FirstEnergy

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SECRETARY'S BUREAU

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

November 9, 2016

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 2016 report on market prices and price trends in the PJM Interconnection LLC markets during 2015, 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/cdc

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

cc: Johnnie Simms, Bureau of Investigation and Enforcement
Tanya J. McCloskey, Office of Consumer Advocate
Steven Gray, Office of Small Business Advocate

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

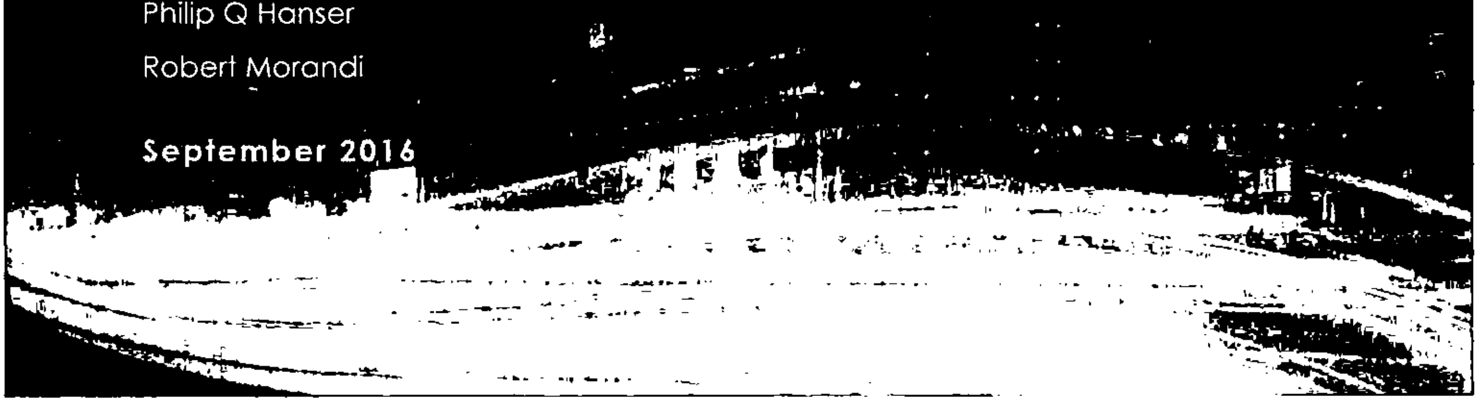
PREPARED FOR

Met-Ed®
Penelec®
Penn Power®
West Penn Power®
FirstEnergy Companies

PREPARED BY

Mariko Geronimo Aydin
Philip Q Hanser
Robert Morandi

September 2016



THE Brattle GROUP

This report was prepared for the Met-Ed, Penelec, Penn Power, and West Penn Power FirstEnergy Companies. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

Table of Contents

Executive Summary

This report was prepared by The Brattle Group on behalf of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company, collectively "the Companies," pursuant to the settlement agreement approved by the Pennsylvania Public Utility Commission ("PA PUC") in the proceeding at Docket Nos. A-2010-2176520 and A-2010-2176732. This agreement requires the Companies to submit an annual report addressing wholesale market prices and price trends in PJM in the calendar years 2011, 2012, 2013, 2014, and 2015. This is the fifth and final of such reports. The Companies are part of a Regional Transmission Organization ("RTO")—the PJM Interconnection L.L.C. ("PJM")—and its competitive wholesale marketplace. The Companies operate in four Pennsylvania zones of PJM: Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Allegheny Power System ("APS") for West Penn, and the Penn Power portion of the American Transmission Systems load zone ("ATSI"). This report summarizes PJM market outcomes and trends, with a specific focus on the portion of the footprint where the Companies operate. 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 2015, the market trends in the four zones served by the Companies were mostly in line with the general trends observed in the overall PJM market. Total wholesale costs, in dollars per megawatt-hour ("MWh") of total customer load, decreased in all four zones relative to 2014, by 33% in Met-Ed, 28% in Penelec, 21% in APS, and 6% in Penn Power zones. Total wholesale cost is primarily composed of the costs of energy, capacity, and transmission service charges, but it also includes the cost of ancillary services and other charges.

The decrease in Companies' wholesale costs from 2014 to 2015 was largely driven by lower energy prices. In 2015, wholesale energy prices decreased significantly compared to the prior year due to lower gas prices throughout the RTO and lower demand for energy.

In the day-ahead market, 2015 average zonal on-peak locational marginal prices ("LMPs") decreased relative to 2014 by 29–37% in the four Company zones. Similarly, off-peak LMPs decreased by 24–36%. In the real-time market, average zonal peak-hour LMPs decreased by 29–37%, and off-peak LMPs decreased by 24–32%. Overall, the all-hour load-weighted average real-time LMPs in PJM decreased from about $53/MWh in 2014 to about $36/MWh in 2015. In 2015, the APS zone had the highest load-weighted average energy price, primarily due to transmission congestion. Also, as a smaller effect, compared to other Company zones, APS loads tended to be relatively more coincident with higher-priced hours (thereby the higher-priced hours are weighted more).

In the PJM capacity market, continued price separation resulted in higher capacity prices in the Mid-Atlantic Area Council ("MAAC") Locational Deliverability Area ("LDA"), which includes Penelec and Met-Ed, than in the rest of the system, which includes APS. The ATSI zone, which includes Penn Power, experienced significant price separation from the rest of the RTO in the last part of the year due to transmission constraints in the capacity market. Capacity charges in the Company zones contributed about \$6–14/MWh to wholesale costs in 2014 and about \$8–14/MWh in 2015. Under PJM's centralized capacity market, the Reliability Pricing Model ("RPM"), the two Base Residual Auctions ("BRA") held for the 2014/15 and 2015/16 capacity delivery years cleared at capacity prices of \$136.50/MW-day and \$167.46/MW-day, respectively, in MAAC; \$125.99/MW-day and \$357.00/MW-day, respectively, in the ATSI zone; and \$125.99/MW-day and \$136.00/MW-day, respectively, in the rest of the system. Four other capacity auctions were held in 2015, including the Base Residual Auction for the 2018/19 delivery year, and three incremental auctions for prior delivery years. Compared to the prior auction the 2018/19 BRA resulted in similar, but slightly higher, prices for future supply in MAAC (\$149.98/MW-day), and continued price convergence between MAAC and the unconstrained RTO. PJM attributed these results to a combination of demand-side and supply-side effects, including a rightward-shift in the capacity market's demand curve, and lower net energy market revenues that resulted in higher capacity market offers.

Transmission service charges did not change significantly in the Company zones relative to 2014 except in the Penn Power zone where it increased materially, but still remained below the PJM average. Contribution to total wholesale cost in 2015 was \$2.49–6.73/MWh in the Company zones.

PJM operates competitive markets for four ancillary services: regulation (frequency control), synchronized reserves, non-synchronized reserves, and day-ahead scheduling reserves. Prices in these markets were generally lower in 2015 than in 2014, reflecting lower demand and lower fuel costs, and contributions to total wholesale cost remained below \$1/MWh for all products combined. Black start service is procured by PJM on a non-market basis in order to ensure reliable restoration following a blackout. In 2015, charges for black start service remained about the same as in 2014 for the Company zones, contributing \$0.01–0.05/MWh to the total wholesale costs. Reactive power (voltage control) is also procured by PJM on a non-market basis. In 2015, charges for reactive power mostly decreased relative to 2014, contributing \$0.29–0.50/MWh to total wholesale costs in the Company zones.

According to the assessment of PJM's Independent Market Monitor, the PJM wholesale market continued to operate in a competitive manner during 2015; and all markets yielded competitive outcomes despite some concerns with market structure, participant behavior, and market design.

I. Introduction

I.A. PURPOSE

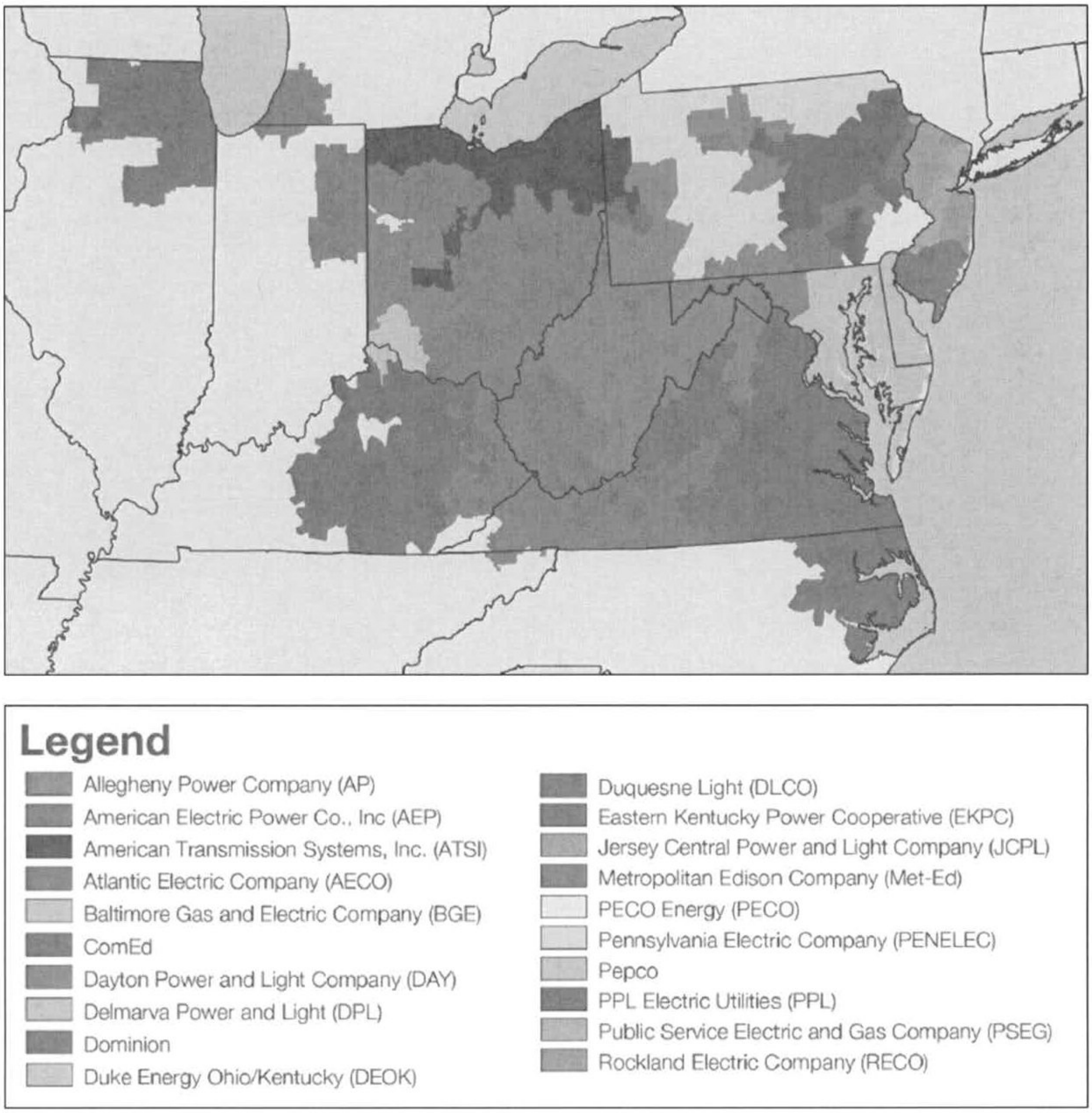
This is the fifth annual report prepared by The Brattle Group on behalf of the Companies to comply with the Companies' commitment under the settlement agreement approved by the PA PUC in the proceeding at Docket Nos. A-2010-2176520 and A-2010-2176732. The report summarizes market outcomes and trends for the calendar year 2015 in the Pennsylvania portion of the PJM marketplace 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. THE PJM MARKET

PJM operates a wholesale market for energy, capacity, and ancillary services that covers all or parts of thirteen states and the District of Columbia. The PJM footprint remained unchanged from 2014 to 2015 with 20 load zones, eight of which are fully or partially located within Pennsylvania. The Companies operate in four Pennsylvania zones of PJM: the Met-Ed Zone, the Penelec Zone, the APS Zone, and the Penn Power portion of the ATSI Zone.[1] The Met-Ed and Penelec zones were part of the PJM market when it was designated an RTO by the FERC in 2001. The APS and ATSI zones were integrated into PJM in 2002 and 2011, respectively. The locations for each of the twenty load zones within the PJM footprint are shown in Figure 1.

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

Figure 1[2]
PJM's Footprint in 2015



[2] (Monitoring Analytics, LLC 2015), Section 1: Introduction, Figure 1-1.

II. Wholesale Power Costs

II.A. Wholesale Power Costs 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) Day-Ahead Scheduling Reserve; (12) black start; (13) North American Electric Reliability Corporation/ReliabilityFirst Corporation ("NERC/RFC") charges; (14) RTO Startup and Expansion; (15) economic load response; (16) transmission facility charges; (17) non-synchronized reserves; (18) capacity to meet a Fixed Resource Requirement ("FRR"); (19) emergency energy; and (20) emergency load response. Capacity (FRR), emergency energy, and emergency load were new line items reported by the market monitor for the 2013 market year and continue to represent a minor component of the total wholesale cost of electricity. Table 1 summarizes the magnitude of each component of the wholesale cost for PJM and the Companies' zones in 2015.

Table 1
Wholesale Costs of Electricity in 2015[3,4,5,6]
($/MWh)

	PJM	Penelec	Met-Ed	APS	Penn Power
Real-Time Load Wtd. LMP (Energy)	$36.16	$36.17	$35.80	$38.13	$33.54
Marginal Congestion Cost	*$0.04*	*-$0.28*	*-$1.07*	*$1.45*	*-$2.43*
Marginal Transmission Losses	*$0.02*	*$0.64*	*$0.67*	*$0.17*	*-$0.37*
Capacity	$11.12	$8.48	$9.85	$8.04	$13.84
Transmission Service Charges	$7.08	$2.49	$2.49	$2.60	$6.73
Operating Reserves (Uplift)	$0.38	$0.52	$0.35	$0.45	$0.29
Reactive	$0.37	$0.44	$0.50	$0.34	$0.29
PJM Administrative Fees	$0.44	$0.44	$0.44	$0.44	$0.44
Regulation	$0.23	$0.23	$0.23	$0.23	$0.23
Transmission Enhancement Cost Recovery	$0.51	$1.12	$0.83	$1.49	$0.87
Synchronized Reserves	$0.12	$0.16	$0.16	$0.09	$0.09
Transmission Owner (Schedule 1A)	$0.09	$0.08	$0.08	$0.00	$0.03
Day Ahead Scheduling Reserve (DASR)	$0.10	$0.10	$0.10	$0.10	$0.10
Black Start	$0.06	$0.03	$0.05	$0.01	$0.04
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
Economic Load Response	$0.02	$0.02	$0.02	$0.02	$0.02
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves	$0.02	$0.03	$0.03	$0.00	$0.00
Capacity (FRR)	$0.13	N/A	N/A	N/A	N/A
Emergency Energy	$0.00	$0.00	$0.00	$0.00	$0.00
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$56.86	$50.33	$50.95	$51.95	$56.54

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, Day-Ahead Scheduling Reserve, 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, reflecting the marginal cost of delivering that energy to a given location within the PJM system.

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 and non-synchronized reserve costs for the Mid-Atlantic Dominion (MAD) subzone is shown. However, portions of these zones are located outside of the MAD subzone, and, consequently, consumers located in those areas incur lower reserve costs. Note that in prior reports we assigned MAD subzone prices to APS, which is also partially located in the MAD subzone.

5 The Market Monitor calculates Transmission Enhancement Cost Recovery charges based on settlement data unavailable to Brattle. The calculated values for utility subzones thus reflect the total charges for those zones and not just the amount billed by PJM.

6 (Monitoring Analytics, LLC 2016) and Brattle analysis.

Energy and capacity costs make up the vast majority of the total wholesale cost. On average for the Companies' zones, the largest two components make up approximately 88% of the total wholesale cost in 2015. Energy costs represent the largest single component for the Companies' zones, at an average of 69% of their total wholesale price.[7] As shown in Table 1, energy costs vary by load zone, reflecting the regional variation in LMPs. Energy costs were higher than the PJM average in the APS zone, and lower than the PJM average in the Met-Ed and Penn Power zones, reflecting the fact that the APS South interface was transmission constrained, while Penn Power and Met-Ed lay in less congested areas. Further discussion of energy costs can be found in Section II.B.

Similar to energy prices, capacity prices may vary by location, although price separation is less common in comparison to the energy market. For 2015, however, wholesale capacity costs in Penn Power are the highest among the Companies' zones, mostly due to relatively high capacity prices in the ATSI zone in the latter part of the year. Similar to 2013 and 2014, the auctions determining capacity prices for the calendar year 2015 experienced price separation in the Locational Deliverability Areas that contain the Companies' zones Penelec and Met-Ed. As such, the Companies' zonal average capacity costs tend to be higher than the PJM average. In contrast, capacity auctions held for 2011 had seen no such price separation, and zonal average capacity costs did not differ greatly from the PJM average.

Non-market-based transmission service charges are the third-largest component of wholesale costs. These charges represent payments to transmission owners for providing network integration, and both firm and non-firm point-to-point transmission service.

Figure 2 shows the breakdown of wholesale costs in 2015, by component, for each load zone.

[7] Energy costs are the real-time load-weighted average PJM LMPs, made up of two transmission costs (marginal transmission losses and transmission congestion) and one generation cost (marginal energy).

Figure 2
Wholesale Costs of Electricity in 2015[8]
(% of Total, by Component)

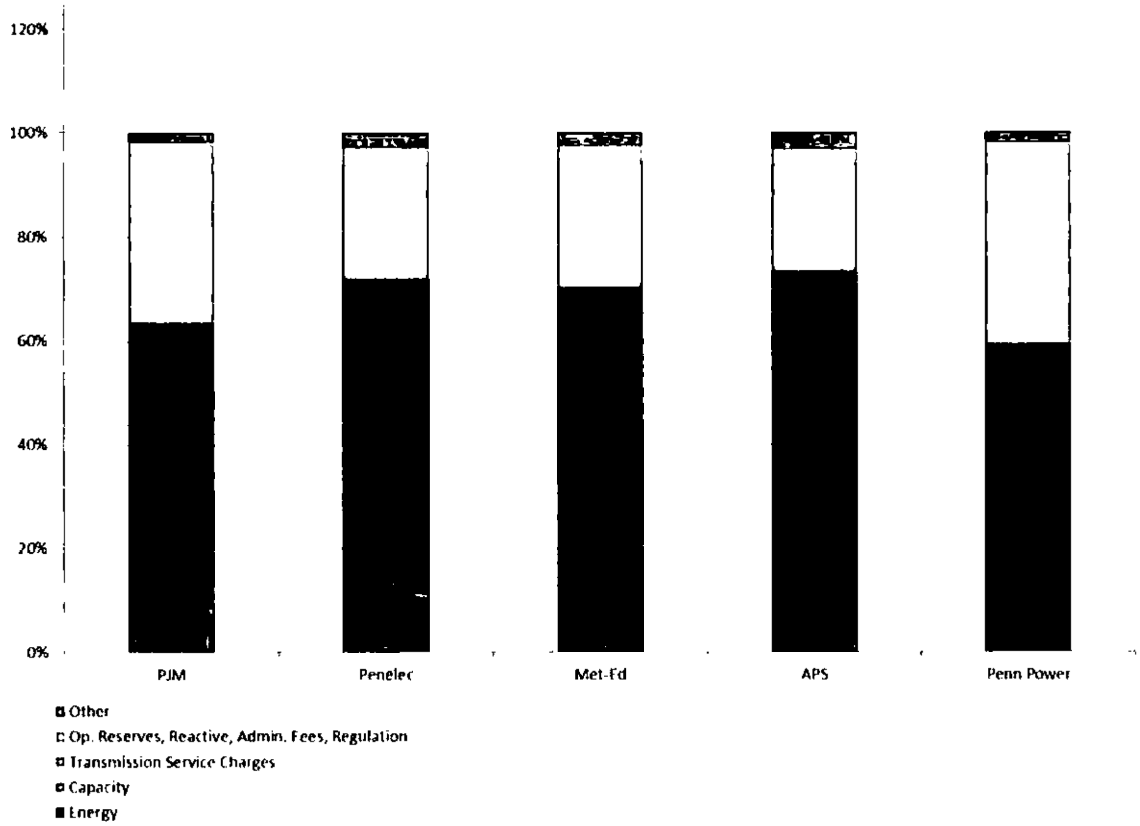


Table 2 shows the total wholesale cost of electricity by component for the prior calendar years 2013 and 2014. Table 3 shows the percentage change in wholesale cost components from 2013 to 2015 and from 2014 to 2015. Between 2014 and 2015, the total cost of wholesale power decreased by approximately 21%. Met-Ed and Penelec experienced larger decreases in total cost at 33% and 28%, respectively, compared to 2014, while Penn Power saw a smaller decrease in cost at 6%. The decrease in prices was the result of both lower demand and fuel prices. If fuel costs in 2015 had been the same as 2014, the load-weighted LMP would still have been 21% lower in 2015, reflecting lower demand.[9] Capacity costs in the APS and Penn Power zones increased the most when compared to capacity costs in 2013 and 2014, due to higher prices in

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8 As shown above in Table 1, marginal transmission congestion costs and marginal transmission losses are a component of total cost of energy (LMP). In congested areas, such as APS, transmission congestion costs are approximately 4% of the LMP. In less congested areas, such as Penn Power, there is a transmission congestion *credit* of approximately 7%. Similarly, marginal transmission losses range from a *cost* of about 2% of the LMP to a *credit* of approximately 1% of the LMP.

9 (Monitoring Analytics, LLC 2016).

the "unconstrained RTO" and a spike in ATSI prices, respectively. In 2014 Penn Power had the lowest wholesale cost of power of the four zones, which was reversed in 2015 due to a significant capacity cost increase. Further discussion on capacity prices can be found in Section II.C.

Table 2
Wholesale Costs of Electricity in 2013 and 2014[10,11]
($/MWh)

	2013					2014				
	PJM	Penelec	Met-Ed	APS	Penn Power	PJM	Penelec	Met-Ed	APS	Penn Power
Real-Time Load Wtd. LMP (Energy)	$38.66	$38.71	$39.72	$37.70	$41.03	$53.14	$51.94	$56.09	$53.11	$46.74
Congestion	*$0.01*	*-$0.10*	*$0.34*	*-$0.57*	*$2.86*	*-$0.02*	*-$1.32*	*$1.56*	*-$1.03*	*-$6.02*
Loss	*$0.02*	*$0.63*	*$0.75*	*-$0.11*	*-$0.20*	*$0.02*	*$0.50*	*$1.12*	*$0.08*	*-$1.06*
Capacity	$7.13	$12.53	$14.67	$1.68	$1.88	$9.01	$11.50	$13.64	$6.24	$6.65
Transmission Service Charges	$5.20	$2.49	$2.49	$2.70	$2.99	$5.95	$2.50	$2.50	$2.58	$3.38
Operating Reserves (Uplift)	$0.59	$0.86	$0.86	$0.53	$0.53	$1.18	$1.32	$1.16	$1.30	$0.91
Reactive	$0.80	$2.32	$0.72	$0.67	$1.12	$0.40	$0.54	$0.49	$0.38	$0.39
PJM Administrative Fees	$0.43	$0.43	$0.43	$0.43	$0.43	$0.44	$0.44	$0.44	$0.44	$0.44
Regulation	$0.24	$0.24	$0.24	$0.24	$0.24	$0.33	$0.33	$0.33	$0.33	$0.33
Transmission Enhancement Cost Recovery	$0.39	$0.56	$0.63	$0.64	$0.57	$0.42	$0.80	$0.78	$0.93	$0.70
Synchronized Reserves	$0.04	$0.06	$0.06	$0.06	$0.02	$0.21	$0.31	$0.31	$0.11	$0.11
Transmission Owner (Schedule 1A)	$0.08	$0.08	$0.08	-	$0.03	$0.09	$0.08	$0.08	$0.00	$0.03
Day Ahead Scheduling Reserve (DASR)	$0.06	$0.06	$0.06	$0.06	$0.06	$0.05	$0.05	$0.05	$0.05	$0.05
Black Start	$0.14	$0.03	$0.05	$0.01	$0.00	$0.08	$0.03	$0.06	$0.01	$0.02
NERC/RFC	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.01	N/A	N/A	N/A	N/A	$0.01	N/A	N/A	N/A	N/A
Load Response	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Economic Load Response	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.02	$0.01	$0.01
Capacity (FRR)	$0.11	N/A	N/A	N/A	N/A	$0.20	N/A	N/A	N/A	N/A
Emergency Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
Emergency Load Response	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Total	$53.97	$58.45	$60.10	$44.81	$48.99	$71.64	$69.98	$76.06	$65.60	$59.88

From 2013 to 2015 the total price of wholesale power increased by an average of approximately 5% for PJM as a whole. APS and Penn Power saw larger increases of 16% and 15% respectively while Penelec and Met-Ed saw 14% and 15% decreases, respectively. Several other components of total wholesale costs increased over the two years. For example, Transmission Enhancement Cost Recovery and Day Ahead Scheduling Reserve increased 31% and 67% respectively, although combined they still only make up 1% of the total wholesale cost of power.

10 (Monitoring Analytics, LLC 2015), (Monitoring Analytics, LLC 2014).

11 Subzone values for the reactive and transmission enhancement cost recovery have been corrected or revised from prior reports.

Table 3
Percent Change in Wholesale Cost Components[12,13]

	% Change (2015 vs. 2013)					% Change (2015 vs. 2014)				
	PJM	Penelec	Met-Ed	APS	Penn Power	PJM	Penelec	Met-Ed	APS	Penn Power
Real-Time Load Wtd. LMP (Energy)	-6%	-7%	-10%	1%	-18%	-32%	-30%	-36%	-28%	-28%
Capacity	56%	-32%	-33%	378%	637%	23%	-26%	-28%	29%	108%
Transmission Service Charges	36%	0%	0%	-4%	125%	19%	-1%	-1%	1%	99%
Operating Reserves (Uplift)	-36%					-68%	-61%	-69%	-66%	-68%
Reactive	-54%	-81%	-31%	-49%	-74%	-8%	-20%	2%	-10%	-27%
PJM Administrative Fees	2%	2%	2%	2%	2%	0%	0%	0%	0%	0%
Regulation	-4%	-4%	-4%	-4%	-4%	-30%	-30%	-30%	-30%	-30%
Transmission Enhancement Cost Recovery	31%	98%	31%	134%	54%	21%	39%	6%	61%	24%
Synchronized Reserves	200%	N/A	N/A	N/A	N/A	-43%	-48%	-48%	-24%	-24%
Transmission Owner (Schedule 1A)	13%	0%	0%		10%	0%	0%	0%		25%
Day Ahead Scheduling Reserve (DASR)	67%	67%	67%	67%	67%	100%	100%	100%	100%	100%
Black Start	-57%					-25%	5%	-22%	-4%	147%
NERC/RFC	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
RTO Startup and Expansion	0%					0%				
Load Response	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Economic Load Response	100%	100%	100%	100%	100%	0%	0%	0%	0%	0%
Transmission Facility Charges	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Synchronized Reserves						0%	59%	59%	-65%	-65%
Capacity (FRR)	18%	N/A	N/A	N/A	N/A	-35%	N/A	N/A	N/A	N/A
Emergency Energy						-100%	-100%	-100%	-100%	-100%
Emergency Load Response	-100%	-100%	-100%	-100%	-100%	-100%	-100%	-100%	-100%	-100%
Total	5%	-14%	-15%	16%	15%	-21%	-28%	-33%	-21%	-6%

II.B. Wholesale Energy Prices

The LMP at any pricing node within the PJM system is comprised of three cost components: marginal energy, marginal transmission losses, 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.

There were no shortage pricing events due to scarcity in 2015.[14]

Table 4 and Table 5 summarize the zonal day-ahead and real-time simple average LMPs and their components for the calendar years 2013 through 2015. The difference between average real-time

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12 (Monitoring Analytics, LLC 2016), (Monitoring Analytics, LLC 2015), (Monitoring Analytics, LLC 2014), and Brattle analysis.

13 Changes from 2013 to 2015 for operating reserves, synchronized reserves, black start, and non-synchronized reserves are not shown due to changes in methodology for calculating these line items in this report.

14 (Monitoring Analytics, LLC 2016).

and day-ahead LMPs is small, typically under $1.00 per MWh. As in the case of overall wholesale cost of power, we observe similar trends in the LMPs over time with energy prices increasing between 2013 and 2014 but decreasing between 2014 and 2015. Between 2014 and 2015, the Companies' zones experienced a 26.8% (APS) to 36.7% (Met-Ed) decrease in day-ahead prices, and a 26.8% (Penn Power) to 35.1% (Met-Ed) decrease in real-time prices. In 2015, APS had the highest simple average LMP, primarily due to transmission congestion.

Table 4
Zonal Day-Ahead, Simple Average LMP Components
Calendar Years 2013–2015[15]
($/MWh)

	2013				2014				2015			
Zone	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss
APS	36.74	37.04	-0.12	-0.18	47.83	48.95	-0.85	-0.27	35.02	33.95	1.10	-0.03
Penn Power	35.59	37.04	-1.06	-0.38	43.96	48.95	-4.32	-0.67	31.58	33.95	-2.00	-0.36
Met-Ed	38.27	37.04	0.69	0.55	52.07	48.95	2.67	0.45	32.94	33.95	-1.13	0.12
Penelec	38.13	37.04	0.35	0.75	49.22	48.95	-0.15	0.42	33.65	33.95	-0.62	0.33

Table 5
Zonal Real-Time, Simple Average LMP Components
Calendar Years 2013–2015[16]
($/MWh)

	2013				2014				2015			
Zone	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss
APS	36.00	36.52	-0.40	-0.11	47.60	48.21	-0.61	0.00	34.79	33.34	1.29	0.15
Penn Power	37.27	36.52	1.53	-0.78	42.71	48.21	-4.53	-0.97	31.28	33.34	-1.79	-0.27
Met-Ed	37.41	36.52	0.23	0.66	49.60	48.21	0.54	0.86	32.17	33.34	-1.69	0.52
Penelec	37.01	36.52	-0.09	0.58	47.63	48.21	-0.99	0.41	33.47	33.34	-0.44	0.57

Table 6 and Table 7 summarize the zonal day-ahead and real-time, load-weighted average LMPs by component for the calendar years 2013 through 2015. 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 as well as across load zones.

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15 Simple annual averages of LMP data compiled by Ventyx, Inc., the Velocity Suite.

16 Simple annual averages of LMP data compiled by Ventyx, Inc., the Velocity Suite.

Table 6
Zonal Day-Ahead, Load-Weighted Average LMP Components
Calendar Years 2013–2015[17,18]
($/MWh)

	2013				2014				2015			
Zone	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss
APS	38.23	38.62	-0.21	-0.18	52.89	54.55	-1.41	-0.25	38.07	36.96	1.16	-0.05
ATSI	38.13	38.69	-0.85	0.29	49.57	52.72	-3.63	0.47	34.46	36.18	-2.04	0.31
Met-Ed	40.04	38.62	0.83	0.59	58.52	53.87	4.00	0.65	36.33	36.61	-0.49	0.20
Penelec	39.29	38.14	0.38	0.77	53.60	53.40	-0.32	0.51	36.18	36.35	-0.54	0.37

Table 7
Zonal Real-Time, Load-Weighted Average LMP Components
Calendar Years 2013–2015[19]
($/MWh)

	2013				2014				2015			
Zone	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss
APS	37.70	38.39	-0.57	-0.11	53.11	54.07	-1.03	0.08	38.13	36.52	1.45	0.17
ATSI	42.12	38.43	3.27	0.42	48.65	52.12	-4.04	0.57	34.03	35.64	-1.90	0.29
Met-Ed	39.72	38.63	0.34	0.75	56.09	53.42	1.56	1.12	35.80	36.20	-1.07	0.67
Penelec	38.71	38.18	-0.10	0.63	51.94	52.76	-1.32	0.50	36.17	35.82	-0.28	0.64

Table 8 contains the zonal peak and off-peak simple average LMPs for the day-ahead and real-time energy markets in 2015. In the day-ahead market, average zonal peak and off-peak LMPs decreased by 29% and 25% respectively from 2014 to 2015. Average real-time, peak-hour LMPs decreased by 33%, and off-peak LMPs decreased by 27%. Of the Companies' zones, APS Zone shows the only positive transmission congestion cost component for both the day-ahead and real-time markets.

17 2013 values: (Monitoring Analytics, LLC 2014), Section 11: Congestion and Marginal Losses, p. 325.

2014 and 2015 values: Load-weighted annual averages of LMP data compiled by Ventyx, Inc., the Velocity Suite.

18 Due to a lack of more granular data in the market monitor reports, and for consistency in how we report zones, values for ATSI are used in Table 6 and Table 7 as opposed to Penn Power.

19 2013 values: (Monitoring Analytics, LLC 2014), Section 11: Congestion and Marginal Losses, p. 325.

2014 and 2015 values: Load-weighted annual averages of LMP data compiled by Ventyx, Inc., the Velocity Suite.

Table 8
Zonal On- and Off-Peak Average Day-Ahead and Real-Time LMPs in 2015
($/MWh)

2015 Day-Ahead Simple Average								
Zone	LMP		Energy		Congestion		Loss	
	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
APS	41.76	29.09	40.71	28.00	1.13	1.08	-0.08	0.00
Penn Power	37.80	26.12	40.71	28.00	-2.44	-1.62	-0.47	-0.27
Met-Ed	40.19	26.57	40.71	28.00	-0.79	-1.42	0.27	-0.01
Penelec	40.74	27.42	40.71	28.00	-0.40	-0.82	0.43	0.23
PJM RTO	42.79	29.31	40.71	28.00	1.92	1.23	0.16	0.07

2015 Real-Time Simple Average								
Zone	LMP		Energy		Congestion		Loss	
	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
APS	40.93	29.39	39.38	28.03	1.40	1.19	0.14	0.17
Penn Power	36.93	26.32	39.38	28.03	-2.12	-1.51	-0.33	-0.21
Met-Ed	38.44	26.67	39.38	28.03	-1.70	-1.68	0.75	0.32
Penelec	39.96	27.77	39.38	28.03	-0.20	-0.65	0.78	0.38
PJM RTO	39.44	28.08	39.38	28.03	0.04	0.03	0.02	0.02

As reflected in the transmission congestion component of LMPs, transmission congestion may arise in both the day-ahead and the real-time (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 a 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 may be summed up by zone to yield a net transmission congestion cost.[20] The net transmission congestion cost for a given zone, or the RTO, may be positive or negative. The sign of the net 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 is a reflection of the relative magnitude of transmission congestion costs and credits paid and received by all market participants located within the zone.

Total net transmission congestion costs for PJM are summarized in Table 9. Overall, total congestion costs decreased by $546.9 million (28.3%) from $1.932 billion in 2014 to $1.385 billion in 2015. Similarly, annual day-ahead congestion costs decreased by over $599 million,

[20] 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.

decreasing 26.9% from 2014. The decreasing congestions costs in 2015 reversed a pattern of increasing transmission congestion costs seen from 2013 to 2014.

Table 9
Transmission Congestion Costs from 2013 to 2015[21,22]
(Million $)

Total Congestion Costs in 2015

	Day-Ahead Market				Balancing Market				
Control Zone	**Load Payments**	**Generation Credits**	**Explicit**	**Total**	**Load Payments**	**Generation Credits**	**Explicit**	**Total**	**Grand Total**
APS	$60.4	-$41.8	-$1.8	$100.4	$1.6	-$0.1	-$8.4	-$6.8	$93.7
ATSI	-$154.5	-$170.6	-$0.6	$15.4	$0.9	$12.6	-$1.6	-$13.3	$2.1
Met-Ed	-$11.0	-$41.1	-$2.7	$27.4	$3.5	$3.4	$0.9	$1.0	$28.4
Penelec	-$63.8	-$141.2	$0.4	$77.8	$0.4	$11.5	-$2.3	-$13.4	$64.4
PJM Total	$614.2	-$967.6	$50.3	$1,632.1	$0.6	$69.8	-$177.6	-$246.9	$1,385.3

Total Congestion Costs in 2014

	Day-Ahead Market				Balancing Market				
Control Zone	**Load Payments**	**Generation Credits**	**Explicit**	**Total**	**Load Payments**	**Generation Credits**	**Explicit**	**Total**	**Grand Total**
APS	-$71.9	-$298.2	-$17.1	$209.2	$10.0	$24.6	-$5.1	-$19.7	$189.5
ATSI	-$270.6	-$305.2	-$7.3	$27.3	$3.5	$28.7	-$11.5	-$36.8	-$9.4
Met-Ed	$65.0	$58.0	-$2.8	$4.1	$3.5	$7.7	$1.9	-$2.4	$1.7
Penelec	-$95.0	-$246.5	-$5.1	$146.4	-$5.5	$22.9	-$4.2	-$32.6	$113.8
PJM Total	$595.5	-$1,671.2	-$35.4	$2,231.3	$52.7	$218.1	-$133.6	-$299.1	$1,932.2

Total Congestion Costs in 2013

	Day-Ahead Market				Balancing Market				
Control Zone	**Load Payments**	**Generation Credits**	**Explicit**	**Total**	**Load Payments**	**Generation Credits**	**Explicit**	**Total**	**Grand Total**
APS	-$9.7	-$109.6	$4.8	$104.7	$3.5	$8.6	-$6.7	-$11.9	$92.8
ATSI	-$62.6	-$71.6	$8.8	$17.8	$14.4	$15.8	-$38.4	-$39.7	-$21.9
Met-Ed	$41.4	$17.2	$2.4	$26.6	$0.3	$2.0	-$3.8	-$5.5	$21.1
Penelec	-$2.2	-$47.0	$5.7	$50.6	-$1.3	$3.6	-$5.4	-$10.3	$40.3
PJM Total	$281.2	-$592.5	$137.6	$1,011.3	$5.9	$131.3	-$209.0	-$334.4	$676.9

Net transmission congestion costs can be attributed to individual transmission facilities that constrain the most economic dispatch. For 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 Conastone-Northwest line, which has the highest transmission congestion impact in PJM, contributed 7.9% (approximately $108.8 million)[23] to 2015 net PJM

21 (Monitoring Analytics, LLC 2016), (Monitoring Analytics, LLC 2015), (Monitoring Analytics, LLC 2014).

22 For more information on transmission congestion costs by zone, please see Appendix A.

23 (Monitoring Analytics, LLC 2016), Section 11: Congestion and Marginal Losses, Table 11-24.

transmission congestion cost, and it is one of the top constraints for the Met-Ed, Penelec, and APS zones.[24] The AP South interface, usually responsible for price separation between the eastern and western parts of PJM, had the highest transmission congestion impact in 2014 ($486.8 million)[25] but contributed only $56.2 million (4.1%) to the total congestion costs in 2015.[26] Other major interfaces are also among the largest contributors to zonal transmission congestion in 2015.

II.C. WHOLESALE CAPACITY PRICES

PJM operates the RPM capacity market that consists of a three-year forward Base Residual Auction and up to three incremental auctions[27] for each capacity delivery year. Capacity delivery years are defined as June 1 through May 31 of the following calendar year. Consequently, for calendar year 2015, PJM procured capacity in two BRAs: one for the delivery year 2014/15 (BRA held in May 2011), and one for the delivery year 2015/16 (BRA held in May 2012). For the 2014/15 delivery year, 1st, 2nd, and 3rd incremental auctions were held during the months of September 2012, July 2013, and February through March 2014, respectively.[28] For the 2015/16 delivery year, 1st, 2nd, and 3rd incremental auctions were held during the months of September 2013, July 2014, and February 2015, respectively. In 2015 the latest BRA, held in August 2015, was for the 2018/19 delivery year.

Average capacity costs reported in Table 1 are derived from the total procurement costs in all RPM capacity auctions. Capacity prices in RPM auctions are expressed in terms of dollars per MW per day ($/MW-day). Capacity prices may vary by Locational Delivery Area, which are capacity zones that represent potentially capacity-constrained areas of the PJM footprint. Each LDA is defined as a collection of zones and subzones. The composition and geography of LDAs modeled in RPM is illustrated in Figure 3. As shown, the Met-Ed and Penelec zones are part of the MAAC LDA, while APS and Penn Power (part of the ATSI Zone) have been sometimes

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[24] Top transmission constraints in 2015 for the Companies were *Bagley – Graceton Line, 5004/5005 Interface, and the Bedington – Balck Oak Interface.* (Monitoring Analytics, LLC 2016), Appendix G. Top constraints for the RTO in 2015 were the Conastone-Northwest line, the Bagley-Graceton line, 5004/5005 Interface, the Bedington-Black Oak Interface, and the Cherry Valley flowgate. (Monitoring Analytics, LLC 2016), Section 11: Congestion and Marginal Losses, Table 11-24.

[25] (Monitoring Analytics, LLC 2016), Section 11: Congestion and Marginal Losses, Table 11-25.

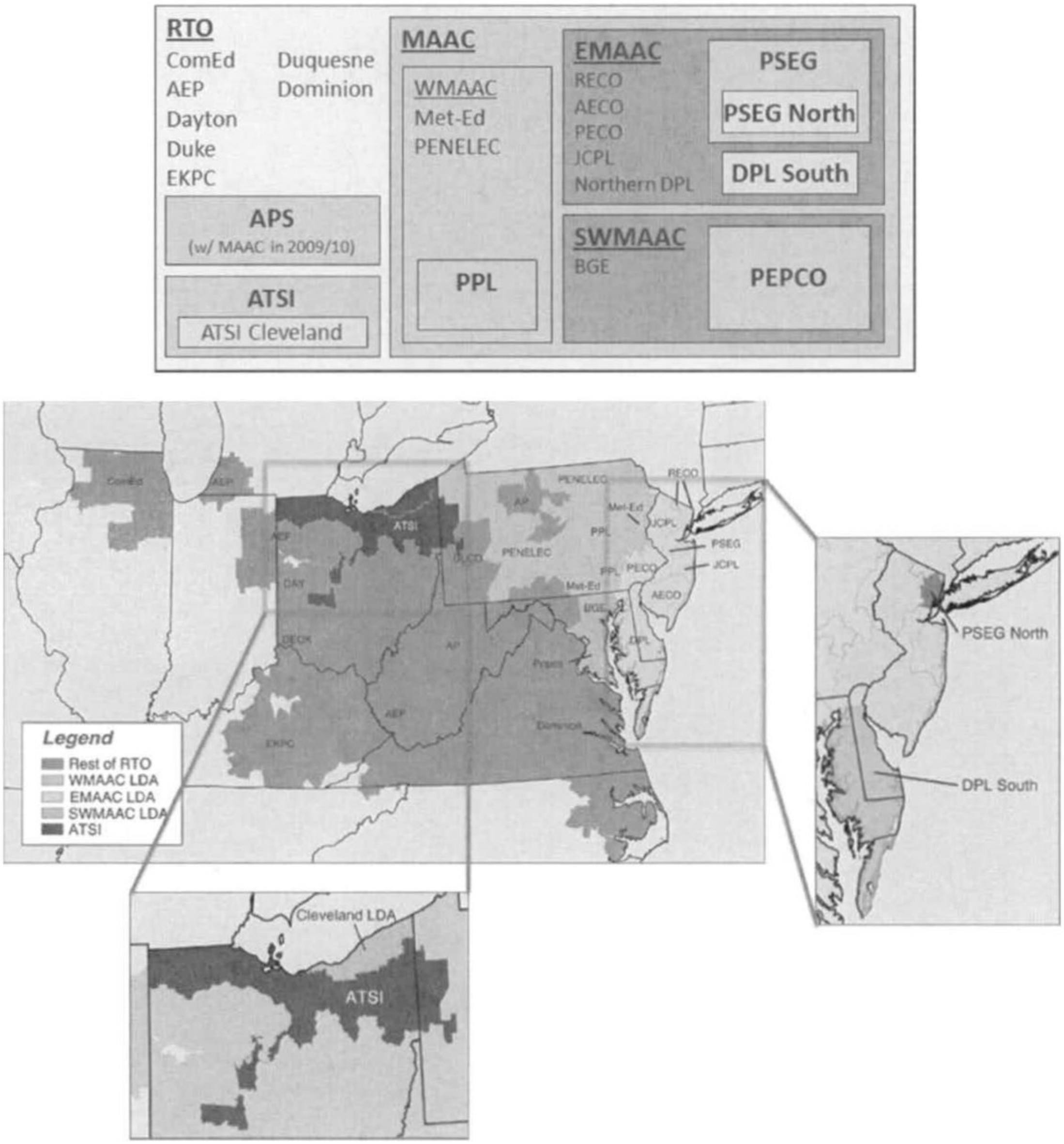
[26] (Monitoring Analytics, LLC 2016), Section 11: Congestion and Marginal Losses, Table 11-24.

[27] Following the BRA, up to three incremental auctions are held for each delivery year – 20 months, 10 months, and 3 months before each delivery year – that can be used by market participants to adjust their commitments and by PJM to procure additional capacity.

[28] Updated information on RPM auctions can be found at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.

constrained areas within the "rest of RTO" (or "unconstrained RTO") areas.[29] In 2010 ATSI fully participated in the BRA for the first time, for the 2013/14 capacity delivery year. In 2015 ATSI was fully integrated in the RPM capacity market.

Figure 3[30]
Locational Deliverability Areas in PJM



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29 Potentially, any load zone could be defined as an LDA. In the 2015/16 BRA held in May 2012, PJM modeled ATSI Zone as a separate LDA.

30 (Monitoring Analytics, LLC 2015), Section 5: Capacity, Figures 5-3, 5-4, 5-5.

Table 10 summarizes RPM market-clearing prices in the Companies' zones for annual capacity resources delivered in the 2015 calendar year. Capacity price separations indicate that MAAC was more capacity-constrained than the rest of the RTO in 2015, and ATSI was severely capacity-constrained in the latter part of the year.

MAAC prices cleared at $136.50/MW-day (versus $125.99/MW-day in RTO) for the 2014/15 delivery year (through May 2015) and at $167.46/MW-day (versus $136.00/MW-day in RTO) for in the 2015/16 delivery year (June through December of 2015). Although ATSI was included in the BRAs starting with the 2013/14 delivery year, 2015/16 was the first delivery year when ATSI was modeled as a separate LDA.[31] 2015/16 BRA prices in ATSI spiked to $357.00/MW-day due to transmission constraints. Price separation between MAAC and the rest of the RTO persisted in all incremental auctions for both delivery years.[32]

Historically, incremental auctions have cleared at prices below BRA clearing prices. This trend continued in the auction for 2014/15 delivery, although MAAC clearing prices in the 3rd incremental auction came very close to BRA clearing prices. For the 2015/16 delivery year the incremental auctions were more constrained, and prices in the 2nd and 3rd incremental auctions cleared at or above the BRA prices. Cleared volumes in incremental auctions are much lower than in the BRAs,[33] and therefore their impact on overall capacity costs is relatively small.

Table 10
Wholesale Capacity Prices in 2015[34]
($/MW-day)

Delivery Year	Locational Delivery Area	Base Residual Auction	1st Incremental Auction	2nd Incremental Auction	3rd Incremental Auction
2014/15	RTO	$125.99	$5.54	$25.00	$25.51
	MAAC	$136.50	$16.56	$56.94	$132.20
	ATSI	$125.99	$5.54	$25.00	$25.51
2015/16	RTO	$136.00	$43.00	$136.00	$163.20
	MAAC	$167.46	$111.00	$153.56	$184.77
	ATSI	$357.00	$168.37	$216.54	$163.20

31 An LDA is modeled in the BRA and has a separate capacity demand (VRR) curve if: (1) its CETL/CETO margin is less than 115%; (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; (3) the LDA is likely to have a locational price adder based on a PJM analysis using historic offer price levels; or (4) the LDA is EMAAC, SWMAAC, and MAAC.

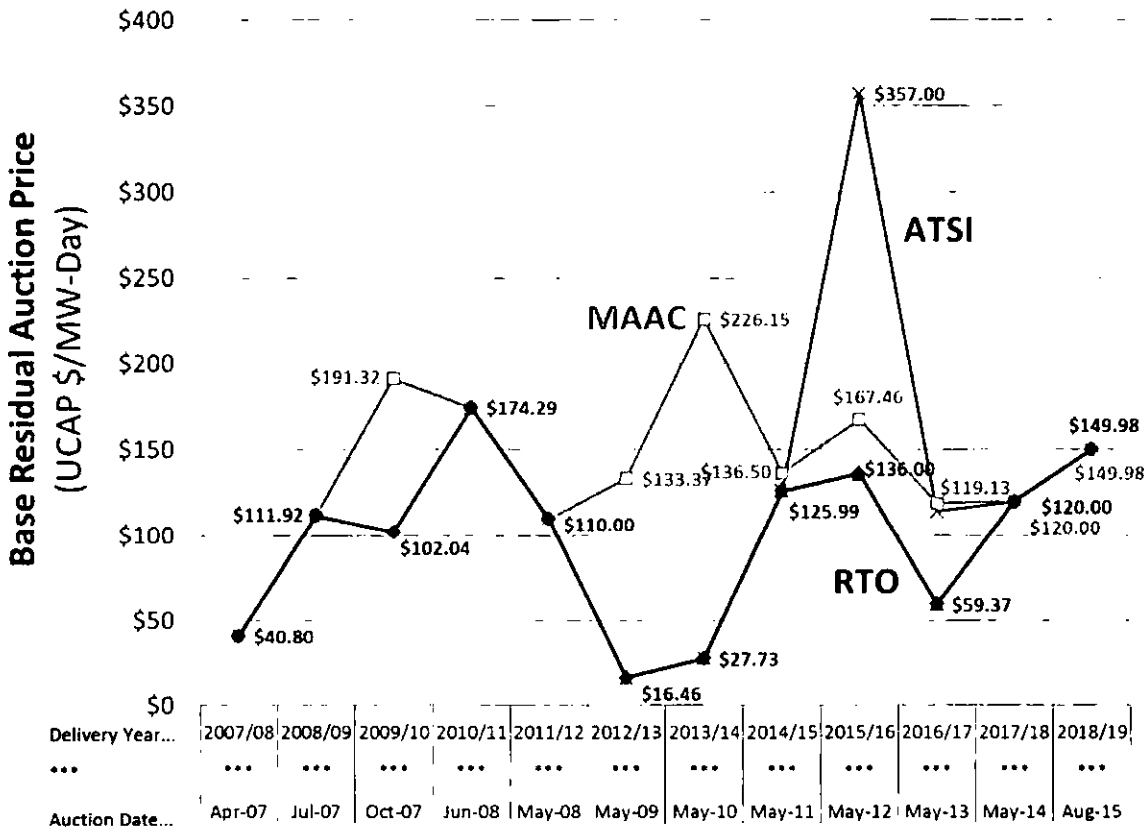
32 For Annual and Extended Summer resources.

33 (PJM 2014d).

34 For Annual or Base Capacity resources.

Figure 4 shows the BRA auction clearing prices for MAAC, ATSI, and the unconstrained part of PJM (rest of the RTO) from the first RPM delivery year 2007/08 through 2018/19. The very high capacity prices in ATSI for 2015/16 delivery were relieved in the 2016/17 BRA due to assumed transmission investments in the latter auction. After 2016/17 prices in ATSI generally follow those in MAAC or in the rest of RTO. Capacity prices in MAAC have fluctuated in and out of price convergence with the unconstrained part of PJM (including APS and unconstrained ATSI) due to varying supply and demand conditions particular to each auction.

Figure 4[35]
Base Residual Auction Clearing Prices in MAAC and Unconstrained RTO Through the 2018/19 Capacity Delivery Year
(UCAP $/MW-Day)



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[35] (Monitoring Analytics, LLC 2016), Section 5: Capacity, Table 5-21. The figure shows capacity prices for Annual and Base capacity resources only.

II.D. Other Wholesale Costs

PJM Transmission Service Charges are not market-based, but instead are based on annual transmission revenue requirements by a transmission owner, or transmission zone. This charge 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 make up about 4–6% of wholesale power cost.

The operating reserve (uplift) component reported in Table 1 is the average price per MWh of some of PJM's out-of-market operating reserve charges. It includes charges for day-ahead operating reserves, balancing (real-time) operating reserves, and synchronous condensers, but excludes other out-of-market charges already included in other LMP components: reactive operating reserve credits (included in the reactive component) and black start operating reserve credits (included in the black start component).[36]

Zone-specific ancillary services charges include charges for regulation, ten-minute synchronized and non-synchronized reserve, Day-Ahead Scheduling Reserve, black start service, and reactive power. Similarly, PJM ensures the adequacy of reactive power by specific revenue requirements by load zone. Regulation, ten-minute synchronized reserve, and ten-minute non-synchronized reserve are cleared and co-optimized with energy in the real-time market. The Day-Ahead Scheduling Reserve market satisfies the supplemental reserve requirement in the day-ahead market, which allows generation resources to receive compensation based upon cleared supply at a market-clearing price. Black start service and reactive power are not market-based charges. PJM ensures the availability of black start reserves by charging transmission customers by load ratio share and compensating black start unit owners according to specific revenue requirements. For a more detailed discussion of PJM ancillary services markets in 2015, see Section IV.

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 wholesale cost of power.

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, while providing forward-looking

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[36] For more information please see (Monitoring Analytics, LLC 2016), Section 4: Energy Uplift.

locational marginal price signals for capacity to market participants. Basic features of RPM include a 3-year forward centralized Base Residual Auction and incremental auctions (discussed above) to procure required reserves, a downward-sloping demand curve for reserves, market design to support locational new entry when needed, and market design to attract a variety of capacity resources.

RPM Demand Curve

The demand for capacity is based on an administratively-determined, downward-sloping demand curve, also called the Variable Resource Requirement ("VRR") curve. The 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. Consequently, the RPM demand curve reflects a *lower* demand for reserves at relatively high capacity prices (i.e., above net CONE), assuming that at these price levels customers would be willing to increase the risk and cost of load interruption events in exchange for lower capacity costs. Conversely, the RPM demand curve reflects a *higher* demand for reserves at relatively low capacity prices (i.e., below net CONE), assuming that at these price levels customers would be willing to increase capacity costs in order to reduce the risk and cost of load interruption events. VRR curves are created for RPM auctions to represent RTO-wide market demand and market demand in each modeled LDA.

RPM Price Signals

The RPM capacity market interacts with and works in tandem with PJM energy markets to provide price and revenue signals to attract new, and retain existing, capacity. RPM signals the need for new capacity by reaching market price levels consistent with Net CONE. 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, in theory, the PJM capacity market interacts with the energy and ancillary services markets. Specifically, whenever net revenues earned in the energy and ancillary services markets rise, the Net CONE will decrease, resulting in lower prices paid through the demand curve for capacity, and vice versa.[37] 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 the

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[37] In the RPM capacity market, the Net Energy and Ancillary Services ("E&AS") revenue offset is based on the historical average of the three most recent calendar years, plus $2,100/MW-year as defined in the PJM tariff. (PJM 2015b), Attachment DD, Section 5.10.a.v.A. Starting with the 2018/19 capacity delivery year, Gross CONE and E&AS values will be evaluated every fourth delivery year. (PJM 2015b), Attachment DD, Section 5.10.a.vi. Unless CONE values are revised for a given delivery year, the prior-year CONE value, escalated using the Applicable United States Bureau of Labor Statistics Composite Index, is used. (PJM 2015b), Attachment DD, Section 5.10.a.iv.B.

capacity auctions. The combined effect in theory is that as the net revenues in the energy and ancillary services market rise, capacity prices will tend to fall.

However, this correlation between energy and capacity prices can be obscured by shifts in market fundamentals, like supply development boom and bust cycles, and would only be realized in the long-run over many years. RPM clearing prices have periodically approached theoretical long-run sustainable levels but are typically well below. RPM clearing prices can also be sensitive to administratively-determined auction parameters and rules. Part of the market monitor's work is to investigate whether RPM prices reflect market fundamentals or the result of administratively-determined parameters and market structure.

RPM Supply Resource Types

The RPM capacity market strives to allow a range of resource types to meet resource adequacy requirements, although there have been some market design challenges in fairly compensating resources that have inherently different operating characteristics. Given the forward nature of the market, both existing and planned resources are allowed to participate. Resources that are available only on a seasonal basis, such as extended summer and limited capacity resources, are also allowed to participate starting with the 2014/15 BRA. Furthermore, in addition to traditional generating capacity, demand resources, energy efficiency, and transmission upgrades may be also offered in the RPM capacity auctions.

Key Changes in RPM in 2015

The basic features of the RPM design, discussed above, remained in place during 2015. In addition, two key changes occurred:

- New market rules for Capacity Performance: In June 2015 FERC approved changes to PJM's capacity market rules that incentivize improved performance and reliability of committed capacity resources during system emergencies.[38] PJM began transitioning to this Capacity Performance framework in subsequent RPM auctions in 2015. PJM held two transition auctions in August and September 2015—for the 2016/17 and 2017/18 capacity delivery years, respectively—to procure a portion of the updated reliability requirements for those years. The 2018/19 Base Residual Auction held in August 2015 was also transitional and it partially incorporated Capacity Performance rules. Capacity Performance will be fully integrated to RPM for the 2020/21 capacity delivery year.
- New demand curve (VRR curve) shape and level: The August 2015 Base Residual Auction incorporated FERC-approved changes to the shape of the VRR curve and key inputs to calculating the curve.[39] The new parameters are expected to enhance the demand curve's ability to meet reliability objectives under a variety

[38] For more information please see (PJM 2014e).

[39] (PJM 2014).

of market conditions. The VRR curve shape was changed from a concave curve to a convex curve that better matches the marginal value of capacity. The administrative Gross Cost of New Entry which helps determine the height of the VRR curve, was lowered to reflect more current actual plan costs.

III.B. Results of PJM Capacity Auctions in 2015

Four RPM auctions were held during the 2015 calendar year:

- BRA for the 2018/19 delivery year (held in August 2015);
- 1st incremental auction for the 2017/18 delivery year (September 2015);
- 2nd incremental auction for the 2016/17 delivery year (July 2015); and
- 3rd incremental auction for the 2015/16 delivery year (February 2015).

As shown previously in Figure 4, the BRA for 2018/19 delivery cleared at a price of $149.98/MW-day uniformly in the Companies' capacity areas, including the WMAAC, APS, and ATSI LDAs.[40] The auction saw some price separation in MAAC, where prices cleared at $75/MW-day in PPL portion of WMAAC, $210.63/MW-day in EMAAC, and $200.21/MW-day in ComEd. Capacity Performance resources cleared prices about $15/MW-day higher in all LDAs. Supply offers for Capacity Performance were likely higher to reflect increased costs of weatherization, improved maintenance, or costs for fuel assurance, which would have put upward pressure on clearing prices.

Compared to the 2017/18 BRA, which cleared mostly uniformly at $120/MW-day, 2018/19 capacity prices for Base Capacity resources (equivalent to Annual resources in 2017/18) cleared almost $30/MW-day higher in the Companies' LDAs. PJM attributed these 2018/19 BRA results to a combination of demand-side and supply-side effects.[41] Factors that contributed to higher prices include a new rightward-shifted VRR curve that resulted in higher clearing prices all else being equal, and lower net energy market revenues that resulted in higher capacity market offers. A decrease in offered imports and an increase in exports may have also contributed to higher prices. These factors were partially offset by a slightly lower target reliability requirement, and a lower administrative Net CONE used to build the VRR curves for the RTO and LDAs.

III.C. Cost of New Entry and Revenue Adequacy

Net revenue is the total wholesale market revenue earned from PJM energy, capacity, and ancillary services markets, including a return on investment, depreciation, and taxes, net of

40 These are resource clearing prices for Base Capacity resources. Corresponding prices for Capacity Performance resources are $164.77/MW-day.

41 (PJM 2014a).

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 avoided by shutting down the plant; if net revenue is consistently less than avoidable fixed costs, the generator is considered to be at risk for retirement based on PJM market design and performance. These potential retirements may be considered premature if the assets yield some value that is not captured in the markets, as has been the discussion in New England and New York with integrating markets and public policy objectives.

PJM's market monitor performs two types of analyses on generator revenue adequacy. The first compares the levelized capital and fixed costs of a hypothetical new generator to an estimate of net revenues that plant *would have* earned in recent historical years. This analysis tests to see if PJM's marketplace has yielded enough net revenues to theoretically support a new entrant in a given year.[42] The second analysis compares the avoidable fixed costs of existing generators on the system to actual net revenues. This analysis is also a screen, to see if PJM's marketplace yields enough net revenues to retain existing generation that is already built and, if not, what types of generators are most at-risk for retirement.[43,44]

Plant Types for Hypothetical New Entry Analysis

Net revenues vary from year to year depending on market outcomes, and also by generating technology type. PJM's market monitor has traditionally performed annual assessments of zonal revenue adequacy of hypothetical new entrant plants for three reference technologies: (1) gas-fired combustion turbines, (2) combined cycle gas plants, and (3) coal plants.[45] Starting with the 2012 State of the Market Report, the market monitor began reporting results of its net revenue analysis for other generation technologies, including new entrant integrated gasification combined cycle (IGCC) in the Dominion zone (discontinued in the 2014 report), new entrant nuclear plant in the AEP zone (all zones starting with the 2014 report), new entrant solar installation in the PSEG zone, and new entrant wind in the ComEd and Penelec zones. Starting with the 2013 and State of the Market Report, the market monitor also reports results for new entrant diesel plant for all zones. Net revenues are calculated using a hypothetical dispatch against historical day-ahead and real-time energy prices for each calendar year.

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42 However, this analysis does not necessarily indicate whether new entry will occur, since investors would need an attractive going-forward (not historical) view on net revenues.

43 Unavoidable fixed costs that would be incurred regardless of plant operating status (for an already-built existing plant) are not part of this revenue adequacy analysis.

44 Again, this analysis is limited in that it does not provide a going-forward view on net revenues, which would be important when considering plant retirement. The analysis does not necessarily indicate which units will retire.

45 (Monitoring Analytics, LLC 2016), Section 7: Net Revenue.

Results from Hypothetical New Entry Analysis

Table 11 summarizes net revenues for the Companies' zones and for PJM as a whole for the calendar years 2013 through 2015.[46] The adequacy of net revenues to incent investment in new generation is assessed by comparing net revenue estimates to the levelized fixed costs of each plant type.[47] Net revenues as a percentage of these levelized fixed costs are shown in the rightmost three columns of Table 11. These levelized fixed cost estimates reflect mostly favorable economics for new entrant combustion turbines, combined cycle plants, and wind plants, although the revenue of wind plants reflect support by both state and federal subsidies in the Penelec zone, as reported in the bottom panel of Table 11.[48] According to this analysis, new entrant coal plants, diesel plants, and nuclear plants would not have made enough in market revenues in 2013, 2014, or 2015 to cover their levelized capital and fixed costs.[49] In 2015 economics for new entrant combustion turbines and combustion turbines are most favorable in Penelec, due to relatively high energy market revenues calculated for that zone. In 2015, the revenue adequacy of all types of plants in all of the Companies' PJM zones, and in PJM on average, *decreased* compared to 2014, mostly due to lower energy market revenues across the board.

[46] The market monitor did not report net revenue estimates for the ATSI Zone for years prior to 2014.

[47] In 2015, PJM's market monitor assumed a twenty-year levelized fixed cost of $112/kW-year for combustion turbines; $146/kW-year for combined cycle plants; $517/kW-year for coal plants, $171/kW-year for diesel plants; $936/kW-year for nuclear plants, $203/kW-year for wind installations, and $234/kW-year for solar installations. (Monitoring Analytics, LLC 2016), Section 7: Net Revenue, Table 7-4.

[48] The net energy revenues for wind in Penelec shown in Table 11 include a $23/MWh federal Production Tax Credit, a $1/MWh Investment Tax Credit, and $14.80/MWh from Renewable Energy Certificates. (Monitoring Analytics, LLC 2016), Section 7: Net Revenue, Page 265.

[49] As shown in shown in Table 11, the PJM average total net revenues in 2015 covered only 22% of the levelized fixed costs of a new entrant coal plant, 40% of the levelized fixed costs of a new entrant diesel plant, and 30% of a new entrant nuclear plant.

Table 11[50]
Net Revenues Estimates for New Entrants

New Entrant Combustion Turbine	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2013	2014	2015	2013	2014	2015
APS	$36,211	$109,699	$107,173	33%	101%	96%
ATSI	N/A	$98,838	$136,200	N/A	91%	122%
Met-Ed	$99,855	$118,388	$103,824	91%	109%	93%
PENELEC	$110,828	$184,642	$169,691	101%	170%	152%
PJM avg.	$79,006	$116,216	$107,173	72%	107%	96%

New Entrant Combined Cycle	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2013	2014	2015	2013	2014	2015
APS	$75,327	$152,301	$146,300	50%	104%	100%
ATSI	N/A	$140,585	$174,097	N/A	96%	119%
Met-Ed	$134,082	$177,196	$140,448	89%	121%	96%
PENELEC	$159,693	$251,882	$207,746	106%	172%	142%
PJM avg.	$114,497	$166,945	$144,837	76%	114%	99%

New Entrant Coal Plant	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2013	2014	2015	2013	2014	2015
APS	$83,511	$186,499	$103,403	17%	37%	20%
ATSI	N/A	$176,418	$134,424	N/A	35%	26%
Met-Ed	$137,547	$241,944	$113,744	28%	48%	22%
PENELEC	$137,547	$211,701	$103,403	28%	42%	20%
PJM avg.	$117,898	$216,742	$113,744	24%	43%	22%

New Entrant Diesel	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2013	2014	2015	2013	2014	2015
APS	$9,189	$51,759	$57,970	6%	32%	34%
ATSI	N/A	$46,906	$100,595	N/A	29%	59%
Met-Ed	$70,446	$98,665	$71,610	46%	61%	42%
PENELEC	$68,914	$80,873	$64,790	45%	50%	38%
PJM avg.	$49,006	$79,256	$68,200	32%	49%	40%

New Entrant Nuclear	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2013	2014	2015	2013	2014	2015
APS	$256,352	$369,923	$280,698	32%	42%	30%
ATSI	N/A	$352,308	$299,411	N/A	40%	32%
Met-Ed	$328,451	$440,385	$271,341	41%	50%	29%
PENELEC	$328,451	$413,962	$271,341	41%	47%	29%
PJM avg.	$304,418	$405,154	$280,698	38%	46%	30%

New Entrant Wind	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2013	2014	2015	2013	2014	2015
PENELEC	$176,533	$231,699	$186,644	90%	117%	92%

50 (Monitoring Analytics, LLC 2016), Section 7: Net Revenue, Tables 7-4 through 7-16. Note that many of the 2013 and 2014 values are changed significantly from prior reports, apparently due to updates in the market monitor's net revenue calculation.

Actual Net Revenues in PJM

In addition to the net revenue analysis for hypothetical new entrants, the market monitor performed an actual net revenue analysis of existing units by comparing the avoidable costs of each generator to the actual revenues they earned from PJM markets. The market monitor found that since 2009, PJM capacity market revenues have been sufficient for the majority of plants to cover any shortfalls between energy and ancillary services market revenues and avoidable costs.[51] In 2015 PJM market revenues matched or exceeded avoidable costs for 100% of all hydro and pumped storage units, 94–100% of combined cycle units (depending on specific technology), 97–100% of combustion turbine units, 94% of all diesel units, 87% of oil or gas steam units, and 50–62% of coal units.[52] The market monitor also found that 11,908 MW of capacity (almost all coal) is at-risk for retirement in addition to already-planned retirements.[53] Due to lack of data, the market monitor's analysis excludes nuclear units.[54]

Actual New Entry in PJM

The RPM capacity market is intended to play 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 about 63,441 MW of capacity, as summarized in Table 12. This includes new generation, upgrades of existing generators, generation reactivations, demand and energy efficiency resources, withdrawn or canceled retirements, and capacity imports.

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51 (Monitoring Analytics, LLC 2016), Section 7: Net Revenue, Tables 7-29 and 7-30.

52 (Monitoring Analytics, LLC 2016), Section 7: Net Revenue, Table 7-30. The ranges reflect values for different unit types within each category. For example, 50–62% for coal units reflects 62% for sub-critical coal and 50% for super-critical coal.

53 (Monitoring Analytics, LLC 2016), Section 7: Net Revenue, p. 273.

54 (Monitoring Analytics, LLC 2016), Section 7: Net Revenue, p. 272.

Table 12[55]
Impact of RPM on Capacity Availability to Date
Through the 2018/19 Base Residual Auction Results
(MW)

Change in Capacity Availability	Installed Capacity (MW)
New Generation	**29,464**
Generation Upgrades (excluding reactivations)	**8,354**
Generator Reactivations	**1,560**
Demand Resources and Energy Efficiency	**12,416**
Withdrawn and Canceled Retirements	**4,620**
Net Imports	**7,027**
Total	**63,441**

IV. Ancillary Service Markets

PJM currently procures four types of ancillary services products through organized markets: (1) regulation, (2) synchronized reserve, (3) non-synchronized reserve, and (4) day-ahead scheduling reserve.[56]

In addition, PJM also procures reactive power and black start service on a non-market basis and compensates the resources providing these services on the basis of incentive rates or costs.

The remainder of this section discusses each of these ancillary services in greater depth.

IV.A. Regulation

Regulation reserves are procured by PJM to be able to respond within 5 minutes or less to regulation signals sent by PJM every two seconds. PJM transmits two distinct regulation signals: "RegA," for ramp-limited resources with relatively limited flexibility but better ability to sustain energy output, and "RegD," for energy-limited resources with relatively high flexibility but limited ability to sustain energy output. To participate in the regulation market resources must qualify to respond to one or both signals. Regulation resources include generators with quick response capabilities, storage resources, and demand response resources. PJM operates a single

[55] (PJM 2014a), Table 10.

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

market for regulation, and the market clearing price is the uniform price paid for regulation across the RTO footprint.

PJM implemented significant changes to the regulation market in 2012, and modified its settlement methodology based on FERC's order in 2013. PJM's market monitor recognizes the improvements in the regulation market since 2012, but finds that the FERC-ordered treatment of the "marginal benefit factor" (explained below) in regulation market settlements is a structural flaw resulting in over-procurement of the more flexible (RegD) regulation resources and incorrect market signals for storage resources to enter the market.[57] In December 2015 PJM and its stakeholders began addressing the issue by implementing an interim fix as they work on more comprehensive adjustments to the regulation market rules to more accurately reflect the value of RegD.

Throughout 2015 the regulation market had the same basic structure and rules:[58, 59]

- Marginal benefit factor, used to convert RegA and RegD into substitutable and equivalent RegA "effective MW" that can meet the hourly requirement.
- Hourly regulation requirement of 700 effective MW during peak hours and 525 effective MW during off-peak hours.
- Performance scores, calculated for each regulation resource and regulating hour to measure responsiveness to PJM's regulation signals.
- Joint optimization of RegA and RegD needed to meet the requirement,[60] using the marginal benefit factor to quantify the tradeoffs of using one versus the other, and incorporating historical performance scores.
- Single Regulation Market Clearing Price ("RMCP"), based on three-component supply offers: a capability component that reflects the cost of reserving MW, a performance component that reflects the cost of ramping, and a PJM-calculated Lost Opportunity Cost (LOC) component that reflects any incremental lost opportunity to clearing in the energy market.
- Price-clearing mechanism based on performance offers: the three-component supply offers are ranked on the performance component, which sets the Regulation Market Performance Clearing Price ("RMPCP"). The remaining components of the marginal supply offer (capability and LOC) set the residual Regulation Market Capacity Clearing Price ("RMCCP"). The final RMCP is the total marginal supply offer (by definition, the same as RMPCP plus RMCCP).

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57 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 394.

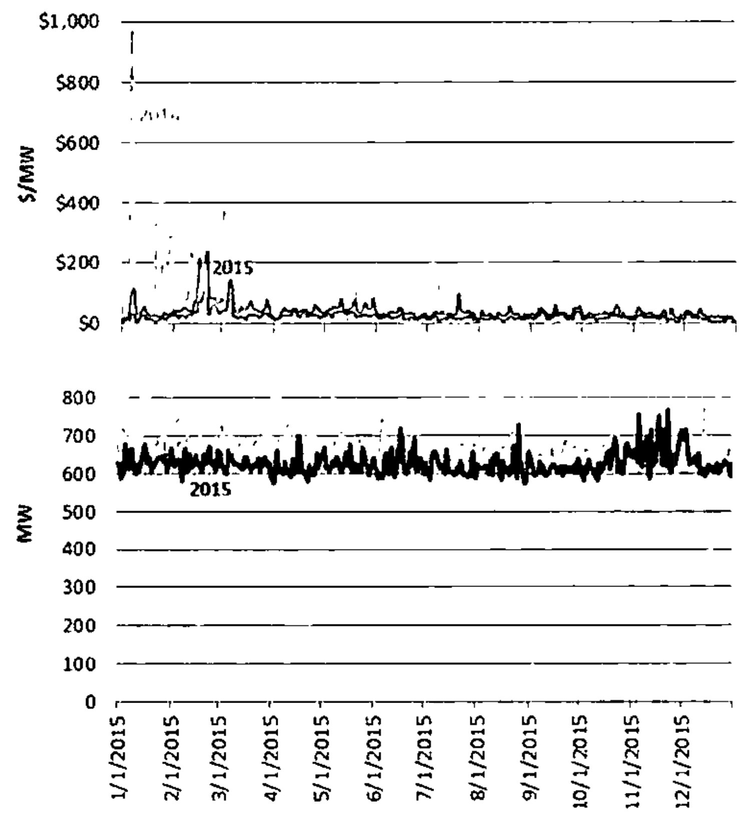
58 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, pp. 393–412.

59 (PJM n.d.).

60 PJM's real-time market not only jointly optimizes within regulation, but among energy and all ancillary services (regulation, synchronized reserves, and non-synchronized reserve).

In 2015 the annual weighted average RMCP was $31.92/MW (unadjusted MW), significantly lower than $44.15/MW in 2014, mostly due to less constrained system conditions during the months January through March.[61] Figure 5 shows PJM's publicly-available data on 2014 and 2015 daily average regulation market clearing prices (RMCP) and associated MW scheduled.[62] Compared to 2014, the data indicate more moderate prices early in 2015 and similar volumes of MW scheduled throughout the year.

Figure 5
Daily Average Regulation Market Clearing Prices (RMCP, $/MW) and Regulation Reserves Scheduled (MW) in 2014 and 2015[63]



[61] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 379 and (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 409.

[62] It is not clear why the PJM-published data differs from the market monitor report.

[63] Based on 2014 and 2015 hourly data published by PJM. (PJM 2015c), (PJM 2016a). Daily prices reflect a weighted average of RMCP and daily quantities reflect the maximum unadjusted MW scheduled.

IV.B. Synchronized Reserve

PJM satisfies its contingency reserve requirements defined under the NERC Performance Standard BAL-002-0 (Disturbance Control Performance)[64] by maintaining ten-minute primary reserves. PJM's primary reserve requirement is 2,175 MW, which is 150% of the largest contingency on the system, and that requirement may be met either by synchronized or non-synchronized reserves, with some restrictions.[65] At least 1,450 MW of the requirement must be met by synchronized reserve located in the Mid-Atlantic Dominion ("MAD") subzone and at least 1,700 of all primary reserve must be deliverable to the MAD subzone.[66]

PJM distinguishes two types of synchronized reserves: **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 ten minutes; and (b) **Tier 2**, consisting 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.[67]

Tier 1 resources are preferred because they provide reserves at zero additional cost. Tier 2 reserves are procured in the synchronized market if there are not sufficient Tier 1 resources available. If Tier 2 resources are needed the synchronized reserve market "clears" and the marginal Tier 2 resource sets a Synchronized Reserve Market Clearing Price ("SRMCP") which is paid to all cleared Tier 2 resources with an obligation to respond to a reserve event. Tier 1 resources have no obligation to respond to a reserve event but they are credited when they do.[68] Tier 1 event response credits averaged $50.99/MW in 2015.[69]

A special market rule allows Tier 1 resources (in addition to Tier 2) to receive the SRMCP when the *Non*-Synchronized Reserve Market Clearing Price ("NSRMCP") is greater than zero. The market monitor recommends that this special market rule be eliminated entirely, even for *selected* Tier 1 resources, since it essentially results in windfall payments to Tier 1 without providing any incentives for performance or to provide more Tier 1 resources.[70]

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[64] Available at http://www.nerc.com/files/BAL-002-0.pdf. Last accessed May 2016.

[65] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 367.

[66] Not to be confused with the capacity zones shown in Figure 3, the Mid-Atlantic Dominion Subzone for reserve is defined dynamically based on transmission constraints, but essentially covers the eastern half of PJM. In most hours in 2015 the MAD subzone was defined as east of the Bedington–Black Oak interface constraint. In some hours the subzone was east of the AP South interface. (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 367.

[67] (PJM 2015a), Section 4.

[68] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 371–372.

[69] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 372.

[70] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 372–373.

Figure 6 illustrates daily average Tier 2 synchronized reserve procured and market-clearing prices in the Mid-Atlantic Dominion Subzone. In 2015, the average amount of Tier 2 reserves cleared in the Mid-Atlantic Dominion Subzone was 314.8 MW, compared to 352.6 MW in 2014.[71] The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone during cleared hours was $10.12/MW, versus $15.50/MW in 2014.[72] The relatively high prices in 2014 were driven by January 2014 system conditions.

Tier 2 is mostly provided by combustion turbines. Similar to 2014, contribution of demand resources to the supply of synchronized reserves remained significant in 2015 but much lower than in prior years. Demand resources represented 18% of all cleared Tier 2 synchronized reserves in 2015, compared to 15% in 2014.[73]

During times of reserve shortage, PJM applies a penalty factor to energy prices to reflect the very high cost of re-dispatching in those hours to satisfy reserve requirements. This penalty factor was established as part of PJM's scarcity pricing reforms in 2012, and specific values are scheduled to gradually increase by June 1, 2015. In January through May 2015 the Synchronized Reserve Penalty Factor and the Non-Synchronized Reserve Penalty Factor were both equal to $550/MWh. Starting June 1, 2015, the penalty factors were increased to $850/MWh.[74] There were no shortage pricing events in 2015, compared to two days in early January 2014.[75]

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71 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 381.

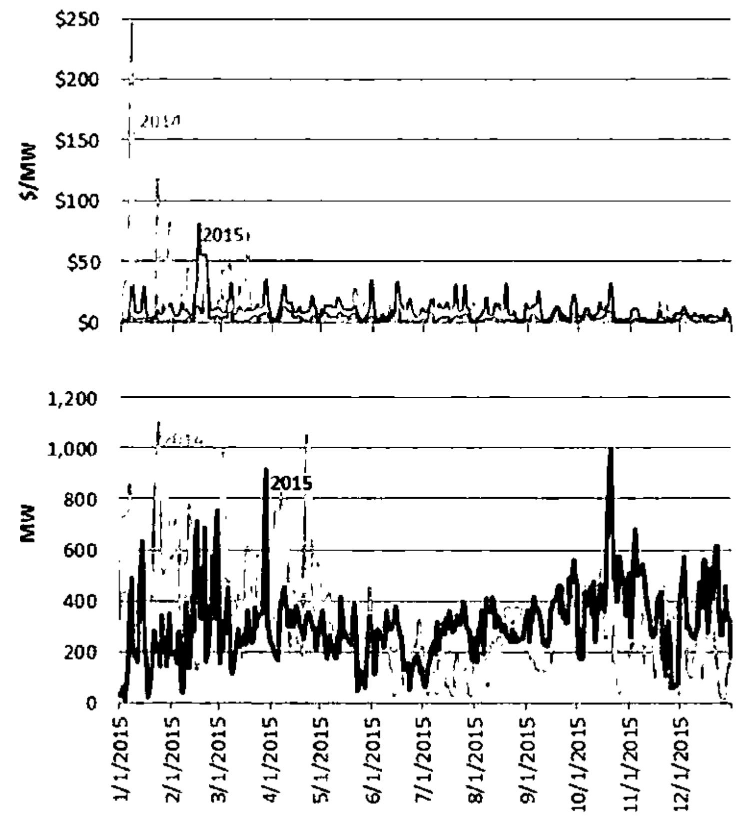
72 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 357.

73 (Monitoring Analytics, LLC 2014), Section 10: Ancillary Services, p. 310; (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 376–377.

74 (PJM 2015a), Section 2; (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 369.

75 (Monitoring Analytics, LLC 2016), Section 3: Energy Market, p. 140.

Figure 6
Daily Average Mid-Atlantic Dominion Subzone Synchronized Reserve Market Clearing Prices ($/MW) and Tier 2 Purchases (MW) in 2014 and 2015[76]



[76] Based on 2014 and 2015 hourly data published by PJM. (PJM 2015d), (PJM 2016b). Daily prices reflect a weighted average of SRMCP and daily quantities reflect the average of Tier 2 MW scheduled.

IV.D. NON-SYNCHRONIZED RESERVE

Ten-minute reserve that is *not* synchronized to the grid can be used to meet PJM's primary reserve requirement of 2,175 MW, with some restrictions.[77] At least 1,450 MW of the requirement must be met by synchronized reserve located in the Mid-Atlantic Dominion subzone. The remaining primary reserve requirement can be met by non-synchronized reserve.

Non-synchronized reserve must be generation capable of responding to PJM dispatch within ten minutes.[78] Examples of such resources include shutdown run-of-river hydro, shutdown pumped hydro, and offline combustion turbines. The market monitor finds that almost all non-synchronized reserve resources in 2015 were combustion turbines (58.4%) and hydro (38.8%), with diesels as a small share (2.8%).[79] Demand resources and generators with spare capacity that are synchronized to the grid are not eligible to provide non-synchronized reserves.

There is no pre-defined non-synchronized reserve requirement. Non-synchronized reserves are only procured to meet the balance of the PJM primary reserve requirement when it is not met by synchronized reserves. All resources capable of providing non-synchronized reserves must be offered; however, there are no offer prices associated with such reserves. Instead, non-synchronized reserve prices are determined by lost opportunity costs. As a result, the non-synchronized reserve price is expected to be zero in most hours, except those hours when available reserves become scarcer.

In 2015 the non-synchronized reserve price was greater than zero in 1,089 hours in the Mid-Atlantic Dominion reserve zone, and 1,055 hours in the RTO subzone,[80] compared to 541 hours in the Mid-Atlantic Dominion subzone and 379 hours in the RTO reserve zone in 2014.

IV.E. DAY-AHEAD SCHEDULING RESERVE

Day-Ahead Scheduling Reserve ("DASR") is procured to satisfy PJM's thirty-minute supplemental reserve requirement with a mechanism that can allow generation resources to offer reserve energy and be compensated for the cleared supply. DASR requirements are determined for the NERC-defined ReliabilityFirst Corporation region ("RFC") and Dominion area separately. The RFC DASR requirement is based on the region's historical load under-forecast and generator outage rates.[81] In 2015, the DASR requirement was 5.93% of forecasted peak load, down from 6.27% in 2014.[82] The market monitor finds that PJM has significant discretion to increase the

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77 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, pp. 366 & 377.

78 (PJM 2015a), Section 4b.

79 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 388.

80 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 365.

81 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 367.

82 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 362.

DASR requirement.[83] Between May and September 2015 PJM increased DASR demand significantly in 344 hours, putting upward pressure on clearing prices.[84] In 2015 PJM changed to a more conservative calculation of DASR MW supply, also putting upward pressure on clearing prices.

In 2015 43.6% of the hours cleared at a price of $0.00, down significantly from 94.1% of hours in 2014.[85] The maximum clearing price was of $199.83 in February 2015, down from $534.66/MW in January 2014 (driven by extreme weather conditions in winter 2013/14). For hours when the clearing price was above $0, the annual weighted-average DASR clearing price in 2015 was $2.99/MW.[86]

DASR resources have no obligations to perform during real-time, and they are often not available when needed.[87] Similar to prior years, PJM's market monitor concluded that economic withholding remains an issue in the DASR market, arguing that marginal cost of providing DASR is zero. The market monitor recommends eliminating the DASR market entirely and replacing it with a reserve market in the real-time market.

IV.F. Black Start Service

Black start service is procured to ensure reliable restoration following a blackout. PJM works in conjunction with transmission owners to identify capable resources in the appropriate locations. Restoration plans identify critical resources and PJM defines a minimum critical black start level for each transmission zone, while providing out-of-market incentives to the transmission owners to provide such service.[88] Since there is no organized market for black start service PJM periodically issues requests for proposals to provide service from any willing party in a given location.

Generators are compensated for black start service based on (a) a revenue requirement formula specified in Section 18 of Schedule 6A of PJM's Open Access Transmission Tariff, plus (b) payments for scheduling in the DASR market or committing in the real-time market.[89] The cost is then allocated to transmission customers proportionally based on load ratios. Generally, the

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[83] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 391.

[84] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 392.

[85] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 367 and Table 10-26.

[86] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 392.

[87] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 390.

[88] (Monitoring Analytics, LLC 2014), Section 10: Ancillary Services, p. 318.

[89] (Monitoring Analytics, LLC 2014), Section 10: Ancillary Services, p. 318. Note that the revenue requirement includes NERC Critical Infrastructure Protection capital costs for black start units in Met-Ed and Penelec.

market monitor finds black start payments to be non-transparent and recommends PJM to release confidentiality restrictions on this information.[90]

The 2015 black start charges totaled $53.6 million, composed of $48.4 million in revenue requirement charges and $5.2 million in operating reserve charges.[91] This is a decrease compared to 2014 total charges of $60 million.[92]

IV.G. 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 a service provided by PJM, which customers must purchase. Reactive power services were developed in response to a need for an accurate portrayal of voltage and reactive resources and capability.

Each network and point-to-point customer is charged a rate for reactive services that is based on (a) the suppliers' reactive revenue requirements, and (b) payments for scheduling in the DASR market or committing in the real-time market.[93] Similar to black start service, charges are allocated to customers based on percentage of load. Total reactive power charges in 2015 were $289 million, composed of $278.4 million in revenue requirement charges and $10.7 million in operating reserve charges.[94]

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[90] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p.412.

[91] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, pp. 363–364.

[92] (Monitoring Analytics, LLC 2014), Section 10: Ancillary Services, p. 319, Table 10-30.

[93] (Monitoring Analytics, LLC 2014), Section 10: Ancillary Services. p. 386.

[94] (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 364.

VI. Conclusion

Overall, PJM market prices attempt to reflect market fundamentals, but they are also a reflection of market design choices and market performance. In 2015, compared to 2014, market dynamics were driven by lower natural gas prices, lower demand, less severe winter conditions in the first part of the year, and locational price convergence in the capacity market. Despite a number of suggestions for market design improvements, the market monitor has found that market performance was mostly competitive, with a few exceptions discussed below.

VI.A. Market Performance in 2015

Overall competitiveness of wholesale markets is assessed by PJM's Independent Market Monitor by examining various aspects, including: (1) market structure, (2) participant behavior, (3) market design, and (4) 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 tests and the Herfindahl-Hirschman Index ("HHI").
- "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 as well.
- "Market design" refers to a set of rules and procedures that are created to minimize the exercise of market power in structurally uncompetitive markets, as well as 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 the PJM market monitor's assessment of the performance of PJM markets in 2015. The market monitor's assessment has not changed since last year, with the exception of the addition of a formal assessment of some aspects of PJM's Financial Transmission Rights ("FTR") auction (not shown in the table). According to the market monitor's final assessment for 2015, all markets shown in Table 13 yielded competitive outcomes despite some concerns with market structure, participant behavior, and market design.

Table 13[95]
Market Monitor's Assessment of PJM Markets in 2013

Market	Market Structure: Aggregate	Market Structure: Local	Participant Behavior	Market Design	Market Performance
Energy	Competitive	Not Competitive	Competitive	Effective	Competitive
Capacity	Not Competitive	Not Competitive	Competitive	Mixed	Competitive
Regulation	Not Competitive	N/A	Competitive	Flawed	Competitive
Synchronized Reserve	N/A	Not Competitive	Competitive	Mixed	Competitive
Day-Ahead Scheduling Reserve	Competitive	N/A	Mixed	Mixed	Competitive
FTR Auction	Competitive	N/A	Competitive	Flawed	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 the energy market, transmission constraints were found to create local markets with high supply ownership concentrations. This non-competitive market structure was corrected by PJM, by using the Three Pivotal Supplier tests to screen for market concentrations, and by mitigating supply offers of those who fail the test. Similarly, the capacity and regulation markets had failures of the Three Pivotal Supplier tests and subsequent mitigated supply offers.

Despite relatively high ownership concentration in some PJM markets, participant behavior in all markets, with the exception of the Day-Ahead Scheduling Reserve market, was judged to be competitive. In the Day-Ahead Scheduling Reserve market, participant behavior was mixed because 37.9% of daily offers reflected economic withholding.[96]

Market design in the energy market was determined to be effective. Capacity market design was determined to have mixed effectiveness due to several market rules that allow lower-quality capacity resources to compete on-par with higher-quality resources. Synchronized reserve market design was determined to have mixed effectiveness due to a flaw in how economic (Tier 1) synchronized reserve is compensated when the non-synchronized market clears at a non-zero price. The Day-Ahead Scheduling Reserve market was determined to have mixed effectiveness due to the absence of Three Pivotal Supplier tests and offer mitigation. Finally, the regulation market was determined to be flawed primarily due to a flawed definition of opportunity cost and inconsistent implementation of marginal benefit factors.

In addition to the wholesale market, there is competition in the Pennsylvania retail sector. As of January 1, 2016, the percentage of residential customers served by an alternative supplier in the Companies' territories ranged from 22.6% in the Penn Power service territory to 31.8% in the Met-Ed service territory, representing 22.4% and 32.2% of the retail load, respectively.[97] The percentage of commercial load served by an alternative supplier ranged from 64.4% in the West

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95 (Monitoring Analytics, LLC 2016), Section 1: Introduction, pp. 6–8.

96 (Monitoring Analytics, LLC 2016), Section 10: Ancillary Services, p. 391–392.

97 (Pennsylvania Office of Consumer Advocate 2016).

Penn territory to 72.8% in the Met-Ed territory. The percentage of industrial load served by an alternative supplier ranged from 90.3% in the West Penn territory to 98.3% in the Penelec territory.

Acronyms

APS	Allegheny Power Company
ATSI	American Transmission Systems, Inc.
BRA	Base Residual Auction
DASR	Day-Ahead Scheduling Reserve
E&AS	Energy and Ancillary Services
FRR	Fixed Resource Requirement
FTR	Financial Transmission Rights
GROSS CONE	Gross Cost of New Entry (gross investment cost)
HHI	Herfindahl-Hirschman Index
LDA	Locational Deliverability Area
LMP	Locational Marginal Price
MAAC	Mid-Atlantic Area Council
MAD	Mid-Atlantic Dominion (reserve subzone)
MET-ED	Metropolitan Edison Company
MWH	Megawatt-Hour
NERC/RFC	North American Electric Reliability Corporation/ReliabilityFirst Corporation
NET CONE	Net Cost of New Entry (gross investment cost, minus net revenues from energy, ancillary services, and operating reserve markets)
NSRMCP	Non-Synchronized Reserve Market Clearing Price
PA PUC	Pennsylvania Public Utility Commission
PENELEC	Pennsylvania Electric Company
PENN POWER	Pennsylvania Power Company

PJM	PJM Interconnection, L.L.C.
RFC	ReliabilityFirst Corporation
RMCCP	Regulation Market Capability Clearing Prices
RMCP	Regulation Market Clearing Price
RMPCP	Regulation Market Performance Clearing Price
RPM	Reliability Pricing Model (auction-based portion of capacity market)
RTO	Regional Transmission Organization
SRMCP	Synchronized Reserve Market Clearing Price
VRR	Variable Resource Requirement (RPM demand curve)
WEST PENN	West Penn Power Company

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Appendix[98]

APS Control Zone

Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2015

				Day Ahead				Balancing					Event Hours	
No	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Bedington - Black Oak	Interface	500	-5.10	-30.90	-4.80	21.00	0.80	0.60	1.70	1.90	22.80	5,866	688
2	AP South	Interface	500	-5.00	-19.10	-0.60	13.40	0.10	-0.10	0.10	0.30	13.70	2,570	84
3	Person - Halifax	Flowgate	MISO	7.30	0.60	0.10	6.80	0.00	0.00	0.00	0.00	6.80	2,824	12
4	Dravosburg - West Mifflin	Line	DLCO	12.60	5.90	0.80	7.50	0.50	0.10	-1.30	-1.00	6.50	904	514
5	Mahans Lane - Tidd	Line	AEP	9.80	5.20	1.00	5.60	-0.10	-0.10	-1.40	-1.40	4.20	2,098	788
6	Conastone - Northwest	Line	BGE	13.50	10.20	0.70	4.00	0.30	-0.50	-0.80	0.00	3.90	5,072	3,468
7	Bagley - Graceton	Line	BGE	13.70	10.80	0.80	3.70	0.00	-0.40	-0.50	-0.20	3.50	7,088	3,946
8	Valley	Transformer	Dominion	-0.80	-4.00	0.10	3.30	0.20	0.00	-0.10	0.10	3.40	1,736	180
9	Tiltonsville - Windsor	Line	AP	3.30	0.50	0.30	3.10	0.00	0.00	0.00	0.00	3.00	658	20
10	AEP - DOM	Interface	500	-1.70	-4.70	-0.50	2.50	0.20	-0.10	0.10	0.40	2.90	2,656	88
11	5004/5005 Interface	Interface	500	-25.60	-28.40	-2.10	0.80	0.00	-0.50	1.40	1.90	2.60	1,356	612
12	Joshua Falls	Transformer	AEP	1.30	-0.60	0.20	2.10	0.10	0.00	-0.10	0.00	2.00	1,128	108
13	USAP - Woodville	Line	DLCO	4.30	1.60	0.40	3.10	0.00	0.00	-1.20	-1.10	1.90	358	222
14	502 Junction	Transformer	AP	1.70	-0.20	-0.10	1.70	0.10	-0.10	0.00	0.20	1.90	82	16
15	Pleasants - St. Marys	Line	AP	0.00	0.00	0.00	0.00	-1.30	0.30	-0.20	-1.80	-1.80	11	58
16	Belmont	Transformer	AP	4.30	6.10	0.50	-1.30	0.00	-0.30	-0.60	-0.30	-1.60	1,680	188
24	Enon Tap - Gilboa	Line	AP	3.60	2.80	0.30	1.20	-0.10	0.00	-0.30	-0.40	0.70	1,110	190
26	Bartonsville - Stephenson	Line	AP	0.50	-0.10	0.00	0.70	0.00	0.00	0.00	0.00	0.70	92	0
28	Butler - Karns City	Line	AP	0.40	-0.30	0.00	0.70	0.00	0.00	0.00	0.00	0.60	1,008	66
32	Kingwood - Pruntytown	Line	AP	0.30	-0.10	0.00	0.50	0.00	0.00	0.00	0.00	0.50	226	0

ATSI Control Zone

Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2015

				Day Ahead				Balancing					Event Hours	
No	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	-44.30	-40.20	-0.70	-4.80	-0.60	3.70	0.30	-4.00	-8.80	1,356	642
2	Bedington - Black Oak	Interface	500	-31.40	-26.90	-0.30	-4.80	0.10	1.00	0.20	-0.70	-5.50	5,866	688
3	Monroe - Bayshore	Flowgate	MISO	10.50	6.90	0.00	3.70	-0.20	-0.10	-0.10	-0.10	3.60	1,144	430
4	Juniper	Transformer	500	3.80	0.30	0.10	3.60	0.00	0.00	0.00	0.00	3.60	210	6
5	AP South	Interface	MISO	-19.90	-16.90	-0.30	-3.40	0.00	0.10	0.10	-0.10	-3.40	2,570	84
6	Person - Halifax	Flowgate	AEP	-14.60	-11.60	0.00	-3.00	0.00	0.00	0.00	0.00	-3.00	2,824	12
7	Ottawa - West Fremont	Line	500	-1.90	-5.00	0.10	3.10	0.00	0.10	0.00	-0.10	3.00	536	42
8	Beaver - Mansfield	Line	ATSI	-1.00	-3.50	0.10	2.60	-0.30	-0.70	-0.10	0.30	2.90	240	146
9	Bayshore - Jeep	Line	AEP	1.70	-0.90	0.00	2.60	-0.10	0.00	0.00	-0.10	2.50	170	84
10	Lakeview - Greenfield	Line	AEP	1.50	-1.40	0.30	3.30	0.00	0.40	-0.40	-0.80	2.50	948	234
11	AEP - DOM	Interface	AEP	-14.20	-12.20	0.00	-2.10	-0.10	0.20	0.00	-0.30	-2.40	2,656	88
12	West Akron - Brush	Line	DLCO	5.30	3.60	0.00	1.70	-0.10	-0.50	0.00	0.40	2.10	250	80
13	Mahans Lane - Tidd	Line	ATSI	-9.40	-8.00	-0.20	-1.50	-0.10	0.40	0.20	-0.40	-1.90	2,098	788
14	Lakeview - Ottawa	Line	500	1.00	-0.50	0.20	1.70	0.00	0.00	0.00	0.00	1.70	390	0
15	Bagley - Graceton	Line	ATSI	2.40	1.40	-0.20	0.80	0.00	-0.20	0.50	0.70	1.60	7,088	3,946
17	Astor - Crestwood	Line	ATSI	1.10	-0.30	0.10	1.50	0.00	0.00	0.00	0.00	1.50	550	0
25	Juniper - Northfield	Line	ATSI	1.00	0.10	0.10	0.90	0.20	0.00	-0.10	0.10	1.00	498	16
29	Hoyt Dale - Maple	Line	ATSI	-3.60	-4.10	-0.10	0.40	0.80	2.10	0.10	-1.20	-0.80	142	170
32	Clinic Hospital - Inland	Line	ATSI	0.70	0.10	0.10	0.70	0.00	0.00	0.00	0.00	0.70	278	0
34	Babb - Evans	Line	ATSI	0.70	0.00	0.00	0.70	0.00	0.00	0.00	0.00	0.70	66	0

98 (Monitoring Analytics, LLC 2016), Appendix G.

Met-Ed Control Zone
Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2015

				Day Ahead				Balancing					Event Hours	
No	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Bagley - Graceton	Line	BGE	-28.70	-41.70	-1.00	12.10	0.50	1.30	0.90	0.10	12.20	7,088	3,946
2	Conastone - Northwest	Line	BGE	-27.60	-36.70	-1.40	7.70	0.20	2.00	1.60	-0.20	7.50	5,072	3,468
3	Jackson - Three Mile Island	Line	Met-Ed	2.80	-1.80	0.50	5.10	0.60	-0.90	-1.00	0.60	5.70	408	92
4	5004/5005 Interface	Interface	500	21.70	24.60	-0.60	-3.50	1.00	0.50	-0.10	0.40	-3.10	1,356	642
5	Gardners - Texas East	Line	Met-Ed	2.50	-0.60	0.20	3.20	0.00	0.50	-0.10	-0.60	2.70	2,126	222
6	Glenarm - Windy Edge	Line	BGE	-4.90	-6.90	-0.10	1.90	0.10	0.20	0.20	0.10	2.00	1,802	844
7	Middletown Jct - Three Mile Island	Line	Met-Ed	0.60	-1.00	0.10	1.70	0.00	0.00	0.00	0.00	1.70	276	0
8	Hummelstown - Middletown Jct	Line	Met-Ed	0.10	-0.30	0.00	0.40	0.20	-1.30	-0.50	1.00	1.30	46	34
9	East	Interface	500	1.10	-0.20	-0.20	1.10	0.00	0.00	0.10	0.10	1.10	1,080	32
10	Hunterstown	Transformer	Met-Ed	1.20	0.20	0.10	1.10	0.00	0.00	0.00	0.00	1.10	490	0
11	Person - Halifax	Flowgate	MISO	2.90	3.70	-0.20	-1.10	0.00	0.00	0.00	0.00	-1.10	2,824	12
12	Middletown Jct - Brunner Island	Line	PPL	-0.30	-1.10	0.00	0.90	0.00	0.00	0.00	0.00	0.90	296	0
13	West	Interface	500	3.00	3.90	0.10	-0.90	0.00	0.00	0.00	0.00	-0.90	638	98
14	Wescosville	Transformer	PPL	0.80	0.20	0.20	0.80	0.00	0.00	0.00	0.00	0.80	428	22
15	Mahans Lane - Tidd	Line	AEP	2.60	3.40	0.00	-0.80	0.10	0.00	0.00	0.00	-0.80	2,098	788
20	Jackson - North Hanover	Line	Met-Ed	0.40	0.10	0.00	0.30	0.00	0.00	0.00	0.00	0.30	84	4
22	Ironwood - South Lebanon	Line	Met-Ed	0.00	-0.30	0.00	0.30	0.00	0.00	0.00	0.00	0.30	32	0
24	Three Mile Island	Transformer	Met-Ed	0.50	0.40	0.10	0.30	0.00	0.00	-0.10	0.00	0.30	208	54
28	Middletown Jct - Yorkhaven	Line	Met-Ed	0.10	0.00	0.20	0.20	0.00	0.00	0.00	0.00	0.20	710	0
33	Brunner Island - Yorkana	Line	Met-Ed	0.10	-0.10	0.00	0.20	0.00	0.00	0.00	0.00	0.20	104	0

Penelec Control Zone
Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2015

				Day Ahead				Balancing					Event Hours	
No	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	-35.60	-74.20	-2.30	36.30	0.60	7.10	2.10	-4.40	31.90	1,356	642
2	Conastone - Northwest	Line	BGE	-27.10	-38.10	-0.20	10.80	0.80	2.30	0.10	-1.40	9.40	5,072	3,468
3	Bagley - Graceton	Line	BGE	-28.40	-38.20	0.20	9.90	0.60	1.30	0.00	-0.60	9.30	7,088	3,946
4	Bedington - Black Oak	Interface	500	-23.40	-32.70	-0.40	9.00	0.30	0.30	0.10	0.10	9.10	5,866	688
5	Mahans Lane - Tidd	Line	AEP	8.40	13.80	0.10	-5.20	-0.10	-0.20	-0.20	-0.10	-5.30	2,098	788
6	Central	Interface	500	-3.40	-8.80	-0.50	4.80	0.00	0.10	0.10	0.00	4.80	582	82
7	AP South	Interface	500	-10.50	-15.10	-0.20	4.40	0.10	0.10	0.00	0.00	4.40	2,570	84
8	Dravosburg - West Mifflin	Line	DLCO	6.00	9.90	0.00	-4.00	-0.10	0.10	0.00	-0.10	-4.10	904	514
9	SENECA	Interface	PENELEC	0.60	2.10	0.80	-0.70	-0.40	0.60	-2.00	-3.00	-3.70	1,876	2,364
10	West	Interface	500	-3.70	-7.70	-0.20	3.70	0.00	0.40	0.10	-0.30	3.50	638	98
11	Person - Halifax	Flowgate	MISO	3.80	6.50	0.00	-2.70	0.00	0.00	0.00	0.00	-2.70	2,824	12
12	Glenarm - Windy Edge	Line	BGE	-5.00	-7.30	0.00	2.40	0.20	0.10	0.10	0.10	2.50	1,802	844
13	East	Interface	500	-4.20	-6.80	-0.30	2.30	0.00	0.10	0.10	0.00	2.30	1,080	32
14	Hoyt Dale - Maple	Line	ATSI	3.20	5.20	0.00	-2.00	-0.30	-0.10	0.00	-0.10	-2.10	142	170
15	Edgewood - Shelocta	Line	PENELEC	4.80	3.20	0.10	1.70	0.00	-0.50	-0.20	0.30	2.00	281	26
18	Niles Valley - Sabinsville	Line	PENELEC	0.50	0.50	0.40	0.00	0.10	-0.60	0.10	-0.50	-1.20	-1	134
20	Falconer - Warren	Line	PENELEC	0.00	0.00	0.00	0.00	0.10	0.30	-0.90	-1.10	-1.10	0	16
27	Lewis Run	Transformer	PENELEC	0.50	-0.30	0.00	0.80	0.00	0.10	0.20	0.00	0.80	492	36
33	Homer City	Transformer	PENELEC	0.10	-0.70	0.00	0.80	0.00	0.10	-0.10	-0.10	0.70	644	288
38	East Towanda - Tennessee Gap Tap	Line	PENELEC	0.50	0.20	0.20	0.60	0.00	0.00	0.00	0.00	0.60	1,918	12

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