STEVENS & LEE
LAWYERS & CONSULTANTS
17 North Second Street
16th Floor
Harrisburg, PA 17101
(717) 234-1090 Fax (717) 234-1099
www.stevenslee.com

Direct Dial: (717) 255-7364
Email: rlh@stevenslee.com
Direct Fax: (610) 988-0851

November 17, 2008

HAND DELIVERED

James J. McNulty, Secretary
Commonwealth of Pennsylvania
Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: *En Banc* Hearing on Current and Future Wholesale Electricity Markets
Docket No. M-2008-2066901

Dear Secretary McNulty:

Enclosed please find the original and ten (10) copies of the Reply Comments on behalf of PJM Interconnection, LLC (PJM) for filing in the above captioned matter. Also enclosed is a disk containing an electronic copy of the document.

If you have any questions, please contact me.

Respectfully submitted,

STEVENS & LEE

Renardo L. Hicks

Enclosure
cc: Hon. Louis G. Cocheres, Administrative Law Judge

Commonwealth of Pennsylvania

Pennsylvania Public Utility Commission

En Banc Hearing on Current and Future Wholesale Electricity Markets

Docket No. M-2008-2066901

November 6, 2008

Reply Comments by PJM Interconnection, LLC, November 17, 2008

PJM Interconnection, LLC (PJM) participated in the Pennsylvania Public Utility Commission's first *En Banc* Hearing on the Current and Future Wholesale Electric Markets on October 23, 2008. PJM's input, presented by Andrew Ott, Senior Vice President of Markets, summarizes PJM's position on the Wholesale Electricity Markets. PJM believes that certain presentations made during the Second *En Banc* on November 6, 2008 do not accurately represent the current situation in the Wholesale Electricity Markets and compel this reply testimony.

During the Second *En Banc*, an example was given using the industrial retail rates for electricity in Maryland and West Virginia (with Maryland's being higher priced), within areas of both states served by the same company, Allegheny Energy. Both West Virginia and Maryland are part of PJM and suppliers in both states including Allegheny participate in PJM's Wholesale Markets. The difference in retail rates is therefore best attributed to issues other than the presence of PJM's wholesale market, including each state's approach to retail restructuring.

Also during the hearing, it was asserted that PJM's Capacity Market, or Reliability Pricing Model will cost customers in PJM's service territory between $25 and $30 billion over the five delivery years for which auctions have been conducted. This is simply not the case, as the inherent and erroneous assumption in this calculation is electrical capacity has historically been without cost. Please see **Attachment 1** for a detailed explanation of the evolution of the PJM capacity markets and the success of PJM's Reliability Pricing Model in attracting infrastructure investment.

During the hearing, several presenters discussed the issue of the need for additional access to PJM data by the states and state utility commissions such as the Pennsylvania Public Utility Commission. It should be noted that, as enhanced by the recent Federal Energy Regulatory Commission settlement between the PJM states and

PJM involving PJM's Market Monitor (122 FERC ¶ 61,257, 2008), PJM states were granted access to PJM data consistent with their explicit requests. Since the settlement, no complaints about lack of access to data have been received by PJM.

Additionally, during the Second *En Banc*, testimony was presented that the Wholesale Markets, as operated by PJM, cost customers millions of dollars in the form of excess costs for electricity. This is not the case, and in fact, the operations of RTO's such as PJM lead to savings in the billions of dollars per year in reliability, energy investment, energy production costs, and grid services. Please see **Attachment 2** for detail on the value PJM provides to the region it serves.

ATTACHMENT 1

Quantifying the Cost of the Reliability Pricing Model

Introduction

Since the implementation of the Reliability Pricing Model, there has been considerable discussion regarding the impact of RPM on the cost to consumers for capacity. Some analyses have attempted to quantify the cost impacts of RPM by multiplying total capacity obligation times the RPM auction clearing prices. This approach implicitly assumes there was a zero cost for capacity prior to RPM implementation which is not a reasonable assumption. PJM has performed analysis of historic capacity prices as explained below in order to quantify the potential impact of RPM verses what capacity prices would have been absent RPM implementation. Based on this analysis, the range of total impact of RPM over the five year period[1] is $2.915 to $4.824 billion.

Capacity Market Evolution

All load serving entities in the PJM region are required to ensure they have sufficient capacity contracts to ensure their peak demand can be served. The capacity product is essentially a contract with resources that entitles the purchaser to the energy supply (or demand reductions) from the resource during high load periods when supply is at or near shortage conditions. The capacity requirement and the capacity product are not new; load serving entities have been required to procure capacity in PJM since the 1970s. Prior to the implementation of PJM markets in 1998, utilities met their capacity requirements by either building generation or bilaterally contracting for capacity with neighboring utilities. When PJM implemented the wholesale power markets in 1998, PJM also implemented capacity auctions to provide an additional alternative for load serving entities to procure capacity. As utilities divested their generation assets and as retail competition emerged, most load servers satisfied their capacity obligation through bilateral contracting. Consequently capacity auctions became a necessary mechanism by which load serving entities, without generation of their own, could balance capacity portfolios. Moreover, capacity auctions provided a transparent price discovery mechanism to serve as a price reference for forward, bilateral capacity contracts.

The short term capacity auction design that was in place from 1998 through 2007 was modified several times in an attempt to address issues that were identified by the PJM, the PJM market monitor and by PJM stakeholders. Many of the identified issues were related to the short term nature of the capacity credit market. The capacity product by its nature is a long term commitment for generation to be available to ensure reliable energy supply during peak load periods. In fact, prior to 1999, the PJM rules required all load serving entities to provide a minimum of a two year capacity supply plan to meet its projected peak load plus the installed reserve margin set by the PJM power pool. In 1999, the capacity rules were relaxed to attempt to accommodate retail loads switching by providing a daily capacity credit auction. The short term capacity auction created incentives for load servers to selectively reduce reliance on longer term contracts in favor

[1] The five year period covers the following Delivery years for which a Base Residual Auction has already been completed: (2007/2008, 2008/2009, 2009/2010, 2010/2011 and 2011/2012).

of short term arrangements which artificially distorted capacity prices. The short term auctions also allowed suppliers to make daily decisions regarding where to sell their capacity instead of the historic requirement to commit for a multi-year period. The issue with the switch to a short term auction design lead the market monitor to conclude: "*The ability of LSEs to meet their capacity obligation in a daily market and the corresponding ability of generators to make a daily decision about where to sell their capacity helps create a set of incentives that fall short of maximizing the reliability of the PJM system.*"[2]

In 2004 additional problems were identified related to a lack of locational capacity requirements which provided another indicator that further highlighted the need for capacity market reform to better align the capacity product with the fundamental system reliability requirements. The Reliability Pricing Model was implemented in 2007 to address reliability concerns caused by the dysfunction in the previous capacity market model. The Reliability Pricing Model eliminated the short term capacity auction concept and required forward capacity commitments for at least a one year period. The RPM also implemented locational capacity requirements to better align the assignment of capacity obligations with the transmission planning process.

Since the implementation of the Reliability Pricing Model, there has been considerable discussion regarding the impact of RPM on the cost to consumers for capacity. Some analyses have attempted to quantify the cost impacts of RPM by multiplying total capacity obligation times the RPM auction clearing prices. This approach implicitly assumes there was a zero cost for capacity prior to RPM implementation which is not a reasonable assumption. While capacity costs were low in recent years because of excess supply and an inadequate market design, the historic costs of capacity were substantially higher. In fact, the very low capacity prices observed in 2004 - 2006 were abnormally low when compared to the longer term trend of historic bilateral market prices. Therefore the expectation of load serving entities with regard to hedging capacity costs should be based on long term historic trends with adjustment for changes in input costs. PJM was requested by stakeholders to develop a method to assess RPM impacts. This effort necessarily requires PJM to speculate on what capacity prices would have been if RPM had not been implemented. PJM has developed the following historical price evaluation to compare the RPM results to historic capacity prices that occurred during the summer of 2000 when capacity market supply conditions approached the conditions expected had RPM not been implemented.

Historical Price Evaluation

One potential estimate of RPM cost impacts can be calculated based upon historical capacity market results in which similar supply-demand conditions closely match those expected persist had RPM not been implemented.

[2] PJM 2000 State of the Market Report issued by the PJM Market Monitor, page 59. http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/state-of-the-market-report-2000.pdf

In 2005, PJM was facing substantial reliability challenges as we looked forward into the 2008 – 2011 period. PJM had reported increasing generation retirement requests while very little new generation was entering the generation interconnection process. PJM had identified substantial reliability violations that could not be solved with transmission alone. With increasing demand growth, lack of demand response, increasing generation retirements and lack of new generation entry, the PJM region was facing a future capacity shortfall.

Therefore to assess the RPM impacts on consumer costs, the most appropriate historic price reference will be the capacity auction prices that occurred when the market was approaching capacity shortage conditions that were forecast to occur in the 2008-2011 period. Analysis of past auction results must be approached with caution because the short term auction design was susceptible to the exercise of market power by both generators and loads. At certain times during the summer of 2000, PJM was capacity deficient mirroring the forecast capacity deficiency for 2008-2011.[3] During the summer period, the volume weighted average capacity prices for multi-monthly, monthly and daily capacity auctions were $135.80, $179.38, and $148.84 per MW-day in June, July and August respectively.[4] The selection of this time period is also appropriate because the market monitor concluded that the auction results for the 2000 summer period were driven by supply demand fundamentals and were not a result of an exercise of market power.[5] The 2000 summer period was indicative of the cost of providing the capacity product during periods of short supply when the market was functioning normally. The average cost of capacity in the 2000 summer was $154.57 per MW-day.

Table 1 shows an impact of RPM when compared to 2000 summer period capacity costs. The table lists the comparison result for each RPM Delivery year for which an RPM auction was held (2007/2008, 2008/2009, 2009/2010, 2010/2011 and 2011/2012). For each year, the cleared capacity MW for each region was multiplied by the difference between the RPM clearing price and the historic reference price of $154.57 which quantified the RPM impact in dollars per day. The annual impact was then calculated for only those regions with a positive daily impact by multiplying the daily impact times 365 days. The total impact was calculated to be $2.915 billion dollars over the five year period.

[3] PJM 2000 State of the Market Report issued by the PJM Market Monitor, page 53. http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/state-of-the-market-report-2000.pdf
[4] PJM 2000 State of the Market Report issued by the PJM Market Monitor, page 52.
[5] PJM 2000 State of the Market Report issued by the PJM Market Monitor, page 58.

Table 1 – RPM Impact Analysis Using Historic Reference Price

Market Year	LDA	Cleared MW	Resource Clearing Price	Historical Capacity Price Reference	RPM Impact $ per Day	Annual RPM Impact (Positive Values Only)
2007/2008	EMAAC	30,797.8	$197.67	$154.67	$1,324,305.40	$483,371,471
2007/2008	RTO	88,410.2	$40.80	$154.67	($10,067,269.47)	
2007/2008	SWMAAC	10,201.2	$188.54	$154.67	$345,514.64	$126,112,845
2008/2009	EMAAC	30,231.3	$148.80	$154.67	($177,457.73)	
2008/2009	RTO	88,745.1	$111.92	$154.67	($3,793,853.03)	
2008/2009	SWMAAC	10,621.2	$210.11	$154.67	$588,839.33	$214,926,355
2009/2010	MAAC+APS	62,633.0	$191.32	$154.67	$2,295,499.45	$837,857,299
2009/2010	RTO	69,598.8	$102.04	$154.67	($3,662,984.84)	
2009/2010	SWMAAC	9,914.7	$237.33	$154.67	$819,549.10	$299,135,422
2010/2011	DPL-SOUTH	1,519.7	$186.12	$154.67	$47,794.57	$17,445,016
2010/2011	RTO	130,670.8	$174.29	$154.67	$2,563,761.10	$935,772,800
2011/2012	RTO	132,221.5	$110.00	$154.67	($5,906,334.41)	
Total						$2,914,621,209

In order to provide an upper bound on the range of RPM impacts, table 2 listed below provides the impact analysis utilizing the lowest monthly volume weighted average capacity price, $135.80 for the summer 2000 period which occurred in June of that year.

Table 2 – RPM Impact Analysis Using Lower Bound Historic Reference Price

Market Year	LDA	Cleared MW	Resource Clearing Price	Historical Capacity Price Reference	RPM Impact $ per Day	Annual RPM Impact (Positive Values Only)
2007/2008	EMAAC	30,797.8	$197.67	$135.80	$1,905,459.89	$695,492,858
2007/2008	RTO	88,410.2	$40.80	$135.80	($8,398,969.00)	
2007/2008	SWMAAC	10,201.2	$188.54	$135.80	$538,011.29	$196,374,120
2008/2009	EMAAC	30,231.3	$148.80	$135.80	$393,006.90	$143,447,519
2008/2009	RTO	88,745.1	$111.92	$135.80	($2,119,232.99)	
2008/2009	SWMAAC	10,621.2	$210.11	$135.80	$789,261.37	$288,080,401
2009/2010	MAAC+APS	62,633.0	$191.32	$135.80	$3,477,384.16	$1,269,245,218
2009/2010	RTO	69,598.8	$102.04	$135.80	($2,349,655.49)	
2009/2010	SWMAAC	9,914.7	$237.33	$135.80	$1,006,639.49	$367,423,414
2010/2011	DPL-SOUTH	1,519.7	$186.12	$135.80	$76,471.30	$27,912,026
2010/2011	RTO	130,670.8	$174.29	$135.80	$5,029,519.09	$1,835,774,469
2011/2012	RTO	132,221.5	$110.00	$135.80	($3,411,314.70)	
Total						$4,823,750,025

Therefore based on historical capacity price analysis, the range of total impact over the five year period is $2.915 to $4.824 billion.

The historical method employed above likely overestimates the RPM cost impacts because it does not escalate capacity prices to current year dollars and it does not account for recent rapid cost increases in construction and maintenance. Additionally, this method does not account for the costs of emergency transmission upgrades, rotating blackouts and reliability must run contracts which would likely have been necessary absent the capacity market reform.

Generation Investment Results under RPM

PJM commissioned the Brattle group to perform a comprehensive assessment of RPM performance to evaluate the overall effectiveness of RPM in encouraging and sustaining infrastructure investments to maintain resource adequacy consistent with reliability requirements. The Brattle report concluded that over the first five RPM auctions, over 4600 MW of existing generation had been retained that would have retired absent the capacity market reform and that 3,274 MW of new generation has been committed in the RPM auctions as a result of the implementation of RPM.[6] The report also concluded that 2900 MW of capacity uprates and 1800 MW of new Demand Response were committed as a result of RPM implementation. The PJM Market Monitoring Unit (MMU) has indicated that existing generators have committed to at least $5.1 Billion of investment over the 5 year period of RPM auctions based on analysis of the Avoidable Project Investment Recovery Rate (APIR) information submitted to the MMU by the resource owners. This analysis supports to Brattle group finding that a substantial amount of existing generation has remained available that would have otherwise retired. This analysis also appears to indicate that the RPM revenues are being invested in environmental compliance projects and generation performance upgrades which has enhanced the reliability of the grid.

[6] Brattle Report, page 2-3, http://www.pjm.com/documents/ferc/documents/2008/20080630-er05-1410-000.pdf

ATTACHMENT 2

PJM Efficiencies Offer Regional Savings

RELIABILITY –
resolving transmission constraints, gains in economic efficiency from regional reliability planning – from $470 million to $490 million in annual savings

GENERATION INVESTMENT –
reduced reserve requirements and increased demand response – from $640 million to $1.2 billion in annual savings

ENERGY PRODUCTION COST –
efficiency of centralized dispatch over a large region – from $340 million to $445 million in annual savings

GRID SERVICES –
cost-effective procurement of synchronized reserve, regulation – from $134 million to $194 million in annual savings

Total –
as much as $2.3 billion in savings to the region *each year*

The following summarizes the impact of specific elements of PJM's role that produce benefits and economic value for the region it serves. These components of PJM's RTO operations produce as much as $2.3 billion in annual value for the region.

PJM Operations yield $2.3 billion in savings

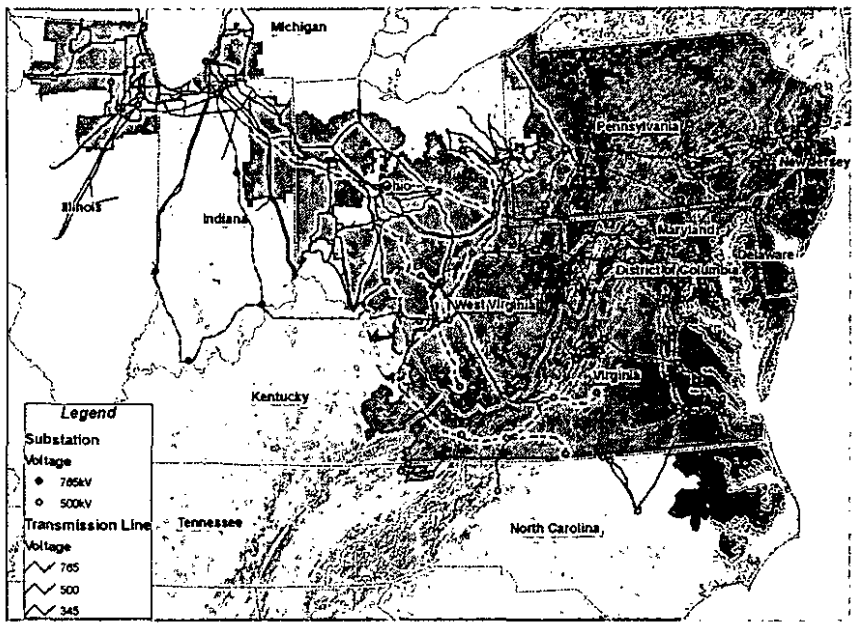
Reliability Savings

PJM's ability to direct changes in the output of generating resources (redispatch) rather than curtail power-sales transactions to deal with transmission congestion enables it to deal with transmission constraints more effectively. By reducing the need for curtailments over a wide area – transmission loading relief procedures, or TLRs – PJM's narrowly targeted redispatch procedures resolve transmission constraints more quickly. This approach has significantly reduced the need for transaction curtailments to maintain transmission system reliability.

Annual savings: $80 million to $100 million

By planning for future reliability needs on a regionwide rather than a utility-by-utility or state-by-state basis, PJM's Regional Transmission Expansion Planning (RTEP) process helps focus on transmission upgrades that meet reliability criteria and increase economic efficiency.

Annual savings: $390 million



Generation Investment Savings

The large size of the PJM market area, combined with its diversity of demand and resources, reduces the overall level of capacity needed to ensure adequate reserves of electricity to meet peak demand or emergency situations. This capacity buffer, known as the reserve margin, would need to be higher without the PJM RTO. Consumers avoid the costs of additional generation to meet higher levels of reserves.

Annual savings: $366 million to $900 million

The commitment of demand-response resources to reduce load during system peaks also forestalls the cost of building additional generating facilities. Through the Reliability Pricing Model (RPM), demand response competes on an equal footing with generation and transmission in the capacity market. Through RPM, the quantity of demand response that is providing capacity in the PJM footprint has increased by more than 1,800 megawatts.

Annual savings: $275 million

Energy Production Cost Savings

PJM's centralized dispatch of the numerous resources over its expanded territory produces significant efficiencies and cost savings compared with the previous operation of independent control areas across the region. The increasing effectiveness of PJM's dispatch operations also has reduced operating reserve costs.

Annual savings: $340 million to $445 million

Grid Services Savings

By operating markets for grid services, also known as ancillary services, across its footprint, PJM achieves economies in providing services that are essential to the reliability of the electric system. Synchronized reserve service supplies electricity if the grid has an unexpected need for more power on short notice, while regulation helps match generation and load by correcting for short-term changes in electricity use that might affect system stability.

Annual savings: $134 million to $194 million