FirstEnergy.

2800 Pottsville Pike
PO Box 16001
Reading, PA 19612-6001

July 5, 2012

Ms. Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor, 1 North
Harrisburg, PA 17105-3265

Re: *Joint Application of West Penn Power Company doing business as Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience Under Section 1102(A)(3) of the Public Utility Code Approving a Change of Control of West Penn Power Company and Trans-Allegheny Interstate Line Company*; Docket Nos. A-2010-2176520 and A-2010-2176732

Dear Ms. Chiavetta:

In accordance with paragraph 54 of the Joint Petition for Settlement approved in the above-referenced proceeding, enclosed please find the 2012 report on market prices and price trends in the PJM Interconnection LLC markets, prepared by The Brattle Group.

While the Companies assume the information presented in the enclosed report is accurate, they have not verified it and do not adopt these findings as their own. All of the facts, opinions, and arguments presented are those of The Brattle Group.

Enclosed is an extra copy of this transmittal letter and a stamped, self-addressed envelope in order that you may indicate receipt of this letter.

Sincerely,

Richard A. D'Angelo
Manager
Rates and Regulatory Affairs, PA

cc: Johnnie Simms, Bureau of Investigation and Enforcement
Irvin A. Popowsky, Office of Consumer Advocate
Steven Gray, Office of Small Business Advocate

The Brattle Group

Annual Report on Wholesale Market Prices and Trends in the Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company Service Areas

July 2, 2012

Attila Hajos
Philip Hanser
Charles Russell

Prepared for

FirstEnergy

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Contents

EXECUTIVE SUMMARY

This report was prepared by *The Brattle Group* on behalf of Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (collectively, "the Companies") contained in the settlement agreement approved by the Pennsylvania Public Utility Commission ("PA PUC") in Docket Nos. A-2010-2176520 and A-2010-2176732. The Companies are part of the PJM Interconnection LLC ("PJM") competitive wholesale market. They operate in four Pennsylvania zones of PJM: Metropolitan Edison Company ("Met-Ed Zone"), Pennsylvania Electric Company ("PENELEC Zone"), Allegheny Power System ("APS Zone") for West Penn, and the Penn Power portion of the American Transmission Systems load zone ("ATSI Zone"). This report summarizes market outcomes and trends in PJM, with a specific focus on the portion of the footprint where the Companies operate. Market outcomes and trends in other parts of the PJM market are reported only to the extent they affect the areas served by the Companies.

In 2011, market dynamics in PJM were primarily driven by market fundamentals, especially falling natural gas prices and rising coal prices. Declining gas prices significantly improved the economics of gas-fired plants. Lower profitability and an array of pending environmental rules, including the Environmental Protection Agency's Mercury and Air Toxics Standards ("MATS"), negatively affect coal plants' economics. The result of these regulations in combination with the improved economics of gas-fired generation is significant reductions in coal-fired generation capacity in PJM. It is expected that a total of 18,886 MW of coal-fired generation will retire by 2019. In addition, PJM's market monitor estimates that an additional 5,764 MW of coal capacity is at the risk of retirement because those plants were unable to earn sufficient revenues to cover their avoidable costs in 2011.

Market trends in the four zones served by the Companies largely reflected overall market trends in PJM in 2011. Total wholesale costs including the costs of energy, ancillary services, capacity, transmission, and other charges, fell in all four zones. Met-Ed Zone, the only zone with total wholesale power costs above the PJM average, has seen a greater than 11% year-over-year decline. Wholesale costs in the PENELEC and APS Zones fell, by 6.8% and 3.4% respectively.[1] This reveals a trend in PJM that the largest wholesale cost declines occurred in the more congested zones, such as Met-Ed, while decreases in other less congested zones were more modest. The primary drivers of decreases in wholesale costs were lower capacity and energy prices, although some smaller components changed more in relative terms. In 2011, energy and capacity costs on average represented 76% of the total wholesale costs of power in PJM.

In 2011, Met-Ed remained the zone with the highest average energy price, primarily due to transmission congestion. In the day-ahead market, average zonal peak-hour locational marginal prices ("LMPs") decreased by 3.9% from 2010 to 2011, while off-peak LMPs decreased by 4.5%. Average real-time, peak-hour LMPs decreased by 2.8%, and off-peak LMPs decreased by 4.9%. The Met-Ed Zone continues to show the largest positive transmission congestion component for both peak- and off-peak hours. The price decreases between 2010 and 2011 were offset by year-on-year price increases from 2009 to 2010 when on-peak LMPs rose on average by 22% and off-peak LMPs rose on average by 16%. Total net transmission congestion costs, consisting of transmission congestion costs to loads, transmission congestion credit to generators, and transmission congestion charges for point-to-point transactions decreased in PJM, including the Companies' four zones.

[1] Penn Power was not integrated into PJM until June 2011. Due to the lack of comparable data on overall wholesale costs, year-on-year changes in wholesale costs for this zone are not provided in this report.

PJM's reliability pricing model ("RPM") capacity market is a forward capacity market that interacts with and works in tandem with the PJM energy market to provide price and revenue signals to attract new and retain existing capacity. Capacity is procured three years in advance of each delivery year, which runs from June through May of the following year. Consequently, capacity prices for calendar year 2011 were determined in capacity auctions for two delivery years: 2010/11 and 2011/12. RPM is a locational capacity market that can result in differential capacity prices between zones, depending on transmission constraints. In all capacity auctions held for parts of calendar year 2011, the Met-Ed, PENELEC, and APS Zones remained in the unconstrained part of the regional transmission organization ("RTO"), and as result paid the same capacity price. Capacity prices for the 2010/11 and 2011/12 delivery years were $174.29/MW-day to $110/MW-day, respectively. Since the ATSI Zone was integrated into PJM in 2011 but did not participate in the PJM capacity auctions for the 2011/12 and 2012/13 delivery years, two transitional ATSI Zone Fixed Resource Requirement ("FRR") integration auctions were held in March 2010. The auction held for the 2011/12 delivery year cleared at $108.89/MW-day.

Four capacity auctions were held in 2011, including the Base Residual Auction ("BRA") for the 2014/15 delivery years, and three incremental auctions for prior delivery years. Capacity prices in the unconstrained part of the market, including the APS and ATSI Zones, increased. PJM attributed this increase to three main factors: (1) increased costs associated with the retrofits necessary to comply with new environmental regulations; (2) lower capacity supply in the western portion of PJM; and (3) decrease in energy and ancillary services revenue offsets. The Mid-Atlantic Area Council MAAC Locational Deliverability Area ("LDA"), containing the Met-Ed and PENELEC Zones, was much less affected by the cost of environmental retrofits because generators in this part of PJM had either previously installed such controls or reflected these costs in their offers in previous capacity auctions. Capacity prices in MAAC decreased, driven primarily by: (1) the increase in the transmission import limit; (2) the decrease in reliability obligations; and (3) greater demand resource participation. Overall, the PJM capacity market continued to attract new capacity, although there was a reduction in the commitment of coal-fired capacity. According to PJM, it is likely that the cost of environmental retrofits reflected in the offers made them uneconomic compared to lower cost resources, such as demand response and energy efficiency, and as a result they did not clear. The rapid growth of demand resources has continued. In fact, nearly 2,700 MW, or about 19% of the total amount of demand response that cleared in the auction, is located in the Companies' four zones. Energy efficiency also grew, albeit at a slower pace. Of the total 832 MW of cleared energy efficiency, about 2% are located in the Companies' zones.

PJM operates competitive markets for three ancillary services: regulation, synchronized reserves, and day-ahead scheduling reserves. Regulation prices decreased by about 10% in 2011, resulting in lower regulation costs, although the decrease in the regulation price was partially offset by a slight increase in the total hourly regulation requirement. The regulation market was the only PJM market where the market monitor designated its design as flawed. The monitor's concern is related to the method the opportunity costs to provide regulation are determined: the real-time opportunity cost is based on real-time energy prices which are determined after the regulation market closes. Any differences in the forecasted energy prices used to determine the opportunity costs used during the regulation market clearing and the real-time energy prices used to calculate real-time opportunity costs may result in differences between the regulation market clearing price and the actual unit cost of procuring regulation. The market monitor recommended that the hourly regulation market clearing price be determined after the close of the operating hour, and thus the opportunity cost would be calculated based on actual, real-time energy prices. On October 20, 2011, the Federal Energy Regulatory Commission ("FERC") issued Order No. 755, requiring RTOs to compensate resources providing regulation according to their actual performance and not just capability. Once implemented, this new approach will be a significant departure from the current method of compensation for regulation. PJM is currently in the process of redesigning its regulation market.

PJM's market monitor concluded that in 2011, the synchronized reserve market was not structurally competitive in the Mid-Atlantic Subzone. Furthermore, it raised concerns about the inadequacy of the incentive and penalty structure to ensure response during synchronized reserve events. Resources which provided synchronized reserves are paid the higher of the market clearing price or their offer plus a unit-specific opportunity cost. The market monitor raised concerns regarding the inefficiency of calculating opportunity costs based on LMP forecasts for clearing the synchronized reserve market, while calculating opportunity costs based on real-time LMP to determine compensation. This inefficiency is similar to that reported for the regulation market: the market price for synchronized reserves is significantly lower than the actual unit cost paid to resources providing those reserves.

According to the assessment of PJM's Independent Market Monitor, the PJM wholesale market continued to operate in a competitive manner during 2011. All but the regulation market yielded competitive outcomes. The regulation market was determined to not be competitive because the application of PJM's current opportunity cost methodology resulted in market prices that deviated from the competitive price which reflects the actual marginal cost of the marginal resource. In addition, the market designs of the PJM capacity and day-ahead scheduling reserve ("DASR") markets were deemed mixed.

I. INTRODUCTION

I.A. PURPOSE

This report was prepared by *The Brattle Group* on behalf of the Companies in order to comply with the Companies' commitment contained in the settlement agreement approved by the PA PUC in Docket Nos. A-2010-2176520 and A-2010-2176732. The report summarizes market outcomes and trends in the Pennsylvania portion of the PJM market where the Companies operate. Market outcomes and trends in other parts of the PJM market are not reported unless they affect the areas served by the Companies. This report was prepared using publicly available data and information. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone.

I.B. BRIEF DESCRIPTION OF THE PJM MARKET

PJM operates a wholesale market for energy, capacity, and ancillary services that covers all or parts of 13 states and the District of Columbia. The PJM footprint is currently divided into 18 load zones, seven of which are fully or partially located within Pennsylvania. The Companies operate in four Pennsylvania zones of PJM: the Met-Ed Zone, PENELEC Zone, APS Zone, and the Penn Power portion of the ATSI Zone.[2] Met-Ed and PENELEC Zones were part of the PJM market when it was designated a RTO by FERC in 2001. The APS and ATSI Zones were integrated into PJM in 2002 and 2011, respectively. This report summarizes market prices and trends for calendar year 2011 in the Met-Ed Zone, PENELEC Zone, APS Zone, and Penn Power's portion of the ATSI zone.

II. WHOLESALE POWER COSTS

II.A. TOTAL COST OF WHOLESALE POWER IN PJM

The wholesale cost of power purchased in the PJM market consists of a number of components, including: (1) energy; (2) capacity; (3) transmission service charges; (4) operating reserves (uplift); (5) reactive power; (6) PJM administrative fees; (7) regulation; (8) transmission enhancement cost recovery charges; (9) synchronized reserves; (10) transmission owner (Schedule 1A) charges; (11) DASR; (12) black start; (13) North American Electric Reliability Corporation/ReliabilityFirst Corporation ("NERC/RFC") charges; (14) RTO Startup and Expansion; (15) load response; and (16) transmission facility charges. Table 1 summarizes the magnitude of these charges for PJM and the Companies' zones in 2011.

[2] By PJM's convention, load zones bear the name of a large utility service provider working within their boundaries; however, the nomenclature applies to the geographic area within the PJM footprint, not to any single company.

Table 1
Wholesale Cost of Electricity in 2011[3,4,5]
($/MWh)

	PJM	PENELEC	Met-Ed	APS	Penn Power
Energy	$45.94	$45.12	$49.51	$45.49	$42.92
Marginal Congestion Cost	*$0.05*	*-$0.25*	*$2.87*	*$0.05*	*-$2.56*
Marginal Transmission Losses	*$0.02*	*$0.38*	*$0.82*	*-$0.13*	*-$0.51*
Capacity	$9.72	$9.68	$9.68	$9.68	$7.21
Transmission Service Charges	$4.42	$2.46	$2.46	$2.65	$2.36
Operating Reserves (Uplift)	$0.79	$1.06	$1.06	$1.06	$1.06
Reactive	$0.42	$0.19	$0.51	$0.46	$0.39
PJM Administrative Fees	$0.37	$0.37	$0.37	$0.37	$0.37
Regulation	$0.32	$0.32	$0.32	$0.32	$0.32
Transmission Enhancement Cost Recovery	$0.29	$0.06	$0.07	$0.07	N/A
Synchronized Reserves	$0.09	$0.19	$0.19	$0.19	$0.00
Transmssion Owner (Schedule 1A)	$0.09	$0.08	$0.08	N/A	$0.03
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.05	$0.05	$0.05	$0.05
Black Start	$0.02	$0.02	$0.03	$0.00	$0.00
NERC/RFC	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.01	N/A	N/A	N/A	N/A
Load Response	$0.01	$0.00	$0.00	$0.00	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$62.56	$59.61	$64.35	$60.36	$54.72

The price of wholesale power is the average price per MWh that buyers of electricity pay in the PJM marketplace. Some charges, such as the PJM Administrative Fees, regulation, DASR and NERC/RFC charges do not vary by zone. Other components, however, are either based on locational prices or allocated zonally. This is especially true for energy prices as the PJM energy market is based on a system of LMPs, whereas the price of energy reflects the marginal cost of delivering that energy to a given location within the PJM system.

Energy and capacity costs make up the vast majority of the total wholesale cost. On average, the top two components make up approximately 90% of the total wholesale cost. Energy costs represent the largest single component for all load zones at an average of 76% of the total

[3] Note that Table 1 reports average cost per megawatt hour of energy; however actual charges may be allocated differently. For example, capacity costs are allocated not on the basis of energy (MWh) consumed, but based on each customer's contribution to the PJM coincident peak load (so-called Peak Load Contribution) during the five highest summer load hours.

[4] For the Met-Ed and PENELEC Zones, the average synchronized reserve cost for the Mid-Atlantic subzone is shown, however portions of these two zones are located outside that synchronized reserve subzone, and consequently consumers located in those areas incur a lower synchronized reserve cost.

[5] Source: 2011 PJM State of the Market Report ("PJM 2011 SOM") and Brattle analysis.

wholesale price.[6] As shown in Table 1, energy costs vary by load zone, reflecting the regional variation in LMPs. They are approximately the same in the PENELEC and APS Zones as the PJM average. As reflected in the marginal transmission congestion cost component of the energy price, energy costs are higher than the PJM average in the Met-Ed Zone and lower than the PJM average in the Penn Power area, reflecting the fact that the Met-Ed Zone is located in a more congested area of PJM while Penn Power lies in a less congested area. Further discussion of energy costs is included in Section II.B. Similarly to energy prices, capacity prices may vary by location, although price separation is less common in comparison to the energy market. Given that there was no price separation in the 2011/12 capacity auction and only minimal price separation in the 2010/11 capacity auction, the Companies' zones do not differ greatly from the PJM average in terms of capacity costs. Pursuant to its Fixed Resource Requirement ("FRR") capacity plans, PJM held a separate capacity auction for the ATSI Zone for the 2011/12 delivery year. The capacity clearing prices were slightly lower than the RTO clearing price for the 2011/12 auction. For this reason, there is a slight difference in capacity cost of wholesale power for ATSI Zone. Transmission service charges are not market-based charges, but instead are payments to transmission owners for providing network integration and firm and non-firm point-to-point transmission service. Figure 1 shows the breakdown of wholesale costs, by component, for each load zone.

[6] The energy component is the real time load weighted average PJM LMP, that is made up of two transmission costs (marginal transmission costs and transmission congestion) and one generation cost (marginal energy costs).

Figure 1
Wholesale Cost of Electricity in 2011[7]
(% of Total, by Component)

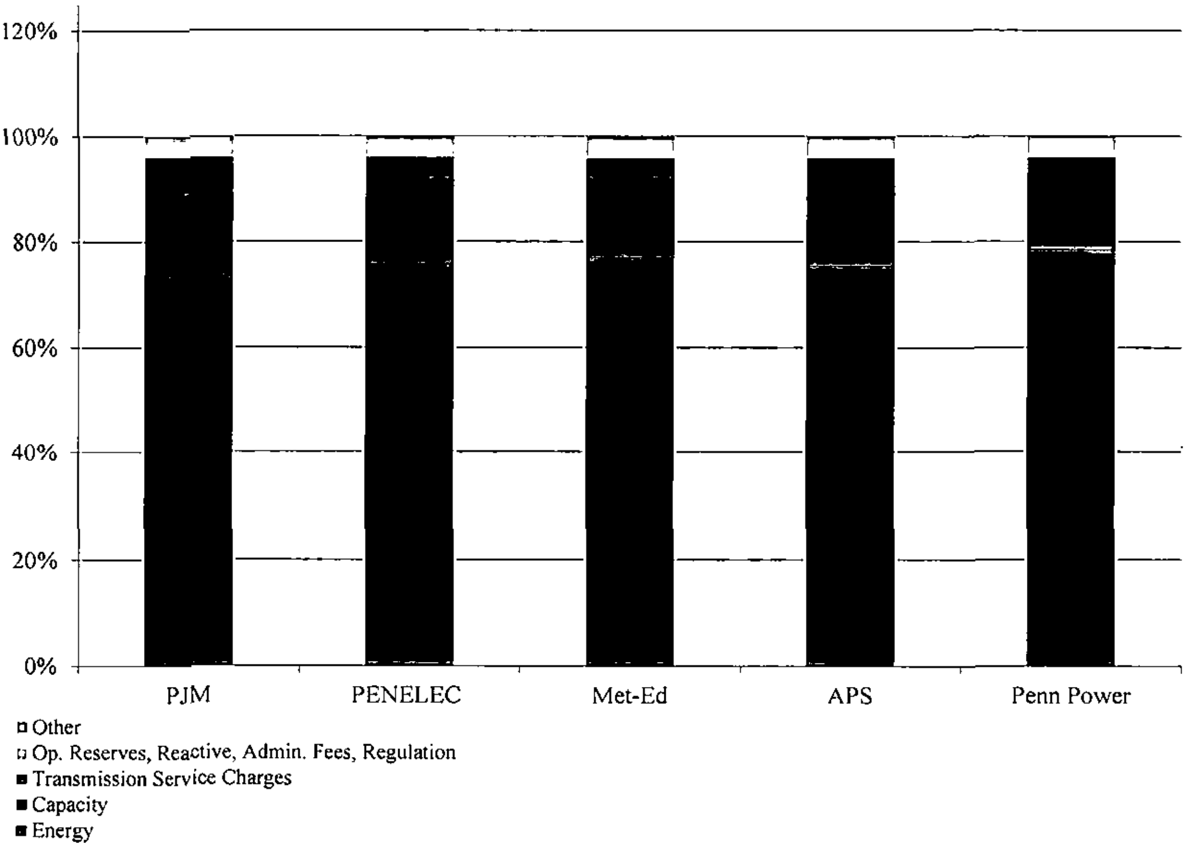


Table 2 shows the total wholesale cost of electricity by component for calendar years 2009 and 2010.[8] Between 2010 and 2011 the total cost of wholesale power fell by approximately 6%. Larger reductions in wholesale costs were registered in the Met-Ed and PENELEC Zones, at 11.4% and 6.8%. In the APS Zone, wholesale cost fell by less than the PJM average. The reduction in wholesale costs was primarily driven by a decline in energy and capacity prices. Several factors influenced the decrease in energy prices, including changes in demand and supply, as well as the continuing decline in natural gas prices. Capacity costs in the Met-Ed and PENELEC Zones decreased the most when compared to average capacity costs in 2010. Further discussion on capacity prices is contained in Section II.C.

[7] As show above in Table 1, marginal transmission congestion costs and marginal transmission losses are a component of total cost of energy (LMP). In the congested areas, such as Met-Ed, transmission congestion costs are approximately 6% of the LMP. In less congested areas, such as Penn Power, there is a transmission congestion *credit* of approximately 6%. Similarly, marginal transmission losses can range from a *cost* of about 2% of the LMP to a *credit* of approximately 1% of the LMP.

[8] ATSI Zone is not included due to a lack of comparable data prior to its integration into PJM on June 1, 2011.

Table 2
Wholesale Cost of Electricity in 2009 and 2010[9,10]
($/MWh)

	2009				2010			
	PJM	PENELEC	Met-Ed	APS	PJM	PENELEC	Met-Ed	APS
Energy	$39.05	$38.57	$42.32	$40.59	$48.35	$45.17	$53.47	$47.63
Marginal Congestion Cost	*$0.05*	*-$0.18*	*$2.27*	*$1.41*	*$0.08*	*-$1.73*	*$4.22*	*$0.01*
Marginal Transmission Losses	*$0.03*	*-$0.11*	*$0.97*	*-$0.06*	*$0.04*	*-$0.28*	*$1.05*	*-$0.26*
Capacity	$11.02	$13.56	$13.56	$7.44	$12.15	$14.04	$14.04	$9.54
Transmission Service Charges	$4.00	$2.52	$2.52	$2.76	$4.00	$2.42	$2.42	$2.62
Operating Reserves (Uplift)	$0.48	$0.66	$0.66	$0.76	$0.79	$1.15	$1.15	$1.24
Reactive	$0.36	$0.20	$0.52	$0.47	$0.44	$0.19	$0.51	$0.45
PJM Administrative Fees	$0.31	$0.31	$0.31	$0.31	$0.36	$0.36	$0.36	$0.36
Regulation	$0.34	$0.34	$0.34	$0.34	$0.35	$0.35	$0.35	$0.35
Transmission Enhancement Cost Recover	$0.09	$0.02	$0.02	$0.03	$0.21	$0.03	$0.04	$0.05
Synchronized Reserves	$0.05	$0.09	$0.09	$0.09	$0.06	$0.12	$0.12	$0.12
Transmssion Owner (Schedule 1A)	$0.08	$0.08	$0.08	N/A	$0.09	$0.08	$0.08	N/A
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
Black Start	$0.02	$0.02	$0.03	$0.00	$0.02	$0.02	$0.03	$0.00
NERC/RFC	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.01	N/A	N/A	N/A	$0.01	N/A	N/A	N/A
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$55.82	$56.38	$60.46	$52.81	$66.86	$63.97	$72.61	$62.40

Between 2009 and 2011 the total price of wholesale power grew by an average of 12% in PJM. Smaller increases than the PJM average were registered in the Met-Ed and PENELEC Zones, while wholesale costs grew faster than the PJM average in the APS Zone. Higher energy prices were the main reason behind wholesale cost increases between 2009 and 2010, although smaller components, on an average dollar per MWh basis, such as Transmission Enhancement Costs, had a larger percentage increase; almost tripling in two years. As a percentage of total wholesale cost however (approximately 0.1%), they still had very little impact on the total wholesale price. Table 3 shows the percentage change in wholesale cost components between 2009-2011 and 2010-2011.

9 ATSI Zone and its subzone of Penn Power did not join PJM until June of 2011. Due to the lack of comparable data on total wholesale cost of electricity for 2009, Penn Power is not included in this and the next table.

10 Source: 2010 and 2011 PJM SOM and Brattle analysis.

Table 3
Percent Change in Wholesale Cost Components[11]

	% Change (2011 vs. 2010)				% Change (2011 vs. 2009)			
	PJM	PENELEC	Met-Ed	APS	PJM	PENELEC	Met-Ed	APS
Energy	-5.0%	-0.1%	-7.4%	-4.5%	17.6%	17.0%	17.0%	12.1%
Marginal Congestion Cost	*-34.4%*	*-85.7%*	*-32.0%*	*501.5%*	*10.6%*	*34.0%*	*26.7%*	*-96.2%*
Marginal Transmission Losses	*-34.9%*	*-237.9%*	*-21.4%*	*-49.5%*	*-25.2%*	*-438.8%*	*-15.2%*	*123.6%*
Capacity	-20.0%	-31.1%	-31.1%	1.4%	-11.8%	-28.7%	-28.7%	30.0%
Transmission Service Charges	10.5%	1.7%	1.7%	1.2%	10.5%	-2.4%	-2.4%	-4.0%
Operating Reserves (Uplift)	0.0%	-8.2%	-8.2%	-14.7%	64.6%	61.2%	61.2%	38.5%
Reactive	-4.5%	0.9%	0.4%	1.2%	16.7%	-3.8%	-1.6%	-4.0%
PJM Administrative Fees	2.8%	2.8%	2.8%	2.8%	19.4%	19.4%	19.4%	19.4%
Regulation	-8.6%	-8.6%	-8.6%	-8.6%	-5.9%	-5.9%	-5.9%	-5.9%
Transmission Enhancement Cost Recovery	38.1%	66.6%	59.5%	49.5%	222.2%	248.2%	234.1%	149.5%
Synchronized Reserves	50.0%	62.4%	62.4%	62.4%	80.0%	122.5%	122.5%	122.5%
Transmssion Owner (Schedule 1A)	0.0%	0.0%	0.0%	-	12.5%	0.0%	0.0%	-
Day Ahead Scheduling Reserve (DASR)	400.0%	400.0%	400.0%	400.0%	-	-	-	-
Black Start	0.0%	-14.2%	7.2%	3.4%	0.0%	-19.4%	8.9%	-2.3%
NERC/RFC	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
RTO Startup and Expansion	0.0%	-	-	-	0.0%	-	-	-
Load Response	-	271.2%	0.0%	-86.1%	-	-52.2%	354.8%	-55.8%
Transmission Facility Charges	-	-	-	-	-	-	-	-
Total	-6.4%	-6.8%	-11.4%	-3.3%	12.1%	5.7%	6.4%	14.3%

II.B. WHOLESALE ENERGY PRICES

The LMP at any pricing node within the PJM system is comprised of three components: marginal energy, marginal transmission loss, and marginal transmission congestion. The marginal energy component is the incremental cost of energy without considering the cost of transmission losses and transmission congestion. The marginal transmission loss component captures the marginal cost of transmission system losses, specific to a given location, while the marginal transmission congestion component captures the impact that load or generation has on transmission constraints. Table 4 and Table 5 summarize the zonal day-ahead and real-time simple average LMPs and their components for 2009, 2010 and 2011. The difference between average real-time and day-ahead LMPs is small, typically under one dollar per MWh. There has been some price convergence over time; the difference between average real-time and day-ahead prices decreased between 2009 and 2011. As in the case of overall wholesale cost of power, we observe similar trends in the LMPs over time with energy prices rising between 2009 and 2010 and falling between 2010 and 2011. In 2011, Met-Ed remained the zone with the highest average energy price, primarily due to transmission congestion.

[11] Source: 2010 and 2011 PJM SOM and Brattle analysis.

Table 4
Zonal Day-Ahead, Simple Average LMP Components
Calendar Years 2009 - 2011[12,13]
($/MWh)

	2009				2010				2011			
Zone	LMP	Energy	Congestio	Loss	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss
APS	$37.80	$37.15	$0.62	$0.03	$44.42	$44.61	$0.06	-$0.25	$42.96	$42.72	$0.29	-$0.05
Penn Power	$30.63	$27.86	$2.07	$0.71	$35.16	$33.28	$1.14	$0.75	$38.95	$41.59	-$1.46	-$1.18
Met-Ed	$40.35	$37.15	$2.10	$1.10	$48.98	$44.61	$3.13	$1.24	$45.82	$42.72	$2.37	$0.72
PENELEC	$37.09	$37.15	-$0.10	$0.03	$43.94	$44.61	-$0.68	$0.01	$42.79	$42.72	-$0.17	$0.24

Table 5
Zonal Real-Time, Simple Average LMP Components
Calendar Years 2009 - 2011[14]
($/MWh)

	2009				2010				2011			
Zone	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss
APS	$38.29	$37.01	$1.32	-$0.03	$44.62	$44.72	$0.12	-$0.22	$42.91	$42.77	$0.23	-$0.09
Penn Power	$30.23	$27.48	$2.07	$0.68	$34.12	$32.31	$1.14	$0.68	$38.66	$41.19	-$1.88	-$0.66
Met-Ed	$39.94	$37.01	$2.03	$0.90	$49.14	$44.72	$3.47	$0.95	$45.82	$42.77	$2.34	$0.72
PENELEC	$36.85	$37.01	-$0.06	-$0.09	$43.07	$44.72	-$1.42	-$0.24	$42.95	$42.77	-$0.19	$0.37

Table 6 and Table 7 summarize the zonal day-ahead and real-time, load-weighted average LMPs by component for 2009, 2010 and 2011. As prices tend to be higher in high-load hours, the load-weighted LMPs are typically higher than the simple average LMPs. This is demonstrated across years and as well as across load zones.

[12] 2009 values, page 90, Table 2-55 Zonal Day-Ahead, 2010 PJM SOM. 2010 and 2011 values, page 393, Table G-5 Zonal Day-ahead, 2011 PJM SOM.

[13] LMPs for the Penn Power portion of ATSI Zone are an average from June 1, 2011 through December 31, 2011. The 2009 and 2010 values are simple averages from the FirstEnergy Zone in MISO.

[14] 2009 values, page 87, Table 2-51 Zonal Real-Time, 2010 PJM SOM. 2010 and 2011 values page 392, Table G-2 Zonal Real-Time, 2011 PJM SOM.

Table 6
Zonal Day-Ahead, Load-Weighted Average LMP Components
Calendar Years 2009 - 2011[15,16]
($/MWh)

	2009				2010				2011			
Zone	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss
APS	$39.97	$39.44	$0.51	$0.02	$47.08	$47.42	-$0.05	-$0.28	$47.66	$47.96	-$0.16	-$0.15
Penn Power	$31.72	$29.73	$1.39	$0.60	$37.36	$35.51	$1.09	$0.76	$46.14	$50.87	-$3.07	-$1.66
Met-Ed	$42.72	$39.16	$2.38	$1.18	$52.78	$47.72	$3.70	$1.35	$52.37	$48.08	$3.28	$1.01
PENELEC	$38.50	$38.64	-$0.19	$0.04	$45.52	$46.41	-$0.88	$0.00	$47.41	$47.72	-$0.56	$0.24

Table 7
Zonal Real-Time, Load-Weighted Average LMP Components
Calendar Years 2009 - 2011[17,18]
($/MWh)

	2009				2010				2011			
Zone	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss
APS	$40.59	$39.24	$1.41	-$0.06	$47.08	$47.42	-$0.05	-$0.28	$48.57	$48.99	-$0.22	-$0.20
Penn Power	$31.30	$28.97	$1.76	$0.57	$36.11	$34.33	$1.10	$0.69	$46.88	$51.24	-$3.85	-$0.51
Met-Ed	$42.32	$39.08	$2.27	$0.97	$53.47	$48.20	$4.22	$1.05	$53.64	$49.22	$3.42	$1.00
PENELEC	$38.57	$38.87	-$0.18	-$0.11	$45.17	$47.19	-$1.73	-$0.28	$48.18	$48.27	-$0.46	$0.37

Table 8 contains the zonal peak and off-peak simple average LMPs for the day-ahead and real-time energy markets in 2011. In the day-ahead market, average zonal peak-hour LMPs decreased by 3.9% from 2010 to 2011, while off-peak LMPs decreased by 4.5%. Average real-time, peak-hour LMPs decreased by 2.8%, and off-peak LMPs decreased by 4.9%. Met-Ed Zone continues to show the largest positive transmission congestion component for both peak- and off-peak hours. The price decreases between 2010 and 2011 were offset by year-on-year price increases from 2009 to 2010 when on-peak LMPs rose on average by 22% and off-peak LMPs rose on average by 16%.

15 2009 values, page 87, Table 2-78 Zonal and PJM Day-Ahead, 2009 PJM SOM. 2010 and 2011 values, page 268, Table 10-4 Zonal and PJM day-ahead, 2011 PJM SOM.

16 2009 and 2010 ATSI values are load-weighted averages from the FirstEnergy zone in MISO.

17 2009 values, page 84, Table 2-75 Zonal and PJM Real-Time, 2009 PJM SOM. 2010 and 2011 values, page 268, Table 10-3 Zonal and PJM real-time, 2011 PJM SOM.

18 Note that load-weighted average LMPs listed in Table 7 differ from average energy costs reported in Table 1 and Table 2. The differences are due to the different methodology used by PJM's market monitor to calculate load-weighted averages and differences in estimated and meter corrected hourly loads used to weight the hourly prices.

Table 8
Zonal On- and Off-Peak Average Day-Ahead and Real-Time LMPs in 2011
($/MWh)

2011 Day-Ahead Simple Average

Zone	LMP		Energy		Congestion		Loss	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
APS	$50.60	$36.30	$50.62	$35.84	$0.12	$0.44	-$0.14	$0.02
Penn Power	$46.52	$32.39	$50.68	$33.71	-$2.63	-$0.44	-$1.53	-$0.88
Met-Ed	$54.32	$38.40	$50.62	$35.84	$2.74	$2.06	$0.97	$0.50
PENELEC	$50.44	$36.12	$50.62	$35.84	-$0.51	$0.13	$0.33	$0.15
PJM RTO	$50.45	$35.61	$50.62	$35.84	$0.00	-$0.12	-$0.16	-$0.11

2011 Real-Time Simple Average

Zone	LMP		Energy		Congestion		Loss	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
APS	$50.85	$35.99	$51.13	$35.48	-$0.09	$0.50	-$0.20	$0.00
Penn Power	$46.17	$32.15	$50.35	$33.27	-$3.43	-$0.53	-$0.75	-$0.58
Met-Ed	$55.19	$37.66	$51.13	$35.48	$3.16	$1.63	$0.91	$0.55
PENELEC	$51.17	$35.79	$51.13	$35.48	-$0.40	$0.00	$0.44	$0.30
PJM RTO	$51.20	$35.56	$51.13	$35.48	$0.04	$0.05	$0.03	$0.02

As reflected in the transmission congestion component of the LMPs, transmission congestion may arise in both the day-ahead and the real-time (or balancing) market. Loads located on the constrained side of a transmission constraint pay a transmission congestion cost, while loads located on the unconstrained side of the constraint receive a transmission congestion credit. Similarly, the energy price paid to generators in the constrained area includes a transmission congestion credit, while generators located in the uncongested part of the market are assessed a transmission congestion cost in terms of lower energy payments. Transmission congestion costs and credits for loads and generators, as well as explicit transmission congestion costs associated with point-to-point energy transactions may be summed up by zone to yield a net transmission congestion cost for the zone.[19] The net transmission congestion cost for a given zone may be both positive and negative. The sign of the net zonal transmission congestion cost does not necessarily reveal whether loads in the given zone tend to pay a transmission congestion cost or receive a transmission congestion credit, but rather it is a reflection of the relative magnitude of transmission congestion costs and credits paid and received by the various entities located within the zone.

[19] Note that inadvertent interchange between PJM and its neighboring markets may generate additional transmission congestion costs that are not reflected in LMPs and are charged to market participants separately.

Net zonal transmission congestion costs and total net transmission congestion costs for PJM are summarized in Table 9. Overall, total net transmission congestion costs in PJM were $999 million dollars in 2011, consisting of $112.2 million in transmission congestion costs to loads, $1,010 million in (implicit) transmission congestion costs to generators, and a net transmission congestion credit of $123.1 to point-to-point transactions. Transmission congestion costs have significantly decreased compared to 2010, when net transmission congestion costs were $1,423 million.

Table 9
Zonal Transmission congestion Costs in 2010 and 2011[20]
(million $)

Total Congestion Costs in 2011

	Day-Ahead Market				Balancing Market				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
APS	$6.9	-$143.7	-$2.6	$148.1	$5.7	$8.0	-$1.8	-$4.1	$143.9
ATSI	-$73.8	-$78.5	$1.6	$6.3	$2.1	$8.0	-$3.3	-$9.2	-$2.9
Met-Ed	$46.0	$48.1	$0.5	-$1.7	$1.7	$0.8	-$0.7	$0.2	-$1.5
PENELEC	-$45.9	-$108.1	$0.7	$62.9	$4.2	$7.2	-$1.2	-$4.2	$58.7
PJM Total	$36.3	-$1,141.8	$66.9	$1,245.0	$75.9	$131.9	-$190.0	-$246.0	$999.0

Total Congestion Costs in 2010

	Day-Ahead Market				Balancing Market				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
APS	-$5.9	-$313.4	$0.8	$308.4	$11.7	$32.9	-$5.2	-$26.4	$282.0
ATSI	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Met-Ed	$62.9	$53.9	$1.3	$10.4	-$0.9	$0.1	-$1.6	-$2.5	$7.8
PENELEC	-$124.0	-$221.9	$1.0	$98.9	$17.1	$8.6	-$0.7	$7.8	$106.7
PJM Total	$251.4	-$1,364.8	$96.9	$1,713.1	-$0.2	$110.1	-$179.3	-$289.6	$1,423.6

Of the Companies' zones, ATSI[21] and Met-Ed had a net zonal transmission congestion credit, while APS and PENELEC had a net transmission congestion cost.[22] APS had the highest net transmission congestion cost, primarily due to negative net day-ahead transmission congestion credits to generators. In line with the general trend in PJM, transmission congestion costs in all zones decreased from 2010.

Net zonal transmission congestion costs can be attributed to individual transmission facilities that constrain the most economic dispatch. The list of most congested transmission facilities for each zone, including associated transmission congestion costs, is summarized in Appendix A. For

[20] Source: PJM 2011 SOM, Table G-6 and Table G-7.

[21] Net transmission congestion costs are reported by the market monitor for the entire ATSI Zone, not just Penn Power.

[22] In other words, total transmission congestion costs incurred by load in Met-Ed Zone were lower than the total transmission congestion payments received by generators within the zone. In the APS and PENELEC Zones lower energy payments due to transmission congestion outweighed the lower energy cost to load.

each zone the transmission constraints that have the largest transmission congestion cost impact are also among the top constraints for PJM as a whole. For example, the AP South interface which has the highest transmission congestion impact in PJM, contributing 24% to the total net PJM transmission congestion cost,[23] is also the top constraint for the APS and ATSI Zones. The AP South interface is usually responsible for price separation between the eastern and western parts of PJM. Other major interfaces are also among the largest contributors to zonal transmission congestion. The top constraint in the Met-Ed Zone is the West Interface, while for PENELEC Zone it is the 5004/5005 Interface. These constraints are also among the top three constraints in PJM in terms of their impact on transmission congestion costs.

II.C. Wholesale Capacity Prices

PJM operates the RPM capacity market that consists of three-year forward Base Residual Auctions ("BRAs") and up to three incremental auctions[24] for each year. Capacity is procured for RPM delivery years which run from June 1 through May 31 of the following calendar year. Consequently, for calendar year 2011, PJM procured capacity in two BRAs: one for delivery year 2010/11 held in January 2008[25] and one for delivery year 2011/12 held in May 2008. In addition, a 3rd incremental auction was held for delivery year 2010/11 in January 2010, and a 1st and 3rd incremental auction was held for delivery year 2011/12 in June 2009 and February-March 2011, respectively.

Average capacity costs reported in Table 1 are derived from the procurement costs in the RPM capacity auctions. Capacity prices in these auctions are expressed in terms of dollars per MW per day ($/MW-day). Capacity prices may differ by LDAs that represent potentially congested parts of the PJM footprint, and they are modeled in RPM as collections of zones and subzones. As shown in Figure 2, Met-Ed and PENELEC Zones are part of the MAAC LDA; APS and ATSI Zones are part of the unconstrained RTO.[26]

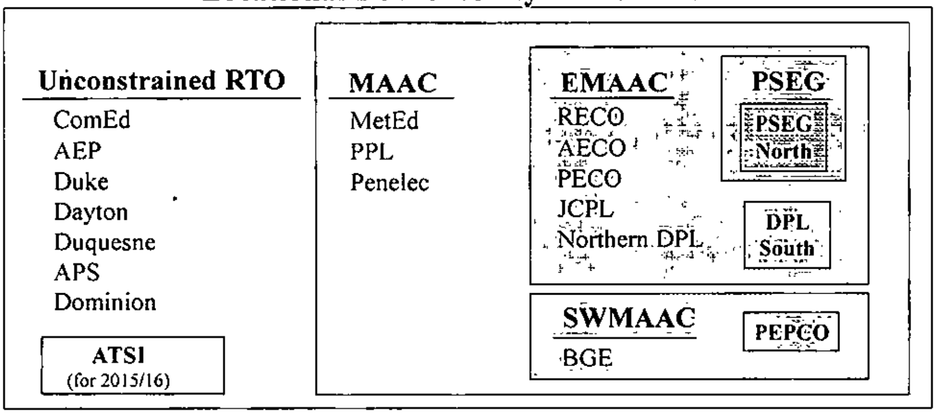
[23] PJM 2011 SOM, Table 10-27.

[24] Following the BRA, up to three incremental auctions are held for each delivery year—23 months, 13 months, and 4 months before each delivery year—that can be used by market participants to adjust their commitments and by PJM to procure additional capacity.

[25] Note that prior to the 2011/12 delivery year, RPM auction followed a compressed schedule, and BRAs were held with a shorter than the usual three-year lead time.

[26] Potentially, any load zone could be defined as an LDA. For the 2015/16 BRA held in May 2012, PJM will model ATSI Zone as a separate LDA.

Figure 2
Locational Deliverability Areas in PJM



Capacity prices from each RPM auction that was held for delivery during calendar year 2011 are summarized in Table 10. In all of these auctions the Companies' zones remained in the unconstrained part of the RTO, and as a result paid the same capacity price. BRA auction clearing prices fell between 2010/11 and 2011/12 from $174.29/MW-day to $110/MW-day. On August 17, 2009, FirstEnergy Service Company submitted a request to the FERC to integrate the ATSI Zone into PJM effective June 1, 2011.[27] Since ATSI Zone utilities did not participate in the BRAs for the 2011/12 and 2012/13 delivery years, two transitional ATSI Zone FRR integration auctions were held in March 2010. The auction held for the 2011/12 delivery year cleared at $108.89/MW-day.

Historically, incremental auctions have consistently cleared at prices below BRA clearing prices; however the volumes that clear in incremental auctions are much lower than in the BRAs. For example, in the BRA for the 2010/11 delivery year 132,190 MW of unforced capacity cleared, while in the 3rd incremental auction for the same delivery year only 1,845 MW cleared.[28] Similarly, in the BRA for the 2011/12 delivery year 132,221 MW of unforced capacity cleared, while in the 1st and 3rd incremental auction for the same delivery year only 361 MW and 1,557 MW, respectively, cleared.[29]

Table 10
Wholesale Capacity Prices in 2011
($/MW-day)

Delivery Year	Base Residual Auction	ATSI FRR Integration Auction	1st Incremental Auction	2nd Incremental Auction	3rd Incremental Auction
2010/11	$174.29	N/A	N/A	N/A	$50.00
2011/12	$110.00	$108.89	$55.00	N/A	$5.00

Figure 3 below shows BRA auction clearing prices for MAAC and the unconstrained part of PJM (rest of the RTO) from the first RPM delivery year 2007/08 through 2014/15. Capacity

[27] Docket ER09-1589-000.

[28] PJM 2011 SOM, Table 4-9, and PJM 2010/2011 RPM Third Incremental Auction Results, January 2010.

[29] PJM 2011 SOM, Table 4-9, PJM 2011/2012 RPM First Incremental Auction Results, June 2009; and PJM 2011/2012 RPM Third Incremental Auction Results; March 2011.

prices in MAAC (including PENELEC and Met-Ed Zones) remained around the long-term average during 2011. Capacity prices in the unconstrained part of PJM (including, APS, and after 2013/14, ATSI Zones) were above the historical average. Furthermore, the BRAs for the next two years cleared at very low prices. For further discussion of RPM capacity auctions, see Section III.

Figure 3

Evolution of Base Residual Auction Clearing Prices in MAAC and Unconstrained RTO

II.D. Other Wholesale Costs

PJM Transmission Service Charges are not market-based and are based on annual transmission revenue requirements by a transmission owner, or transmission zone. This charge, based on annual revenue requirements, includes network integration services (serving network load) and both firm and non-firm point-to-point transmission services. These charges for the Companies' Zones are consistently lower than the PJM average.

Apart from energy, capacity and the transmission service charges, the remaining charges typically make up less than 10% of wholesale power cost. The operating reserve (uplift) component is the average price per MWh of operating reserve charges. It is broken into three components: day-ahead, synchronous condensing and balancing charges. The balancing portion is broken down further into generation and transactions, lost opportunity cost, canceled resources and charges due to local transmission constraints. The generation and transactions category further separates into reliability charges, deviation charges and lost opportunity costs and canceled resource charges. Of the hierarchy above, the only sub-categories that are zone-specific are the reliability charges and the deviation charges which are broken down into the RTO, East and West (for both real-time load and real-time exports). The remaining charges are allocated on an RTO-wide basis.

Zonal-specific ancillary services charges include charges for reactive power, synchronized reserves and black start reserves. Reactive power and black start reserves are not market-based charges. PJM ensures the availability of a black start by charging transmission customers by load ratio share and compensating black start unit owners according to specific revenue requirements.[30] Similarly, PJM ensures the adequacy of reactive power by specific revenue requirements by load zone. Synchronized reserves, along with regulation, are cleared in a real-time market. The DASR market satisfies the supplemental reserve requirement which allows generation resources to receive compensation based upon cleared supply at a market clearing price. For a more detailed discussion of PJM ancillary services markets see Section IV below.

The remaining components in the cost of wholesale power do not change by zone, and are often too small to recognize the distinction between zones or add a significant amount to the total cost.

III. RPM CAPACITY MARKET

III.A. INTRODUCTION

The RPM capacity market is designed to ensure that reliability and resource adequacy requirements are achieved at the lowest possible cost. The demand for capacity is based on an administratively-determined, downward-sloping demand curve such that the market price rises as the PJM capacity reserve margin increase, and falls as the reserve margin decreases. The capacity demand curve is anchored at the net cost of new entry ("Net CONE") in such a manner that the capacity clearing price equals Net CONE approximately at the target reserve level. Net CONE represents the amount of revenue in $/kW-year that a new entrant must earn in capacity payments, in addition to net energy and ancillary services revenues, in order to recover the investment cost levelized over the lifetime of the plant. Net CONE is calculated by subtracting energy and ancillary services revenues from gross investment cost ("gross CONE"). As a result of this offset, the PJM capacity market interacts with the energy and ancillary services markets. Whenever net revenues earned in the energy and ancillary services markets rise, the Net CONE will decrease, resulting in a reduced demand for capacity. At the same time, capacity suppliers earning higher margins in the energy and ancillary services markets will be able to lower their offer prices in capacity auctions. The combined effect is that as the net revenues in the energy and ancillary services market rise, capacity prices will tend to fall.

The RPM capacity market interacts with and works in tandem with the PJM energy market to provide price and revenue signals to attract new and retain existing capacity. It signals the need for new capacity when new capacity is needed; once the target reserve target is reached, the demand curve and corresponding capacity prices drop off steeply. Another key feature of the

[30] Section 9, 2011 PJM SOM.

RPM market design is that it signals scarcity through locational prices. These prices signal not just the need for new capacity but also the attractiveness of a particular location for that capacity.

Lastly, the RPM capacity market allows a range of resource types to meet resource adequacy requirements. Given the forward nature of the market, not just existing but also planned resources are allowed to participate. Furthermore, in addition to traditional generating capacity, demand resources, energy efficiency, and transmission upgrades may be also offered in the RPM capacity auctions.

III.B. Results of PJM Capacity Auctions in 2011

Four RPM auctions were held during 2011: the BRA for the 2014/15 delivery year; the 1st incremental auction for the 2013/14 delivery year; the 2nd incremental auction for the 2012/13 delivery year; and the 3rd incremental auction for the 2011/12 delivery year.

As shown in Figure 3, the BRA for 2014/15 cleared at an RTO price of $125.99/MW-day and a MAAC price of $136.50/MW-day.[31] Compared to the 2013/14 BRA, capacity prices in the unconstrained RTO rose and in MAAC fell from $27.73/MW-day and $226.15/MW-day, respectively. PJM attributed the *increase* in the unconstrained RTO capacity price to primarily three main factors, listed in the order of price impact:[32]

- *Increase* in generator avoidable costs associated with the environmental retrofits, reflected in capacity auction offers;
- *Decrease* in total offered capacity in the western portion of PJM; and
- *Decrease* in energy and ancillary services offset, from $13,495/MW-year to $11,119/MW-year.[33]

Unlike the unconstrained RTO, the MAAC LDA was much less affected by the cost of environmental retrofits because generators in the eastern part of PJM had either previously installed such controls or reflected these costs in their offers in previous BRAs. The *decrease* in the MAAC capacity price was driven primarily by three main factors:[34]

- *Increase* in the transmission limit into the MAAC LDA[35] from 4,460 MW in the 2013/14 BRA to 5,694 MW for 2014/15[36];
- *Decrease* in reliability obligations in MAAC from 73,142 MW in the 2013/14 BRA to 72,187 MW for 2014/15[37]; and
- *Increase* in the volume of demand resource offers in MAAC from 5,871 MW in the 2013/14 to 8,413 MW in 2014/15.[38]

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31 These are resource clearing prices for annual resources.

32 PJM 2014/2015 RPM Base Residual Auction Results Report Addendum, May 2011.

33 PJM 2014/2015 RPM Base Residual Auction Planning Period Parameters, February, 2011.

34 Ibid.

35 Given that BRAs are held three years in advance of delivery, transmission limits between LDAs must be estimated by taking into account future planned transmission upgrades. Because the schedule of such transmission upgrades may change, assumed transmission limits may vary significantly from year to year.

36 PJM 2014/2015 RPM Base Residual Auction Planning Period Parameters, Table 3, February, 2011.

37 Ibid; Table 4.

38 PJM 2014/2015 RPM Base Residual Auction Results Report Addendum, Table 2A, May 2011.

The 2014/15 BRA was conducted under new rules that incorporated significant design changes. Two new demand resource types were introduced: (1) Annual Demand Resources ("Annual DR"); and (2) Extended Summer Demand Resources ("Extended Summer DR"). The old demand resource type was renamed Limited Demand Resource ("Limited DR"). Unlike Limited DR, which can only be activated by PJM up to 10 times a year and only for up to 6 hours in duration per event, Annual and Extended Summer DR can be called upon more frequently and for longer durations.[39] The new RPM design recognizes the greater capacity obligations, and thus greater reliability value, of these resource types by clearing the RPM auctions in a manner that may yield higher prices for Annual and Extended Summer DR than for Limited DR.[40] In the 2014/15 BRA, Extended Summer DR and annual resources (generation and Annual DR), cleared at the same price: $136.50/MW-day in MAAC, and $125.99/MW-day in the unconstrained RTO. The clearing price for Limited DR was uniform at $125.47/MW-day across the RTO. Thus the price premium for annual and extended summer resources was $11.03/MW-day in MAAC and $0.52/MW-day in the unconstrained RTO. Lastly, 2011/12 was the last delivery year when demand resources could participate under the Interruptible Load for Reliability ("ILR") option. Demand resources could certify as ILR immediately prior to the delivery period, without participating in the BRA or an incremental auction, and receive payments based on BRA clearing prices. Starting with 2012/13, all demand-side resources must be committed under an RPM auction or through a bilateral replacement transaction to receive capacity payments.

In addition to the above factors, the following trends can be observed from the results of the 2014/15 BRA:

- o The RPM capacity market continued to attract new capacity. 4,170 MW of incrementally new capacity was offered, which was partially offset by a 2,620 MW decrease in capacity supply due to retirements and derates.[41]
- o There was a reduction of about 6,900 MW of committed coal-fired capacity. According to PJM, it is likely that the cost of environmental retrofits reflected in the offers made them uneconomic compared to lower cost resources, such as demand response and energy efficiency, and as a result they did not clear.[42]
- o The rapid growth of demand resources has continued. In the 2014/15 BRA DR offers increased by 20%. The vast majority of that capacity, 14,118 MW, cleared. 2,700 MW, or about 19% of the total, is located in the Companies' zones.[43]
- o Energy efficiency also grew, albeit at a slower pace. Of the total 832 MW of cleared energy efficiency, about 2% are located in the Companies' zones.

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[39] Annual DR must be able to respond to PJM calls in all seasons, while Extended Summer DR must be able to respond to an unlimited number of calls during the summer period. Extended Summer resources include all Annual resources and the newly-defined Extended Summer DR (i.e., all resources that must be available at least as often as Extended Summer DR). All generating capacity is considered to be Annual resource.

[40] The new RPM auction designs ensures that an adequate amount of Annual and Extended Summer DR is procured by setting a minimum amount of these two types of capacity that must be procured for the RTO and each LDA in each base auction.

[41] PJM 2014/2015 RPM Base Residual Auction Results Report Addendum, Table 6, May 2011.

[42] PJM 2014/2015 RPM Base Residual Auction Results—Addendum, pp.1-2; May 2011.

[43] Ibid, Table 2C.

III.C. COST OF NEW ENTRY AND REVENUE ADEQUACY

Net revenue is the total revenue earned from PJM wholesale markets for energy, capacity, and ancillary services, including a return on investment, depreciation and taxes, net of variable costs. Net revenue is the generator's net income that can be used to cover its fixed costs; as such, net revenue is an indicator of profitability. Investment in new generation will be incented only if net revenue is expected to cover the generator's fixed cost in the long term. For an existing generator, net revenue can be compared to the fixed costs that can be avoidable by shutting down the plant; if net revenue is consistently less than avoidable fixed costs, the generator is at a risk of retirement.

Net revenues vary from year to year, depending on market outcomes, and also by generating technology. PJM's market monitor performs annual assessments of revenue adequacy of hypothetical new entrant plants for three reference technologies: (1) gas-fired combustion turbine; (2) combined cycle gas plant; and (3) coal plant.[44] Given an assumed set of performance characteristics, a hypothetical dispatch is calculated for each of these plants against historical day-ahead and real-time energy prices for each calendar year. Table 11 summarizes net revenues for the Companies' zones and for PJM as whole for calendar years 2009 through 2011. The adequacy of net revenues to incent investment in new generation can be assessed by comparing net revenue estimates to the levelized fixed costs of each plant type.[45] Net revenues as a percentage of these levelized fixed costs are also shown in Table 11. During the period from 2009 through 2011, only new combined cycle plants would have earned sufficient net revenue to cover their total fixed costs. During the 2009-2011 period, coal plants were the least revenue adequate, followed by combustion turbines, and combined cycle plants. By 2011, combined cycle plants in all of the Companies' zones had achieved net revenue adequacy to fully cover their fixed costs.

Combustion turbines and combined cycle plants tend to have the highest level of net revenue adequacy in the APS and Met-Ed Zones. Coal plants are the most net revenue adequate in the Met-Ed and PENELEC Zones.

[44] PJM 2011 SOM, Section 6.

[45] PJM's market monitor assumed a 20-year levelized fixed cost for 2009-2011 that range from $110/kW-year to $131/kW-year for combustion turbines; $154/kW-year to $175/kW-year for combined cycle plants; and $447/kW-year to $475/kW-year for coal plants.

Table 11
Net Revenues Estimates for New Entrants

New Entrant Combustion Turbine

	Net Revenue ($/MWh-year)			% of 20-year levelized fixed costs		
Zone	**2009**	**2010**	**2011**	**2009**	**2010**	**2011**
APS	$64,691	$95,149	$81,295	50%	73%	74%
ATSI	N/A	N/A	N/A	N/A	N/A	N/A
Met-Ed	$64,485	$102,063	$89,139	50%	78%	81%
PENELEC	$60,779	$86,964	$80,428	47%	66%	73%
PJM	**$62,533**	**$92,302**	**$84,724**	**49%**	**70%**	**77%**

New Entrant Combine Cycle

	Net Revenue ($/MWh-year)			% of 20-year levelized fixed costs		
Zone	**2009**	**2010**	**2011**	**2009**	**2010**	**2011**
APS	$110,100	$157,928	$165,046	64%	90%	107%
ATSI	N/A	N/A	N/A	N/A	N/A	N/A
Met-Ed	$105,964	$164,561	$163,137	61%	94%	106%
PENELEC	$100,637	$147,669	$160,532	58%	84%	104%
PJM	**$102,060**	**$152,465**	**$158,791**	**59%**	**87%**	**103%**

New Entrant Coal Plant

	Net Revenue ($/MWh-year)			% of 20-year levelized fixed costs		
Zone	**2009**	**2010**	**2011**	**2009**	**2010**	**2011**
APS	$92,558	$161,061	$145,923	21%	35%	31%
ATSI	N/A	N/A	N/A	N/A	N/A	N/A
Met-Ed	$101,945	$201,539	$108,685	23%	43%	23%
PENELEC	$115,208	$184,704	$142,161	26%	40%	30%
PJM	**$102,255**	**$177,412**	**$121,162**	**23%**	**38%**	**26%**

In addition to the results reported in Table 11, the PJM market monitor analyzed a number of sensitivity cases to analyze the impact of changes in net revenue on the return on investment in new generation.

- Combustion turbines earn more from capacity revenues than combined cycle or coal plants. For example, in 2011, the share of capacity revenues on the total net revenue for the hypothetical new combustion turbine was 55%, while for combined cycle and coal plants it was 31% and 38%, respectively.
- Note that in the absence of capacity revenues, even combined cycle generators would not have been net revenue inadequate in 2011.
- Capacity revenues are a function of energy and ancillary services revenues.

The RPM capacity market plays a crucial role in ensuring long-term revenue adequacy. PJM estimates that since the launch of the current resource adequacy construct in 2007, the RPM capacity market has attracted or retained over 42,000 MW of capacity, as summarized in Table 12. This includes new generation, upgrades of exiting generators, generation reactivations, demand and energy efficiency resources, withdrawn or canceled retirements and capacity imports.

Table 12[46]
Impact of RPM on Capacity Availability to Date

Change in Capacity Availability	Installed Capacity (MW)
New Generation	7,477
Generation Upgrades (excluding reactivations)	5,149
Generator reactivations	539
Demand Resources and Energy Efficiency	16,287
Withdrawn and Canceled Retirements	3,715
Net Imports	9,006
Total	**42,173**

PJM's market monitor estimates that 5,764 MW of RPM coal capacity is at the risk of retirement.[47] This estimate includes the capacity of those generators that did not cover their avoidable costs in 2011 or would not be able to cover the cost of installing MATS compliant environmental controls.

[46] PJM 2014/2015 RPM Base Residual Auction Results Report.

[47] PJM 2011 SOM, p.13

IV. ANCILLARY SERVICE MARKETS

PJM currently procures three ancillary services products in organized markets: (1) regulation; (2) synchronized reserves; and (3) DASR.[48] Other ancillary services are procured outside PJM's market mechanisms and are generally compensated on the basis of incentive rates or costs. These services include reactive power and black start reserves. The remainder of this section contains a discussion of each of these ancillary services.

IV.A. REGULATION

Regulation reserves are procured to be able to respond to minute-to-minute changes in load. PJM operates a single market for regulation, and the market clearing price is the uniform price paid for regulation across the RTO footprint. The demand for regulation is administratively determined; current regulation requirements are calculated as 1% of forecasted daily peak load for on-peak hours, and 1% of forecasted minimum daily load for off-peak hours. The average hourly regulation requirement in 2011 was 925 MW, a slight increase from 2010.[49] Regulation may be self-scheduled by load serving entities or procured by PJM in the regulation market. In 2011, the 81.8% of the required regulation was purchased in the PJM regulation market.[50] The weighted average clearing price was $16.21/MWh, which represents a 10% decrease from 2010.[51] Daily average prices and regulation requirements in 2011 are shown in Figure 4.

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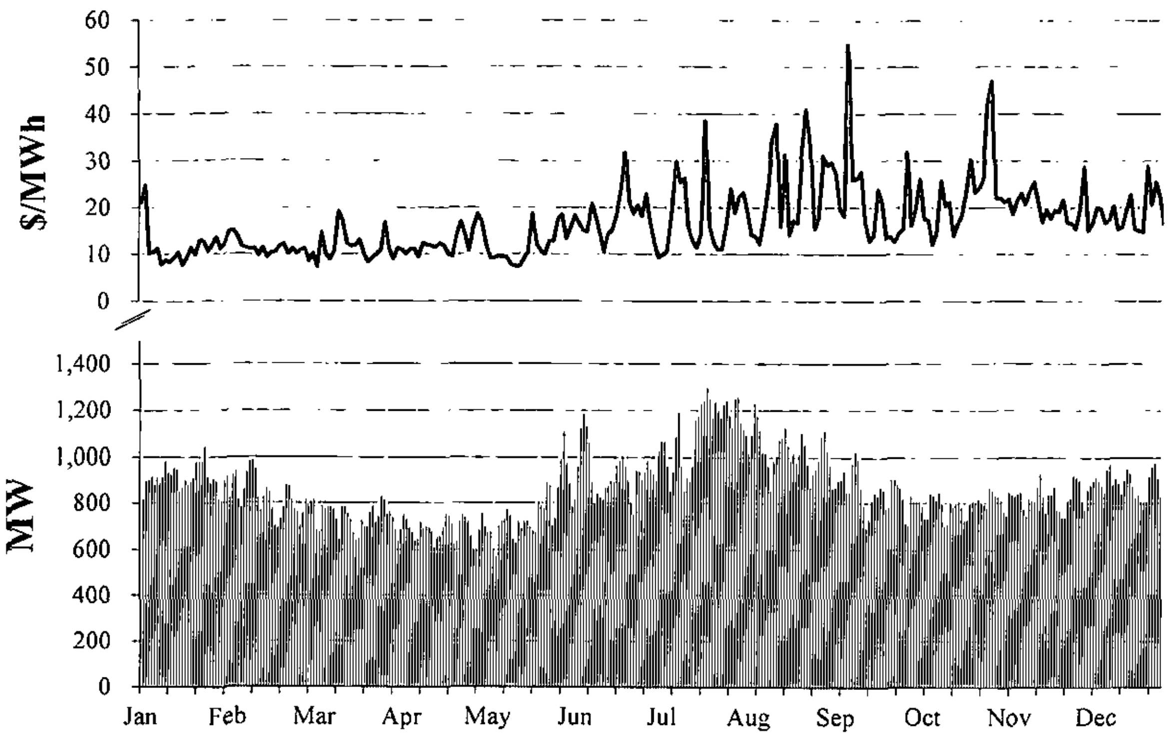
[48] Energy imbalance service, defined in FERC Order No. 888, is provided through the PJM real-time energy market.

[49] PJM 2011 SOM, p. 225.

[50] Ibid.

[51] Ibid.

Figure 4
Daily Average Regulation Requirements (MW) and Market Clearing Prices ($/MWh) in 2011



In the PJM regulation market, each supplier must submit a cost-based offer, which is limited to cost of providing regulation plus $12.00, and optionally a price-based offer. PJM will calculate and add to both types of offers the generator's forecasted opportunity cost of not being able to sell energy while providing regulation. The compensation for providing regulation is based on the higher of the product of the market clearing price for regulation and the amount of regulation provided, or the supplier's real-time opportunity cost. PJM's market monitor has noted that while most regulation providers receive the market clearing price, a substantial portion of the regulation market clearing price is determined by opportunity cost.[52] Furthermore, the real-time opportunity cost is based on real-time LMPs which are determined after the regulation market closes. Any differences in the forecasted LMPs, used to determine the opportunity costs used during the regulation market clearing, and the real-time LMPs, used to calculate real-time opportunity costs, may result in differences between the regulation market clearing price and the actual unit cost of procuring regulation. For example, in 2011 the weighted average regulation price was $16.21/MWh, while the weighted average regulation cost was $29.28/MWh.[53] The market monitor has raised this issue as a cause for concern, and recommended that the hourly regulation market clearing price be determined after the close of the operating hour, and thus the opportunity cost would be calculated based on actual, real-time LMPs.

Not all generators are eligible to provide regulation, nor are all eligible generators required to submit regulation offers. Prior to clearing, the regulation market is subject to the three pivotal

[52] PJM 2011 SOM, p. 237.

[53] PJM 2011 SOM, p. 238.

supplier test. In 2011, 82% of the hours failed this test, and PJM's market monitor concluded that the regulation market was characterized by structural market power.[54] Traditionally generators were the only resources providing regulation, however after PJM modified some of its participation rules in November 2011, demand resources began participating in the regulation market, although these resources had virtually no impact on the regulation market in 2011.[55]

On October 20, 2011 FERC issued Order No.755,[56] requiring RTOs to compensate resources providing regulation according to their actual performance and not just capability. Traditionally, resources providing regulation were paid based on their capability, irrespective of whether they were actually dispatched or not. Thus, a fast-response resource frequently dispatched to balance load could have received the same compensation as a slower-response resource that was never actually dispatched. PJM commissioned a study to analyze the impact of fast response regulation, and is currently in the process of redesigning its regulation market. It is expected that these changes will result in a lower overall regulation requirement and the introduction of new metrics to measure regulation performance. The objective is to lower the cost of required regulation.

IV.B. Synchronized Reserves

Synchronized reserves are procured to replace capacity that becomes unavailable on a short notice. PJM distinguishes two types of synchronized reserves: (a) Tier 1, which includes units that are online, following economic dispatch, and are able to ramp up, or demand resources that are able to reduce their load within 10 minutes; and (b) Tier 2, which consist of units that are synchronized to the grid and operating at a level that deviates from economic dispatch, and dispatchable demand resources that can automatically drop load in response to a signal from PJM.[57] Tier 2 reserves are procured in the market only if there are not sufficient Tier 1 resources available. Tier 1 resources are paid only when they respond to a reserve event, while Tier 2 resources are compensated for their synchronized reserve capability that clears in the market. There is a market clearing price only for Tier 2 reserves. Offers submitted into the synchronized reserve market may not exceed the unit's variable cost plus $7.50. For the purposes of determining the Tier 2 synchronized reserve market clearing price, each unit's opportunity cost, based on estimated LMPs, is also taken into account. The demand for synchronized reserves is administratively determined, typically based on the largest single contingency of each reserve zone.

The PJM synchronized reserve market contains two reserve zones and one subzone: the RFC Synchronized Reserve Zone and its subzone, the Mid-Atlantic Subzone, and the Southern Synchronized Reserve Zone. The Mid-Atlantic Subzone is defined by the Bedington-Black Oak Interface, and includes all of the Met-Ed zone, and parts of the APS and PENELEC zones. In

[54] PJM 2011 SOM, p. 235.

[55] PJM 2011 SOM, p. 236.

[56] Docket Nos. RM11-7-001 and AD10-11-001.

[57] PJM Manual 11: Energy & Ancillary Services Market Operations, Section 4, Revision: 50, Effective Date: April 3, 2012.

2011, much of the synchronized reserve requirement was met by Tier 1 resources.[58] Only the Mid-Atlantic Subzone market for Tier 2 reserves cleared on a consistent basis. The synchronized reserve market outside the Mid-Atlantic subzone cleared less than 1% of the hours in 2011.[59] Figure 5 illustrates daily average Tier 2 reserve requirements and market clearing prices in the Mid-Atlantic Subzone. The total synchronized reserve requirement for Mid-Atlantic is usually 1,300 MW. The demand for Tier 2 reserves is reduced by the amount of Tier 1 reserves available in the subzone and the amount of Tier 1 capacity located outside but can be imported into the zone.

Demand resources are active participants in the synchronized reserve market. They exert a significant impact on the Tier 2 market clearing price, despite the fact that demand resource participation is limited to 25% of the synchronized reserve requirement in each reserve zone.[60] In 2011, demand resource accounted for 29.3% of all cleared Tier 2 resources; in 6% of the hours when the market cleared, demand resources were the only cleared resources.[61]

PJM's market monitor concluded that in 2011 the synchronized reserve market was not structurally competitive in the Mid-Atlantic Subzone.[62] Furthermore, it raised concerns about the inadequacy of the incentive and penalty structure to ensure response during synchronized reserve events. Resources which provided synchronized reserves are paid the higher of the market clearing price or their offer plus a unit-specific opportunity cost. The market monitor raised concerns regarding the inefficient calculation of opportunity costs based on LMP forecasts for clearing the synchronized reserve market, while calculating opportunity costs based on real-time LMP to determine compensation. This inefficiency is similar to that reported for the regulation market: the market price for synchronized reserves is significantly lower than the actual unit cost paid to resources providing those reserves.

[58] PJM 2011 SOM, p. 246.

[59] PJM 2011 SOM, p. 248-249.

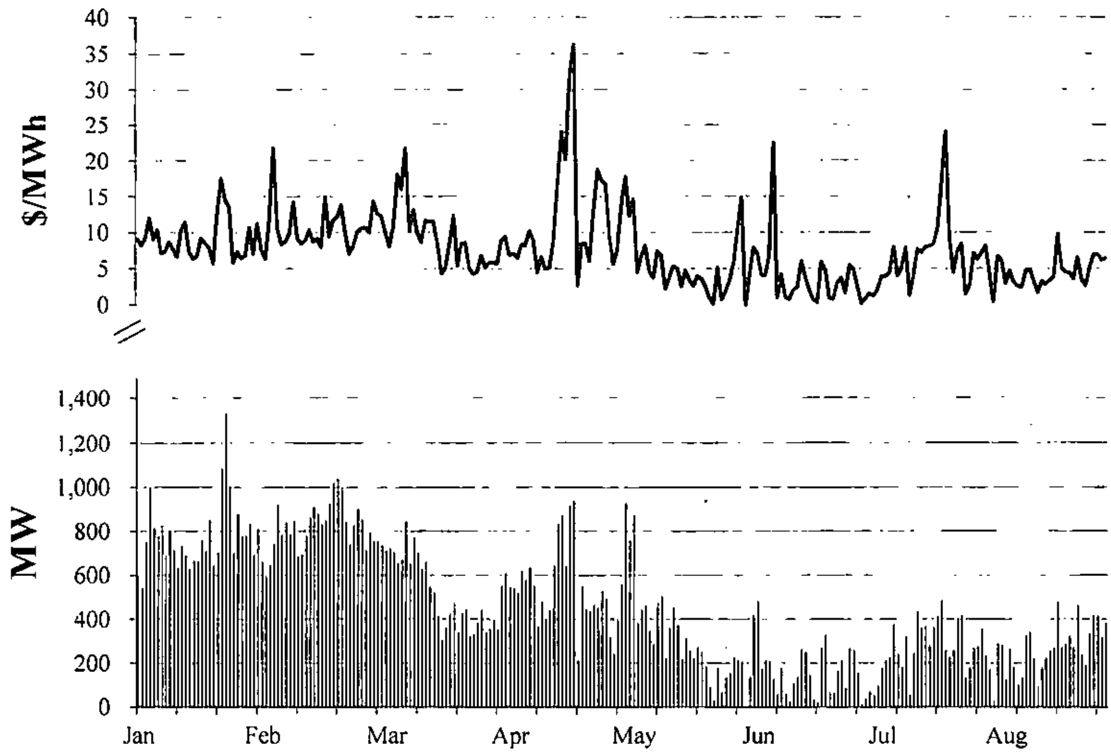
[60] PJM Manual 11, Section 4.

[61] PJM 2011 SOM, p. 248-250.

[62] PJM 2011 SOM, p. 250.

Figure 5

Daily Average RFC Mid-Atlantic Subzone Tier 2 Synchronized Reserve Requirements (MW) and Market Clearing Prices ($/MWh) in 2011



IV.C. DAY-AHEAD SCHEDULING RESERVES

DASRs are procured to satisfy PJM's 30-minute supplemental reserve requirement. DASR requirements are determined for the RFC and Dominion regions separately. The RFC DASR requirement is based on the region's historical load under-forecast and generator outage rates. In 2011, the DASR requirement was 7.11% of forecasted peak load.[63] The Dominion DASR requirement was based on its share of the VACAR Reserve Sharing Agreement; set at 422 MW. The combined RTO DASR requirement is procured in the DASR market.

In 2011, in more than half of the hours, the DASR market cleared at a $0.00 clearing price, and 97% percent of the hours cleared at prices below $0.03. DASR prices tend to rise when energy prices are high, due to lost opportunity costs. The maximum DASR clearing price in 2011 was $217.12/MWh. PJM's market monitor concluded that economic withholding remains an issue in the DASR market, arguing that marginal cost of providing DASR is zero. In contrast, 5% of the units offered at or above $50, and more than 4% offered above $900 during the first five months of 2011.[64]

[63] PJM 2011 SOM, p. 255.

[64] PJM 2011 SOM, p.256.

IV.D. Black Start Reserves

Black start reserves are procured to ensure reliable restoration following a blackout. PJM works in conjunction with transmission service providers to locate capable resources in the appropriate locations. Restoration plans identify critical resources and PJM defines a minimum critical black start level for each transmission zone.[65] The execution of acquiring black start capability and soliciting rates and revenue requirements has been a point of scrutiny for several years. The original Schedule 6A of the PJM Open Access Transmission Tariff ("OATT"), a schedule of rates for units identified as critical in restoration plans,[66] was structured to compensate transmission owners to continue to provide the service. A majority of the capital investment required to provide the service had been made previously. It was discovered that the cost recovery rates in 6A were not sufficient to allow new units to install equipment necessary to provide the service.[67] In May of 2009, FERC approved the new reforms which allow black start service providers to recover the costs of new investment.[68]

As mentioned in the discussion on wholesale power, there is no organized market for black start service. PJM may accept proposals to provide service from any willing party in a given location. PJM's market monitor points out that the separate planning for each transmission zone significantly constrains the flexibility to consider how to restart the grid.[69] One of the barriers to a competitive process is that proposal requests cannot be accepted as reasonable rates as the market is "characterized by inelastic demand and substantial local market power."[70] One of the recommendations from the market monitor is to re-evaluate how black start service is procured to ensure rates are solicited in a least-cost manner for the entire PJM market.

IV.E. Reactive Power

Reactive power is a requirement for a generator, or other resource, in PJM to maintain transmission voltages within acceptable limits. Reactive supply and voltage control from generation is provided by PJM which customers must purchase. Charges are based on a rate that allocates reactive revenue requirements to network and point-to-point customers.[71] Reactive services were developed in response for an accurate portrayal of voltage and reactive resources and capability. Similar to black start reserves, charges are allocated to customers based on percentage of load. The wholesale cost component in Table 1 is calculated using the zonal revenue requirements and the corresponding zonal load.

V. CONCLUSION

Overall, PJM markets are governed by market fundamentals and market performance. In 2011, market dynamics were driven by falling gas prices and rising coal prices, resulting in an overall

[65] Page 257, 2011 State of the Market Report

[66] Page 257, 2011 State of the Market Report

[67] PJM 2010 SOM, footnote 67, p.258.

[68] Docket Nos. ER09-730-000 and ER09-730-001.

[69] PJM 2010 SOM, p.259.

[70] Ibid.

[71] PJM Manual 27: Open Access Transmission Tariff Accounting.

decrease in electricity prices. Market performance was mostly competitive, with a few exceptions discussed in the next section.

V.A. Market Performance in 2011

Overall competitiveness of wholesale markets can be assessed by examining its various aspects, including: (1) market structure; (2) market participant behavior; (4) market design; and (4) overall market performance. Market structure refers to the concentration of supply assets, both on an aggregate, market-wide basis, as well as regionally. A concentrated market provides a greater incentive for the exercise of market power and is more likely to yield uncompetitive outcomes. PJM's market monitor uses various metrics to measure market concentration, including the three pivotal supplier test and the Herfindahl-Hirschman Index ("HHI"). Market participant behavior refers to the actual conduct by market participants. Uncompetitive market participant behavior is not limited to concentrated market structures, and may occur in less concentrated markets, too. Market design refers to a set of rules and procedures that are created to minimize the exercise of market power in structurally uncompetitive markets, and to prevent uncompetitive behavior in general. A flawed market design may be insufficient to prevent uncompetitive market outcomes. Market performance refers to the overall outcome of the market in a given period, and is a function of market structure, market participant behavior, and market design.

Table 13 summarizes PJM market monitor's assessment of the performance of PJM markets in 2011. According to this assessment, all but the regulation market yielded competitive outcomes. The regulation market was determined not to be competitive because the application of PJM's current opportunity cost methodology resulted in market prices that deviated from the competitive price that reflects the actual marginal cost of the marginal resource.[72]

Table 13[73]
Market Monitor's Assessment of PJM Markets in 2011

	Market Structure		Participant	Market	Market
Market	**Aggregate**	**Local**	**Behavior**	**Design**	**Performance**
Energy	Competitive	Not Competitive	Competitive	Effective	Competitive
Capacity	Not Competitive	Not Competitive	Competitive	Mixed	Competitive
Regulation	Not Competitive	N/A	Competitive	Flawed	Not Competitive
Synchronized reserves	N/A	Not Competitive	Competitive	Effective	Competitive
DASR	Competitive	N/A	Mixed	Mixed	Competitive

As in previous years, the capacity and regulation markets, as well as all local sub-markets, were determined to be structurally not competitive. In other words, the competitive structure of PJM markets remained unchanged in 2011. Despite relatively high ownership concentration in some PJM markets, participant behavior in all markets, except the DASR market, was judged to be competitive. In the DASR market, participant behavior was mixed because the market monitor

[72] PJM 2011 SOM, footnote 12, p.5.

[73] PJM 2011 SOM, Section 1.

found evidence of economic withholding by some market participants, however overall market performance was not affected.[74]

Some of these deficiencies have been addressed in 2011. For example, PJM and its market monitor identified an issue regarding the Guaranteed Load Drop ("GLD") option used for measuring the performance of demand resources.[75] The key concern was how to measure compliance against the committed amount of demand resource capacity, and what should be the appropriate reference point or baseline. PJM argued that allowing DR to measure its performance against a baseline that depends on recent load levels may provide an incentive for curtailment service providers to include assets in their portfolios with little ability to perform because over-performance by other assets in the portfolio will often allow the portfolio to perform at the expected level. PJM analysis has indicated that this issue could result in the commitment of a large number of low-quality DR which could lead to future reliability problems. To address this, PJM modified its baseline methodology that caps the baseline under the GLD option at each resource's peak load contribution.

In addition to the competitive wholesale market, there is also competition in the Pennsylvania retail sector. As of April 1, 2012, the percentage of retail customers served by an alternative supplier ranged from 16.2% in Met-Ed's service territory to 24.4% in the Penn Power service territory, representing 20.3% and 25.5% of the retail load, respectively.[76] The percentage of commercial load served by alternative suppliers ranges from 58.9% in Met-Ed's territory to 68.9% in Penn Power's territory. Lastly, the share of industrial load served by competitive retail suppliers ranges from 89.3% in West Penn's territory to 98.8% in Penn Power's territory.

[remainder of page left blank]

[74] PJM 2011 SOM, p.6.

[75] PJM Filing to FERC in Docket No. ER11-3322-000 on April 7, 2011.

[76] Pennsylvania Electric Shopping Statistics, PA Office of Consumer Advocate April 1, 2012.
http://www.oca.state.pa.us/Industry/Electric/elecstats/Stats0412.pdf

APPENDIX A

APS Control Zone
Top Transmission congestion Cost Impacts (By Facility): Calendar Year 2011

				Day Ahead				Balancing					Event Hours	
No.	Contraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	-26.30	-91.60	-7.80	57.60	5.50	5.70	6 50	6 30	63.90	8,222	2,026
2	Belmont	Transformer	AP	34.30	7.20	0.90	28.00	-2.40	-3.30	-0.60	0.30	28.30	8,742	998
3	5004/5005 Interface	Interface	500	-20.20	-29.70	-3.80	5.70	1.40	1.70	4.40	4.00	9.70	1,810	940
4	Bedington Black Oak	Interface	500	-3.10	-11.60	-1.90	6.50	0.00	0.10	0.10	0.10	6.60	1,358	14
5	Yukon	Transformer	AP	4.40	0.00	0 20	4.60	0.20	0 40	-0.10	-0 30	4.30	750	180
6	AEP-DOM	Interface	500	-1.30	-4.70	0.00	3.30	0.10	0 10	0 30	0 40	3.70	3,572	370
7	Bedington	Transformer	AP	1.20	-2.70	-0 20	3.60	-0.10	0.60	0.30	-0.40	3.20	464	206
8	Wylie Ridge	Transformer	AP	6.00	9.70	3.70	0.00	-0.10	-0 30	-3.10	-2.90	-2.90	3,836	760
9	West	Interface	500	-18 50	-24.40	-3 20	2.60	0 10	0.00	0.10	0.10	2.80	1,734	40
10	Wolfcreek	Transfomer	AEP	5.70	8.20	1.00	-1.50	-0.50	-0 60	-1.00	-0.90	-2 40	5,094	452
11	Tiltonsville - Windsor	Line	AP	2 60	0.70	0.30	2.10	-0.20	0.00	-0.20	-0.40	1.70	2,008	144
12	Dickerson - Quince Orchard	Line	Pepco	-6.80	-5.20	-0.90	-2.50	-0.80	-0.20	1.30	0.80	-1.70	284	152
13	Mount Storm	Line	AP	-0.40	-1.90	0.20	1.60	0.00	0.00	0.00	0.00	1.60	162	0
14	Danville - East Danville	Line	AEP	0.30	-1.10	0.20	1.50	0 00	0.00	0.00	0.00	1.50	9,216	0
15	Valley	Transformer	Dominion	-0.80	-2.00	0.00	1.20	0.30	0.20	0.10	0.20	1.40	438	196
16	Gore - Hampshire	Line	AP	-2.10	-3.80	-0.40	1.30	0.00	0.00	0.00	0.00	1.30	1,654	0
19	Mount Storm	Transformer	AP	0 00	0 00	0.00	0.00	0 60	1.10	-0.60	-1.10	-1.10	0	218
21	Kingwood - Pruntytown	Line	AP	0 80	-0.10	0.10	0.90	0.00	-0.10	0.00	0.00	0.90	404	28
25	Hamilton - Weirton	Line	AP	1.00	0.30	0.10	0.80	0.00	0.00	0.00	0.00	0.80	304	6
26	Halfway - Marlowe	Line	AP	0.50	-0.20	0.00	0.70	0.00	0.00	0.00	0.00	0.70	158	18

ATSI Control Zone
Top Transmission congestion Cost Impacts (By Facility): Calendar Year 2011

				Day Ahead				Balancing					Event Hours	
No.	Contraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	-27.80	-27.10	-1.30	-2 00	-0.20	2.40	1.80	-0.80	-2.90	8,222	2,026
2	Niles - Evergreen	Line	ATSI	3.20	0 80	0.80	3.20	-0.40	0.20	-0.60	-1.20	1.90	892	54
3	Dickerson - Quince Orchard	Line	Pepco	-4.20	-3.50	0.00	-0.70	-0.20	0.40	0.00	-0.60	-1.30	284	152
4	West	Interface	500	-21.80	-20.70	-0.10	-1.20	0.00	0.00	0.00	0.00	-1.20	1,734	40
5	Bayshore - Jeep	Line	ATSI	0.80	-0 20	0.00	1.00	0.40	0.20	0.00	0.20	1.20	32	12
6	Clover	Transformer	Dominion	-2.80	-2 30	0.40	-0.20	0.20	0.40	-0.60	-0.80	-1.00	2,476	938
7	Beaver - Sammis	Line	DLCO	-0.50	-1.50	-0.10	0.90	0.00	0.00	0.00	0.00	0.90	442	22
8	Burnham - Munster	Flowgate	MISO	4.50	3.70	0.10	0.90	0.00	0.00	0.00	0.00	0.90	2,304	0
9	South Canton - Torrey	Line	AEP	1.40	0 60	0.00	0.80	0.00	0.00	0.00	0.00	0.80	82	16
10	Danville - East Danville	Line	AEP	-3 80	-3 30	-0.20	-0.80	0.00	0.00	0.00	0.00	-0.80	9,216	0
11	5004/5005 Interface	Interface	500	-5.00	-5.10	-0.10	0.00	0.20	1.20	0.20	-0.70	-0.80	1,810	940
12	Muskingum River - Waterford	Line	AEP	0.80	0.70	0.10	0 10	0.10	-0.10	-1.00	-0.70	-0.60	1,028	106
13	AEP-DOM	Interface	500	-4.40	-3.80	-0.10	-0.80	0.00	0.10	0.20	0.20	-0.60	3,572	370
14	Benton Harbor - Palisades	Flowgate	MISO	0.00	0.00	0.00	0.00	-0 20	0.00	-0.40	-0.60	-0.60	134	264
15	Jeep - Dixie	Line	ATSI	0 40	-0.10	0.00	0.50	0.00	0.00	0.00	0.00	0.50	28	0
20	Sammis - Wylie Ridge	Line	ATSI	-1.20	-1.80	-0.20	0.40	0.00	0.00	0.00	0.00	0.40	484	8
29	Lakeview - Ottawa	Line	ATSI	0.20	0.00	0.00	0 20	0.00	0.00	0.00	0 00	0 30	46	4
31	Galion - GM Mansfield	Line	ATSI	0.30	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.20	36	0
35	Galion - Leaside	Line	ATSI	0.10	0.10	0.00	0.10	0.10	0.00	0.00	0.10	0.20	44	22
42	Brookside - Wellington	Line	ATSI	0.10	0.00	0.10	0.20	0.00	0.00	0.00	0.00	0.20	224	0

METED Control Zone
Top Transmission congestion Cost Impacts (By Facility): Calendar Year 2011

				Day Ahead				Balancing					Event Hours	
No.	Contraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	10.90	15.50	0.10	-4.60	0.00	0.00	0.00	0.00	-4.60	1,734	40
2	Cly - Collins	Line	Met-Ed	1.90	-1.30	0.10	3.30	-0.50	0.40	0.00	-0.90	2.30	710	324
3	Wylie Ridge	Transformer	AP	4.40	6.30	0.10	-1.80	0.10	0.00	0.00	0.10	-1.70	3,836	760
4	Hunterstown	Transformer	Met-Ed	1.60	0.00	0.00	1.50	0.00	0.00	0.00	0.00	1.50	164	18
5	Middletown Jct - TMI	Line	Met-Ed	0.40	-0.70	0.00	1.10	0.00	0.00	0.00	0.00	1.10	62	0
6	Crete - St Johns Tap	Flowgate	MISO	2.40	3.40	0.00	-1.00	0.10	0.00	0.00	0.10	-0.90	6,708	2,230
7	Graceton - Raphael Road	Line	BGE	-3.30	-4.60	-0.20	1.10	-0.10	0.20	0.10	-0.20	0.90	2,314	830
8	East	Interface	500	0.40	-0.20	-0.10	0.50	0.00	0.00	0.00	0.00	0.50	1,044	44
9	Carlisle Pike - Roxbury	Line	PENELEC	0.60	0.10	0.00	0.50	0.00	0.00	0.00	0.00	0.50	268	8
10	Dickerson - Quince Orchard	Line	Pepco	1.30	1.90	0.00	-0.50	0.20	0.10	0.00	0.10	-0.50	284	152
11	East Frankfort - Crete	Line	ComEd	0.90	1.30	0.00	-0.40	0.00	0.00	0.00	0.00	-0.40	3,092	658
12	Middletown Jctn. - Three Mile I	Line	Met-Ed	0.00	0.00	0.00	0.00	-0.10	0.10	-0.10	-0.40	-0.40	0	30
13	Burnham - Munster	Flowgate	MISO	1.00	1.40	0.00	-0.40	0.00	0.00	0.00	0.00	-0.40	2,304	0
14	Conastone - Graceton	Line	BGE	0.10	-0.30	0.00	0.30	0.00	0.00	0.00	0.00	0.30	236	0
15	Glenarm - Windy Edge	Line	BGE	-1.10	-1.40	0.00	0.40	0.00	0.00	0.00	0.00	0.30	1,366	316
22	Glendon - Hosensack	Line	Met-Ed	0.10	-0.10	0.00	0.20	0.00	0.00	0.00	0.00	0.20	140	2
29	Hunsterstown - Lincoln	Line	Met-Ed	0.10	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.10	220	16
31	Middletown Jct - Yorkhaven	Line	Met-Ed	0.10	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.10	74	0
39	Cly - Newberry	Line	Met-Ed	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.10	22	0
71	Manor - Safe Harbor	Line	Met-Ed	-0.10	-0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14	6

PENELEC Control Zone
Top Transmission congestion Cost Impacts (By Facility): Calendar Year 2011

				Day Ahead				Balancing					Event Hours	
No.	Contraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Inferface	500	-14.90	-39.40	-1.70	22.80	1.70	3.00	2.50	1.30	24.10	1,810	940
2	AP South	Inferface	500	-38.80	-54.60	-0.40	15.50	2.70	0.70	0.90	2.90	18.40	8,222	2,026
3	West	Inferface	500	-11.10	-26.80	-1.40	14.30	0.00	0.10	0.10	0.00	14.30	1,734	40
4	Wylie Ridge	Transformer	AP	8.10	20.00	0.80	-11.10	-0.60	-0.40	-0.40	-0.60	-11.70	3,836	760
5	Crete-St Johns Tap	Flowgate	MISO	7.40	10.00	0.10	-2.50	-0.30	0.20	-0.10	-0.60	-3.10	6,708	2,230
6	Altoona - Bear Rock	Line	PENELEC	-2.80	-5.50	-0.10	2.60	0.70	0.60	0.20	0.20	2.90	380	154
7	Johnstown - Seward	Line	PENELEC	2.00	-0.60	0.00	2.60	0.00	0.00	0.00	0.00	2.60	102	0
8	Bedington - Black Oak	Inferface	500	-5.10	-7.50	-0.10	2.20	0.00	0.00	0.00	0.00	2.20	1,358	14
9	Butler - Karns City	Line	AP	5.50	3.90	0.30	2.00	-0.20	0.00	-0.10	-0.30	1.70	772	116
10	Susquehanna	Transformer	PPL	0.50	-1.30	-0.10	1.60	0.00	0.00	0.00	0.00	1.60	240	0
11	Yukon	Transformer	AP	0.90	-0.90	0.00	1.80	0.00	0.20	0.00	-0.20	1.60	750	180
12	East	Inferface	500	-2.40	-4.20	-0.30	1.50	0.00	0.10	0.10	0.00	1.50	1,044	44
13	Graceton - Raphael Road	Line	BGE	-3.10	-3.80	-0.10	0.60	0.20	0.10	0.10	0.20	0.80	2,314	830
14	East Frankfort - Crete	Line	ComEd	2.90	3.60	0.10	-0.60	0.00	0.10	-0.10	-0.20	-0.80	3,092	658
15	Danville - East Danville	Line	AEP	0.40	1.20	-0.10	-0.80	0.00	0.00	0.00	0.00	-0.80	9,216	0
17	Laurel Lake - Tiffany	Line	PENELEC	0.70	0.10	0.10	0.70	0.00	0.00	0.00	0.00	0.70	154	0
23	Seward	Transformer	PENELEC	0.40	0.20	0.00	0.20	-0.20	0.50	0.00	-0.80	-0.50	42	44
26	East Towanda - S. Troy	Line	PENELEC	0.20	0.10	0.30	0.50	0.00	0.00	0.00	0.00	0.50	1,440	0
28	Hooversville - Scalp Level	Line	PENELEC	2.90	2.10	0.10	0.80	-0.20	0.10	-0.10	-0.40	0.50	434	110
35	Handsome Lake - Wayne	Line	PENELEC	0.20	-0.20	0.00	0.40	0.00	0.00	0.00	0.00	0.40	48	0

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07/05/2012
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