	0.7%	0.9%	0.1%	0.1%	0.1%	0.1%	0.1%
Switchyard circuit breakers external	0.4%	0.9%	0.6%	4.0%	0.8%	0.0%	0.1%	0.1%	0.4%	0.1%
Lightning	1.5%	1.4%	1.9%	0.6%	0.8%	0.1%	0.2%	0.2%	0.1%	0.1%
Transmission line	0.1%	0.7%	0.4%	0.1%	0.7%	0.0%	0.1%	0.0%	0.0%	0.1%
Storms	0.4%	0.1%	0.3%	0.2%	0.6%	0.0%	0.0%	0.0%	0.0%	0.1%
Hurricane	0.0%	0.1%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%
Lack of water	0.2%	0.4%	0.3%	0.8%	0.3%	0.0%	0.1%	0.0%	0.1%	0.0%
Transmission equipment at the 1st substation	0.1%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission equipment beyond the 1st substation	3.0%	3.8%	0.0%	3.3%	0.2%	0.2%	0.5%	0.0%	0.3%	0.0%
Miscellaneous regulatory	15.4%	14.4%	0.5%	0.0%	0.0%	1.1%	1.9%	0.0%	0.0%	0.0%
Other catastrophe	10.6%	0.0%	0.0%	8.3%	0.0%	0.7%	0.0%	0.0%	0.9%	0.0%
Fire, not related to a specific component	0.6%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other fuel quality problems	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Low BTU coal	1.7%	0.1%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Plant modifications strictly for compliance with new or changed regulatory requirements	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Regulatory proceedings and hearings	1.6%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	6.9%	13.2%	9.9%	10.5%	12.0%

An outage is an outage, regardless of the cause. Lack of fuel is especially noteworthy because the lack of fuel reasons are arguably not outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. It is significant that some OMC outages are classified as economic. Firm gas contracts could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage. If a particular unit or set of units have outages on a regular basis for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.

If there were units in a constrained Locational Deliverability Area (LDA) that regularly had a higher rate of OMC outages than other units in the LDA and in PJM, and that cleared in the capacity auctions, the supply and demand in that LDA would be affected. The payments to the high OMC units would be too high and the payments to other units in the LDA would be too low. This market signal, based on the exclusion of OMC outages, favors generating units with high forced outage rates that result from causes classified as OMC, compared to generating units with no OMC outages.

With the OMC rules in place, if a new unit were considering entry into a constrained LDA and had choices about the nature of its fuel supply, the unit would not have an incentive to choose the most reliable fuel source or combination of fuel sources, but simply the cheapest. The OMC outage rules would provide the wrong incentive. While it is up to the generation investor to determine its fuel supply arrangements, the generation investor must also take on the risks associated with its fuel supply decisions rather than being able to shift those risks to other generation owners and to customers, which is exactly what occurs under the OMC rules as currently implemented. This issue is especially critical in a time when almost all incremental conventional generation in PJM is gas fired.

The NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules.[19]

It is clear that OMC outages defined as lack of fuel should not be identified as OMC and should not be excluded from the calculation of XEFORd and EFORp.

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[19] See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf> When a Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of Unforced Capacity such Installed Capacity Suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as Outside Management Control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that PJM review all requests for OMC carefully, develop a clear, transparent set of written public rules governing the designation of outages as OMC and post those guidelines. Any resultant OMC outages may be considered by PJM but should not be reflected in forced outage metrics which affect system planning or market payments to generating units.

The MMU recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage. The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice.

Table 3 shows the impact of OMC outages on EFORd for 2011. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2011 was lack of fuel. Combustion turbine units have natural gas fuel curtailment outages that were also classified as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. In 2011, coal steam XEFORd was 1.1 percentage points less than EFORd, which translates into a 995 MW difference in unforced capacity.

Table 3 PJM EFORd vs. XEFORd: Calendar year 2011

	EFORd	XEFORd	Difference
Combined Cycle	3.2%	3.0%	0.2%
Combustion Turbine	7.8%	6.4%	1.5%
Diesel	9.0%	3.0%	6.0%
Hydroelectric	2.2%	1.7%	0.5%
Nuclear	2.8%	1.6%	1.2%
Steam	11.2%	10.1%	1.1%
Total	7.9%	6.8%	1.0%

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[20] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).

In 2011, PJM EFOF was 5.3 percent. This means that 5.3 percent of generation availability was lost as a result of forced outages. Table 4 shows that forced outages for boiler tube leaks, 19.5 percent of the systemwide EFOF, were the largest single contributor to EFOF. In addition to the top 19 identified causes, All Other Causes accounted for the remaining 20.7 percent of lost generation availability due to forced outages.

Table 4 Contribution to EFOF by unit type by cause: Calendar year 2011

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	3.6%	0.0%	0.0%	0.0%	0.0%	24.3%	19.5%
Electrical	10.2%	15.0%	8.2%	15.0%	12.8%	5.3%	6.8%
Boiler Piping System	13.4%	0.0%	0.0%	0.0%	0.0%	6.9%	6.1%
Boiler Air and Gas Systems	0.1%	0.0%	0.0%	0.0%	0.0%	7.4%	5.9%
Economic	0.7%	4.5%	2.6%	3.3%	0.0%	6.7%	5.6%
Catastrophe	0.7%	1.5%	13.7%	21.9%	44.6%	0.6%	4.7%
Feedwater System	2.5%	0.0%	0.0%	0.0%	2.6%	4.9%	4.2%
Generator	1.9%	0.4%	0.7%	3.9%	0.0%	5.0%	4.1%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	5.0%	4.0%
Circulating Water Systems	3.9%	0.0%	0.0%	0.0%	8.3%	2.2%	2.6%
Reserve Shutdown	3.7%	14.7%	1.6%	0.6%	0.4%	1.5%	2.2%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	2.1%
Miscellaneous (Generator)	9.0%	6.0%	0.9%	3.2%	1.6%	1.2%	1.9%
Fuel Quality	0.0%	0.0%	1.8%	0.0%	0.0%	2.4%	1.9%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	1.8%
Auxiliary Systems	3.2%	14.2%	0.0%	0.2%	0.0%	0.7%	1.5%
Valves	7.4%	0.0%	0.0%	0.0%	0.0%	1.4%	1.5%
Cooling System	0.1%	0.0%	0.2%	8.0%	1.4%	1.5%	1.4%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	14.9%	0.0%	1.3%
All Other Causes	39.2%	43.8%	70.3%	43.9%	13.4%	18.3%	20.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The fifth largest single contributor to lost generation availability was the Economic category, which was the cause of 5.6 percent of generation availability lost as a result of forced outages. Economic reasons are not physical causes of forced outages.

Table 5 shows the categories which are included in the Economic category.[21] Lack of fuel that is considered Outside Management Control accounted for 97.0 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 1.7 percent.

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20 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

21 The classification and definitions of these outages are defined by NERC GADS.

OMC Lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels,"[22] and was used by 55 combined cycle, combustion turbine and steam units in 2011. Only a small number of units used other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 5 Contributions to Economic Outages: 2011

	Contribution to Economic Reasons
Lack of fuel (OMC)	97.0%
Lack of fuel (Non-OMC)	1.7%
Lack of water (Hydro)	0.6%
Other economic problems	0.5%
Fuel conservation	0.2%
Problems with primary fuel for units with secondary fuel operation	0.0%
Total	100.0%

Table 6 Contribution to EFOF by unit type: Calendar year 2011

	EFOF	Contribution to EFOF
Combined Cycle	2.6%	5.0%
Combustion Turbine	1.9%	5.8%
Diesel	4.2%	0.1%
Hydroelectric	0.7%	1.1%
Nuclear	2.3%	8.6%
Steam	7.7%	79.5%
Total	4.9%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units had the largest share (50.1 percent) of PJM capacity, had a high duty cycle and in 2011 had an EFORd of 11.2 percent which yields a 79.5 percent contribution to PJM systemwide EFOF. Using the values in Table 6 the contribution of individual unit type causes to PJM systemwide EFOF can be determined. For example, the value for boiler tube leaks in Table 4 multiplied by the contribution value in Table 6 for the same unit type will yield the percent contribution to the EFOF for that outage cause. Boiler

22 The classification and definitions of these outages are defined by NERC GADS.

tube leaks contributed 24.3 percent of the EFOF for steam units, total EFOF for steam units was 7.7 percent, which means that boiler tube leaks account for 1.9 percentage points of the 7.7 percent steam unit EFOF.

The EFORp Metric

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August.[23] This results in approximately 500 hours per year. There will be 493 such hour in 2012, there were 489 such hours in 2011, and there were 485 such hours in 2010. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like the XEFORd metric, EFORp excludes OMC outages.

Table 7 shows the contribution of each unit type to the system EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Forced MW for a unit type is the EFORp multiplied by the generators' net dependable summer capability.

Table 7 Contribution to EFORp by unit type (Percentage points): Calendar years 2010 to 2011

	2010	2011
Combined Cycle	0.4	0.2
Combustion Turbine	0.5	0.5
Diesel	0.0	0.0
Hydroelectric	0.0	0.1
Nuclear	0.5	0.4
Steam	3.8	3.5
Total	5.2	4.7

23 See "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012). The hour ending 15:00 EPT through the hour ending 19:00 EPT on any day during the calendar months of June through August that is not a Saturday, Sunday, or a federal holiday, and the hour ending 8:00 EPT through the hour ending 9:00 EPT and the hour ending 19:00 EPT through the hour ending 20:00 EPT on any day during the calendar months of January and February that is not a Saturday, Sunday, or a federal holiday. The total number of hours is approximately 500, and can vary from year to year.

Table 8 PJM EFORp data by unit type: Calendar years 2010 to 2011

	2010	2011
Combined Cycle	3.0%	1.6%
Combustion Turbine	2.9%	3.4%
Diesel	3.3%	2.3%
Hydroelectric	1.1%	1.9%
Nuclear	2.9%	2.1%
Steam	7.7%	7.0%
Total	5.2%	4.7%

A Comparison of EFORd, XEFORd and EFORp Results

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[24] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, forced outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than EFORd and lower than XEFORd, suggesting that units elect to take forced outages, excluding OMC outages, during off-peak hours, as much as it is within their control to do so. That is consistent with the incentives created by the PJM Capacity Market. Even larger differences would be expected if units' performance incentives were based on a forced outage metric which did not exclude OMC outages.

Table 9 shows the capacity-weighted class average of EFORd, XEFORd and EFORp and the differences between the metrics.

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24 See "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Definitions.

Table 9 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2011[25]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.2%	3.0%	1.6%	0.2%	1.5%
Combustion Turbine	7.8%	6.4%	3.4%	1.5%	4.4%
Diesel	9.0%	3.0%	2.3%	6.0%	6.7%
Hydroelectric	2.2%	1.7%	1.9%	0.5%	0.3%
Nuclear	2.8%	1.6%	2.1%	1.2%	0.8%
Steam	11.2%	10.1%	7.0%	1.1%	4.2%
Total	7.9%	6.8%	4.7%	1.0%	3.2%

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Table 10.

Table 10 PJM EFORd, XEFORd and EFORp: Calendar year 2011[26]

	EFORd	XEFORd	EFORp
January	7.5%	6.2%	4.4%
February	7.8%	6.1%	3.7%
March	7.2%	6.1%	NA
April	5.7%	4.7%	NA
May	7.2%	6.7%	NA
June	6.9%	6.2%	4.5%
July	6.2%	5.8%	4.8%
August	6.5%	5.8%	4.7%
September	8.0%	6.2%	NA
October	7.8%	5.8%	NA
November	7.1%	5.2%	NA
December	6.3%	5.0%	NA

On a monthly basis, unit availability as measured by the equivalent availability factor increased during the summer months of June, July and August, primarily due to decreasing planned and maintenance outages, as illustrated in Figure 3.

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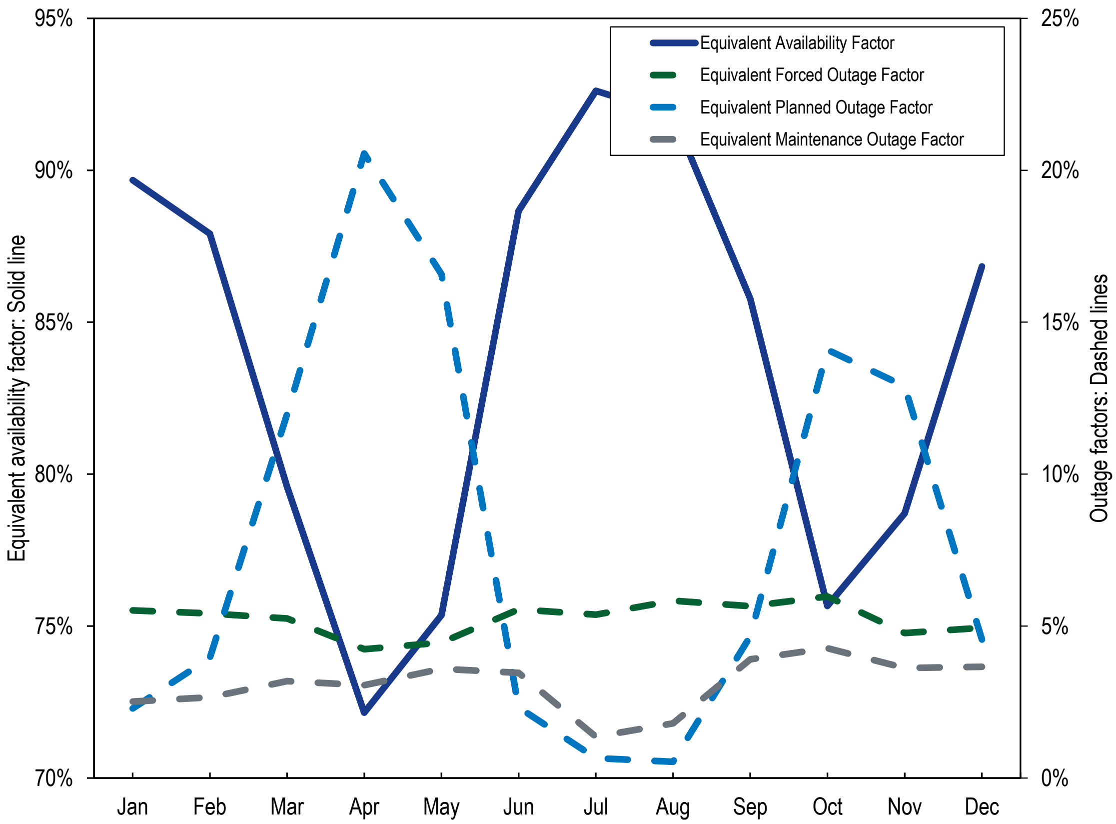
25 EFORp is only calculated for the peak months of January, February, June, July, and August.

26 EFORp is only calculated for the peak months of January, February, June, July, and August.

Figure 3 PJM monthly generator performance factors: 2011



Implications of Using XEFORd or EFORp Rather Than EFORd

PJM uses forced outage rates to determine the level of reserve margin above forecasted peak load which must be maintained in order to keep the system reliable.

The Probabilistic Reliability Index Study Model (PRISM) model PJM uses to run the Reserve Requirement Study (RRS) uses EFORd to calculate the Installed Reserve Margin (IRM). The Installed Reserve Margin (IRM) is the installed capacity percent above the forecasted peak load required to satisfy a Loss of Load Expectation (LOLE) of, on average, 1 Day in 10 Years.

The determination of the Forecast Pool Requirement (FPR) using XEFORd means using the lower XEFORd measure rather than EFORd, which results in a higher FPR than would be the case if EFORd were used. XEFORd is used to determine the FPR presumably because XEFORd is used to calculate the UCAP amounts to be offered in the RPM Auctions for individual generating units. The use of XEFORd in the FPR calculation means that the total required UCAP that must be procured in an RPM Auction is higher than it would be if EFORd were used. In aggregate, the higher UCAP is associated with the same ICAP. In theory therefore there is no impact on the total ICAP procured and overall reliability is not affected.

But that is not the result on an individual unit basis or on an individual LDA basis. The use of XEFORd biases the selection of units in RPM and results in a different mix of units than would result if EFORd were used. For example, if a 100 MW unit had a 50 percent EFORd, it could offer only 50 MW into RPM if EFORd were used as the metric. It could also offer only 50 MW if XEFORd were used as the metric and none of its forced outages were classified as OMC. However, if another 100 MW unit with a 50 percent EFORd could classify all its forced outages as OMC, its XEFORd would be 0 percent and it could offer 100 MW into the RPM Auction. Thus, the use of XEFORd creates a bias between units with OMC outages and units without OMC outages that have the same EFORd. The result is that units with OMC outages will clear more MW and be paid more as a result than units without OMC outages when they have identical EFORd rates and they both clear at the same price in an RPM Auction.

If all units had the same proportion of OMC outages, this would not matter. But that is not the case. The declared OMC outages are very asymmetrically distributed and a very small number of units account for most OMC outages.

Performance Incentives

There are a number of performance incentives in the capacity market, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market.[27] The most basic incentive is that associated with the reduction of payments for a failure to perform. In any market, sellers are not paid when they do not provide a product. That is only partly true in the PJM Capacity Market. In addition to the exclusion of OMC outages, which reduces forced outage rates resulting in payments to capacity resources not consistent with actual forced outage rates, other performance incentives are not designed to ensure that capacity resources are paid when they perform and not paid when they do not perform.

Under the peak hour availability charge, the maximum exposure to loss of capacity market revenues is 50 percent in the first year of higher than 50 percent EFORp. That percent increases to 75 percent in year two of sub 50 percent performance and to 100 percent in year three, but returns to a maximum of 50 percent after three years of better performance.

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27 This section focuses on capacity resources that are not in FRR plans. The FRR incentives differ from the incentives discussed here.

This limitation on maximum exposure is in addition to limitations that result from the way in which PJM applies the OMC rules in the calculation of EFORp and XEFORd, is in addition to the exclusion for gas availability in the winter, which is over and above the OMC exclusion, and is in addition to the case where a unit has less than 50 service hours in a delivery year and can use the lower of the delivery year XEFORd or EFORp.

Not all unit types are subject to RPM performance incentives. In addition to the exceptions which apply to conventional generation as a result of EFORp and XEFORd calculations, wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules. Hydro generation capacity resources are not subject to peak season maintenance compliance rules.[28]

Given that all generation is counted on for comparable contributions to system reliability, the MMU recommends that all generation types face the same performance incentives.

The potential interactions among the performance incentives are important in evaluating the total performance incentives facing capacity resources. The capacity resource charges for non performance are not additive. If a unit is subject to a charge associated with non performance for a day, other charges are not added for that same non performance.

Nonetheless, a unit which fails the generation resource test every day of the delivery year and does not purchase replacement capacity, or a unit which has a capacity resource deficiency every day of the delivery year and does not purchase replacement capacity, could face the loss of 100 percent of its capacity revenue for the unit. Under these circumstances, total non performance would result in total non payment. In addition, such a unit could pay back more than 100 percent of its capacity revenue if the unit owner failed to buy replacement capacity.

Relationship among the types of performance charges

- Generation Resource Rating Test Failure Charge
    - Does not apply if the unit paid the Capacity Resource Deficiency Charge.
    - Does not apply if the unit paid the Peak Season Maintenance Compliance Penalty Charge.
- Capacity Resource Deficiency Charge

[28] PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012) p. 98.

    - Does not apply if the unit paid the Generation Resource Rating Test Failure Charge.
    - Does not apply if the unit paid the Peak Season Maintenance Compliance Penalty Charge.
- Peak-Hour Period Availability Charge
    - Applies to the approximately 500 peak hours.
    - Capacity shortfall is limited to 50 percent of the unit's UCAP commitment.
        - If the 50 percent limit is triggered, the limit increases to 75 percent in year two.
        - If the 75 percent limit is reached, the limit increases to 100 percent in year three.
    - Does not include days on which the unit paid the Generation Resource Rating Test Failure Charge, Capacity Deficiency Charge, or Peak Season Maintenance Compliance Penalty Charge.[29]
- Peak Season Maintenance Compliance Penalty Charge
    - Only applies to maintenance outages not authorized by the Office of the Interconnection.
    - Does not apply if the unit failed the Generation Resource Rating Test Failure Charge.
    - Does not apply if the unit paid the Capacity Resource Deficiency Charge.

For example, the peak hour availability charge does not apply if the unit unavailability results in a rating test failure or a capacity resource deficiency charge or penalty.

If a unit failed to perform for any of the identified RPM peak load hours in a year, it would be subject to a 50 percent reduction in RPM revenues from the peak hour availability charge. But, if that unit had less than 50 service hours during peak hours, the reduction would be less than 50 percent if the unit's overall delivery year EFORd is less than the unit's EFORp.

The maximum charge to which a unit could be subject for non performance during a delivery year depends on the nature of the non performance. The Capacity Resource Deficiency Charge is equal to the seller's weighted average resource clearing price for the resource, plus the higher of 0.20 times the seller's weighted average resource clearing

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[29] The peak hour availability charge calculation "shall not include any day such a resource was unavailable if such unavailability resulted in a charge or penalty due to delay, cancellation, retirement, de-rating, or rating test failure." PJM. OATT Attachment DD § 10(e).

price for the resource or $20 per MW-day. The charge could be greater than the RPM revenues received.

Peak Hour Availability Charge

In concept, units do not receive RPM revenues to the extent that they do not perform during defined peak hours, but there are significant limitations on this incentive in the current rules.

The maximum level of RPM revenues at risk are based on the difference between a unit's actual Peak Period Capacity Available (PCAP) and the unit's expected Target Unforced Capacity (TCAP). PCAP is based on EFORp while TCAP is based on XEFORd-5. PCAP is the resource position, while TCAP is the resource commitment. In other words, if the forced outage rate during the peak hours (EFORp) is greater than the forced outage rate calculated over a five year period (XEFORd-5), the unit owner may have a capacity shortfall of up to 50 percent of the unit's capacity commitment in the first year.

(PCAP) Peak Period Capacity = ICAP * (1 - EFORp)

(TCAP) Target Unforced Capacity = ICAP * (1 – XEFORd-5)

Peak Period Capacity Shortfall = TCAP - PCAP

The Peak-Hour Period Availability Charge is equal to the seller's weighted average resource clearing price for the delivery year for the LDA.[30]

The peak hour availability charge understates the appropriate revenues at risk for underperformance because it is based on EFORp and because it is compared to a five year XEFORd. Both outage measures exclude OMC outages. The use of a five year average XEFORd measure is questionable as the measure of expected performance during the delivery year because it covers a period which is so long that it is unlikely to be representative of the current outage performance of the unit. The UCAP sold during a delivery year is a function of ICAP and the final Effective EFORd,[31] which is defined to be the XEFORd calculated for the 12 months ending in September in the year prior to the Delivery Year.

30 PJM. OATT Attachment DD § 10 (j).

31 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), p. 159

This maximum level of RPM revenues at risk is reduced by several additional factors including the ability to net any shortfalls against over performance across all units owned by the same participant within an LDA and the ability to use performance by resources that were offered into RPM but did not clear as an offset.[32]

Excess Available Capacity (EAC) may also be used to offset Peak Hour Availability shortfalls. EAC is capacity which was offered into RPM Auctions, did not clear but was offered into all PJM markets consistent with the obligations of a capacity resource. EAC must be part of a participant's total portfolio, but does not have to be in the same LDA as the shortfall being offset, unlike the netting provision.[33]

There is a separate exception to the performance related incentives related to lack of gas during the winter period. Single-fuel, natural gas-fired units do not face the Peak-Hour Period Availability Charge during the winter if the capacity shortfall was due to non-availability of gas to supply the unit.[34] The result is an exception, analogous to the lack of fuel exception, except much broader, which appears to have no logical basis.

There is a separate exception to the performance related incentives related to a unit that runs less than 50 hours during the RPM peak period. If a unit runs for less than 50 peak period service hours, then the EFORp used in the calculation of the peak hour availability charges is based on PCAP calculated using the lower of the delivery year XEFORd or the EFORp.[35]

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[36]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[37]

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[32] PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.

[33] PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.1.

[34] PJM. OATT Attachment DD § 7.10 (e).

[35] PJM. OATT Attachment DD § 7.10 (e).

[36] PJM. OATT Attachment DD § 7.10 (a).

[37] PJM. OATT Attachment DD § 7.10 (e).

Capacity Resource Deficiency Charge

A capacity owner may not be able to meet their obligation to provide capacity every day for reasons including but not limited to unit cancellations or delays, unit deratings or retirements, or increases in EFORd between the determination of the sell offer EFORds and the final Effective EFORd for the Delivery Year.[38] If this occurs, unit owners must pay for the difference between the unit's Daily RPM Generation Resource Position and its Daily RPM Resource Commitments, or obtain replacement capacity.

The unit is charged daily for any MW shortfall at the daily deficiency rate which is equal to the seller's weighted average resource clearing price for the resource, plus the higher of 0.20 times the seller's weighted average resource clearing price or $20 per MW-day.[39]

Capacity resource owners may obtain replacement capacity in the same LDA and with the same or better temporal characteristics (product type availability). DR sellers may avoid paying the Capacity Resource Deficiency Charge due to permanent departure of the associated load from the system if the relief from the charges is granted by PJM.[40]

Generator Resource Rating Test Failure

A failure to test to the amount of ICAP committed in an RPM Auction results in a unit ICAP shortfall, unless the owner obtains replacement capacity.[41] Capacity owners may avoid being tested in the winter. Capacity owners may perform an unlimited number of tests in order to achieve compliance.

The associated charge is equal to the ICAP shortfall times (1 – Effective EFORd) times the daily deficiency rate, which is equal to the seller's weighted average resource clearing price for the resource, plus the higher of 0.20 times the seller's weighted average resource clearing price for the resource or $20 per MW-day.[42] The charge applies to every day in the delivery year starting with the first test failure.

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38 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), § 8.2.1.

39 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Definitions 9.1.3.

40 PJM. OATT Attachment DD § 8.4.

41 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), § 8.4.6.

42 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), § 9.1.5; and PJM. OATT Attachment DD § 7.1 (b).

Generation owners may obtain replacement capacity in the same LDA to offset any testing shortfall charges. Outages and shortfalls in unit commitment due to unit delay, derating or retirement are considered when determining ICAP shortfalls that result from testing. In other words, a unit will not pay both a capacity resource deficiency charge and a test failure charge for the same day.[43]

Peak Season Maintenance (PSM) Compliance Charge[44]

If a unit owner takes a planned or maintenance outage during the peak season without PJM approval, the owner is subject to the peak season maintenance compliance charge.

This is a daily charge equal to the shortfall in capacity times the daily deficiency rate which is equal to the seller's weighted average resource clearing price for the resource, plus the higher of 0.20 times the seller's weighted average resource clearing price for the resource or $20 per MW-day.[45] The capacity shortfall is the unit ICAP commitment for the delivery year minus (the summer dependable rating minus the amount of capacity out of service).

Capacity resource owners may obtain replacement capacity in the same LDA and with the same or better temporal characteristics (product type availability) which offsets any charges.

Any unit derating is considered when determining the capacity shortfall. In other words, a unit will not pay a capacity resource deficiency charge, a test failure charge and a peak season maintenance charge for the same day. A unit will only pay one of these three charges for any MW reduction for a day. In addition, a unit will not pay one of these three charges plus a peak hour availability charge.

Conclusion

One test of whether the capacity market is working is whether the incentives are adequate to support continued investment in existing capacity and investment in new capacity such that reliability targets are met. A second and equally important test of whether the capacity market is working is whether customers, who must pay for capacity, are getting what they pay for.

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43 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), § 8.4.5.1.

44 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), § 8.4.7.

45 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), § 9.1.6; and PJM. OATT Attachment DD § 9(d).

The first test is straightforward. The test is passed if PJM reliability targets continue to be met as the result of investment in existing and new units. The second test is more complex. Part of what customers are paying for is reliability. Thus, the first test is part of the second test. In order to meet the first test, customers pay for capacity in order to ensure overall revenue sufficiency which is required for the PJM energy and capacity markets to work together as an integrated whole. Capacity market prices are designed to provide for recovery of the net cost of capacity and not the gross cost of capacity. The net cost of capacity is the gross cost less the net revenues from the energy and ancillary services markets. Capacity markets, in effect, provide for the payment of the residual revenues necessary, after accounting for net revenues from the energy market, to ensure revenue adequacy.

The least cost market design would ensure that customers pay only for the most cost effective set of generating units that provide a combination of energy and ancillary services when they are needed to meet demand. In order to achieve the least cost design, generating units that receive capacity payments must meet correctly defined obligations, including making competitive offers every day in the energy market, correctly measuring their available capacity and receiving payment only when available to provide energy when needed to meet customers' demand.

The IMM concludes the current market design is not the least cost way to meet the design objective. The IMM's recommendations are intended to ensure that the capacity market design is the least cost way to meet the design objective of reliability. While it is possible to maintain a reliable system with a capacity market design that overpays as a result of the incorrect definition of capacity, of the mismeasurement of capacity and of the payment of capacity revenues even when units do not meet performance standards, that is not in customers' best interests, is not in the interests of competitive generation suppliers and is not in the interests of a competitive market design. Customers, who pay $7 billion per year on average for capacity, should be assured that they receive full value for that payment.

MMU Recommendations

The recommendations included here are the recommendations which are most relevant to the requests of OPSI, including additional recommendations developed based on the preparation of this report:

- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.
    - The MMU recommends that there be an explicit requirement that capacity unit offers into the Day-Ahead Energy Market be

competitive, where competitive is defined to be the short run marginal cost of the units.

  - The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. All revenues should be at risk under the peak hour availability charge.

  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

  - Given that all generation is counted on for comparable contributions to system reliability, the MMU recommends that all generation types face the same performance incentives.

  - The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.

  - The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period.

- The MMU recommends that PJM eliminate all Out of Management Control (OMC) outages from use in planning or capacity markets. PJM recommends that pending elimination of OMC outages, that PJM review all requests for Out of Management Control (OMC) carefully, implement a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage.[46]

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[46] This recommendation differs from the recommendation in the *2011 State of the Market Report for PJM*, but is a recommendation in the *2012 State of the Market Report for PJM, January through June.*

Attachment A

November 3, 2011

Mr. Howard Schneider
Chair, Board of Managers
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403-2497

Dear Mr. Schneider:

The Maryland Public Service Commission, the New Jersey Board of Public Utilities, the Delaware Public Service Commission, and the District of Columbia Public Service Commission ("State Commissions") write to express our view that the Brattle Group's Performance Assessment of PJM's Reliability Pricing Model ("RPM") dated August 26, 2011, ("Performance Assessment") is deficient in its attempt to satisfy its obligation to "report on the performance of RPM"[1] because the Performance Assessment does not identify, much less analyze and respond to, the well-publicized concerns of PJM's Independent Market Monitor ("IMM"). This letter, however, should not be construed as supporting specific recommendations from the IMM or the Brattle Group on how to improve the RPM or as supporting RPM itself.

[1] PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (Order Denying Rehearing and Approving Settlement Subject to Conditions) (2006).

Each year the IMM publishes a voluminous State of the Market report, with a substantial portion dedicated to the capacity market and certain aspects of the energy market that are related to the capacity market. The absence of a response to the IMM's RPM-related concerns is a serious omission that precludes us and FERC from properly evaluating RPM. The IMM is not just another stakeholder, but a neutral entity upon which market participants and regulators rely to identify flaws in PJM's markets. State Commissions in particular do not have the resources to review the wholesale market in detail. We rely heavily on the unbiased analysis of the IMM to bring to light market structure issues.

The explicit purpose and scope of the performance assessment demands a detailed review of and response to the IMM's concerns about RPM. Brattle conducted stakeholder interviews to identify key areas of concern, evaluate individual RPM design elements, and develop recommendations for possible modifications (if any) to improve the effectiveness of RPM. Brattle also interviewed the IMM, which is responsible for an ongoing review of RPM and is, therefore, a unique and valuable resource to Brattle in its effort to conduct its own study. Yet Brattle barely mentions the IMM's long-running efforts. This failure to address the concerns the IMM has identified, at length, calls into question the efficacy of the performance assessment of the RPM.

The IMM's concerns should be the starting point for Brattle, but instead were relegated in whole to the Appendix to the Performance Assessment; Brattle noted in the Appendix that "we did not separately summarize comments by the independent market monitor as they were consistent with the IMM's public statements, documents, and presentation posted at www.monitoringanalytics.com." Perhaps, if Brattle had listed the IMM's detailed recommendations on obligations of capacity resources, strengthening the incentives in the RPM Capacity Market, and that the terms of Reliability Must Run Service be reviewed, refined and standardized, which can be found succinctly summarized on page 363 of the 2010 State of the Market Report for PJM, they would have seen fit to address them in the body of the report. We are, quite frankly, bewildered at the disconnect between the Performance Assessment and the IMM's efforts regarding these issues.

The IMM recommends in the 2010 State of the Market Report, for example, that "the obligations of capacity resources be more clearly defined in the market rules."[2] The Performance Assessment notes that a key design element of RPM is "explicit market monitoring and mitigation rules, including a must offer requirement for existing generating resources and IMM review and mitigation of new entrant offers," but there is no elaboration on the critical and contentious must-offer requirement elsewhere. The IMM had four detailed recommendations in the 2010 State of the Market Report concerning the obligations of capacity resources in RPM:

[2] 2010 State of the Market Report at 363.

- The MMU[3] recommends that there be an explicit requirement that capacity unit offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.

- The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM is developing these protocols.

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

- The MMU recommends that PJM review all requests for Out of Management Control (OMC) carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM consider eliminating lack of fuel as an acceptable basis for an OMC outage.[4]

These and other recommendations are not discussed in the report. In addition, the IMM stated in the State of the Market Report:

> The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. The MMU recommends that capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.

The Performance Assessment contains no analysis of why generators should be paid 50% of their capacity payment even if they do not perform, despite the obvious fact that capacity payments, or the lack thereof, are essential to the entire RPM construct. The Performance Assessment's only comment on penalty mechanisms was to observe that penalties were comparable between demand response and generation. On a related subject, there was no analysis of why PJM experiences emergency generation events even in off-peak seasons when the *raison d'être* of RPM is to obtain sufficient resources to reliably meet customers' electricity needs during the peak hour of the peak day of the year.

The performance assessment is *the* opportunity for consumers to evaluate whether they are getting value for the billions of dollars a year they pay for capacity. Because of the failure of the study to address the concerns of the IMM, we still have no answer to this question. Although State Commissions may not always agree with the IMM's

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[3] Consistent with the terminology in PJM's Tariff dating to when the IMM was internal to PJM, the Independent Market Monitor is sometimes referred to as the Market Monitoring Unit, or MMU.

[4] 2010 State of the Market Report at 363.

recommendations, the failure of the RPM Performance Assessment to address the IMM's concerns results in a fatal flaw in this vital review.

Accordingly, the State Commissions request that the PJM Board require a supplemental Performance Assessment that comprehensively and objectively evaluates the performance of the RPM market before any changes to RPM are formally proposed by PJM.

DATED: November 3, 2011

BY:

/s/ Douglas R. M. Nazarian____________
DOUGLAS R. M. NAZARIAN
CHAIRMAN
On behalf of the Maryland Public Service Commission

/s/ Lee A. Solomon___________________
LEE A. SOLOMON
PRESIDENT
On behalf of the New Jersey Board of Public Utilities

/s/ William O'Brien___________________
WILLIAM O'BRIEN
EXECUTIVE DIRECTOR
On behalf of the Delaware Public Service Commission

/s/ Betty Ann Kane___________________
BETTY ANN KANE
CHAIRMAN
On behalf of the District of Columbia Public Service Commission

Ohio | **Public Utilities Commission**

John R. Kasich, Governor
Todd A. Snitchler, Chairman

Commissioners

Paul A. Centolella
Cheryl Roberto
Steven D. Lesser
Andre T. Porter

November 9, 2011

Mr. Howard Schneider
Chair, Board of Managers
PJM Interconnection, LLC
955 Jefferson Avenue
Norristown, Pennsylvania 19403

Subject: Brattle Group's Performance Assessment of PJM's Reliability Pricing Model

Dear Mr. Schneider:

I write on behalf of the Public Utilities Commission of Ohio ("Commission") to express our views regarding significant deficiencies in the Second Performance Assessment of PJM's Reliability Pricing Model ("Performance Assessment") conducted by the Brattle Group with a report issued on August 26, 2011. According to the report, the scope of the Performance Assessment was to include, among other things, "key areas of concern," as identified by stakeholders, and "an evaluation of individual RPM design elements."[1] It is the opinion of this Commission that the Performance Assessment failed to adequately satisfy its scope in two ways: the failure of the Performance Assessment to 1) determine whether RPM accomplishes its intended purpose; and 2) address the concerns of PJM's Independent Market Monitor ("IMM").

In the first place, the RPM is an administrative mechanism for establishing capacity subsidies to incent necessary investment. A key concern of this Commission is whether the RPM accomplishes its intended purpose. The Performance Assessment does not answer the fundamental question of whether such a mechanism can actually facilitate the development of liquid long-term forward markets. Consequently, the recommendations in the Performance Assessment could increase RPM costs without greater assurance that RPM will produce results that reflect consumer preferences. We welcome the opportunity to discuss these concerns with you and PJM staff.

Secondly, the Performance Assessment failed to identify, analyze and respond to the concerns of PJM's Independent Market Monitor ("IMM"). Specifically, the IMM recommended in

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[1] Second Performance Assessment of PJM's Reliability Pricing Model, Market Results 2007/08 through 2014/15, the Brattle Group, August 26, 2011, pg. i.

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Columbus, Ohio 43215-3793

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its 2010 State of the Market Report that "the obligations of capacity resources be more clearly defined in the market rules."[2] The IMM suggested that:

1) there be an explicit requirement that capacity unit offers into the day-ahead energy market be competitive, *i.e.* the short run marginal cost of the units;

2) a unit that is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis;

3) PJM review all requests for Out of Management Control ("OMC") carefully, develop a transparent set of rules governing the designation of outages as OMC, and post those guidelines along with a recommendation that the lack of fuel be eliminated as an acceptable basis for an OMC outage; and

4) "that capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical."[3]

The Performance Assessment is deficient in addressing the aforementioned concerns of the IMM, and in the opinion of this Commission, therefore fails to include "key areas of concern" and "an evaluation of individual RPM design elements."[4]

Of note is the Brattle Group's failure to address the rationale for continuing to pay generators when they fail to produce energy during critical periods as per suggestion 4, above. This omission is particularly problematic in the opinion of this Commission because Ohio relies upon PJM to conduct competitive and transparent markets. These features of PJM markets require that participating generators be held to high standards. In a state such as Ohio—where customers pay electricity rates that include reliability pricing model derived capacity costs, and where competitive markets continue to be relied upon—the failure of the Performance Assessment in addressing these concerns is especially troubling.

This Commission and the State of Ohio are not alone in our consternation at the Performance Assessment. In a November 3, 2011, letter, the states of Delaware, Maryland, New Jersey, and the District of Columbia indicated, among other matters, stated their concerns about the aforementioned deficiencies. To the extent that their concerns align with those of this Commission, we join them and the opinions they expressed in their November, 3, 2011, letter. To echo those states and the District of Columbia, this Commission believes that the Performance Assessment is "the opportunity for consumers to evaluate whether they are getting value for the billions of dollars

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[2] State of the Market Report for PJM, Monitoring Analytics, p. 363.

[3] *Id.*

[4] Second Performance Assessment of PJM's Reliability Pricing Model, Market Results 2007/08 through 2014/15, the Brattle Group, August 26, 2011, pg. i.

a year they pay for capacity," and "the failure of the RPM Performance Assessment to address the IMM's concerns results in a fatal flaw in this vital review."[5]

Accordingly, the Ohio Commission respectfully requests that the concerns I have identified and those highlighted by the IMM be seriously considered for inclusion in any formal RPM-related filings at FERC.

Respectfully,

Todd A. Snitchler

Todd A. Snitchler
Chairman, Public Utilities Commission of Ohio

TAS/ATP/glw
cc: Raj Barua, Executive Director, OPSI
Douglas R. M. Nazarian, Chairman, Maryland Public Service Commission
Lee A. Solomon, President, New Jersey Board of Public Utilities
William O'Brien, Executive Director, Delaware Public Service Commission
Betty Ann Kane, Chairwoman, District of Columbia Public Service Commission

[5] November 3, 2011, letter from the States of Delaware, Maryland and New Jersey, and the District of Columbia, p. 3-4.

Organization of PJM States, Inc. (OPSI)

President: **Hon. Greg R. White,** Commissioner, Michigan PSC
Vice President: **Hon. Edward S. Finley, Jr.,** Chairman, North Carolina UC
Secretary: **Hon. Mary W. Freeman,** Commissioner, Tennessee RA
Treasurer: **Hon. Richard E. Morgan,** Commissioner, District of Columbia PSC

Members:
Delaware Public Service Commission ● District of Columbia Public Service Commission ● Illinois Commerce Commission Indiana Utility Regulatory Commission ● Kentucky Public Service Commission ● Maryland Public Service Commission Michigan Public Service Commission ● New Jersey Board of Public Utilities ● North Carolina Utilities Commission Public Utilities Commission of Ohio ● Pennsylvania Public Utility Commission ● Tennessee Regulatory Authority Virginia State Corporation Commission ● Public Service Commission of West Virginia.

December 1, 2011 *(via email attachment only)*

Howard Schneider, Esq.
Chairman, Board of Managers
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403

Re: OPSI Board Action

Dear Howard,

It was a pleasure meeting you last month in St. Louis. Earlier today, the OPSI Board of Directors approved the attached resolution. Please have your staff forward this letter and the attached resolution to the rest of your colleagues on the PJM Board and have Denise Foster of your staff contact Raj Barua, OPSI's Executive Director, to coordinate any next steps in this matter.

Sincerely,

/s/ Greg White

Greg R. White
President, OPSI

Attachment
cc: Denise Foster, VP, PJM – State & Member Relations
Dave Anders, Member Services, PJM
Dr. Joe Bowring, Monitoring Analytics

Organization of PJM States, Inc. (OPSI)
President: **Hon. Greg R. White,** Commissioner, Michgan PSC
Vice President: **Hon. Edward S. Finley, Jr.,** Chairman, North Carolina UC
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Delaware Public Service Commission ● District of Columbia Public Service Commission ● Illinois Commerce Commission Indiana Utility Regulatory Commission ● Kentucky Public Service Commission ● Maryland Public Service Commission Michigan Public Service Commission ● New Jersey Board of Public Utilities ● North Carolina Utilities Commission Public Utilities Commission of Ohio ● Pennsylvania Public Utility Commission ● Tennessee Regulatory Authority Virginia State Corporation Commission ● Public Service Commission of West Virginia.

Resolution # OPSI-2011-7

Support in principle for the concerns of PJM's Independent Market Monitor regarding the Brattle Group's Performance Assessment of PJM's Reliability Pricing Model

WHEREAS, on November 3, 2011, the Maryland Public Service Commission, the New Jersey Board of Public Utilities, the Delaware Public Service Commission, and the District of Columbia Public Service Commission ("Four Commissions") jointly wrote to the Chairman of the PJM Board of Managers to express their view that the Brattle Group's Performance Assessment of PJM's Reliability Pricing Model ("RPM") dated August 26, 2011, is deficient in its attempt to satisfy its obligation to report on the performance of RPM because the Performance Assessment does not analyze and respond to, the well-publicized concerns of PJM's Independent Market Monitor; *and*

WHEREAS, on November 9, 2011, the Public Utilities Commission of Ohio ("PUCO") wrote to the Chairman of the PJM Board of Managers to express views similar to the Four Commissions and additional concerns with RPM; *and*

WHEREAS, on November 10, 2011, PJM's CEO responded to the Four Commissions' letter; *and*

WHEREAS, the Four Commissions and PUCO are OPSI Member Regulatory Agencies; *and*

WHEREAS, the concerns expressed by the Four Commissions and PUCO in their letters affect all OPSI Member Regulatory Agencies and their individual jurisdictions;

NOW, therefore, be it resolved that, the OPSI Board of Directors, support in principle that the Brattle Group's Performance Assessment of PJM's Reliability Pricing Model dated August 26, 2011, is deficient in its attempt to satisfy its obligation to report on the performance of RPM because the Performance Assessment does not analyze and respond to, the well-publicized concerns of PJM's Independent Market Monitor; *and*

BE IT further resolved that, approval of this resolution does not bind any individual OPSI Member Regulatory Agency to any specific position; *and*

BE IT further resolved that, this resolution be forwarded to the PJM Board of Managers.

Approved by the Board of Directors of the Organization of PJM States, Inc. on December 1, 2011.
Not present: The Delaware Public Service Commission and the Illinois Commerce Commission.
Abstained: The North Carolina Utilities Commission and the Tennessee Regulatory Authority.

Attachment B

2011 State of the Market Report for PJM

Section 4, Capacity Market

1. The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.
2. The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.
3. The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.
4. The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.

Detailed Recommendations

1. The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.
   a. The MMU recommends that the Short-Term Resource Procurement Target (2.5 percent demand offset) be eliminated.
   b. The MMU recommends that the definition of demand side capacity (Demand Response (DR)) resources be made comparable to generation capacity resources to ensure that all resources provide the same value in the capacity market. The DR product should be defined to require unlimited interruptions.
   c. The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. PJM is addressing some of these barriers to entry.
   d. The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
   e. The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors.
   f. The MMU recommends that PJM use the most current Handy-Whitman Index value to recalculate the ACR for the applicable year and update the ten year annual average Handy-Whitman Index value to recalculate the subsequent default ACR values.
2. The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.
   a. The MMU recommends that there be an explicit requirement that capacity unit offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.

b. The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM is developing these protocols.
c. The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.
d. The MMU recommends that PJM review all requests for Out of Management Control (OMC) carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM propose eliminating lack of fuel as an acceptable basis for an OMC outage.

3. The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.
4. The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.
   a. The MMU recommends that the RMR requirements be modified to make RMR service mandatory.
   b. The MMU recommends that the notice period for retirement be extended from 90 days to at least one year and that both PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses.
   c. The MMU recommends that treatment of costs in RMR filings be clarified. Customers should bear all the incremental costs, including investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Generation owners should bear all other costs.
   d. The MMU recommends that RMR agreements should limit customers' payment obligations to the costs that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed.

2012 State of the Market Report for PJM: January through June – New Recommendations

Section 4, Capacity Market

1. The MMU recommends that PJM eliminate all Out of Management Control (OMC) outages from use in planning or capacity markets. No outages should be treated as OMC because when a unit is not available it is not available, regardless of the reason, and the data and payments to units should reflect that fact. All submitted OMC outages are currently reviewed by PJM's Resource Adequacy Department. The MMU recommends that pending elimination of OMC outages, that PJM review all requests for Out of Management Control (OMC) carefully, implement a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage.

Attachment C

Table 11 RPM Activities

Date	Name
January 6, 2011	Analysis of the 2011/2012 RPM First Incremental Auction http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf
January 6, 2011	Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf
January 14, 2011	Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf
January 28, 2011	Impact of Maryland PSC's Proposed RFP on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf
February 1, 2011	Preliminary Market Structure Screen results for the 2014/2015 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf
March 4, 2011	IMM Comments re MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_EL11-20-000_ER11-2875-000_20110304.pdf
March 21, 2011	IMM Answer and Motion for Leave to Answer re: MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf
June 2, 2011	IMM Protest re: PJM Filing in Response to FERC Order Regarding MOPR No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Protest_ER11-2875-002.pdf
June 17, 2011	IMM Comments re: In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning No. EO11050309 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_NJ_EO_11050309_20110617.pdf
June 27, 2011	Units Subject to RPM Must Offer Obligation http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Units_Subject_to_RPM_Must_Offer_Obligation_20110627.pdf
August 29, 2011	Post Technical Conference Comments re: PJM's Minimum Offer Price Rule Nos. ER11-2875-001, 002, and EL11-20-001 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Post_Technical_Conference_Comments_ER11-2875_20110829.pdf
September 15, 2011	IMM Motion for Leave to Answer and Answer re: MMU Role in MOPR Review No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Motion_for_Leave_to_Answer_and_Answer_ER11-2875-002_20110915.pdf
November 22, 2011	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2012/2013, 2013/2014 and 2014/2015 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20111123.pdf
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12-63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12-63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12-16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf

PJM WHITEPAPER

The Capacity Market Product: Obligations and Performance Incentives of Capacity Resources

August 20, 2012

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Contents

Introduction

The capacity market in PJM Interconnection, known as the Reliability Pricing Model (RPM), was implemented in 2007 following extensive stakeholder deliberation and Federal Energy Regulatory Commission approval. It has demonstrably attracted new generation, retained existing resources and dramatically increased the amount and diversity of demand response participation.[1] The most recent annual RPM auction for the 2015/2016 delivery year demonstrated remarkable flexibility to manage the rapid, unprecedented transition of capacity resources away from coal and toward demand resources and natural gas resulting from environmental compliance costs for coal plants and low natural gas prices.[2]

This paper reviews the current definition of the capacity market product and the obligations for capacity resources in PJM. It is meant to address stakeholder questions regarding capacity resource obligations and to respond to requests from several state commissions and the Organization of PJM States, Inc. (OPSI) to review the pros and cons of the five Independent Market Monitor (IMM) recommendations relating to the obligations of capacity resources in the PJM energy markets.[3]

The paper is organized as follows: (1) the definition of the capacity product in PJM's markets; (2) a brief overview of the RPM capacity market and incentives for committing to obligations as a capacity resource; (3) The obligations of capacity resources to offer into the Day-Ahead Energy Market; (4) performance incentives for capacity resources to deliver on their commitments during the delivery year; (5) a discussion of the ability for capacity resources to be available only during emergency conditions; (6) discussion of reporting outages as out of management control with an emphasis on lack of fuel; (7) the recall of off-system energy sales from capacity resources during system emergencies; and (8) concluding thoughts.

Capacity Product Defined

The capacity product in PJM is a commitment by a generation resource to make energy available in the PJM energy market or, in the case of demand response resources, to reduce energy consumption during certain system conditions.

For generation resources, the chief obligations include:

1. 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]
2. The availability of energy output to energy consumers in the PJM system at prices at or below $1,000 per megawatt-hour as demonstrated by submitting offers in the Day-Ahead Energy Market on a daily basis throughout the 12-month commitment period (June 1 to May 31), unless the resource is unavailable due to a forced or scheduled outage.

3. Make available the energy output to PJM if needed to maintain reliable operations during emergency conditions, which include PJM recall rights for off-system energy sales for committed capacity resources.
4. Avoiding scheduled outages during specified peak load periods and providing outage data to PJM.

If not on an outage and available to provide energy, generation capacity resources must submit both a cost-based energy offer and market-based energy offer into the PJM Day-Ahead Energy Market.

For demand response resources, the chief obligations are:

1. The ability to curtail consumption in accordance with its commitments when PJM declares emergency conditions.
2. Provide measurement and verification of load reductions following emergency conditions as required.

Demand resources can be committed as capacity resources in three different product categories with obligations:

- The "Annual DR" product may be called upon an unlimited number of times per year, all year, for a maximum of ten hours per call.
- The "Extended Summer DR" product may be called upon an unlimited number of times during the summer season from May 1 to October 31 for a maximum of ten hours per call.
- The "Limited DR" product may be called upon only ten times from June 1 to September 30 for a maximum of six hours each call.

Unlike generation capacity resources, demand resources do not have a must-offer requirement in the Day-Ahead Energy Market. All capacity resources, including demand resources, are subject to testing.

As discussed in the next section, the goal of the RPM capacity market is to commit sufficient capacity resources to serve the forecast system peak load plus a reserve margin to account for unexpected system outages or weather conditions.

Resource Adequacy and Incentives to Take Capacity Obligations in RPM

Overview

Resource adequacy is the ability of the electric system to supply the aggregate customer electrical load requirements, especially during peak demand periods, such as a heat wave or cold snap, taking into account reasonably expected unscheduled outages of generation sources and transmission system elements. The incentives and obligations for generation, demand response and other suppliers are very important to the maintenance of annual resource adequacy targets and long-term system reliability.

Resource adequacy also generally means that generation resources that are relied upon for meeting system load are deemed "deliverable" through engineering analysis. A "deliverability test" determines that energy produced by these power plants can be delivered through the transmission grid to all system loads during peak demand periods, consistent with reliability standards.[5]

The Reliability Pricing Model (RPM) is the mechanism by which PJM achieves resource adequacy. It uses a capacity market construct so that existing resources and potential new resources compete to supply capacity to meet forecast peak load plus the installed reserve margin and to ensure the appropriate location of resources.[6]

The RPM capacity market is conducted through a Base Residual Auction (BRA) three years prior to the period when the obligations of capacity resources are in force. This 12-month period runs between June 1 and May 31 of the following calendar year and is referred as the delivery year for capacity. To account for potential changes between the BRA and the delivery year – for example, changes in the load forecast or the ability of suppliers to meet their capacity obligations – PJM conducts three incremental auctions prior to each delivery year.[7] So far, the clearing prices in these incremental auctions have been persistently below BRA prices.

The capacity product in RPM does not contain a firm energy price component.[8] The capacity product can be described as a special type contract in which a generation resource commits to make energy available within the PJM market – if the resource is not on a scheduled or forced outage – or to curtail consumption in the case of demand resources, at a price less than or equal to $1,000/MWh. Consequently, capacity market prices do not include costs to commit capacity resources to firm forward energy prices for their delivery.[9]

Overall, the RPM capacity structure has retained existing generation, supported power plant upgrades and attracted new and diverse resources. The results have been deemed competitive, and the RPM has successfully met the resource adequacy needs for the PJM region with most resources committed three years prior to the period of their obligations.

Supply Offers and Incentives to Commit to Capacity Obligations

Neither PJM nor the FERC can require market participants to continue to operate existing resources, invest in new supply resources, nor can PJM or FERC dictate the location of any new investments. Consequently, it is imperative that supply resources have an incentive to commit to being a capacity resource in the locations needed and take on the obligations associated with being committed as a capacity resource in the RPM capacity market.

The RPM capacity market rules also prohibit withholding of capacity from the market and apply mitigation to supply offers if resources are deemed to possess market power. While there is no explicit requirement that a supply resource must offer its capacity into the RPM capacity market, a resource must justify the decision not to offer into the capacity market in order to ensure the market remain competitive. A resource owner may choose to mothball, retire or export the resource to a neighboring market.

Generation capacity resources and demand resources will only have an incentive to take on capacity obligations and not mothball, retire or export its resource to another market if the resulting revenue streams from PJM's energy, ancillary service and capacity markets are sufficient to cover avoidable costs including any capital investments required to enter the market or continue in commercial operation.[10] This means that mitigation of supply offers must at least ensure that in expectation a resource that clears in the capacity market and is committed to a capacity obligation can at least cover its avoidable costs.

If a supply resource does not offer any part of its capacity into the BRA, it generally is not allowed to offer its unoffered capacity into any later incremental auctions. If a supply resource elects not to participate in RPM, it will not receive any payment from the RPM capacity market.

Market Power Screens in RPM

Prior to conducting the BRA three years in advance of the delivery year, a Preliminary Market Structure Screen is applied to determine the presence of structural market power and identify owners of capacity resources that are deemed to possess structural market power to determine which existing generation capacity resources must submit cost-based offers into the BRA and incremental auctions.[11]

If any capacity supplier fails these tests, they are subject to market power mitigation and cost-based offer caps to prevent the exercise of supplier market power to raise prices above competitive levels. Demand resources and energy efficiency are not subject to market power mitigation and cost-based offer capping. To date in each BRA, no existing generation capacity resources have passed the Preliminary Market Structure Screen and consequently have been subject to market power mitigation and cost-based offers in the RPM capacity market.

Cost-Based Offer Caps in RPM Preserve Incentives to Take on Capacity Obligations

Supply resources are free to offer capacity into the RPM capacity market at market-based offers less than their cost-based offers even if the supply resource owner does not pass any of the Preliminary Market Structure Screens. However, supply resources may submit a market-based offer into the BRA or incremental auctions that is in excess of their cost-based offer only if the supply resource is: (1) a planned generation resource that has not previously offered into and cleared a BRA; (2) a demand resource or energy efficiency resource; or (3) an existing generation capacity resource that has passed the Preliminary Market Structure Screen.

Cost-based offers into the RPM capacity market are constructed around a generation resource's avoidable costs – the costs that would not be incurred if the generating station was shut down inclusive of any capital investments required to allow the resource to continue operating going forward, less the resource specific projected net market revenues (revenues less cost-based offers) from other PJM markets. The projected net market revenues, also known as the Net Energy and Ancillary Service Offset Revenues, are the annual average of the net market revenues from the previous three calendar years of operation.

The Net EAS offset can be viewed as the expectation going forward of the resource's ability to recover fixed, going forward costs in the energy and ancillary service markets in the absence of capacity market revenues. If net energy and ancillary service revenues are not sufficient to cover avoidable costs going forward, revenues from the capacity market are designed to provide the "missing money" so as to retain the capacity resource to maintain resource adequacy reliability.

By construction, the cost-based offer caps in RPM are designed such that an existing generation capacity resource will clear in an RPM auction only if the sum of RPM capacity market revenues, as determined by the capacity price, and expected net energy and ancillary service revenues is greater than the avoidable cost. Therefore, if the historic net energy and ancillary service revenues are a reasonable expectation of future net energy and ancillary service revenues, existing generation capacity resources by clearing an RPM auction and taking on a capacity obligation have a financial incentive to do so since they will in expectation cover their avoidable costs.

The greater the net market revenues are from other PJM markets, the lower the cost-based offer of a mitigated supply resource. It is conceivable that the net market revenues from the PJM energy and ancillary service markets would be high enough that the cost-based offer may be zero.

Planned generation capacity resources, demand resources and energy efficiency, in spite of not being subject to market power mitigation, also have the similar incentives. For example, so long as planned generation resources can cover their avoidable costs, including their capital investment plus a return on capital, through a combination of expected net energy and ancillary service revenues and RPM revenues, they will be willing to be committed as capacity resources with the associated obligations. Demand resources and energy efficiency will be willing to accept a capacity obligation so long as the revenue they receive exceeds their costs of serving as these types of capacity resources.

Day-Ahead Energy Market Offer Obligations: Incentives and Reliability

Currently, generation capacity resources have an obligation to make their capacity available to PJM by offering it in the Day-Ahead Energy Market so long as it is not on a scheduled outage, forced outage or providing energy to another region. With respect to offers in the Day-Ahead Energy Market, generation capacity resources may provide a market-based offer that is above their cost-based offer as described below, which must be below the offer cap of $1,000/MWh, if the resource owner has been permitted by the FERC to charge market-based rates.

The generation capacity resource also must provide a cost-based offer based on the verifiable, short-run marginal cost of operation that can include up to a 10 percent adder to account for any uncertainty in the calculation of costs. The cost-based offer is used for the purposes of market power mitigation in the event the resource is needed to alleviate a transmission constraint and the resource owner is deemed to possess structural market power for the purposes of relieving the constraint as determined by a failure to pass the Three Pivotal Supplier Test. If the market-based offer is less than the cost-based offer, then the market-based offer will continue to be used for the purposes of market power mitigation.

In the previous two State of the Market Reports[12], the IMM recommends an explicit requirement that all capacity resource offers into the Day-Ahead Market be limited to the short-run marginal cost inclusive of any opportunity costs, where appropriate, to ensure competitive market outcomes.[13] In other words, the IMM is recommending capacity resources not be permitted to use market-based offers.

The IMM-proposed requirement that all capacity resources offer at short-run marginal cost in the energy market has the potential to reduce resource adequacy reliability and increase the costs of maintaining resource adequacy by decreasing the incentive for generation capacity resources and demand resources to commit to a capacity obligation, to reduce real-time operational reliability, and to increase costs as has been recognized by the FERC in various orders regarding PJM's markets, and it imposes market power mitigation even when the market structure and results are already competitive.

Reliability Implications of Requiring Offers at Short-Run Marginal Cost for Generation

As the FERC has recognized by allowing a 10 percent adder to cost-based offers, short-run marginal cost cannot be perfectly measured.[14] For example, there may be costs associated with the risk of the unit tripping off-line once it has a financially binding day-ahead market commitment. A resource owner also may wish to account for the expected opportunity cost associated with having to commit day-ahead when it expects real-time prices to be higher than day-ahead prices. Such costs cannot be known or verified with precision until after they have been incurred by the generation owner. And, to the extent that the already allowed 10 percent adder to account for such costs is not sufficient to account for such expected costs, the ability to offer resources at market-based rates allows generation owners to account for these costs and manage the associated performance risks.

Natural gas fired units in PJM and other power markets also face uncertain costs and risks with respect to what they may pay for fuel and transportation. The reason for this uncertainty is the mismatch between the gas market day, which runs from 9 a.m. CPT to 9 a.m. CPT the following day, and the electric market day which follows the 24-hour calendar day. Nominations to schedule the flow of gas on pipelines is due prior to the generator owner knowing what its commitments will be to provide power on a day-ahead basis or in real-time dispatch. As a result owners of gas-fired generation often consume gas off a pipeline and pay spot prices for gas and/or transportation, which can differ from gas prices day-ahead, plus they may incur any additional costs for paying pipeline imbalance charges or paying for released firm transportation capacity, which can be offered at market-based prices. Consequently, owners of gas-fired generation have less certainty about their costs than, for example, coal-fired generators that may have already purchased fuel and secured transportation well in advance of operation.

If generators, especially gas-fired generators, are limited to only offer short-run marginal costs and those costs cannot account for additional costs that may be incurred between the Day-Ahead Energy Market and real-time operations, for example due to the mismatch between the timing of the gas and electric markets, then generators would have less incentive to take on capacity obligations in RPM because they would be taking on the risks of offering their resources at cost-based offers in the energy market, which may not be reflective of true cost, and of being dispatched at prices that are below their actual cost of operation. These risks all can be managed by generators today through the use of market-based offers making it more attractive to commit to a capacity obligation.

Moreover, PJM would have less real-time operational control if generators were being called on for transmission constraint control but have no incentive to operate if they were being dispatched at a loss because the cost-based offer and/or energy market price were less than the actual costs of generator operation in real-time. PJM would then be forced to dispatch more expensive resources to control the transmission constraint or manage system conditions in such a situation.

In the context of the FERC review of the Three Pivotal Supplier Test in 2008 and 2009, the commission concluded previously that mitigation down to short-run marginal cost was not just and reasonable because "mitigation measures imposed on those that fail the screen fail to account for opportunity costs, particularly energy- and environmentally-limited opportunity costs."[15] In the same order, the commission noted, "Default bids that do not account for opportunity costs can lead to inefficient use of scarce resources and increase costs to customers."[16] And, while such opportunity costs may be identified in concept for inclusion into offers at short-run marginal cost, they are not known in advance or easily estimated.

Incentives for Demand Resources Committed as Capacity in the Energy Market

Currently, demand resources committed as capacity resources in RPM do not have a must offer obligation into the Day-Ahead Energy Market but need only respond when PJM declares a maximum generation emergency event. However, the IMM has proposed to extend the must-offer requirement to all capacity resources including demand resources of all types.[17]

Demand resources do not have costs that may be easily defined or verified. The cost to a demand resource to respond to a PJM emergency event or to high prices is the opportunity cost of the foregone consumption of energy, which should be equal to their willingness to pay for energy. For some commercial and industrial consumers of energy that serve as demand resource these opportunity costs are more tangible in terms of postponed or delayed production but are still hard to quantify on a daily or hourly basis given that schedules and business conditions could constantly change this value. For other customers, the opportunity costs may be the value of comfort from lighting or air conditioning or rescheduling activities that is highly subjective to the individual customer and would be impractical to verify on a daily basis for the purposes of market power mitigation.

Moreover, many studies attempting to estimate the opportunity cost of not consuming energy, also known as the value of un-served energy, show this value is in excess of the current $1,000/MWh offer cap for many energy consumers such that a simple must-offer requirement at any value permitted under the offer cap would not be compensate the demand resource for reducing energy consumption alone without also considering the capacity value of the demand resource.[18]

In a recent order approving PJM's shortage pricing proposal, the FERC accepted the proposal to lift the offer cap to the maximum price under shortage conditions for price sensitive demand representing physical demand and virtual bids and further ordered PJM to lift the offer cap for demand resources that are capacity resources because the "proposed $1,000 per MWh cap on capacity demand resources reduces incentives to offer these resources in the day-ahead market. For users that derive more than $1,000 per MWh of value from consuming energy, their cost of providing demand response exceeds $1,000 per MWh, since they give up in excess of $1,000 per MWh of value by reducing energy usage. Such users generally would be unwilling to reduce their energy usage at compensation levels below $1,000 per MWh."[19]

The reliability implications of the FERC order are obvious. Demand resources will only make themselves available to PJM prior to entering emergency conditions if they can be assured that when they are dispatched the compensation they receive from the energy market exceeds the costs of providing the energy through reduction in energy consumption.

Incentives to Commit to Capacity Obligations and Costs in the RPM Capacity Market

A requirement for all capacity resources, including demand resources, to make offers into the Day-Ahead Energy Market at short run marginal cost can only lead to an increase in RPM capacity prices and lower levels of committed capacity resources. There are two main mechanisms by which this could occur.

First, a must-offer requirement for demand resources, as implied by the IMM recommendation, would preclude from being a capacity resource lower cost and likely more plentiful limited demand resources, which are required to be available only during emergency conditions for up to 60 hours per year and which could not meet the daily availability requirement. This reduction in supply, all else being equal, would increase RPM prices and the cost to maintain resource adequacy.

Notably, the results from the 2014/2015 and 2015/2016 BRAs show that many demand resources offering as limited demand resources also offered as extended summer and annual resources, which have unlimited calls during the summer and year respectively, but these offers were at higher prices.[20] So, while there could be similar quantities of demand resources available, they would be available at higher prices, leading to an increase in RPM Capacity prices.[21]

The second mechanism by which RPM capacity price would increase is through the reduction in net energy market revenues that result from enforcing a must offer requirement at short-run marginal cost. In high load hours in which generation resources provide market-based offers in excess of their short-run marginal cost to account for costs that cannot be easily identified or computed, net energy revenues are higher for most generators and these are used to offset the avoidable costs in determining mitigated offers into the RPM capacity market. But, if offers can only be at short-run marginal cost that do not account for other hard to identify costs, net energy market revenues are reduced which puts marginal resources at significant risk on under-recovery of costs. This can lead to increased generation retirements, which in turn will lead to higher RPM capacity market prices.

Results of the Energy Market Are Competitive

Even though generation capacity resources have the ability to make market-based offers, the IMM has concluded participant behavior and market outcomes are competitive and that the energy market design is effective in promoting competitive outcomes in part because, where market power may exist in the alleviation of transmission constraints, there is market power mitigation to ensure competitive outcomes.[22]

A requirement for all generation capacity resources to offer in at only the short-run marginal cost would effectively apply market power mitigation to the energy market at all times and even in situations (the absence of transmission constraint) in which the IMM has determined the market is structurally competitive and market power mitigation is not warranted.[23]

Furthermore, the IMM and PJM have independently confirmed that generation owners are offering in their resources at marginal costs (inclusive of opportunity costs and a 10 percent adder). The IMM has offered the average mark-up component of marginal units in PJM was only 0.006 or 0.6 percent over marginal cost in 2010, and in 2011 the mark-up component of real-time load-weighted average locational marginal price (LMP) was $1.28/MWh or 2.8 percent of real-time LMP and negative for day-ahead LMP providing strong evidence of competitive behavior and market performance.[24]

PJM is concerned that the additional layers of unnecessary mitigation in a market that is operating competitively could have unintended and adverse consequences, which ultimately could create incentives for resources to limit their operational flexibility and availability to PJM, which could inhibit PJM's ability to maintain reliable and efficient system dispatch of resources.

Performance Incentives of Capacity Resources During Peak Periods

In the 2010 State of the Market Report the IMM has recommended "performance incentives in the RPM capacity market design be strengthened."[25] The IMM further recommended "capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical"[26] where the IMM has more specifically articulated, "if a unit defined as a capacity resource does not produce energy when called upon during any of the hours defined as critical, it should receive no capacity revenues."[27]

Incentives to Minimize Forced Outage Rates to Maximize Revenues

Generation capacity resources submit quantity offers into RPM based on their unforced capacity, which is equal to their installed capacity[28] minus a factor that accounts for unexpected times when such capacity is not available. This

"Equivalent Forced Outage Rate" (EFORd)[29] is a measure, in percentage terms, of the likelihood a generation resource takes an unscheduled outage that is deemed to be within the control of the resource owner when requested to operate. For example, if a generation resource has an EFORd of 0.05, or 5 percent, this indicates there is a 5 percent probability of the resource's being on an unscheduled outage within its control when requested to operate.

A generation resource may offer in an EFORd no greater than its most recent annual EFORd value, or its five-year average EFORd. Capping the EFORd value offered prevents the physical withholding of capacity from the RPM capacity market.

Demand resources have a similar factor, known as the DR Factor, which translates the nominated or offered value of demand response into unforced capacity terms based on the reliability benefit of demand response.[30]

Generation capacity resources have strong incentives to minimize the number of forced outages, and by extension their EFORd, so as to maximize the availability of the resource to earn net energy market revenues and the amount of unforced capacity that is considered available to receive RPM capacity payments.

Incentives to Perform During Peak Periods to Earn Net Energy Revenues

Resources taking on capacity obligations have incentives to perform in accordance with those obligations because doing so will help capacity resources cover their avoidable costs. For example, a generation capacity resource committed to a capacity obligation in RPM can only earn sufficient net energy and ancillary service revenues if it makes itself available in PJM's Day-Ahead Energy Market as it is expected to do and to minimize scheduled and forced outages. Failure to be available in the PJM's energy markets erodes a capacity resource's ability to earn net energy and ancillary service revenues that will help cover avoidable costs.

It is especially critical that generation capacity resources be available during the most critical peak hours during the summer and winter seasons to earn revenues that help cover avoidable costs. Capacity resources during peak hours and/or emergency conditions have even stronger incentives to be available as such conditions generally are associated with higher prices in PJM's energy markets. If a generation capacity resource is committed in the Day-Ahead Energy Market, it has an incentive to perform in real-time to avoid having to buy back its position at potentially higher real-time prices. For generation capacity resources not committed in the Day-Ahead Energy Market, there is an incentive to be available in real time to earn Real-Time Energy Market revenues.

And, for many generation capacity resources, these higher priced periods supply a large share of net energy market revenues necessary to cover avoidable costs are earned. Consequently, if a generation capacity resource fails to be available and perform during the most critical hours of need, the foregone net energy market revenues alone could lead to an inability to cover avoidable costs leading to losses over the course of the year for a unit owner.

The IMM recognizes the energy market incentives for generation capacity resources to perform in the PJM energy market and earn net energy market revenues:[31]

> For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing; it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the 500 hours defined as critical in RPM, it will receive no energy revenues for those hours.

The reduction in earned net energy market revenues also has longer-term implications for the viability of a generation capacity resource. In the following year for which a BRA will be held, the mitigated offer cap in the BRA will rise, all else equal, making the resource less competitive with other comparable resources that do operate during the peak periods and increases the risk the unit will not clear in the BRA and be committed as a capacity resource in future delivery years.

If the resource owner believes the reduced revenues due to poor availability and performance is transitory, the owner may offer the resource into the following BRA at an offer below the cap. But, if the resource owner believes the reduced revenues are more representative of unit performance going forward, then offering in at the cap, subsequently not clearing in the BRA would signal that the poor performing resource is not needed and can be replaced more cost-effectively with a better performing resource, all else equal.

Incentives to Perform during Peak Periods to Avoid Penalties that Reduce RPM Revenues

In addition to the strong incentives to be available to earn net energy and ancillary service revenues during peak hours and emergency conditions, if generation capacity resources have greater forced outrages rate during these peak periods, known as EFORp, than they would have on average as shown in the EFORd, they would be subject to penalties that reduce capacity market revenues. Conversely, if a generation capacity resource has a lower peak period equivalent forced outage rate (EFORp) than would be expected on average as indicated by EFORd, they receive additional payments for their exceptional performance that are collected from poor performing Capacity Resources.

Demand resources have similar incentives to perform during peak and emergency conditions as they have similar opportunities to earn energy market revenues, and they would face performance penalties for not performing as they are obligated during emergency conditions.

As it currently stands, if a generation capacity resource fails to provide energy when called upon or to be available at all during all 500 critical peak hours, that resource would forfeit approximately 50 percent of RPM revenues in the first year in which it has not performed. If the resource continues to not perform in a similar manner, it would lose 75 percent of its revenues in the following year, and 100 percent of revenues in the third year.[32]

In much the same way as foregoing net energy market revenue, the forfeiture of at least 50 percent of RPM revenues because an increase in the forced outage rate at peak will also increase the overall EFORd of the resource thereby decreasing the available UCAP to be offered in the subsequent BRA. With the reduced amount of UCAP that can be offered, the market seller offer cap is higher, and it is more difficult for a generation capacity resource to clear in subsequent BRAs and be committed as a capacity resource.

If the poor availability performance is due to a one-time or transitory event, then in future BRAs and incremental auctions the availability performance of the resource should return to normal and the resource owner should have reasonable expectations of clearing in the market (if offering below the offer cap) and continuing forward. However, if the poor performance is the start of a trend, the resource will be less competitive going forward and likely be displaced by better performing resources that are more cost-effective as would be reflected with reduced net energy market revenues.

Capacity Resources Have Reliability Value over the Entire Year

Imposing a new penalty structure that requires forfeiture of all or significant portions of RPM revenues upon capacity resources that do not perform when they are expected to be needed most would ignore the reliability value of generation over the entire year. There are many times that availability of capacity resources outside of those 500 hours are essential for maintaining reliability for situations such as transmission constraint control and congestion management during high load days that may fall outside of those 500 hours, managing maintenance outages of generation capacity resources and transmission, and for reliable system operations overall on a daily basis. The IMM implicitly recognizes the value of capacity resources ***beyond*** the approximately 500 peak hours over the year when it states in the 2010 State of the Market Report: [33]

> Capacity Resources are required to ensure the reliability of the system. Reliability is not defined as the operation of the system only during an emergency but the reliable operation of the system in every hour of the year.

Consequently, if a generation capacity resource would be penalized the entirety of their capacity market revenues for failure to be available and operate during the 500 most critical hours of year, which comprise only 5.7 percent of all hours during the year, the resource has no incentive to honor its capacity obligations in the remaining 94 percent of hours when there remains reliability value to PJM for having the resource available to for managing other reliability issues, which only further jeopardizes reliable system operations during the remainder of the year.

Providing Availability During Emergency Conditions Versus Taking an Appropriate Outage

The IMM has recommended "a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis."[34]

This recommendation is specific to real-time operations and is not specific to the RPM capacity market construct although there are effects on the amount of capacity generators may offer into RPM.

The PJM Tariff outlines the conditions under which all or part of the generation capacity resource can be defined as maximum emergency only such that the resource could be dispatched by PJM only in emergency conditions. These include:

1. Environmental limitations that result in a hard cap on hours;
2. Fuel limitations as a result of conditions beyond the generation owner's control;
3. Temporary emergency physical conditions at a unit as outlined above; and
4. Temporary megawatt additions that allow additional output that is not otherwise available.[35]

Clearly, a generation capacity resource should not be able to designate its capacity as emergency only with the express purpose of avoiding a forced outage and any associated peak hour availability penalties or increases in the forced outage rate when the unit owner reasonably believes that the unit could not operate even if called upon during a Maximum Emergency Generation declaration. From a real-time operations and reliability perspective it is essential for PJM to know whether or not units or other resources available as emergency only can actually perform if called upon.

However, there may be situations where a generation capacity resource has a physical problem that will allow it to operate for only a limited amount of time before the unit becomes unavailable. Rather than using the unit for energy in hours where it is not critical, saving the remaining available run time for the most critical hours during emergency conditions is consistent with the reliability needs of the system.

Energy and Environmentally Limited Opportunity Costs

Recent changes in PJM's market rules can avoid the need to be maximum emergency only for energy and environmental limitations. PJM's market rule now allows generation owners to include in their cost-based offers energy and environmentally limited opportunity costs that are designed to ensure the unit facing such limitation operate in the hours which are most financially advantageous to the generation unit owner and those hours which should be highly correlated to the hours of greatest system need to maintain reliable operations. In this way the unit facing environmental restrictions is always available economically in the Day-Ahead and Real-Time Energy markets while allocating the limited output to the hours where it is most valuable.

Even units with fuel limitations or limited run hours due to an emergency at the units can potentially use the energy and environmentally limited opportunity cost provision to allocate their fuel or limited run hours to the hours in which they will be most valuable to the system and concurrently earn the highest net energy revenues for their limited operation. This is especially true with fuel limitations if the limitation will not allow the generating unit to run at maximum output for at least 72 hours.[36]

Unfortunately, there will likely always be situations in which temporary physical limitations will be sudden and will not allow generation owners sufficient lead time to use the energy and environmentally limited opportunity cost provisions to allocate their limited hours, or there may be great uncertainty as to how many more hours the unit can operate. In such instances, the generation capacity resource still can be available as emergency only as it still is beneficial to have the unit available in emergencies to meet system reliability needs rather than requiring it to take a forced outage and be unavailable.

Implications for RPM Prices and Reliability

There is some relationship between declaring availability as Maximum Emergency only to RPM insofar as it can affect the EFORd calculation of a generating unit or the forced outage rate during peak conditions, either of which affect the amount of capacity in UCAP terms that can be offered into future RPM auctions and/or penalties faced by a Generation Capacity Resource within the delivery year. Qualitatively, eliminating the ability of generation capacity resources to be available as Maximum Emergency only and instead require them to take forced outages increases the EFORd of specific resources and thereby reduces their supply in future RPM auctions. Additionally, such a policy would increase the pool-wide EFORd, which would increase the Installed Reserve Margin determination and, by extension, increase the demand for capacity and would tend to raise prices, all else equal. But, it is unclear how much of a price and quantity impact this would have since it is not clear how much the EFORd would actually increase on a pool-wide basis.

Another implication of restricting units being available as emergency only would be the elimination of all types of demand resources, especially limited demand resources (Limited DR), that can only be called-upon a maximum of ten events for six hours per event. The IMM has explicitly called for the elimination of Limited DR and that the Day-Ahead Energy must-offer requirement be extended to all resources. Currently all demand resources are available as Maximum Emergency only.

It is quite likely that a portion of what currently serves as demand response capacity may choose not to take on the additional capacity obligation implied by the IMM recommendation which would effectively reduce supply in the RPM BRA as is evidenced by the 5,312 MW UCAP and the 6,703 MW UCAP offered as Limited DR only in the 2014/2015 and 2015/2016 BRAs respectively.[37] At the request of PJM stakeholders PJM ran multiple scenario analyses for the 2014/2015 BRA in an attempt to show how prices and the resource mix would change.[38] The scenario definitions reducing supply from the bottom of the supply stack are not a perfect representation of a potential reduction in DR Capacity, but reductions of 4,000 MW and 8,000 MW of supply in the RTO clearly show 2014/2015 RPM prices would have risen from $125.99/MW-day for annual resources to $147.75/MW-day and $215.35/MW-day respectively while reducing committed capacity by approximately 300 MW and 1,650 MW respectively.[39]

Reporting Outages as Out of Management Control

The IMM in the 2010 State of the Market Report and the 2011 State of the Market Report offers the recommendation that “PJM review all requests for Out of Management Control (OMC) carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines”, and “consider eliminating lack of fuel as an acceptable basis for an OMC outage.”

As the IMM points out in its 2010 State of the Market Report, the North American Electric Reliability Corporation Generating Availability Data System and reporting instructions already provide a template for defining and reporting outages that are out of management control.[40] In addition to the guidance provided in the NERC documents, PJM’s Resource Adequacy Planning Department is in the process of developing a more formal set of guidelines/rules as PJM believes that such formal guidance provides greater transparency and certainty to market participants. It is also important to note that generator EFORd data, including out-of-management-control outages, are an important input to PJM planning and reliability studies.

Capacity resources are obligated to follow PJM and NERC outage reporting requirements which pre-date the RPM capacity market construct. These requirements are a determinant of the EFORd that determines the amount of unforced capacity that can be compensated in the RPM capacity market, or the EFORp that determines peak period penalties in RPM. Consequently, it is essential that outages be categorized correctly to avoid incentives to misrepresent the cause for an outage to avoid performance penalties, while simultaneously ensuring that outages truly out of management control will penalize generation capacity resources punitively.

PJM Guidance on Out-of-Management-Control Outages

PJM has broken down the causes of out-of-management-control outages into five categories: transmission/distribution, acts of nature, fuel quality, regulatory, and miscellaneous.

Transmission and Distribution

Management control of transmission and distribution events can be determined most of the time, with a simple test. Assuming the generator boundary is demarcated by the transmission/distribution bus bushings on the generator side, the test is: Absent the generator would the equipment in question (that equipment involved in the failure or maintenance) be used and useful? If the answer is yes, then the event caused by failure or maintenance of said equipment is out of management control. There may be exceptions to the test given circumstances unique to the generator.

Acts of Nature

For acts of nature, the root cause of the failure or maintenance must first be determined. If it is the act of nature that directly causes the failure (or maintenance), then the event can be considered out of management control. For instance, if a tornado rips up switchyard equipment the event is out of management control. Also, if the tornado tosses about objects that impact equipment, such that the equipment fails, the event most likely can be considered out of management control. However, if those objects are property of the plant and were not secured properly (time permitting), the event may not be out of management control. Again, there may be exceptions to these general rules depending on the unique circumstances surrounding the generator and the act of nature.

Fuel Quality

Out of management control events for fuel quality should be rare. Since all fuel is basically rendered with respect to fuel quality specifications, those specifics are delineated in purchase agreements, and, if not met, companies usually can refuse delivery, and there may be contractual terms that require the fuel supply contractor to pay liquidated damages. Although liquidated damages are normally outlined in these contracts, they most likely are specific to the physical damage caused therein, not necessarily lost opportunity in any or all of the PJM markets. However, if the liquidated damages cover lost opportunity in the RPM markets, then out of management control should not be granted since the generator owner would be compensated twice.

However, in certain cases, delivery refusal is not an option, and once accepted by the plant management, any event caused by said fuel cannot be out of management control since the plant management accepted delivery of "out of spec" fuel, and/or made a management decision to sign a contract that required the generator to accept out of spec fuel.

Causes such as wet or frozen coal may not be completely within management control, but these issues can be mitigated by the good utility practices of coal pile management and housekeeping and the scheduled maintenance of fuel delivery and burning (conveyors, feeders, pulverizers, nozzles, etc.) equipment. The probability of deep freezes and heavy rains should have been considered in the design of the fuel delivery and burning systems. Any of these event(s) that had 50 percent probabilities of occurring during the plant lifetime typically are considered in design; however, the plants are not built to those rigorous specifications; they are typically built to less than those specifications due to the expense. Any events that have 50 percent or greater probabilities of occurring during the plant lifetime are normally not considered out of management control since they were more likely to occur than not.

Regulatory

If a regulatory agency forces a generator shutdown until the generator operator complies with regulatory requirements which could not reasonably be foreseen and for which the generator cannot reasonably comply, the event most likely will be out of management control. However, if that shutdown is a result of not meeting a compliance deadline or through the generator's voluntarily entering into an agreement that results in compliance obligation leading to the shutdown, the event cannot be considered out of management control. If the event is caused by exceeding a compliance parameter, that, too, is not out of management control. Exceeding emission and thermal discharge limits are good examples of the regulatory issues that are not considered out of management control.

Miscellaneous

The miscellaneous category contains, but is not limited to events such as labor actions, including strikes or work slowdowns, and lack of fuel.

Labor Actions

With respect to labor actions, if a miners' or railroad workers' strike were to halt coal deliveries, most of these events caused by the lack of coal would be considered out of management control as the labor action is not within the control of the generator owner. However, if one plant has just-in-time inventory and another has 30 days supply on the ground, special consideration might be given to the plant with thirty days supply. Most likely, PJM would be aware of the situation and some form of inventory burn down would be rendered by PJM in order that inventory would be extended by fuel switching or running at reduced capability. For those units with just-in-time inventory, if they cannot burn an alternate fuel, PJM might consider a non out of management control event until many other plants with inventory are also experiencing outages. This would prevent a practice that might appear discriminatory.

In contrast, labor actions at the generating plant itself would not be considered out of management control as management has within its control the ability to reach a compromise with its own workers or hire replacement staff.

Lack of Fuel

The NERC GADS Data Reporting Instructions provides guidance with regard to reporting lack of fuel as an out of management control outage:

> "Lack of fuels (water from rivers or lakes, coal mines, gas lines, etc) in the cases where the operator of the unit is not in control of contracts, supply lines, or delivery of fuels. However, if the operator elected to contract for fuels where the fuel (for example, natural gas) can be interrupted so that the fuel suppliers can sell the fuels to others (part of the plant fuel cost-saving measure), then the lack of fuel is under management control and is not applicable to this case."[41]

For lack of fuel, if the event is caused by lack of inventory (for coal, oil and other fuels in which on site inventories are typically kept) the events cannot be considered out of management control as good utility practice would mandate the availability of back-up fuel or fuel inventories on-site if possible. For plants with just-in-time inventories (except natural gas) no out of management control events are allowed since it would be discriminatory toward those plants with inventory. For natural gas fired resources, if the resource has firm transportation contracts for delivery such that the resource can provide full load to PJM for the day, any event such as a pipeline disruption or operational flow order that causes the lack of fuel can be considered out of management control. For any plant that has made the management decision to purchase lower cost interruptible transportation, the event cannot be considered out of management control.

Typically plants do not generate for the entire day and do not exercise their full transport capacity. Moreover, the timing of the gas market day is not aligned with the electricity market day in PJM. On these days, gas-fired generators only may be able to secure enough transportation through intra-day gas nominations to run for the hours scheduled in the Day-ahead Energy Market. It has been the practice of PJM to allow the plants to shut down when their nominations are exhausted and to not consider them forced out due to the lack of coordination in the timing of the gas market day and electric market day. If PJM disallowed this practice, any single-fueled natural gas unit would be assigned a lack of fuel event on a daily basis after their nominations were exhausted. This would increase systemwide EFORd and cause issues with the planning studies that depend on EFORd.

The above situation should be rare as interstate gas pipelines also have rules and pricing in place that allow the plants to continue to operate on higher-priced gas by letting the plants run at higher costs (including any imbalance penalties) with little or no notice. In this sense, although some units may have exhausted their scheduled natural gas nominations for the generating day, they are not then considered forced out since they have met their obligation and do have the option of taking gas albeit at higher prices if needed by PJM.

Implications for Eliminating Lack of Fuel as an Out-of-Management-Control Outage

In the 2010 State of the Report, the IMM highlights that out of management control outages accounted for 10.6 percent of all forced outage occurrences in 2010, and lack of fuel out of management control accounted for 6.9 percent of all forced outage occurrences.[42] There were 1,468,640 unit-hours of out-of-management-control events in 2010; only 9,500 unit-hours were attributed to out-of-management-control forced lack of fuel. Other types of outages such as planned and maintenance outages can also be classified as out-of-management-control lack of fuel for things such as gas pipeline maintenance, compressor issues and construction, etc.; there were 4,500 unit-hours of these events. Many times, when generators are not given advanced notice of pipeline outages, the events are classified as forced instead of planned or maintenance. Approximately 68 percent of out-of-management-control lack-of-fuel unit-hours were forced; these did include some for pipeline maintenance; ***only 0.6 percent of all*** out-of-management-control unit-hours were for out-of-management-control forced lack of fuel. However, the use of lack of fuel as an out-of-management-control outage is not a market-wide phenomenon in that 98.8 percent of the lack-of-fuel out-of-management-control outages are attributable to a single generation owner.[43] PJM is examining further the issues related to out-of-management-control outages by this single generation owner and hopes to better understand why this one owner accounts for essentially all of the lack of fuel out-of-management-control outages.

A blanket elimination of lack of fuel as an out-of-management-control outage may unnecessarily penalize generation capacity resources for a lack of fuel that may truly be out of their control. For example, major rail transportation disruptions that could prevent coal from being delivered, as was the case several years ago for coal units in the Midwest using Powder River Basin coal, or a major natural gas supply and pipeline disruptions similar to what was seen with Hurricanes Ivan in 2004, Katrina and Ike in 2005 that would exhaust on-site back-up fuel supplies. Of course, hurricanes would fall under acts of nature as well and easily can be seen as out of management control.

RPM does provide incentives for generators to minimize forced outages so as to have as much unforced capacity available to offer into subsequent RPM auctions. Moreover, the PJM energy market also provides an incentive to minimize outages during times of critical need since those periods are correlated with higher energy market prices.

However, any forced outage, whether defined as a forced outage contributing to EFORd or as an out-of-management-control outage, is a potential threat to reliability and is already accounted for in determining the Installed Reserve Margin and by extension the demand for capacity resources in RPM.[44]

The IMM's concern about lack of fuel out-of-management-control outages highlights that it is difficult to discern between an outage due to lack of fuel that is within management control, and thus accounted for in EFORd, and lack of fuel that is best classified as out of management control. If lack of fuel were to be eliminated as an out-of-management-control outage as proposed by the IMM, this would translate into a reduction in the supply of UCAP on a pool-wide basis of 115 MW, based on total non-wind installed capacity of 165,901 MW as of December 31, 2010.[45]

The implied decrease in UCAP supply would have the effect of increasing prices in RPM, all else being equal, although it can be argued that this increase would be small. It could be argued eliminating lack of fuel out of management control in UCAP supply would make the system more reliable as PJM would be accounting for a greater range of outages, and make UCAP supply more consistent with the demand for capacity since all outages including out-of-management-control outages are included in the Installed Reserve Margin determination that defines demand for capacity. On the other hand, it could be argued that eliminating lack of fuel out-of-management-control outages results in double counting the lack of fuel out-of-management-control outages by including in both the Installed Reserve Margin determination and the supply offers resulting in "over-procurement" of capacity that would exceed the one day in 10-year standard.

Recall of Off-System Energy Sales from Capacity Resources

Since the commencement of PJM's market operations in 1997 and pre-dating the RPM capacity market construct, PJM's emergency procedures have provided very clearly that energy exports by capacity resources are recallable in real-time operation when PJM declares Maximum Emergency Generation:[46]

> Recalls energy from Capacity Resources that otherwise deliver to loads outside the Control Area and dispatches that energy to serve load in the Control Area.

The IMM in the 2010 State of the Market Report has reaffirmed that an obligation of a capacity resource is that any energy sales outside of PJM can be recalled when PJM enters emergency or scarcity conditions:[47]

> The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition.

In the context of real-time operations under emergency conditions, recalling energy exports from capacity resources is not as simple as it may seem. At any point in time, there may be scheduled flows of energy to and from PJM with its neighboring control areas such as the New York ISO and MISO. However, if at the time of the emergency declaration PJM is importing more than it is exporting to a neighboring control area, the neighboring control area may then recall its transactions into PJM leaving the PJM with less energy than it had prior to the recall of capacity resources. Furthermore, recalling energy exports may have unintended consequences on the ability to manage transmission congestion and could possibly make transmission constraint control more difficult rather than less difficult. Such situations call for more explicit procedures and protocols as the IMM has plainly stated in the 2010 and 2011 State of the Market Reports.[48]

To this end PJM has recently proposed and implemented changes to Manual 13: Emergency Operations providing more detailed protocols with regard to recalling energy exports from capacity resources. These proposed changes were presented to the Operating Committee on February 10, 2012, the Markets and the Reliability Committee on February 23, 2012.[49] The proposed protocols are reproduced below and reflect the idea that recalling energy sales from capacity resources must be examined to ensure it does not harm reliability:[50]

PJM dispatcher determines the feasibility recalling off-system capacity sales that are recallable (network resources).

- PJM dispatch will determine any limiting transmission constraints internal to PJM that would impact the ability to cut transactions to a specific interface.
- PJM dispatch will identify off-system capacity sales associated with the identified interfaces.
- PJM dispatch will contact the sink Balancing Authority to determine the impact of transaction curtailment.
- If the net result of cutting off-system capacity sales would put the sink Balancing Authority into load shed then PJM will not curtail the transactions unless it would prevent load shedding within PJM.
- If the net result of cutting off-system capacity sales would put PJM in a more severe capacity emergency than it is in currently in due to reciprocal transaction curtailments from the sink Balancing Authority, PJM will not initiate curtailing the transactions.

Conclusions

PJM has no authority to order generators or demand response resources to stay in service, operate and make investments in new capacity. In the absence of such authority, PJM maintains resource adequacy reliability and ensures real-time operational reliability during emergency conditions through the incentives provided by the RPM capacity market and the associated obligations and incentives committed capacity resources have in the PJM Energy Market.

The incentives to be committed as a capacity resource must be synchronized with the obligations of capacity resources. The incentives for undesirable behavior by capacity resources, such as misrepresenting the actual availability status, should be minimized while also accounting for unique circumstances. The incentives provided by the RPM capacity market and associated capacity obligations do dovetail well with performance incentives to ensure that capacity resources are available when they are required.

The primary obligations of generation capacity resources are to be available to provide energy on a daily basis and to avoid outages, especially during peak times, to ensure availability to PJM load when needed. Generation capacity resources have a strong incentive to satisfy this obligation as the more the resource is available, the greater opportunity it will have to earn energy market revenues that will cover avoidable costs. The lower the forced outage rate, the more capacity the resource has available to be compensated in the capacity market.

The primary obligations of demand resources are to be available to reduce consumption when requested by PJM during system emergencies and to provide measurement and verification of the request load reductions.

The strength of these incentives is dependent upon how much latitude the capacity resource has in managing its cost risk through the use of market-based offers in the energy market and in expectation to not be dispatched for energy at a loss. In the case of a demand resource it is the ability to choose, commensurate with the reliability needs of the system, whether to be committed as a limited, extended summer, or annual demand resource based on preferences regarding the frequency and duration of load reductions.

The strength of these incentives also depend on whether or not a capacity resource will be penalized for circumstances out of management control, and will be recognized for making itself available to help ensure reliable operations during system emergencies even under difficult circumstances in which it would be easier to take an outage.

Overall, the performance of RPM capacity market to maintain resource adequacy in the face of challenging economic and policy environments the power industry has witnessed shows how well these incentives are working together. Of course, monitoring and market power mitigation by the IMM and PJM of the incentives provided by PJM's markets remain essential to ensuring capacity resources are not withheld from the market and outcomes in the RPM capacity market and energy markets remain competitive and result in the lowest cost reliability solution for the load being served in PJM.

[1] *See* 2015/2016 Base Residual Auction Results, available at http://wired.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx.

[2] *Id.* The delivery year runs from June 1 to May 31 of the following year.

[3] *See* Delaware Public Service Commission, the District of Columbia Public Service Commission, the Maryland Public Service Commission and the New Jersey State Board of Public Utilities Letter to PJM Board of Managers, November 3, 2011 at http://www.pjm.com/about-pjm/who-we-are/pjm-board/~/media/about-pjm/who-we-are/public-disclosures/md-de-nj-and-dc-commissions-letter-regarding-rpm-performance-assessment.ashx, Public Utilities Commission of Ohio Letter to the PJM Board of Managers, November 9, 2011 at http://www.pjm.com/about-pjm/who-we-are/pjm-board/~/media/about-pjm/who-we-are/public-

disclosures/ohio-commission-letter-regarding-rpm-performance-assessment.ashx, and Organization of PJM States Resolution of December 1, 2011, at: http://www.opsi.us/filings/2011/Resolution-OPSI-2011-7.pdf.

[4] *See* Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA") at http://www.pjm.com/documents/~/media/documents/agreements/raa.ashx and PJM Manual 20: Resource Adequacy Analysis, Revision 04, Effective Date June 1, 2011 at http://www.pjm.com/~/media/documents/manuals/m20.ashx. Reliability Principles and Standards is defined in the RAA as "the principles and standards established by NERC or an Applicable Regional Reliability Council to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time."

[5] *See supra note 5.*

[6] PJM Manual 18: PJM Capacity Market, Revision: 8, Effective Date: January 1, 2010 available at http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx ("PJM Manual 18") at 3.

[7] *Id.* at 56.

[8] A firm energy price component would provide to the buyer of the capacity product the energy output from that capacity at a guaranteed energy price.

[9] The costs associated with committing to provide energy at a firm price are the expected opportunity costs of revenues from higher spot market energy prices that the seller has forgone.

[10] Avoidable costs are costs that the owner of the generation resource would not incur but for remaining in commercial operation. These include fixed operation and maintenance costs, administrative overhead, property taxes, and insurance among others.

[11] The PMSS consists of three separate tests to determine structural market power: (1) The market share of any Capacity Market Seller exceeds twenty percent; (2)The HHI for all such sellers is 1800 or higher; or (3) There are not more than three jointly pivotal suppliers.

[12] See 2010 State of the Market Report for PJM: Volume 2 Detailed Analysis, March 10, 2011 ("*2010 SoM Report*") at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml. The report can also be found on PJM's website at http://www.pjm.com/documents/reports/state-of-market-reports/2010-state-of-market-report.aspx, and *2011 State of the Market Report for PJM: Volume 2 Detailed Analysis,* March 15, 2012 ("*2011 SoM Report*") at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml. The report can also be found on PJM's website at http://www.pjm.com/documents/reports/state-of-market-reports/2011-state-of-market-report.aspx.

[13] *2010 SoM Report* at 357 and *2011 SoM Report at 90.*

[14] *See Terra Comfort Corporation, et al.*, 52 FERC ¶ 61,241 at 61,840 (1990), "With respect to the Applicants' argument that the ten percent adder is a contribution to fixed costs, we have always viewed percentage adders as mechanisms to recover only incremental energy costs. Such adders are traditionally supported by utilities - and approved by the Commission - on the grounds that the ten percent adders recover incidental, miscellaneous expenses **that are expensive or difficult to quantify** (emphasis added). It continues to be the industry's consistent practice to justify ten percent adders to incremental costs as allowing recovery of incremental energy costs, not as providing a contribution to fixed costs."

[15] *PJM Interconnection, L.L.C.,* 126 FERC ¶ 61,145 P 28.

[16] *Id.* at P 42 citing to *H.Q. Energy Services (U.S.), Inc. v. New York Independent System Operator,* 110 FERC ¶ 61,243, at P 29-34 (2005) (recognizing that a hydroelectric unit has a legitimate basis for bidding opportunity costs).

[17] *2010 SoM Report* at 357 and *2011 SoM Report* at 90.

[18] *See* Michael J. Sullivan, Ph.D., Matthew Mercurio, Ph.D., Josh Schellenberg, M.A,—Estimated Value of Service Reliability for Electric Utility Customers in the United States, Prepared for the Office of Electric Deliverability and Energy Reliability, United States Department of Energy, June 2009, available at http://certs.lbl.gov/pdf/lbnl-2132e.pdf at xxi, Table ES-1. ("LBL Study") and Paul Centolella, SAIC, Mindi Farber-DeAnda, SAIC, Lorna A. Greening, Ph.D., Consultant, and Tiffany Kim, SAIC, "Estimates of the Value of Uninterrupted Service for the Mid-West Independent System Operator," available at http://www.hks.harvard.edu/hepg/Papers/2010/VOLL%20Final%20Report%20to%20MISO%20042806.pdf ("SAIC Study"). The LBL Study estimates willingness to pay of $2,600/MWh for residential customers and $25,000/MWh for large commercial and industrial customers. The SAIC study shows an average willingness to pay for residential customers of $1,600/MWh and minimum willingness to pay for commercial and industrial customers of $1,733/MWh.

[19] *PJM Interconnection L.L.C.,* 139 FERC ¶ 61,057 PP 123-131, quote P 131.

[20] See 2014/2015 Base Residual Auction Results at 7, available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx. Of the 14,426 MW (UCAP) offered as Limited DR, 8,622 MW (60%) made coupled offers that allowed these resources to be potentially committed as Annual DR. See also 2015/2016 Base Residual Auction Results at 9, available at http://www.pjm.com/markets-

and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx. Of the 18,091 MW (UCAP) offered as limited demand response, 11,286 MW (62%) made coupled offers that allowed these resources to be potentially committed as annual or extended summer demand response.

21 PJM has recognized that there is a reliability-based limit to the dependence on more limited forms of demand resources and has implemented FERC-approved changes to the RPM capacity market to reflect the limited nature of some demand resources while still permitting cost effective participation that maintains reliability. *See* Demand Response Saturation Analysis at http://pjm.com/~/media/committees-groups/committees/pc/20100811/20100811-item-10-demand-response-saturation-report.ashx and PJM Interconnection, L.L.C filing in ER12-513, December 1, 2011 available at http://www.pjm.com/~/media/documents/ferc/2011-filings/20111201-er12-513-000.ashx, and *PJM Interconnection, L.L.C.* 138 FERC ¶ 61,062 January 30, 2012, for the most recent design changes incorporating different demand resource categories into RPM.

22 2010 SoM Report at 4 and 2011 SoM *Report* at 4.

23 *Id.*

24 2010 SoM Report at 28 and 2011 SoM Report at 32-34,

25 2010 SoM Report at 363 and 2011 SoM Report at 91.

26 *Id.*

27 2010 SoM Report at 360.

28 PJM Manual 21 Rules and Procedures for Determination of Generating Capability, Revision 09, Effective Date: May 1, 2010, at http://www.pjm.com/~/media/documents/manuals/m21.ashx.

29 PJM Manual 22 Generator Resource Performance Indices, Revision 16, Effective Date: November 16, 2011, at http://www.pjm.com/~/media/documents/manuals/m22.ashx.

30 PJM Manual 20: Resource Adequacy Analysis, Revision 04, Effective Date June 1, 2011, at 14, available at http://www.pjm.com/~/media/documents/manuals/m20.ashx.

31 *Id* at 360.

32 PJM Tariff, Attachment DD, Section 10(i).

33 2010 SoM Report at 358.

34 2010 SoM Report at 363 and 2011 SoM Report at 90..

35 PJM Tariff, Attachment K, Section 6A.1.3

36 PJM Manual 13, Section 6.4. Unit owners are required to report fuel limitation to PJM if they cannot operate at maximum output for more than 72 hours.

37 See 2014/2015 Base Residual Auction Results at 7, available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx and 2015/2016 Base Residual Auction Results at 9, available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx.

38 http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-sensitivity-scenario-analysis-results.ashx

39 *Id.*

40 See The NERC GADS (Generator Availability Data System) DRI (Data Reporting Instructions) http://www.nerc.com/page.php?cid=4|43|45 and Appendix K http://www.nerc.com/files/Appendix_K_Outside_Plant_Management_Control.pdf

41 The NERC GADS (Generator Availability Data System) DRI (Data Reporting Instructions), Appendix K at K-2, available at http://www.nerc.com/files/Appendix_K_Outside_Plant_Management_Control.pdf

42 *2010 SoM Report* at 408.

43 *Id.*

44 PJM Manual 20 at 30.

45 2010 SoM Report at 203, Table 3-42 for the installed capacity value of 165,901 MW. For the EFORd values with and without all OMC outages see Table 5-26, p. 410. EFORd without any OMC pool-wide is 6.2% and with OMC is 7.2%. Since lack of fuel OMC is 6.9% of the total OMC, the pool-wide EFORd accounting for just lack of fuel OMC is 6.269%. The difference in UCAP using 6.269% versus 6.2% is equal to 0.00069 multiplied by 165,901 or 115 MW.

46 PJM Manual 13 at 10, available at http://wired.pjm.com/~/media/documents/manuals/m13.ashx.

[47] 2010 SoM Report at 358 and 2011 SoM Report at 90.

[48] 2010 SoM Report at 358.

[49] 2/10/12 OC Meeting Item 7c found at http://www.pjm.com/~/media/committees-groups/committees/oc/20120214/20120214-item-07c-draft-pjm-manual-13-emergency-operations.ashx and the 2/23/12 MRC meeting First Read Item 1C found at http://www.pjm.com/~/media/committees-groups/committees/mrc/20120223/20120223-first-read-item-01c-draft-manual-13-revisions.ashx on pages 22-23 of the proposed revision to manual 13.

[50] PJM Manual 13 Emergency Operations, Revision 48, Effective Date April 3, 2012, at 22, available at http://www.pjm.com/~/media/documents/manuals/m13.ashx.