Before the
New Jersey Board of Public Utilities

In the Matter of the New Jersey Board	**)**	
of Public Utilities Review of the State's	**)**	**Docket No. EO09110920**
Electric Power and Capacity Needs	**)**	

Comments of PJM Interconnection, LLC

I. Introduction

PJM Interconnection, LLC (PJM) is an independent regional transmission system operator authorized by the Federal Energy Regulatory Commission to administer an open access transmission tariff; operate wholesale energy, capacity and ancillary service markets; plan the transmission system; and otherwise conduct the day-to-day operations of the bulk power system across all or part of 13 states and the District of Columbia.[1] PJM participated in the New Jersey Board of Public Utilities (BPU) capacity issues technical conference on June 24, 2010, through the testimony of Michael Kormos, Senior Vice President - Reliability Services, and Steven Herling, Vice President - Planning. Messrs. Kormos and Herling provided an overview of New Jersey's historic and future generation supply and load situation. Throughout the conference questions were directed to the PJM witnesses regarding, and other parties made reference to, PJM's Reliability Pricing Model (RPM), load management programs and Price Responsive Demand (PRD), and recent demand response saturation report. To

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[1] *See Pa. – N.J. – Md. Interconnection, L.L.C.*, 81 FERC ¶ 61,257 (1997), *reh'g denied*, 92 FERC ¶ 61,282 (2000), *modified sub. nom Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (2002).

supplement the record testimony of Messrs. Kormos and Herling on those topics and further assist the BPU in its energy policy deliberations, PJM respectfully requests leave to submit these comments one business day past the comment due date.

II. Comments

A. Reliability Pricing Model

PJM's Reliability Pricing Model (RPM) Capacity Market ensures that sufficient capacity resources will be committed to ensure reliability in the PJM footprint on a three-year forward basis. During the second panel's discussion of what obstacles exist to the assurance of adequate supply resources and transmission infrastructure in New Jersey, there was a suggestion that RPM does not sufficiently assure adequate capacity supply resources in New Jersey with the criticism focusing on the level of the clearing prices and the construct's three year forward procurement providing a one year revenue stream to committed resources. However, RPM was never intended to be the sole source of revenue through which resource development decisions would be made, nor was it intended to be the only mechanism through which new capacity resources could be financed or constructed. Early experience has shown, as PJM witnesses testified, RPM has led to significant current and future investment in (1) new generation, Demand Response and Energy Efficiency resources, (2) uprates to existing resources, and (3) deferred generation retirements.[2] Clearly, RPM in conjunction with expected revenue

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[2] See PJM's technical conference handout at http://www.bpu.state.nj.us/bpu/pdf/energy/HERLING%20AND%20KORMOS.pdf. Of the 848.4 MW of total new generation cleared in RPM through the 2013/2014 delivery year in New Jersey, 231.2 MW are for new units, 432.5 are uprates to existing units, and

streams from PJM's Energy and Ancillary Service Markets are making it worthwhile for some capacity resources developers to make investment decisions today to help ensure resource adequacy requirements are met.

1. Revenue and Costs Driving Investment Decisions

Developers of new capacity resources make investment decisions based upon whether the *expected* stream of revenues over the life of the capacity resource exceeds the *expected* costs. Expectations about future revenue streams and costs over the life of the capacity resource are uncertain at the time of investment as the capacity resource is a long-lived investment and forecasts of the future are not going to be perfectly accurate. If it is expected that revenues will exceed costs, then the investment is made. Conversely, if the expected revenues do not cover expected costs, then the investment will not be made.

In PJM the stream of expected revenues comes from the Energy, Ancillary Service, and RPM Capacity Markets. In this sense, RPM is but one source of revenues that can be earned by resource developers as other revenues can be earned from participating in the PJM Energy and Ancillary Service Markets. Historically, new capacity resources have been unable to cover the entirety of their expected costs through revenues from the Energy and Ancillary Service Markets alone, and RPM

184.7 MW are reactivations of existing units. Additionally, over 1,500 MW of Demand Resources (including Interruptible Load Resources) and 15 MW of Energy Efficiency have cleared through the 2013/2014 delivery year.

Capacity Market revenues are a source of revenues that can help cover the remaining gap between expected revenues and expected costs.[3]

Expected costs encompass the investment cost, including the cost of capital used to finance the investment and a rate of return; fixed, going forward costs such as fixed operation and maintenance cost and administrative costs and any additional investments needed to maintain the resource; and variable operating costs such as the cost of fuel, variable operation and maintenance costs, and environmental costs.

2. Uncertainty Regarding Expected Revenues and Costs and RPM's Role in Mitigating Uncertainty

Given that investment decisions are made in an environment of uncertainty, developers of capacity resources will attempt to mitigate uncertainty related to future streams of revenue and future costs to the extent possible.[4] One avenue for mitigating uncertainty regarding future revenue streams is for resource developers to find counterparties to engage in long-term contracts for the output of the capacity resource.

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[3] For a more detailed, non-technical explanation of these concepts, see "A Review of Generation Compensation and Cost Elements in the PJM Markets," prepared for the PJM Markets and Reliability Committee, January 20, 2010, available at http://www.pjm.com/~/media/committees-groups/committees/mrc/20100120/20100120-item-02-review-of-generation-costs-and-compensation.ashx.

[4] For a detailed discussion of uncertainty in investment decisions and how this relates to RPM, see *Prepared Remarks of Paul M. Sotkiewicz, Ph.D., Senior Economist, PJM Interconnection L.L.C., PJM Long-Term Capacity Issues Symposium, Panel 2:Challemges and Uncertainties in an Uncertain Regulatory Environment,* January 27, 2010, available at http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/ltci/20100126/20100126-panel-2-sotkiewicz-pjm.ashx.

Similarly, resource developers can also mitigate cost uncertainty through long-term contracts for inputs such as fuel to reduce cost uncertainty.

However, in the absence of willing counterparties to sign long-term contracts to mitigate uncertainty, resource developers can mitigate revenue and cost uncertainty through waiting to make the investment decision so that additional information may reveal itself regarding future operating conditions that will determine future streams of revenues. This value to waiting for additional information before making an investment decision is known a “real option”. In waiting for additional information before making the investment decision, the expected value of the investment increases because the investment will be made when the revealed information shows more definitively that the expected revenues of the investment will exceed the expected cost of the investment.

In today’s market environment resource developers may be waiting for additional information regarding, but not limited to, the form and stringency of Federal climate change policy, the form of state environmental policies such the proposed High Electricity Demand Day (HEDD) policy under consideration in New Jersey, the eventual outcome and timing of new transmission investments identified by PJM in its planning process, or development of new natural gas fields such as the Marcellus Shale field. The outcomes on these and other drivers of revenue and costs are large drivers of future revenues and costs, and waiting for these uncertainties to be resolved is in the view of some developers more valuable that making the investment today.

RPM is designed to augment long-term contracting by reducing the value of the “real option” to wait for additional information by providing a revenue stream that is known with certainty three years in advance of the required delivery of the capacity resource. At the conclusion of each Base Residual Auction (BRA), all winning bidders accept a financially binding contractual commitment to provide capacity for one year, three years in advance of the time the capacity is expected to be delivered and available. From a planning and reliability perspective, the financially binding one-year commitment of capacity three years in advance of delivery provides PJM with additional planning certainty in the short-term, and assurance of performance that is enforceable through standard contract enforcement measures. From the perspective of resource developers, RPM provides an opportunity for new entrants to compete with existing capacity providers by providing some certainty in revenue streams in three years in advance of the year of actual operation. The RPM construct also includes a mechanism intended to offer a longer term revenue stream to new resources, called “New Entry Pricing.”   Under this mechanism, new resources have the opportunity to lock in revenue for three years at the level those resources initially cleared in a BRA creating further certainty in future revenue streams for new resources.

3. RPM Does Not Prevent Long-term Contracting and Resource Procurement

RPM was never intended to be the sole market mechanism to complement the Energy and Ancillary Service Markets by which investment in new capacity resources would be made. In fact, the name of the main procurement auction held three years in advance of the delivery year, “Base *Residual* Auction”, was selected specifically to convey the message that RPM does not foreclose long-term resource procurements outside of RPM auctions. Load Serving Entities (LSEs) or other entities with capacity obligations and developers of new capacity resources are free to enter into contracts at mutually agreeable prices and terms that would help the LSEs and other entities meet their capacity obligations while providing revenue certainty for the resource developer. The resulting capacity addition would then be entered into RPM auction, but the actual financial settlement between the LSE and resource developer would be governed by the contract terms. This self-supply of a load's capacity obligation in RPM results in load and the resource developer being indifferent to the RPM clearing price.[5]

4. RPM Clearing Prices are a Signal of Capacity Resource Needs

While it is true that the clearing price of capacity resources in Eastern MAAC has generally been higher than the clearing price in the Rest of RTO since the introduction of RPM, this price differential is reflective of the transmission constraints in moving power from west to east into New Jersey and the need for resources to be located inside New Jersey. Locational pricing under RPM creates incentives for the locationally appropriate construction of necessary resources, including the development of load management and energy efficiency programs, and the retention of existing capacity that might otherwise be retired in PJM to achieve capacity adequacy reliability.

Mr. Herling observed that the amount of generation growth in New Jersey since 1999 has kept the load and generation balance somewhat static, but the future holds the potential for a fair amount of generation retirements with the introduction of environmental limitations, such as those regarding which Mr. William O'Sullivan of the New Jersey Department of Environmental Protection testified, as well as looming

[5] Note that these decisions also may hedge future energy price exposure.

federal climate change legislation. Such environmental policy driven retirements will increase the upward pressure on RPM prices in the future.

Mr. Kormos also noted that there are between 10,000 MW and 11,000 MW of coal resources in the PJM region, including New Jersey, which may be at risk for retiring due to an inability to recover their fixed, avoidable costs, according to analysis performed by the PJM Independent Market Monitor in the 2009 State of the Market Report. To the extent that these resources are located in regions in PJM with low RPM prices, such potential retirements may be optimal as there may be excess capacity in those regions. However, if such retirements are in regions with higher capacity prices, then this is an indication continued upward price pressures and a need for new resources to be developed. In response to questions, Mr. Kormos indicated that Northern New Jersey will be the most fragile area in the system if more generation retirements occur before the 500 kV Susquehanna – Roseland transmission line is constructed, which is borne out by recent RPM clearing prices in the Eastern MAAC LDA where New Jersey located.

In summary, RPM is not an obstacle to resource development in New Jersey as it does not prevent resource developers and entities with load serving obligations to enter into long-term contracts with mutually agreeable prices and terms. RPM exists to assure locational resource adequacy, but locational resource adequacy may also be assured through decisions to hedge future energy and capacity price exposure and the timely construction of required new transmission infrastructure to facilitate the delivery of additional resources into New Jersey.

In addition to pursuing willing counterparties to engage in long-term contracting, RPM provides a market-based mechanism by which resource developers can be assured of some certainty in future revenue streams thereby providing greater incentives to make the investment decision today rather than waiting for additional information on future market conditions to be revealed.

B. Demand Response Saturation

At various points during the technical conference, reference was made to the demand response saturation study recently conducted by PJM. PJM offers the below summary of the study and implications for future rule changes to ensure the record is clear on the purpose of the study and the significance of the results.

As noted above, PJM has experienced a significant increase in the amount of Demand Resources (DR) committed for reliability in New Jersey through the RPM auctions. The projected amount of DR and Interruptible Load Resources (ILR) for the summer of 2010 across the entire PJM region is 6.3%. This demand response is a contractual commitment to interrupt load during the summer period for up to 10 times with a duration of 6 hours for each interruption. The increase in DR coupled with the limited interruption requirements for DR prompted PJM to study the level at which DR saturates the reliability value it may provide. [6]

[6] The study may be found on the PJM website at http://www.pjm.com/~/media/committees-groups/committees/mrc/20100518/20100518-item-05-dr-saturation-report.ashx.

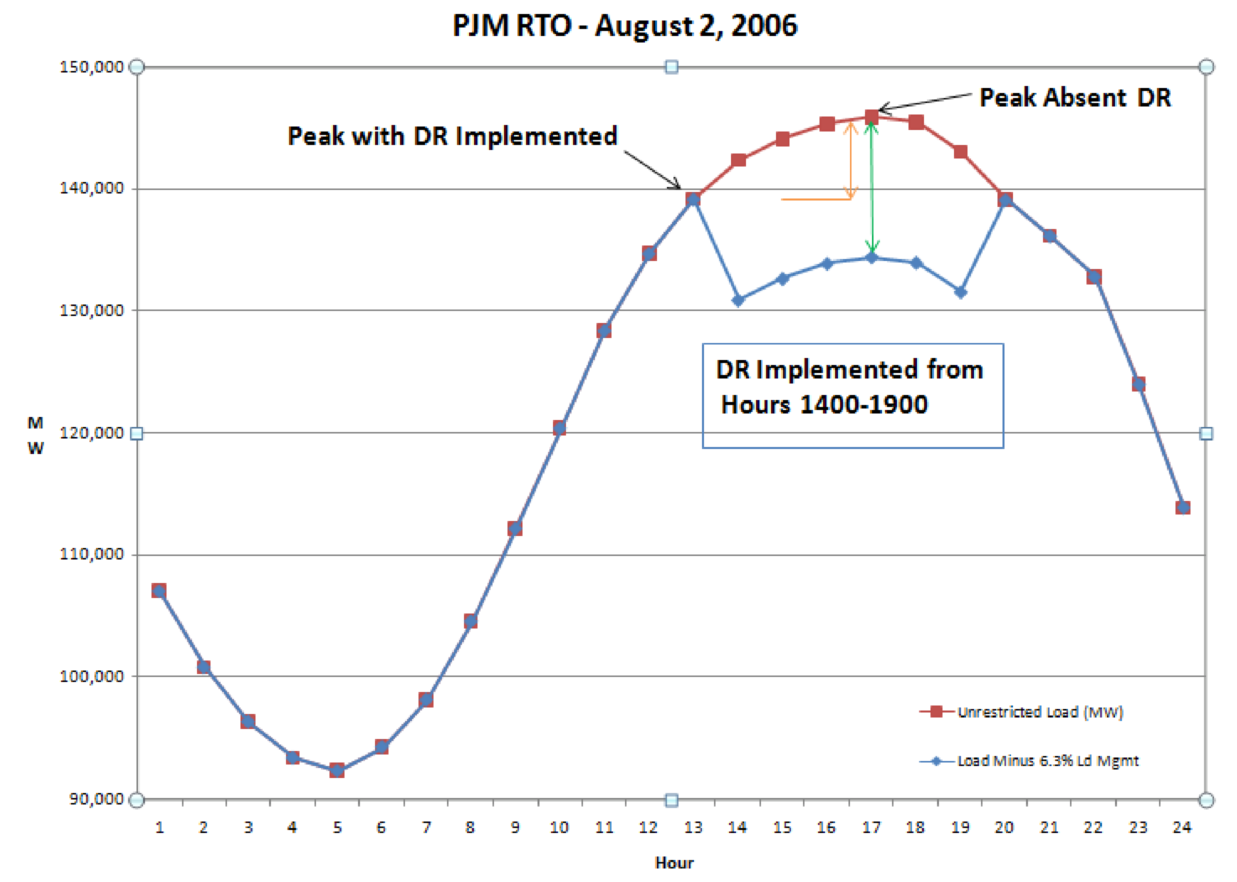
A brief history of demand response in PJM provides the background on the existing demand response programs in PJM today. The product that predated DR was the Active Load Management (ALM), which was first implemented in 1991. Its purpose was to allow Load Serving Entities to reduce their capacity obligations by registering interruptible load customers that would contractually commit to interrupt during peak demand periods. The call for the interruption was at the command of PJM Operations and verification and compliance reviews were performed at the end of each summer. The conceptual basis for ALM was that the customers' commitment to interrupt during peak demand periods eliminated the need for those customers to procure generation capacity for the interruptible portion of their load. The following requirements were established for qualifying an interruptible load program as ALM:

- Customers must be interruptible for up to ten times per summer
- Each interruption could be for up to six hours over the 1200-2000 time period of all summer weekdays
- The amount of ALM was initially limited to 5% of the forecasted unrestricted peak load for each zone, and increased to 7.5% of the RTO forecasted unrestricted peak load in 1995.

At 6.3%, the actual amount of DR in PJM is approaching the limit of 7.5% that had been previously set for ALM. Thus, PJM deemed it necessary to re-examine the limit and the DR interruption requirements that impact the limit. PJM's study examined the LOLP (loss of load probability) impact of DR as its share of total PJM resources increases. The analysis focused on both the PJM Regional Transmission Operator (RTO) region and selected Locational Deliverability Areas (LDAs).

PJM's conclusion from the analysis is that engineering judgment must be applied to select a DR penetration level at which the probability of needing more than ten interruptions is not too large. Based on its analysis, PJM has suggested 8.5% as a reasonable limit; 8.5% is the point at which there is only a 10% chance that more than ten interruptions are needed to ensure reliability (or, a 90% chance of needing ten or fewer interruptions). If the number of permitted interruptions were increased, the percentage threshold for DR across PJM could be higher. For example, the study indicates that the DR saturation level would increase to 11% if the interruption requirement were raised from ten to 15 interruptions per year.

Additionally, PJM evaluated the impact of the six hour interruption duration currently applicable to DR. The intent of the DR program is to shave the daily peak load, not to shift the peak to an hour outside the six hour DR window. According to PJM's analysis, if the DR amount increases to a certain level, however, implementing DR could have the effect of shifting the daily peak to an early afternoon or evening hour. If this occurred, the daily peak would <u>not</u> be reduced by the full amount of DR. This concept is illustrated the Figure below:



The Figure above shows the hourly load curve from PJM's all-time peak day of August 2, 2006. The red curve shows the unrestricted load. If DR had been implemented over the highest six load hours of that day, the metered load would have followed the blue curve. (In this example, DR is assumed to be 6.3% of the weather-normalized peak. As indicated above, a 6.3% DR level is projected for the 2010/2011 Delivery Year.) As illustrated in the Figure, the impact of implementing DR is to shift the daily peak to 1300 hours. As a result, the reduction in the daily peak (the vertical orange line) is less than the amount of DR implemented (the vertical green line).[7]

[7] The required DR window can vary based on the particular load day being examined. This data, however, illustrates the concern that the interruption window may not span the entire peak for a day.

According to PJM's analysis, maintaining the current 6 hour interruption duration would reduce the saturation point for DR to provide a reliability value below what previously has been determined to be the threshold level based on the 10 interruptions per year rule. If, however, an 8.5% RTO limit for DR were established, PJM's analysis indicates the interruption window should be expanded to ten hours to ensure the daily peak is not shifted to an off-peak period.

Additionally, PJM reviewed the impact of the interruption limitations on the Locational Deliverability Areas (LDAs). The LDA analysis results indicate that, under current interruption requirements (10 interruptions with 6 hour interruption duration window), the reliability value of DR saturates at 9.3% for MAAC, 14.0% for Eastern MAAC and 12.4% for Southwestern MAAC. The LDA analysis considered only DR interruptions that were required to address local, not RTO-wide, reliability problems.

Given these findings, if the DR product remains limited to 10 interruptions with a 6 hour interruption window, the analysis indicated the following:

1. The amount of DR RTO-wide should be capped at 8.5% of the forecasted unrestricted peak.

2. The amount of DR in MAAC, Eastern MAAC and Southwestern MAAC should be capped at the levels indicated in the table below. The caps are expressed as a percentage of each LDA's forecasted PJM coincident peak.[8]

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[8] It is important to note that these caps are based on each LDA's CETL for the 2013/2014 Delivery Year. The caps could change significantly for other Delivery Years as the CETL is impacted by factors such as generator retirements and the completion or deferral of planned transmission upgrades.

Proposed DR Limits for 2013/14 Delivery Year:

LDA	DR Limit
MAAC	**9.3%**
Eastern MAAC	**14.0%**
Southwestern MAAC	**12.4%**

However, PJM staff presented the stakeholders with potential alternative considerations to ensure that DR is able to provide the maximum reliability value to the grid. Those alternatives include:[9]

1. Retain the current 10 interruption definition but impose quantity limits in the RPM auction (and consider defining an additional DR product that would have an unlimited interruption requirement and place no restrictions on it in the RPM auction).

2. Implement a minimum quantity limit in the RPM auctions on non-limited resources (generation, Energy Efficiency, and DR that is not limited by the number or duration of interruptions).

3. Change the definition of the current DR product to require more Interruptions.

4. Expand the maximum curtailment duration to 10 hours (if the 10 interruption limitation remains).

PJM stakeholders will continue discussion in the Market Implementation Committee (MIC) of potential modification to PJM market rules to address the concerns identified in PJM's study. Any changes to the RPM market rules will need to be approved by the

[9] PJM staff presented additional initial suggestions for stakeholder consideration to address the reliability concerns identified in the study not focused on the DR product definition. See PJM's presentation to the Market Implementation Committee on June 16, 2010, which may be found at http://www.pjm.com/~/media/committees-groups/committees/mic/20100616/20100616-item-08-dr-saturation.ashx

Market and Reliability Committee and Members Committee and filed with the Federal Energy Regulatory Committee by November 2010 in order to ensure they are in effect in time for the 2011 BRA for the delivery year 2014/2015.

C. Price Responsive Demand

Price Responsive Demand (PRD) is another concept that was discussed at the technical conference that bears emphasis, particularly in the context of the DR saturation study discussed above. PRD is not limited like the supply-side DR product that is centrally dispatched by PJM and limited to a particular number of interruptions during the summer period with a maximum hour duration for each interruption, which was the subject of the demand response saturation study. To be clear, however, PRD is intended to be another option for demand response participation in the PJM market, not a replacement for the existing PJM DR programs.

During the first panel discussion of the technical conference, the PJM witnesses were asked to explain PJM's concept of PRD and to identify the timeline for finalization within the PJM stakeholder process of the wholesale capacity and energy market rules to accommodate PRD. The comments below are intended to provide additional explanation for the concept of price responsive demand as well as to outline the timeline for stakeholder deliberation in the PJM committees.

PJM has been working over the last year with stakeholders to develop wholesale market rules to accommodate the ability of customers, or demand, to respond to energy market price signals without the need for PJM to centrally dispatch that capability or the need for that demand to bid into the wholesale energy market as a supply resource. In this sense, PRD is designed to put demand-side participation in the market back on the demand-side of the market.

PJM is seeking to ensure the wholesale market design is able to accommodate the evolution that is occurring at the retail level to advance customers' ability to respond to price, due in part to the investment in Advanced Metering Infrastructure (AMI) by electric utilities and municipalities across the PJM footprint and retail initiatives investigating dynamic pricing mechanisms and experience with pilot programs. It is important to have a robust and efficient wholesale market design structure in place that can accommodate such developments and provide varying and flexible options for participation in the PJM markets.

The two essential elements of price responsive demand are advanced metering, which records electricity use at least hourly, and dynamic retail rates that are coordinated with real-time wholesale energy market prices, such as critical peak pricing, critical peak rebates, and real-time LMP-based pricing. Rate designs that enable price responsive demand empower consumers to manage their energy expenditures and to directly reduce their costs by choosing when to consume electricity and consequently determine how much they pay. At the same time, price-responsive demand has broader market and power system cost efficiency implications. PRD can defer the need for infrastructure investment by slowing the growth in peak demand. PRD can improve reliability in short-term operations as increases in wholesale energy prices during high demand periods will lead to PRD reducing electricity consumption. Price responsive demand also benefits all load serving entities through savings in capacity charges because it lowers the overall load forecast and capacity requirement, and it benefits the specific the load serving entities serving the PRD customers because it lowers those customers' peak load contributions, against which locational capacity charges are assessed.

To accommodate price responsive demand, the rules governing PJM's energy market, RPM capacity market and transmission planning process will need modification.[10] A PJM stakeholder process has been underway since September 2009 to consider how best to accommodate PRD in PJM's business rules. PJM introduced the proposed PRD rules developed in the Markets and Implementation committee to the Markets and Reliability Committee (MRC) on June 16. PJM anticipates the MRC voting on the proposed rules at its August 4th meeting, followed by the Members Committee voting at its meeting on August 12th. In order to enable load serving entities to submit PRD plans to PJM by December 1 for inclusion in the 2014/15 RPM Base Residual Auction, which will be conducted in May 2011, proposed rule changes would need to be filed with the Federal Energy Regulatory Commission in September 2010.

As noted above, PJM does not intend to replace or eliminate the demand response programs that currently are configured as supply resources that bid into the energy and capacity market. In a number of respects PRD differs from Demand

[10] As the focus of these comments is on the PJM markets, these comments do not address the transmission planning implications for PRD. Also note that the proposed rules contemplate retail choice. The proposed rules would require load servers to separate end-use customers participating in PRD from other customers so that their PRD obligations can be shifted to another LSE if a customer switches service providers.

Response that can be offered as a supply resource into PJM's capacity and energy markets. A key difference between the two options of participation in the capacity market, are reflected in the financial impact to the provider. A DR Resource may receive revenue based on RPM results. Committed PRD would see a reduction in net capacity charges as a result of a lower capacity obligation during the Delivery Year. A comparison of other features between the options is provided below:

	PJM DR/ILR Resource	PJM PRD
Characteristics	Offered as Supply Resource in Capacity & Energy Markets	Reduces Load Forecast (and therefore Reliability Requirements) in Capacity Market
Performance Requirements	RPM resource (ILR or DR) – 10 events per year on weekdays, up to 6 hours per event. If no event then required to do 1 hour test.	LSE implements dynamic prices that produce predictable reduction in demand during emergency conditions
Financial Impact	Receive revenue based on RPM results. Capacity Resource deficiency + event or test deficiency penalty	Reduces LSE capacity obligation during delivery year. Penalties if load is not reduced
Adjustment to Load Forecasts	Add backs used to come up with "unrestricted load" which is used for forecast.	Add backs used to come up with "unrestricted load" which is used for forecast.
Metering Requirements	Interval metering required unless part of 500 MW pilot or direct load control program	Interval Metering Supevisory Control

1. PJM Capacity Market Modifications to Accommodate PRD

PJM's proposed capacity market rule modifications would allow eligible participants to commit a PRD demand reduction as an offset to an LSE's capacity obligation. LSEs operating under a Fixed Resource Requirement Plan would also be able to commit PRD demand reductions to offset their capacity obligations. This has the effect of reducing the demand for capacity in the RPM Base Residual Auction. The alternative to offer the demand reduction into the RPM Base Residual Auction as a Demand Resource would remain. Under this alternative, the Demand Resource is part of the supply curve in the RPM Base Residual Auction.

To be eligible under the proposed rules, an LSE's price responsive load must be: 1) served under a dynamic retail rate structure that changes based on PJM system energy prices and that is directly linked to PJM's real-time LMP at the substation level applicable to the load, and that results in predictable response to varying wholesale electricity prices; 2) subject to advanced metering capable of recording electricity consumption at an interval of one hour or less; and 3) subject to supervisory control to curtail any portion of the committed amount of demand reduction that has not responded to price, should PJM declare an emergency condition.

PRD plans submitted by LSEs to PJM will detail the price responsive characteristics of customer load at the substation level, i.e. the quantity of load consumed at various price levels during the delivery year. Once a PRD Plan is accepted by PJM, PJM will adjust the Preliminary Zonal Peak Load Forecast to account for PRD.[11] PRD plans must define the Maximum Emergency Service Level (MESL) of PRD at a substation level, i.e. the maximum demand permitted for PRD customers at the maximum allowed price level. The substation level detail is critical as PJM operations needs to know relative to particular transmission constraints the load reduction may

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[11] LSEs are permitted to revise PRD plans in the 3rd Incremental Auction if the LSE's final Expected Zonal Peak Load changes relative to the Preliminary Zonal Peak Load used for the Base Residual Auction.

occur; load reductions occurring on the wrong side of a transmission constraint could cause unintended reliability problems.

Under the proposed PRD rules, a load registered and committed in the RPM auction as PRD must perform during a Maximum Emergency Event, and consume at no more than its MESL. During normal system conditions, the load would be expected to adjust consumption based on real time prices as indicated in its submitted price responsive characteristics. But load registered and committed as PRD cannot be offered into the Base Residual Auction as ILR, Energy Efficiency, or DR for the same delivery year it is committed as PRD.

Significant penalties are being proposed for non-compliance of PRD performance during emergency events.[12] The penalty applicable to an LSE for which committed PRD load does not respond in accordance with its commitment is 120% X (MW shortfall) X (forecasted pool requirement) X (final zonal capacity price in $/MW-day X 365). This in effect requires a non-compliant PRD load to buy the capacity it would have bought had it not registered the PRD for the entire Delivery Year, plus a 20% penalty. The 20% penalty is comparable to the penalty applied to a generation resource that does not fulfill its capacity commitment.

PJM also is proposing testing requirements for PRD. The testing requirements differ from those for DR or EE, for which performance is required for a specific season, time period or duration. PRD on the other hand is required to perform during PJM

[12] The proposed rules also include penalties if the customer does not have appropriate equipment in place prior to the start of the delivery year.

Emergency Events at any time during the Delivery Year. Testing is designed to ensure that the committed load has the ability to achieve its MESL by either responding to the real time LMP signal, or reducing load in response to a supervisory control signal.

2. Implications of PRD for PJM's Energy Market

Under the proposed rules, PJM will establish energy market Locational Marginal Prices (LMPs) by taking into account demand curves (i.e., load reduction levels at corresponding energy market prices) submitted in approved PRD plans, and will enable PRD to respond to price prior to any declaration of emergency conditions and corresponding actions.[13] PJM Operations will consider the impact of PRD by means of those predictable demand curves by modeling them in the real-time energy market dispatch algorithms and solutions. PJM, therefore, would not need to centrally dispatch PRD as it would supply-side Demand Resources, but rather PJM would be able to predict that the load would be reduced in response to price and dispatch the remaining resources needed to satisfy real-time load on the system.

[13] For a more detailed explanation of the implications of PRD in the PJM energy market see the presentation that will be discussed at the July 7, 2010, PJM Market Implementation Committee meeting at http://www.pjm.com/~/media/committees-groups/committees/mic/20100707/20100707-item-02-prd-energy-market-example.ashx

III. Conclusion

PJM appreciates the opportunity to provide these additional comments to elaborate upon, and provide additional context for, existing and developing wholesale market rules that were discussed during the June 24th technical conference.

Respectfully submitted,

Denise R Foster

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Dated: July 6, 2010