FirstEnergy.

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

RECEIVED

2015 DEC 22 AM 9: 47

PA. P.U.C.
SECRETARY'S BUREAU

December 16, 2015

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 2015 report on market prices and price trends in the PJM Interconnection LLC markets during 2014, prepared by The Brattle Group.

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

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

Sincerely,

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

cc: Johnnie Simms, Bureau of Investigation and Enforcement
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

Philip Q Hanser

Robert Morandi

December 2015

THE Brattle GROUP

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, requiring 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 fourth of five 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.

Market trends in the four zones served by the Companies largely reflected overall PJM market trends in 2014. Total wholesale costs, in terms of dollars per megawatt-hour ("MWh") of total customer load, increased in all four zones relative to 2013. Wholesale costs in the Met-Ed, Penelec, APS, and Penn Power zones increased by 27%, 20%, 46%, and 22%, respectively. 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.

Energy prices in 2014 increased relative to 2013 due primarily to higher natural gas prices—particularly in the eastern part of the RTO—higher demand, and severe winter conditions in the first part of the year. In the day-ahead market, 2014 average zonal peak-hour locational marginal prices ("LMPs") increased relative to 2013 by 31–42% in the four Company zones. Similarly, off-peak LMPs increased by 15–28%. In the real-time market, average zonal peak-hour LMPs increased by 12–39%, and off-peak LMPs increased by 19–26%. All-hour weighted-average real-time LMPs in PJM increased from about \$39/MWh in 2013 to about \$53/MWh in 2014.

In 2014 the Met-Ed zone had the highest load-weighted average energy price, primarily due to transmission congestion. The congestion component of Met-Ed's LMP was particularly high in the day-ahead market and during peak hours.

Continued price separation in the capacity market 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 and Penn Power. Capacity charges in the Company zones were about \$2–15/MWh in 2013 and about \$6–14/MWh in 2014. Under PJM's centralized capacity market, the Reliability Pricing Model ("RPM"), the two Base Residual Auctions ("BRA") held for the 2013/14 and 2014/15 capacity delivery years cleared at capacity prices of $226.15/MW-day and $136.50/MW-day, respectively, in MAAC, and $27.73/MW-day and $125.99/MW-day, respectively, in the rest of the system. Four other capacity auctions were held in 2014, including the Base Residual Auction for the 2017/18 delivery year, and three incremental auctions for prior delivery years. Compared to 2014 the 2017/18 BRA resulted in similar, but slightly lower, prices for future supply in MAAC ($120/MW-day), and RTO-wide price convergence (most areas cleared at $120/MW-day) indicating a more capacity-constrained system overall. PJM attributed these results to supply-side effects, including decreased imports and demand resources, increased new entry of generating capacity (mostly combined cycle and combustion turbine capacity), and the location of cleared new entry in historically constrained areas.[1]

Transmission service charges did not change significantly in the Company zones relative to 2013 except in the Penn Power zone where it increased by about 13%. Contribution to total wholesale cost in 2014 was $2.50–3.38/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 higher in 2014 than in 2013, reflecting tighter market conditions and higher fuel costs, but contributions to total wholesale cost remained below $1/MWh. Black start service is procured by PJM on a non-market basis in order to ensure reliable restoration following a blackout. In 2014, charges for black start service remained about the same as in 2013 for the Company zones, contributing $0.01–0.06/MWh to the total wholesale costs. Reactive power (voltage control) is also procured by PJM on a non-market basis. In 2014, charges for reactive power decreased relative to 2013, contributing $0.38–0.54/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 2014. All markets yielded competitive outcomes despite some concerns with market structure, participant behavior, and market design.

1 (PJM 2014a).

I. Introduction

I.A. Purpose

This is the fourth 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 2014 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.

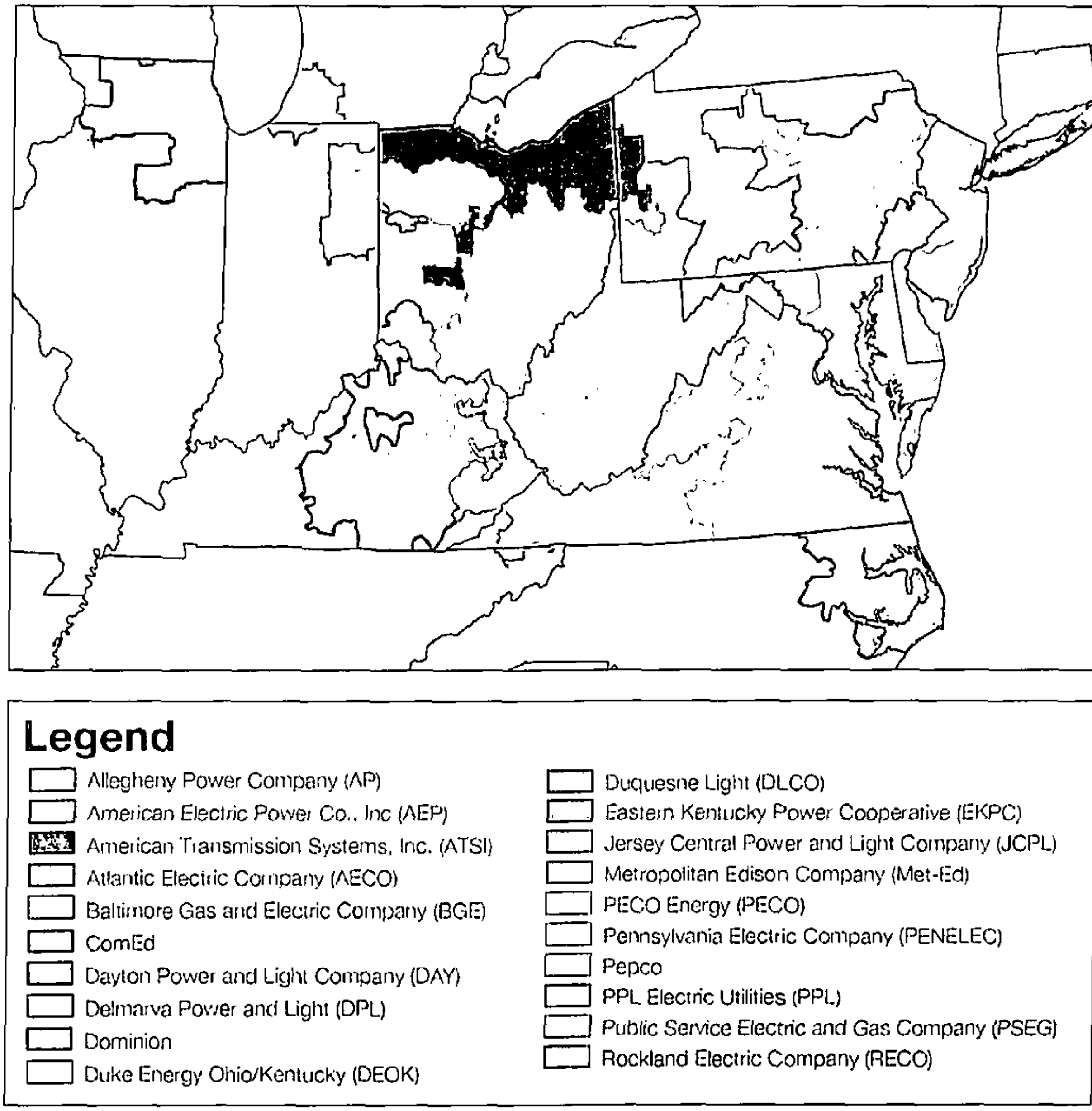
I.B. The PJM Market

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 2013 to 2014 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.[2] 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.

---

[2] 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[3]
PJM's Footprint in 2014



[3] (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 2014.

Table 1
Wholesale Costs of Electricity in 2014[4,5,6,7]
($/MWh)

	PJM	Penelec	Met-Ed	APS	Penn Power
Real-Time Load Wtd. LMP (Energy)	$53.14	$51.94	$56.09	$53.11	$46.74
Marginal Congestion Cost	*($0.02)*	($1.32)	$1.56	($1.03)	($6.02)
Marginal Transmission Losses	*$0.02*	$0.50	$1.12	$0.08	($1.06)
Capacity	$9.01	$11.50	$13.64	$6.24	$6.65
Transmission Service Charges	$5.95	$2.50	$2.50	$2.58	$3.38
Operating Reserves (Uplift)	$1.18	$1.32	$1.16	$1.30	$0.91
Reactive	$0.40	$0.54	$0.49	$0.38	$0.39
PJM Administrative Fees	$0.44	$0.44	$0.44	$0.44	$0.44
Regulation	$0.33	$0.33	$0.33	$0.33	$0.33
Transmission Enhancement Cost Recovery	$0.42	$0.80	$0.78	$0.93	$0.70
Synchronized Reserves	$0.21	$0.31	$0.31	$0.11	$0.11
Transmission Owner (Schedule 1A)	$0.09	$0.08	$0.08	$0.00	$0.03
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.05	$0.05	$0.05	$0.05
Black Start	$0.08	$0.03	$0.06	$0.01	$0.02
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	$0.02	$0.02	$0.01	$0.01
Capacity (FRR)	$0.20	N/A	N/A	N/A	N/A
Emergency Energy	$0.01	$0.01	$0.01	$0.01	$0.01
Emergency Load Response	$0.06	$0.06	$0.06	$0.06	$0.06
Total	$71.64	$69.98	$76.06	$65.60	$59.88

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

4 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.

5 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.

6 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.

7 (Monitoring Analytics, LLC 2015) and Brattle Analysis.

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.

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 92% of the total wholesale cost in 2014. Energy costs represent the largest single component for the Companies' zones, at an average of 78% of their total wholesale price.[8] As shown in Table 1, energy costs vary by load zone, reflecting the regional variation in LMPs. The APS price is close to the PJM average. As reflected in the marginal transmission congestion cost component of the real-time energy price, energy costs are higher than the PJM average in the Met-Ed zone, and lower than the PJM average in the Penn Power zone, reflecting the fact that the Met-Ed zone is located in a more congested area of PJM, while Penn Power lies in a less congested area. Further discussion of energy costs 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. Similar to 2012 and 2013, capacity auctions held for the calendar year 2014 experienced price separation among Locational Deliverability Areas that contain the Companies' zones. As such, zonal average capacity costs differ from 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.

Transmission service charges are not market-based charges, but instead are 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, by component, for each load zone.

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

Figure 2
Wholesale Costs of Electricity in 2014[9]
(% of Total, by Component)

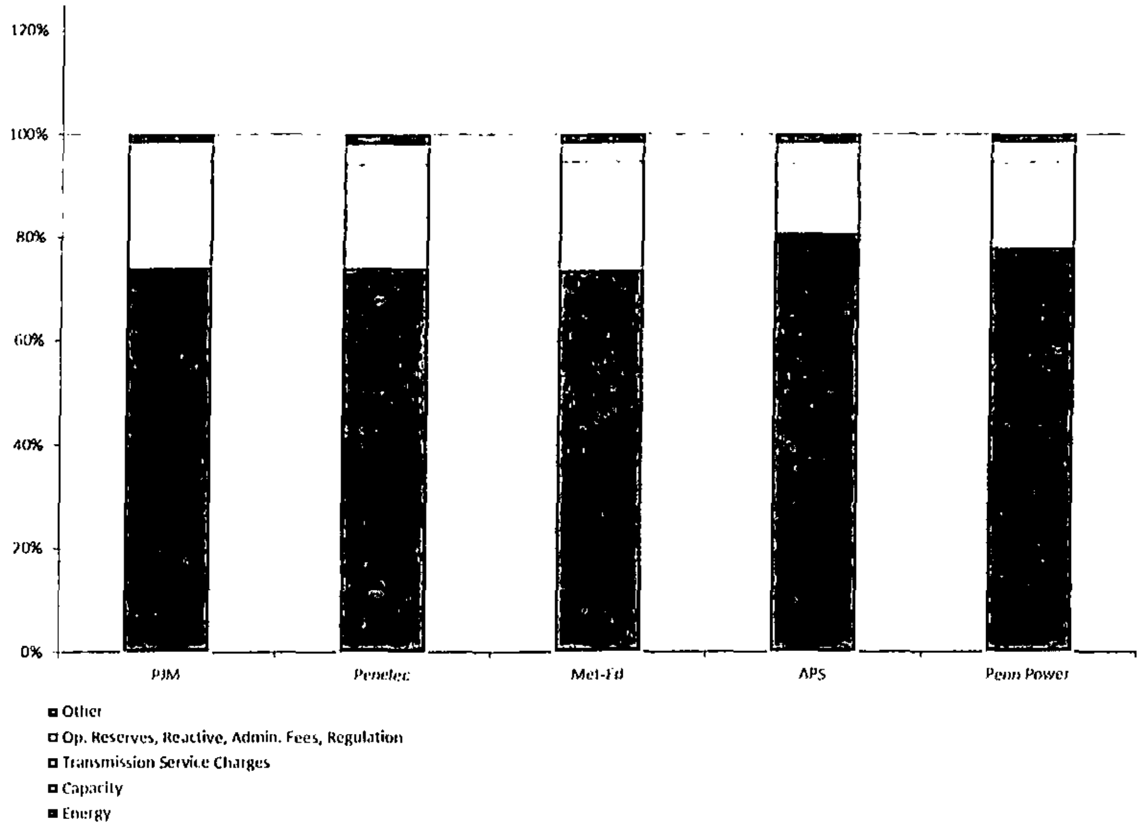


Table 2 shows the total wholesale cost of electricity by component for calendar years 2012 and 2013. *Table 3 shows the percentage change in wholesale cost components from* 2012 *to* 2014 *and* from 2013 to 2014. Between 2013 and 2014, the total cost of wholesale power increased by approximately 32.7%. APS experienced a larger increase in total cost at 46% compared to 2013, while Penelec, Met-Ed and Penn Power saw smaller increases in cost at 20%, 27%, and 22%, respectively. The increase in prices was the result of both higher, weather related, demand and fuel prices. If fuel costs in 2014 had been the same as 2013, the load-weighted LMP would still have been 22.7% higher in 2014, reflecting higher demand, particularly in the first quarter. [10]

---

9 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 Met-Ed, transmission congestion costs are approximately 3% of the LMP. In less congested areas, such as APS, there is a transmission congestion *credit* of approximately 2%. Similarly, marginal transmission losses range from a *cost* of about 2% of the LMP to a *credit* of approximately 2% of the LMP.

10 (Monitoring Analytics, LLC 2015).

Capacity costs in the APS and Penn Power zones increased the most when compared to capacity costs in 2012 and 2013. Further discussion on capacity prices can be found in Section II.C.

Table 2
Wholesale Costs of Electricity in 2012 and 2013[11,12]
($/MWh)

	2012					2013				
	PJM	Penelec	Met-Ed	APS	Penn Power	PJM	Penelec	Met-Ed	APS	Penn Power
Real-Time Load Wtd. LMP (Energy)	$35.23	$35.10	$36.30	$34.86	$33.02	$38.66	$38.71	$39.72	$37.70	$41.03
Congestion	*$0.04*	*-$0.12*	*$0.67*	*$0.04*	*-$0.87*	*$0.01*	*-$0.10*	*$0.34*	*-$0.57*	*$2.86*
Loss	*$0.01*	*$0.56*	*$0.53*	*-$0.09*	*-$0.21*	*$0.02*	*$0.63*	*$0.75*	*-$0.11*	*-$0.20*
Capacity	$6.05	$13.62	$13.62	$3.69	$3.69	$7.13	$12.53	$14.67	$1.68	$1.88
Transmission Service Charges	$4.78	$2.52	$2.52	$2.70	$2.81	$5.20	$2.49	$2.49	$2.70	$2.99
Operating Reserves (Uplift)	$0.79	$0.98	$0.98	$1.02	$1.02	$0.59	$0.86	$0.86	$0.53	$0.53
Reactive	$0.43	$0.78	$0.60	$0.48	$0.45	$0.80	$2.32	$0.72	$0.67	$1.12
PJM Administrative Fees	$0.42	$0.42	$0.42	$0.42	$0.42	$0.43	$0.43	$0.43	$0.43	$0.43
Regulation	$0.26	$0.26	$0.26	$0.26	$0.26	$0.24	$0.24	$0.24	$0.24	$0.24
Transmission Enhancement Cost Recovery	$0.34	$0.46	$0.54	$0.54	$0.48	$0.39	$0.56	$0.63	$0.64	$0.57
Synchronized Reserves	$0.04	$0.08	$0.08	$0.08	$0.00	$0.04	$0.06	$0.06	$0.06	$0.02
Transmission Owner (Schedule 1A)	$0.08	$0.08	$0.08	-	$0.03	$0.08	$0.08	$0.08	-	$0.03
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06	$0.06	$0.06	$0.06	$0.06
Black Start	$0.03	$0.03	$0.03	$0.00	$0.00	$0.14	$0.03	$0.05	$0.01	$0.00
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	$0.01	$0.03	$0.01	$0.02	$0.00	N/A	N/A	N/A	N/A	N/A
Economic Load Response	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*$0.01*	*$0.01*	*$0.01*	*$0.01*	*$0.01*
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	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
Capacity (FRR)	N/A	N/A	N/A	N/A	N/A	$0.11	N/A	N/A	N/A	N/A
Emergency Energy	N/A	N/A	N/A	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00
Emergency Load Response	N/A	N/A	N/A	N/A	N/A	$0.06	$0.06	$0.06	$0.06	$0.06
Total	$48.54	$54.42	$55.51	$44.15	$42.25	$53.97	$58.45	$60.10	$44.81	$48.99

From 2012 to 2014 the total price of wholesale power increased by an average of approximately 48% for PJM as a whole. APS saw a similar increase of 49% while Penn Power, Met-Ed, and Penelec all experienced increases but of lesser magnitude; namely 42%, 37%, and 29% respectively. Several components saw an increase in cost over the two years. For example, Synchronized Reserves and Black Start increased 425% and 167% respectively, although combined they still only make up 0.4% of the total wholesale cost of power.

---

11 (Monitoring Analytics, LLC 2013), (Monitoring Analytics, LLC 2014).

12 *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[13,14]

	% Change (2014 vs. 2012)					% Change (2014 vs. 2013)				
	PJM	Penelec	Met-Ed	APS	Penn Power	PJM	Penelec	Met-Ed	APS	Penn Power
Real-Time Load Wtd. LMP (Energy)	51%	48%	55%	52%	42%	37%	34%	41%	41%	14%
Capacity	49%	-16%	0%	69%	80%	26%	-8%	-7%	271%	254%
Transmission Service Charges	24%	-1%	-1%	-4%	20%	14%	0%	0%	-4%	13%
Operating Reserves (Uplift)	49%					100%				
Reactive	-7%	-30%	-18%	-22%	-12%	-50%	-77%	-32%	-43%	-65%
PJM Administrative Fees	5%	5%	5%	5%	5%	2%	2%	2%	2%	2%
Regulation	27%	27%	27%	27%	27%	38%	38%	38%	38%	38%
Transmission Enhancement Cost Recovery	24%	75%	45%	71%	46%	8%	43%	23%	45%	24%
Synchronized Reserves	425%	N/A	N/A	N/A	N/A	425%	N/A	N/A	N/A	N/A
Transmission Owner (Schedule 1A)	13%	0%	0%		-8%	13%	0%	0%		-12%
Day Ahead Scheduling Reserve (DASR)	0%	0%	0%	0%	0%	-17%	-17%	-17%	-17%	-17%
Black Start	167%					-43%				
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%
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										
Capacity (FRR)	N/A	N/A	N/A	N/A	N/A	82%	N/A	N/A	N/A	N/A
Emergency Energy										
Emergency Load Response	N/A	N/A	N/A	N/A	N/A	0%	0%	0%	0%	0%
Total	48%	29%	37%	49%	42%	33%	20%	27%	46%	22%

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.

In 2014, shortage pricing was triggered on two days and the performance of PJM markets under these scarcity conditions raised concerns related to the adequacy of capacity market incentives and the competitiveness of participant offer behavior under tight market conditions.[15]

---

13 (Monitoring Analytics, LLC 2013), (Monitoring Analytics, LLC 2014), (Monitoring Analytics, LLC 2015), and Brattle analysis.

14 Changes 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.

15 (Monitoring Analytics, LLC 2015).

Table 4 and Table 5 summarize the zonal day-ahead and real-time simple average LMPs and their components for the calendar years 2012 through 2014. The difference between average real-time 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 2012 and 2014. Between 2013 and 2014, the Companies' zones experienced a 23.5% (Penn Power) to 36% (Met-Ed) increase in day-ahead prices, and a 14.6% (Penn Power) to 32.6% (Met-Ed) increase in real-time prices. In 2014, Met-Ed remained the zone with the highest simple average LMP, primarily due to transmission congestion.

Table 4
Zonal Day-Ahead, Simple Average LMP Components
Calendar Years 2012 - 2014[16,17]
($/MWh)

	2012				2013				2014			
Zone	*LMP*	*Energy*	*Cong.*	*Loss*	*LMP*	*Energy*	*Cong.*	*Loss*	*LMP*	*Energy*	*Cong.*	*Loss*
APS	32.82	32.72	0.14	-0.04	36.74	37.04	-0.12	-0.18	47.83	48.95	-0.85	-0.27
Penn Power	31.83	32.72	-0.56	-0.34	35.59	37.04	-1.06	-0.38	43.96	48.95	-4.32	-0.67
Met-Ed	33.68	32.72	0.37	0.59	38.27	37.04	0.69	0.55	52.07	48.95	2.67	0.45
Penelec	33.41	32.72	0.10	0.59	38.13	37.04	0.35	0.75	49.22	48.95	-0.15	0.42

Table 5
Zonal Real-Time, Simple Average LMP Components
Calendar Years 2012 - 2014[18]
($/MWh)

	2012				2013				2014			
Zone	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss
APS	33.08	33.06	0.09	-0.07	36.00	36.52	-0.40	-0.11	47.60	48.21	-0.61	0.00
Penn Power	31.69	33.06	-0.81	-0.56	37.27	36.52	1.53	-0.78	42.71	48.21	-4.53	-0.97
Met-Ed	33.96	33.06	0.44	0.46	37.41	36.52	0.23	0.66	49.60	48.21	0.54	0.86
Penelec	33.50	33.06	-0.10	0.54	37.01	36.52	-0.09	0.58	47.63	48.21	-0.99	0.41

Table 6 and Table 7 summarize the zonal day-ahead and real-time, load-weighted average LMPs by component for the calendar years 2012 through 2014. 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.

---

16 2012 values: (Monitoring Analytics, LLC 2013), Appendix G: Congestion and Marginal Losses, p. 423. 2013 & 2014 values: Simple annual averages of LMP data compiled by Ventyx, Inc., the Velocity Suite.

17 LMPs for the Penn Power portion of ATSI Zone are simple annual averages of LMP data compiled by Ventyx, Inc., the Velocity Suite.

18 2012 values: (Monitoring Analytics, LLC 2013), Appendix G: Congestion and Marginal Losses, p. 423. 2013 & 2014 values: 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 2012 - 2014[19,20]
($/MWh)

	2012				2013				2014			
Zone	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss
APS	34.29	34.26	0.09	-0.06	38.23	38.62	-0.21	-0.18	52.89	54.55	-1.41	-0.25
ATSI	33.55	34.32	-0.69	-0.08	38.13	38.69	-0.85	0.29	49.57	52.72	-3.63	0.47
Met-Ed	35.44	34.29	0.50	0.65	40.04	38.62	0.83	0.59	58.52	53.87	4.00	0.65
Penelec	34.69	33.95	0.12	0.62	39.29	38.14	0.38	0.77	53.60	53.40	-0.32	0.51

Table 7
Zonal Real-Time, Load-Weighted Average LMP Components
Calendar Years 2012 - 2014[21]
($/MWh)

	2012				2013				2014			
Zone	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss	LMP	Energy	Cong.	Loss
APS	34.86	34.91	0.04	-0.09	37.70	38.39	-0.57	-0.11	53.11	54.07	-1.03	0.08
ATSI	34.42	34.99	-0.78	0.21	42.12	38.43	3.27	0.42	48.65	52.12	-4.04	0.57
Met-Ed	36.30	35.11	0.67	0.53	39.72	38.63	0.34	0.75	56.09	53.42	1.56	1.12
Penelec	35.10	34.66	-0.12	0.56	38.71	38.18	-0.10	0.63	51.94	52.76	-1.32	0.50

Table 8 contains the zonal peak and off-peak simple average LMPs for the day-ahead and real-time energy markets in 2014. In the day-ahead market, average zonal peak and off-peak LMPs increased by 36% and 21% respectively from 2013 to 2014. Average real-time, peak-hour LMPs increased by 27%, and off-peak LMPs increased by 23%. Of the Companies' zones, Met-Ed Zone shows the largest positive transmission congestion cost component for both the day-ahead and real-time markets.

---

19 2012 values: (Monitoring Analytics, LLC 2013), Section 10: Congestion and Marginal Losses, p. 299.
2013 values: (Monitoring Analytics, LLC 2014), Section 11: Congestion and Marginal Losses, p. 325.
2014 values: Load-weighted annual averages of LMP data compiled by Ventyx, Inc., the Velocity Suite.

20 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.

21 2012 values: (Monitoring Analytics, LLC 2013), Section 10: Congestion and Marginal Losses, p. 299.
2013 values: (Monitoring Analytics, LLC 2014), Section 11: Congestion and Marginal Losses, p. 325.
2014 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 2014
($/MWh)

2014 Day-Ahead Simple Average								
Zone	LMP		Energy		Congestion		Loss	
	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
APS	58.84	38.24	60.35	39.01	-1.11	-0.62	-0.40	-0.16
Penn Power	54.37	34.88	60.35	39.01	-5.18	-3.57	-0.80	-0.56
Met-Ed	64.19	41.50	60.35	39.01	3.19	2.22	0.66	0.26
Penelec	60.85	39.09	60.35	39.01	-0.09	-0.20	0.59	0.27
PJM RTO	60.65	39.12	60.35	39.01	0.33	0.13	-0.02	-0.02

2014 Real-Time Simple Average								
Zone	LMP		Energy		Congestion		Loss	
	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
APS	57.81	38.71	59.10	38.72	-1.25	-0.05	-0.05	0.05
Penn Power	51.87	34.71	59.10	38.72	-6.08	-3.18	-1.15	-0.82
Met-Ed	61.44	39.28	59.10	38.72	1.17	-0.02	1.17	0.58
Penelec	58.34	38.30	59.10	38.72	-1.34	-0.68	0.58	0.26
PJM RTO	59.12	38.72	59.10	38.72	0.00	-0.01	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, as well as explicit transmission congestion costs associated with point-to-point energy transactions, may be summed up by zone to yield a net transmission congestion cost.[22] The net transmission congestion cost for a given zone, or the RTO, may be both positive and 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 increased by $1.255 billion (185.5%) from $676.9 million in 2013 to $1.932 billion in 2014. Similarly, annual day-ahead congestion costs increased by over $1.22 billion, increasing 120.6% from 2013. 2014 continued the trend of increasing congestion costs seen in

[22] *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.*

2013, which was the first year since 2010 in which transmission congestion costs did not experience a decline.

Table 9
Transmission Congestion Costs from 2012 to 2014[23,24]
(Million $)

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

Total Congestion Costs in 2012

	Day-Ahead Market				Balancing Market				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
APS	$5.1	-$52.6	$8.7	$66.4	$3.7	$9.1	-$8.4	-$13.8	$52.5
ATSI	-$50.7	-$55.7	$1.4	$6.5	$2.7	$6.0	$0.4	-$3.0	$3.5
Met-Ed	$9.4	-$0.6	$1.5	$11.4	$0.0	$1.9	-$2.6	-$4.5	$7.0
Penelec	-$2.5	-$35.0	$2.4	$34.8	$0.9	$0.8	-$2.0	-$1.9	$32.9
PJM Total	$135.5	-$512.5	$131.9	$779.9	$3.0	$68.5	-$185.4	-$250.9	$529.0

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 AP South interface, which has the highest transmission congestion

23 (Monitoring Analytics, LLC 2015), (Monitoring Analytics, LLC 2014), (Monitoring Analytics, LLC 2013).

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

impact in PJM, contributed 25.2% (approximately $486.8 million)[25] to 2014 net PJM transmission congestion cost, and it is the top constraint for the APS and ATSI Zones.[26] The AP South interface is usually responsible for price separation between the eastern and western parts of PJM. Other major interfaces are also among the largest contributors to zonal transmission congestion

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 2014, PJM procured capacity in two BRAs: one for delivery year 2013/14 (BRA held in May 2010), and one for delivery year 2014/15 (BRA held in May 2011). For the 2013/14 delivery year, 1st, 2nd, and 3rd incremental auctions were held during the months of September 2011, July 2012, and February through March 2013, respectively. 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] The latest BRA, held in May 2014, was for the 2017/18 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 congested parts 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 constrained within the non-MAAC areas.[29] In 2010 ATSI fully participated in the BRA for the first time, for the

---

25 (Monitoring Analytics, LLC 2015), Section 11: Congestion and Marginal Losses, p. 400.

26 Top transmission constraints in 2014 for the Companies were *AP South Interface, West Interface, Bedington-Black Oak Interface, Bagley – Graceton Line, Cloverdale Transformer, Benton Harbor – Palisades Flowgate*, and *5004/5005 Interface*. (Monitoring Analytics, LLC 2015), Appendix G. Top constraints for the RTO in 2014 were the AP South Interface, the West Interface, the Bagley-Graceton line, the Bedington-Black Oak Interface, and the Breed-Wheetland flowgate. (Monitoring Analytics, LLC 2015), Section 11: Congestion and Marginal Losses, Table 11-23.

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.

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.

2013/14 capacity delivery year. Consequently, 2014 is the first full calendar year ATSI's capacity prices do not reflect transitional prices ($20.46/MW-day for the 2012/13 delivery year).

Figure 3[30]
Locational Deliverability Areas in PJM

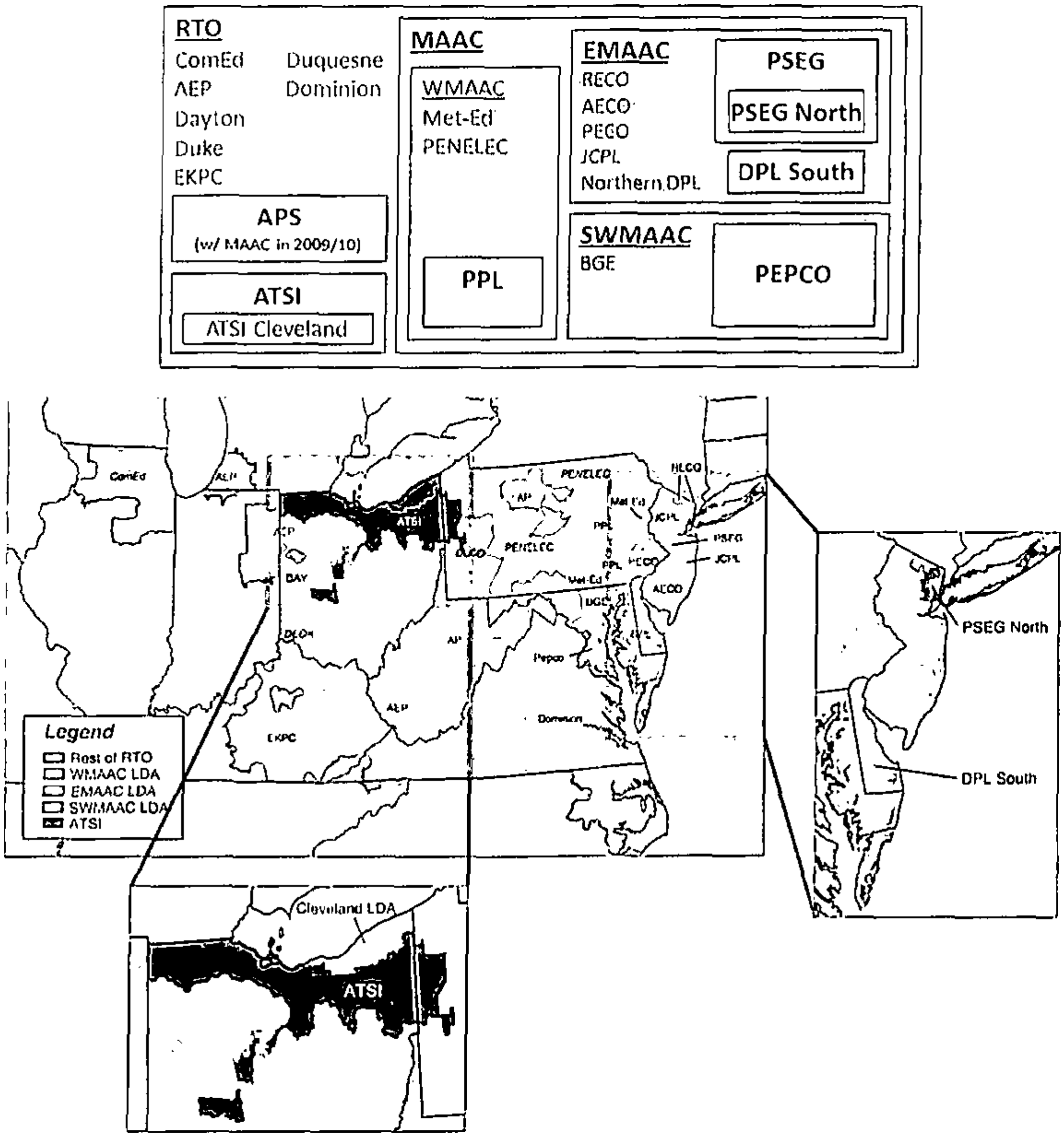


Table 10 summarizes RPM market-clearing prices in the Companies' zones for annual capacity resources delivered in the 2014 calendar year. Capacity price separations indicate that MAAC was more capacity-constrained than the rest of the RTO in 2013, but by summer 2014 that

[30] (Monitoring Analytics, LLC 2014) Section 5: Capacity, Figures 5-1, 5-2, 5-3.

locational constraint was mostly relieved. Price separations also indicate that the system in 2014 had a surplus of low-cost DR with limited performance capability (Limited DR).

MAAC cleared at prices significantly higher than the unconstrained RTO in the Base Residual Auction held for the 2013/14 delivery year (through May 2014), then at unconstrained RTO prices for the 2014/15 delivery year (including June through December of 2014). MAAC prices cleared at $226.15/MW-day (versus $27.73/MW-day in RTO) for the 2013/14 delivery year and at $125.99/MW-day for Annual and Extended Summer resources in the 2014/15 delivery year.

Price separation between MAAC and the rest of the RTO also occurred in the 2nd and 3rd incremental auctions for the 2013/14 delivery year and in all three incremental auctions for the 2014/15 delivery year.[31] Limited DR products cleared at lower prices RTO-wide in the BRA and 1st incremental auctions for the 2014/15 delivery year.

Historically, incremental auctions have cleared at prices below BRA clearing prices. This trend continued in the auctions for 2014 delivery, although MAAC clearing prices in the 3rd incremental auction came very close to BRA clearing prices for the 2014/15 delivery year. Cleared volumes in incremental auctions are much lower than in the BRAs,[32] and therefore their impact on overall capacity costs is relatively small.

Table 10
Wholesale Capacity Prices in 2014[33]
($/MW-day)

Delivery Year	Locational Delivery Area	Base Residual Auction	1st Incremental Auction	2nd Incremental Auction	3rd Incremental Auction
2013/14	RTO	$27.73	$20.00	$7.01	$4.05
	MAAC	$226.15	$20.00	$10.00	$30.00
2014/15	RTO	$125.99	$5.54	$25.00	$25.51
	MAAC	$136.50	$16.56	$56.94	$132.20

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 2017/18. Although ATSI (red line on graph) was included in the BRAs starting with the 2013/14 delivery year,

---

31 For Annual and Extended Summer resources.

32 (PJM 2014d).

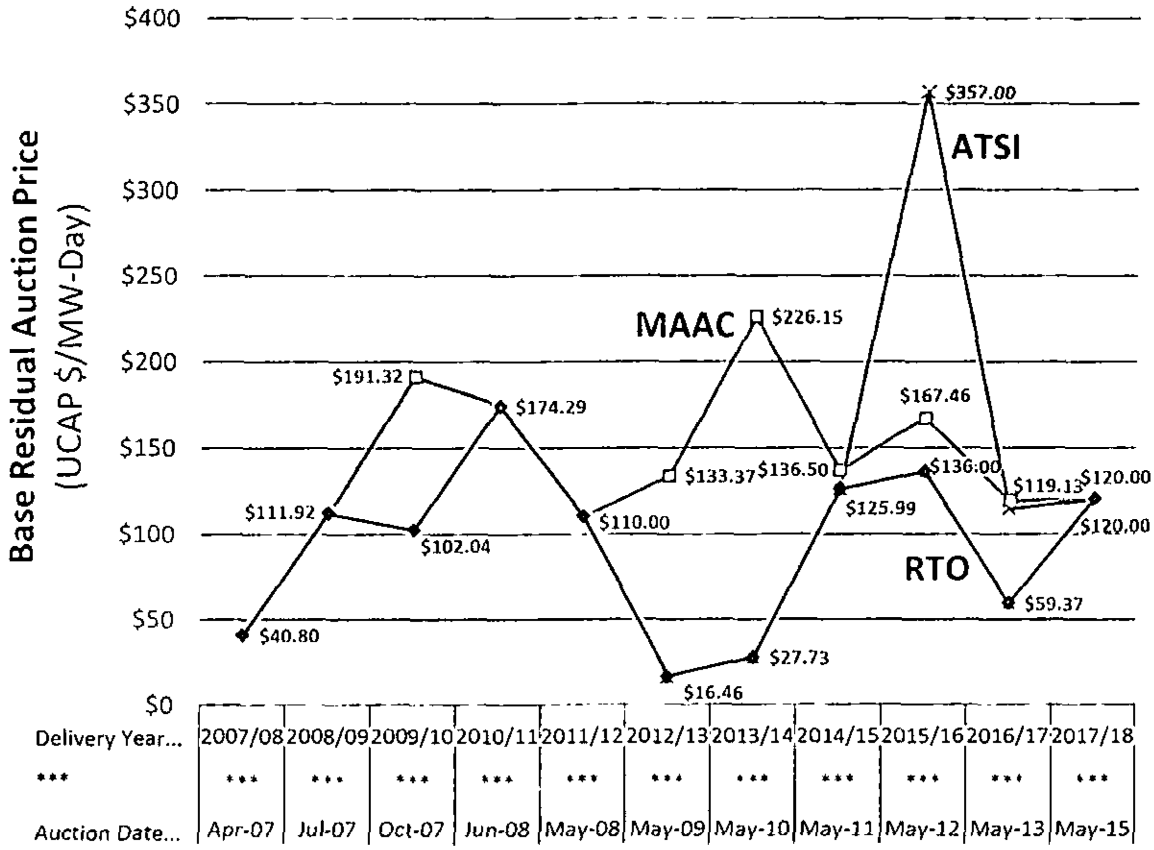
33 For Annual resources.

2015/16 was the first delivery year when ATSI was modeled as a separate LDA.[34] Capacity prices in MAAC (including Penelec and Met-Ed zones) dropped from around the long-term average[35] in the first part of 2014 to unconstrained RTO prices by summer 2014. Conversely, capacity prices in the unconstrained part of PJM (including APS and ATSI) increased significantly from very low prices in the first part of 2014 to levels most recently seen in summer 2011. In more recent auctions, for future delivery years, capacity prices have been less volatile and, although capacity constraints in MAAC have persisted, there has been a lesser degree of price separation between MAAC and the rest of the RTO.

[34] 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.

[35] This is the administratively-determined net Cost of New Entry. See (Pfeifenberger, et al. 2011) Figure 5.

Figure 4[36]
Base Residual Auction Clearing Prices in MAAC and Unconstrained RTO Through the 2017/18 Capacity Delivery Year
(UCAP $/MW-Day)



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 5–6% of wholesale power cost.

---

36 (Monitoring Analytics, LLC 2015), Section 5: Capacity, Table 5-21. The figure shows capacity prices for Annual capacity resources only.

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).[37]

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 2014, 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 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

[37] For more information please see (Monitoring Analytics, LLC 2015), Section 4: Energy Uplift, Table 4-7.

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

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 reached 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.

---

[38] 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.

RPM Supply Resource Types

The RPM capacity market allows a range of resource types to meet resource adequacy requirements. 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 2014

The basic features of the RPM design, discussed above, remained in place during 2014. In addition, three key changes occurred:

- Full integration of ATSI: ATSI joined PJM in June 2011. ATSI did not participate in the Base Residual Auctions for the 2011/12 and 2012/13 capacity delivery years, since these BRAs took place in May 2008 and May 2009, respectively. Instead, PJM held two transitional ATSI Fixed Resource Requirement integration auctions in May 2010. In the same month, ATSI participated in the BRA for the 2013/14 capacity delivery year and in subsequent auctions.

  As a consequence, 2014 is the first full calendar year ATSI capacity prices do not reflect transitional prices. Transitional prices were similar to unconstrained RTO prices for the 2011/12 and 2012/13 delivery years.[39] Continuing the trend, ATSI prices cleared at unconstrained RTO prices in the BRAs for the 2013/14 and 2014/15 delivery years.

- Caps on quantity of capacity-limited products cleared (Limited DR, Extended Summer DR): Prior to the 2014/15 delivery year demand response performance was only required during a limited number of hours in the year. This raised concerns that DR was not providing the same level of reliability as other capacity resources, while receiving the same capacity payments and possibly depressing capacity prices. Starting with the BRA for the 2014/15 delivery year, PJM categorized this DR as Limited DR (or Summer DR), introduced two new capacity products: Extended Summer DR and Annual DR, and enforced constraints on the more limited products by requiring a minimum quantity of Extended Summer DR and Annual DR to be procured during the auction. Until the minimum requirements are met, this allows PJM to select the higher-quality capacity products out-of-merit order.

  Starting with the BRA held in May, 2014—for the 2017/18 delivery year—PJM changed its methodology for applying constraints on the more limited capacity

[39] ATSI transitional prices were $108.89/MW-day and $20.46/MW-day, respectively, and unconstrained RTO prices were $110/MW-day and $16.46/MW-day. (Monitoring Analytics, LLC 2015), Section 5: Capacity, Table 5-21.

products. Instead of requiring a minimum quantity of Extended Summer DR and Annual DR, PJM applied a *maximum* quantity of Limited DR and Extended Summer DR cleared. This more stringent methodology resulted in more higher-quality DR clearing the market, and likely contributed to less DR clearing the market overall.[40]

- Capacity Import Limits for resources external to PJM RTO: Also starting with the BRA held in May, 2014—for the 2017/18 delivery year—PJM enforced limits on the quantity of external resources cleared. This addressed concerns about the impact of large quantities of imports cleared in the prior auction on reliability in the PJM footprint.

III.B. RESULTS OF PJM CAPACITY AUCTIONS IN 2014

Four RPM auctions were held during the 2014 calendar year:

- BRA for the 2017/18 delivery year;
- 1st incremental auction for the 2016/17 delivery year;
- 2nd incremental auction for the 2015/16 delivery year; and
- 3rd incremental auction for the 2014/15 delivery year.

As shown previously in Figure 4, the BRA for 2017/18 delivery cleared at a price of $120/MW-day uniformly for most of the RTO, including the MAAC, APS, and ATSI LDAs.[41] Compared to the 2016/17 BRA, capacity prices cleared at similar levels in MAAC and ATSI and cleared at higher prices in the rest of the RTO (including APS). Capacity prices in APS increased by $60.63/MW-day, from $59.37/MW-day to $120/MW-day.

PJM attributed 2017/18 BRA results to supply-side effects, including decreased imports and demand resources, and increased new entry of generating capacity (mostly combined cycle and combustion turbine capacity).[42] PJM attributed price convergence between MAAC and the rest of the RTO to the location of cleared new entry in historically constrained areas.[43]

Factors that likely maintained prices at $120/MW-day in most LDAs in the 2017/18 BRA include:

- *Significantly less imports cleared*, due to new Capacity Import Limits. Cleared imports decreased from about 6,700 MW in the 2016/17 BRA to about 4,500 MW

40 (PJM 2014a).

41 These are resource clearing prices for annual resources.

42 (PJM 2014a).

43 (PJM 2014a).

in the 2017/18 BRA, closer to the 1,200–3,300 MW range cleared in the 2011/12–2015/16 BRAs.

- *Significant exit of demand response resources*, driven by caps on the quantity of Limited DR and Extended Summer DR, and possibly affected by more stringent requirements on DR Sell Offer Plans and uncertainties related to FERC Order No. 745. Offered DR decreased from about 14,500 MW in the 2016/17 BRA to about 11,300 in the 2017/18 BRA, resulting in about 3,200 MW less DR (unforced) capacity offered, and 1,400 MW less DR capacity cleared.[44]
- *Significant new supply resources* entered the market, from new combined cycle generating units (5,010 MW), other new generating units (379 MW), reactivated steam units (991 MW), incremental generation uprates (474 MW), and incremental energy efficiency (183 MW).[45]

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 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 a risk of retirement.

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.[46] 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.[47,48]

---

[44] (PJM 2014a).

[45] Offered quantities; (PJM 2014a), (PJM 2013a).

[46] *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.

[47] *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.

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.[49] 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 in the 2014 report), new entrant solar installation in the PSEG zone, and new entrant wind in the ComEd and Penelec zones. In the 2013 and 2014 State of the Market Reports, 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.

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 2012 through 2014.[50] 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.[51] 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 a 3-year downward trend for combustion turbine combined cycle plants, and a 3-year upward trend for coal plants. In 2014 combustion turbine plants, combined cycle plants, and wind plants in Penelec would have earned sufficient net revenue to cover their total fixed costs. Combined cycle plants would have also earned sufficient net revenues in Penelec in 2013, and in Met-Ed in 2014. During the period 2012 through 2014, coal plants were the least revenue adequate, followed by diesel and nuclear plants, then by combustion turbine and wind plants.[52] In 2014,

Continued from previous page

48 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.

49 (Monitoring Analytics, LLC 2015), Section 7: Net Revenue.

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

51 In 2014, PJM's market monitor assumed a twenty-year levelized fixed cost of $109/kW-year for combustion turbines; $146/kW-year for combined cycle plants; $504/kW-year for coal plants, $162/kW-year for diesel plants; $881/kW-year for nuclear plants, $198/kW-year for wind installations, and $236/kW-year for solar installations. (Monitoring Analytics, LLC 2015), Section 7: Net Revenue, Table 7-4.

52 The PJM average total net revenues in 2014 covered only 42% of the levelized fixed costs of a new entrant coal plant, 47% of the levelized fixed costs of a new entrant diesel or nuclear plant, and 87% of the levelized fixed costs of a new entrant combustion turbine. Renewable technologies had a higher rate of revenue sufficiency, primarily due to production tax credits and renewable energy

Continued on next page

the revenue adequacy of all types of plants in all of the Companies' PJM zones, and in PJM on average, *increased* compared to 2013 despite higher levelized fixed costs for many technologies, driven by higher winter natural gas and energy prices and higher average capacity prices.

Continued from previous page

credits, which account for 34% of the 2014 net revenue of new wind installations in Penelec. (Monitoring Analytics, LLC 2015), Section 7: Net Revenue, Table 7-20. The total net revenues covered 103% of the levelized costs of new wind installations in Penelec. (Monitoring Analytics, LLC 2015), Section 7: Net Revenue, Table 7-27.

Table 11[53]
Net Revenues Estimates for New Entrants

New Entrant Combustion Turbine						
	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2012	2013	2014	2012	2013	2014
APS	$40,648	$26,129	$86,057	36%	24%	79%
ATSI	N/A	N/A	$78,303	N/A	N/A	72%
Met-Ed	$68,164	$84,811	$105,269	60%	77%	97%
PENELEC	$65,189	$86,068	$148,606	58%	78%	137%
PJM avg.	$54,485	$53,958	$94,035	48%	49%	87%

New Entrant Combined Cycle						
	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2012	2013	2014	2012	2013	2014
APS	$120,834	$88,873	$135,529	78%	59%	93%
ATSI	N/A	N/A	$126,435	N/A	N/A	86%
Met-Ed	$139,501	$146,902	$159,107	90%	98%	109%
PENELEC	$149,678	$167,866	$218,163	96%	111%	149%
PJM avg.	$129,221	$114,939	$148,923	83%	76%	102%

New Entrant Coal Plant						
	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2012	2013	2014	2012	2013	2014
APS	$74,196	$102,069	$211,598	15%	21%	42%
ATSI	N/A	N/A	$200,935	N/A	N/A	40%
Met-Ed	$81,612	$107,399	$220,558	17%	22%	44%
PENELEC	$95,700	$171,249	$251,295	20%	35%	50%
PJM avg.	$66,034	$100,059	$212,912	14%	20%	42%

New Entrant Diesel						
	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2012	2013	2014	2012	2013	2014
APS	$19,816	$8,513	$51,178	13%	6%	32%
ATSI	N/A	N/A	$45,526	N/A	N/A	28%
Met-Ed	$43,744	$64,315	$97,409	29%	42%	60%
PENELEC	$44,003	$64,135	$77,729	29%	42%	48%
PJM avg.	$31,932	$36,135	$75,439	21%	24%	47%

New Entrant Nuclear						
	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2012	2013	2014	2012	2013	2014
APS	$232,430	$255,121	$372,813	29%	32%	42%
ATSI	N/A	N/A	$360,005	N/A	N/A	41%
Met-Ed	$263,089	$323,882	$439,125	33%	40%	50%
PENELEC	$260,727	$322,624	$414,193	33%	40%	47%
PJM avg.	$249,068	$285,909	$410,096	31%	36%	47%

New Entrant Wind						
	Net Revenue ($/MW-year)			% of 20-Year Levelized Fixed Costs		
	2012	2013	2014	2012	2013	2014
PENELEC	$132,802	$162,479	$203,934	68%	83%	103%

53 (Monitoring Analytics, LLC 2015), Section 7: Net Revenue, Tables 7-4 through 7-27. Note some of the 2012 and 2013 values, particularly for PJM, appear to be updated by the market monitor from prior reports.

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.[54] In 2014 PJM market revenues matched or exceeded avoidable costs for 100% of all hydro and pumped storage units, 93–100% of combined cycle units, 96–100% of combustion turbine units, 93% of all diesel units, 88% of oil or gas steam units, and 80–87% of coal units.[55] The market monitor also found that 6,946 MW of capacity (mostly coal) is at-risk for retirement in addition to already-planned retirements.[56] Due to lack of data, the market monitor's analysis excludes nuclear units.[57]

Actual New Entry in PJM

The RPM capacity market plays a crucial role in ensuring long-term revenue adequacy. PJM estimates that since the launch of the current resource adequacy construct in 2007, the RPM capacity market has attracted or retained about 62,500 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.

54 (Monitoring Analytics, LLC 2015), Section 7: Net Revenue, Table 7-35.

55 (Monitoring Analytics, LLC 2015), Section 7: Net Revenue, Table 7-35. The ranges reflect values for different unit types within each category. For example, 80–87% for coal units reflects 80% for sub-critical coal and 87% for super-critical coal. Note that the market monitor also reported that 0% of nuclear units recovered their avoidable costs from PJM markets, but this was based on a rough approximation of avoidable costs.

56 (Monitoring Analytics, LLC 2015), Section 7: Net Revenue, p. 266.

57 (Monitoring Analytics, LLC 2015), Section 7: Net Revenue, p. 266.

Table 12[58]
Impact of RPM on Capacity Availability to Date
Through the 2017/18 Base Residual Auction Results
(MW)

Change in Capacity Availability	Installed Capacity (MW)
New Generation	25,839
Generation Upgrades (excluding reactivations)	7,641
Generator Reactivations	1,560
Demand Resources and Energy Efficiency	12,582
Withdrawn and Canceled Retirements	7,148
Net Imports	7,694
Total	62,464

IV. Ancillary Service Markets

PJM currently procures four ancillary services products in organized markets: (1) regulation, (2) synchronized reserve, (3) non-synchronized reserve, and (4) day-ahead scheduling reserve.[59]

Other ancillary services, procured on a non-market basis, are compensated on the basis of incentive rates or costs. These services include black start service and reactive power. 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 market for regulation, and the market clearing price is the uniform price paid for regulation across the RTO footprint.

58 (PJM 2014a), Table 10.

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

In 2012 significant changes were made to the regulation market then a FERC-ordered modification to settlement methodology was implemented in 2013. The market monitor recognizes significant improvements in the 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 underpayment of the more flexible (RegD) regulation resources.[60]

Throughout 2014 the regulation market had the same basic structure and rules:[61, 62]

- 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,[63] 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).

In 2014 the annual weighted average RMCP was $44.15/MW (unadjusted MW), significantly higher than $30.14/MW in 2013, due to system conditions during the winter (January through March 2014).[64] *The daily weighted average RMCP reached as high as about $450/MW in January* 2014 according to the market monitor.[65] Figure 5 shows PJM's publicly-available data on 2014

---

60 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 335.

61 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, pp. 369–375.

62 (PJM n.d.).

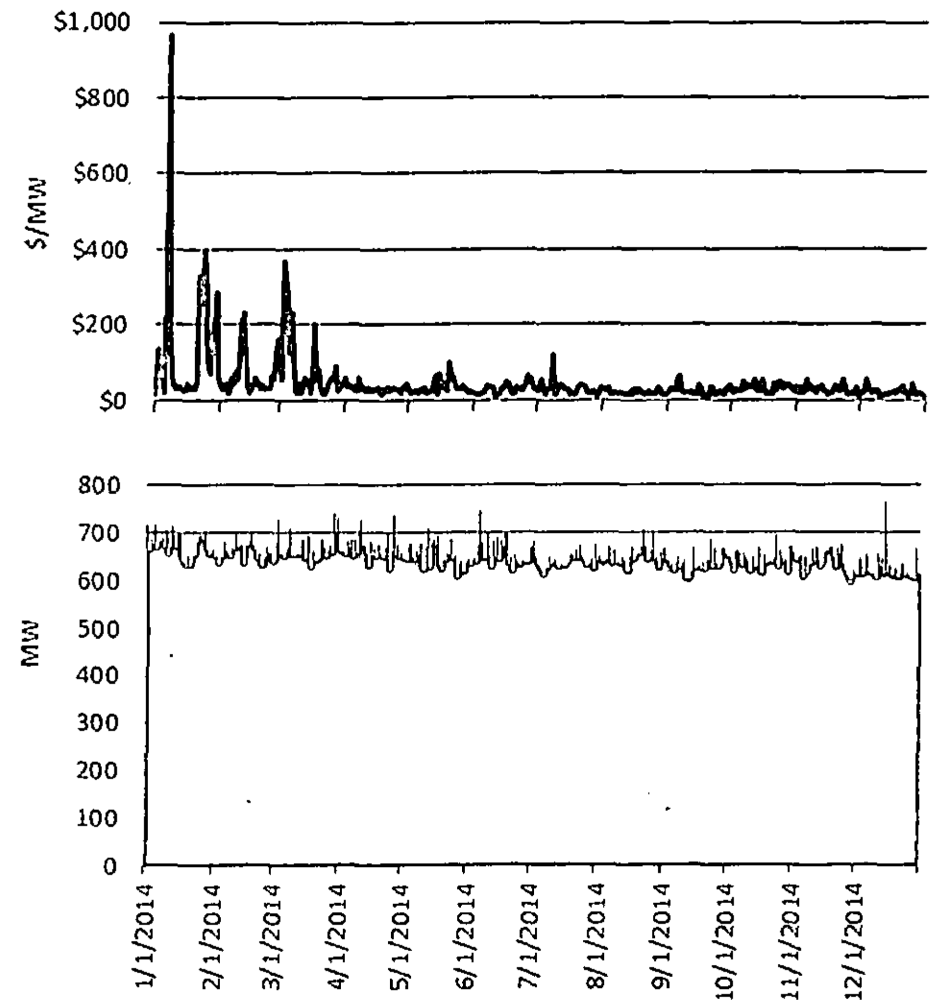
63 PJM's real-time market not only jointly optimizes within regulation, but among energy and all ancillary services (regulation, synchronized reserves, and non-synchronized reserve).

64 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 379.

65 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, Figure 10-27.

daily average regulation market clearing prices (RMCP) and associated MW scheduled, indicating even more dramatic price spikes in January.[66]

Figure 5
Daily Average Regulation Market Clearing Prices (RMCP, $/MW) and Regulation Reserves Scheduled (MW) in 2014[67]



---

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

[67] Based on 2014 hourly data published by PJM. (PJM 2015c). 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)[68] by maintaining ten-minute primary reserves. PJM's primary reserve requirement is 2,063 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.[69] At least 1,375 MW of the requirement must be met by synchronized reserve, and at least 1,300 MW of that synchronized reserve must be located in the Mid-Atlantic Dominion ("MAD") subzone.[70]

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.[71]

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.[72] Tier 1 event response credits averaged $85.23/MW in 2014.[73]

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. Through the first half of 2014 PJM was incorrectly paying both selected *and* deselected[74] Tier 1 resources under this market rule.[75] PJM corrected this settlement issue in June 2014 and deselected Tier 1 resources no longer receive this payment. The market monitor further recommends that this special market rule be eliminated entirely, even for *selected* Tier 1

68 Available at http://www.nerc.com/files/BAL-002-0.pdf.

69 (Monitoring Analytics, LLC 2014), Section 10: Ancillary Services, p. 306.

70 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 2014 the zone was defined east of the Bedington–Black Oak interface constraint. (Monitoring Analytics, LLC 2015), p. 343.

71 (PJM 2015a), Section 4.

72 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 345.

73 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 352.

74 Resources removed from the market solution due to inability to reliably provide Tier 1 reserve.

75 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 350.

resources, since it essentially results in windfall payments to Tier 1 without providing any incentives for performance or to provide more Tier 1 resources.[76]

Figure 6 illustrates daily average Tier 2 synchronized reserve procured and market-clearing prices in the Mid-Atlantic Dominion Subzone. In 2014, the average amount of Tier 2 reserves cleared in the Mid-Atlantic Dominion Subzone was 352.6 MW, compared to 153.8 MW in 2013.[77] The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone during cleared hours was $15.50/MW, versus $7.11/MW in 2013.[78] The relatively high prices in 2014 were driven by January 2014 system conditions.

Contribution of demand resources to the supply of synchronized reserves remained significant in 2014 but much lower than in prior years. Demand resources represented 15% of all cleared Tier 2 *synchronized reserves in 2014, compared to 36% in 2012 and 38% in 2013.*[79]

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 2014 the Synchronized Reserve Penalty Factor and the Non-Synchronized Reserve Penalty Factor were both equal to $400/MWh. Starting June 1, 2014, the penalty factors were increased to $550/MWh.[80] Reserve *shortages occurred in two days in early January 2014, for a total of about seven hours.*[81] Impacts on daily average prices can be seen in Figure 5 and Figure 6—particularly on January 7, 2014, when the daily average RMCP reached almost $1,000/MW and the daily weighted average SRMCP reached almost $250/MW.

---

[76] (Monitoring Analytics, LLC 2015), Section 2: Recommendations, p. 64.

[77] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 355.

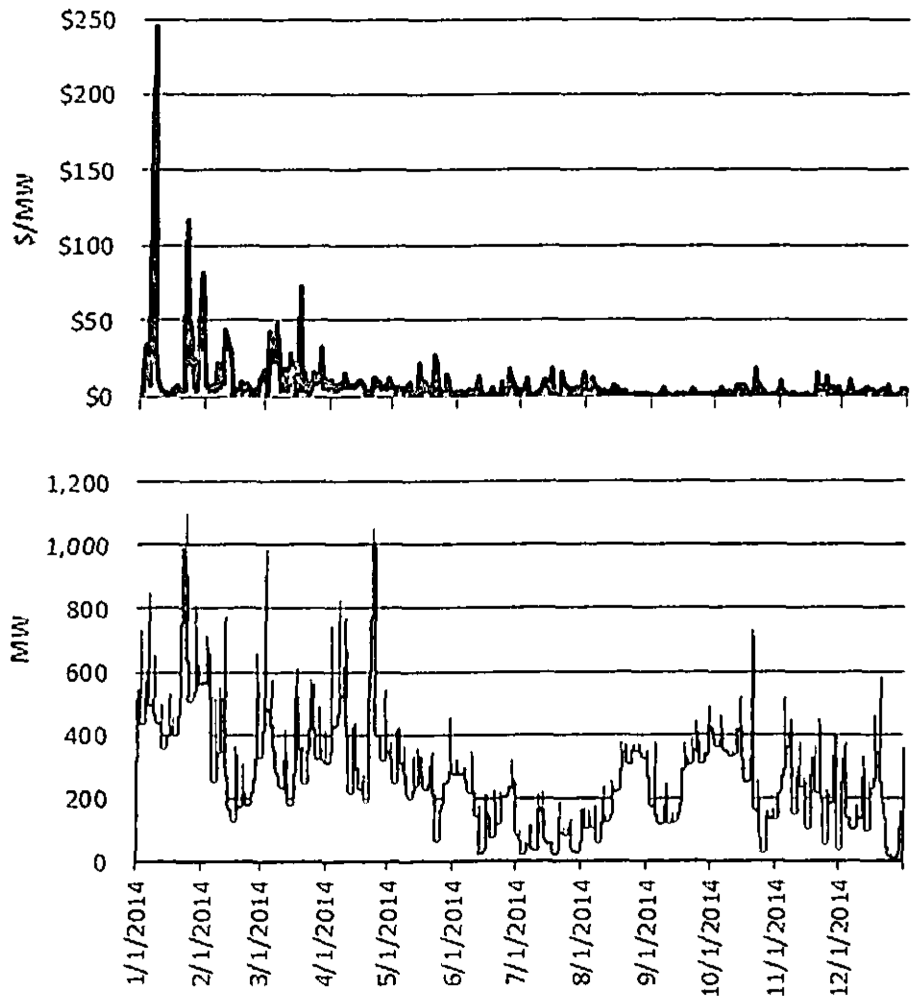
[78] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 357.

[79] (Monitoring Analytics, LLC 2014), Section 10: Ancillary Services, p. 310; (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 353.

[80] (PJM 2015a), Section 2.

[81] (Monitoring Analytics, LLC 2015), Section 3: Energy Market, p. 129.

Figure 6
Daily Average Mid-Atlantic Dominion Subzone Synchronized Reserve Market Clearing Prices ($/MW) and Purchases (MW) and in 2014[82]



[82] Based on 2014 hourly data published by PJM. (PJM 2015d). 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 2,063 MW, with some restrictions.[83] At least 1,375 MW of the requirement must be met by synchronized reserve, and at least 1,300 MW of that synchronized reserve must be 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.[84] Examples of such resources include shutdown run-of-river hydro, shutdown pumped hydro, and offline combustion turbines. The market monitor found that almost all non-synchronized reserve resources are combustion turbines (50%) and hydro (48%), and a small share are diesels (2%).[85] 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 2014 the non-synchronized reserve price was greater than zero in 541 hours (6.2% of hours) in the Mid-Atlantic Dominion reserve zone, and 379 hours (4.4% of hours) in the RTO subzone,[86] compared to 228 hours in the Mid-Atlantic Dominion subzone and 73 hours in the RTO reserve zone in 2013.

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

---

[83] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 342.

[84] (PJM 2015a), Section 4b.

[85] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 364.

[86] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 365.

outage rates.[87] In 2013, the DASR requirement was 6.27% of forecasted peak load, down from 6.91% in 2013.[88]

In 2014 94.1% of the hours cleared at a price of $0.00.[89] There were, however, high DASR prices in January 2014, with a maximum clearing price of $534.66/MW. DASR prices tend to rise when reserves cannot be filled without re-dispatch and when energy prices are high, due to lost opportunity costs. The annual weighted-average DASR clearing price in 2014 was $0.63/MW, down slightly from $0.70/MW in 2013.[90]

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. At the end of 2013, 9.6% of all units offered DASR at or above $5 per MW.[91] 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.[92]

Since there is no organized market for black start service PJM issues requests for proposals to provide service from any willing party in a given location. In 2014 PJM issued two requests for black start, the second of which was for northeastern Ohio and western Pennsylvania.

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.[93] The cost is then allocated to transmission customers proportionally based on load ratios. Generally, the

[87] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 367.

[88] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 367; (Monitoring Analytics, LLC 2014), Section 10: Ancillary Services, p. 316.

[89] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 367 and Table 10-26.

[90] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 367; (Monitoring Analytics, LLC 2014), p. 316.

[91] (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 367.

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

[93] (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.[94]

The 2014 black start charges totaled $60 million, composed of $27 million in revenue requirement charges and $33 million in operating reserve charges.[95] This is a decrease compared to 2013 total charges of $108 million, composed of $21 million in revenue requirement charges and $87 million in operating reserve charges.[96]

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.[97] Similar to black start service, charges are allocated to customers based on percentage of load. Total reactive power charges in 2014 were $310 million, composed of $280.3 million in revenue requirement charges and $29.4 million in operating reserve charges.

94 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p.384.

95 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, pp. 384–385.

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

97 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 386.

VI. Conclusion

Overall, PJM market prices reflect market fundamentals and market performance. In 2014, market dynamics were driven by higher natural gas prices–particularly in the eastern part of the RTO, higher demand, severe winter conditions in the first part of the year, and constrained capacity supply in MAAC. Market performance was mostly competitive, with a few exceptions discussed below.

VI.A. Market Performance in 2014

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 2014. The market monitor's assessment has not changed since last year. According to this assessment, all markets yielded competitive outcomes despite some concerns with market structure, participant behavior, and market design.

Table 13[98]
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

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 9.6% of offers reflected economic withholding.[99]

Market design in the energy market was determined to be effective. Capacity market design was determined to have mixed effectiveness due to a 2.5% holdback in demand in the Base Residual Auctions and inclusion of several types of lower-quality capacity. 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 due to a number of issues, primarily a flawed definition of opportunity cost and inconsistent implementation of marginal benefit factors.

In addition to the competitive wholesale market, there is competition in the Pennsylvania retail sector. As of January 1, 2015, the percentage of residential customers served by an alternative supplier in the Companies' territories ranged from 28.1% in the West Penn service territory to 35.0% in the Penelec service territory, representing 28.7% and 36.9% of the retail load, respectively.[100] The percentage of commercial load served by an alternative supplier ranged from 57.6% in the Penn Power territory to 70.2% in the Met-Ed territory. The percentage of

98 (Monitoring Analytics, LLC 2015), Section 1: Introduction, pp. 6–8.

99 (Monitoring Analytics, LLC 2015), Section 10: Ancillary Services, p. 367.

100 (Pennsylvania Office of Consumer Advocate 2015).

industrial load served by an alternative supplier ranged from 90.9% in the West Penn territory to 96.4% in the Met-Ed 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
EPA	Environmental Protection Agency
FRR	Fixed Resource Requirement
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
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

Bibliography

Frequency Regulation Compensation in the Organized Wholesale Power. Docket Nos. RM11-7-000 and AD10-11-000 (Federal Energy Regulatory Commission, October 20, 2011).

Monitoring Analytics, LLC. "2010 State of the Market Report for PJM, Volume 2: Detailed Analysis." *Reports.* March 10, 2011. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume2.pdf (accessed April 2014).

—. "2011 State of the Market Report for PJM, Volume 2: Detailed Analysis." *Reports.* March 15, 2012. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011/2011-som-pjm-volume2.pdf.

—. "2012 State of the Market Report for PJM, Volume 2: Detailed Analysis." *Reports.* March 14, 2013. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012/2012-som-pjm-volume2.pdf.

—. "2013 State of the Market Report for PJM, Volume 2: Detailed Analysis." *Reports.* March 13, 2014. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml (accessed March 2014).

—. "2014 State of the Market Report for PJM, Volume 2: Detailed Analysis." *Reports.* March 12, 2015. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014.shtml (accessed March 2015).

Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing. ER-14-2940-000 (U.S. Federal Energy Regulatory Commission, November 28, 2014).

Order on Compliance Filing and Accepting Proposed Tariff Changes. Docket Nos. ER12-1204-001 et al. (Federal Energy Regulatory Commission, November 16, 2012).

Pennsylvania Office of Consumer Advocate. "Pennsylvania Electric Shopping Statistics: January 1, 2015." *Pennsylvania Electric Shopping Statistics.* January 1, 2015. http://www.oca.state.pa.us/Industry/Electric/elecstats/ElectricStats.htm (accessed April 2015).

Pfeifenberger, Johannes, Samuel Newell, Kathleen Spees, Attila Hajos, and Kamen Madjarov. "Second Performance Assssment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15." August 26, 2011. http://www.pjm.com/~/media/committees-groups/committees/mrc/20110818/20110826-brattle-report-second-performance-assessment-of-pjm-reliability-pricing-model.ashx.

PJM. "2015/2016 Planning Period Parameters." *PJM Auction User Information.* May 22, 2012a. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2015-2016-planning-period-parameters.ashx (accessed March 2014).

—. "2016/2017 Base Residual Auction Report." *PJM Auction User Information.* May 24, 2013a. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx (accessed March 2014).

—. "2016/2017 Planning Period Parameters." *PJM Auction User Information.* April 30, 2013b. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-planning-period-parameters.ashx (accessed March 2014).

—. "2017/2018 Base Residual Auction (BRA) Results." *Capacity Market (RPM), Delivery Years 2017/2018.* June 18, 2014a. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx (accessed April 2015).

—. "2017/2018 Planning Period Parameters." *RPM Auction User Information.* March 21, 2014b. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx (accessed March 2014).

—. "2017/2018 RPM Resource Model." *RPM Auction User Information.* March 5, 2014c. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-rpm-resource-model.ashx (accessed March 2014).

—. "Auction Results for All Incremental Auctions & Base Residual Auction (xls file)." *Capacity Market (RPM), Delivery Years 2014/2015.* June 5, 2014d. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-auction-results-for-bra-and-all-incremental-auctions.ashx (accessed March 2015).

—. "Map of PJM Territory Served." *Who We Are: Territory Served.* No Date. http://www.pjm.com/~/media/about-pjm/pjm-zones.ashx (accessed March 2014).

—. "PJM Manual 11: Energy & Ancillary Services Market Operations, Revision 74." *Manuals.* April 9, 2015a. https://www.pjm.com/documents/manuals.aspx (accessed April 2015).

—. "PJM Open Access Transmission Tariff." *Agreements / Governing Documents.* February 20, 2015b. https://www.pjm.com/documents/agreements.aspx (accessed April 2015).

—. *PJM Regulation Zone Preliminary Billing Data.* April 2015c. http://www.pjm.com/markets-and-operations/market-settlements/preliminary-billing-reports/pjm-reg-data.aspx (accessed April 2015).

—. "PJM Shortage Pricing Training." *Shortage Pricing.* September 2012, 2012b. http://www.pjm.com/~/media/markets-ops/energy/shortage-pricing/shortage-pricing-training.ashx (accessed April 2014).

PJM Resource Adequacy Planning Department. "PJM Load Forecast Report." *Load Forecast Development Process.* December 12, 2014. http://www.pjm.com/~/media/documents/reports/2015-load-forecast-report.ashx (accessed April 2015).

PJM. *Synchronized Reserve Zone Preliminary Billing Data.* April 2015d. http://www.pjm.com/markets-and-operations/market-settlements/preliminary-billing-reports/sync-reserve.aspx (accessed April 2015).

—. *Training Material.* n.d. http://www.pjm.com/training/training-material.aspx (accessed April 2014).

Appendix A[101]

APS Control Zone
Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2014

				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	AP South	Interface	500	-50.40	-193.30	-9.90	132.90	7.10	18.70	6.30	-5.40	127.60	10,180	1,962
2	West	Interface	500	-97.90	-94.80	-23.60	-26.70	-1.50	4.50	5.90	-0.10	-26.80	3,068	830
3	Bedington - Black Oak	Interface	500	-3.10	-28.70	-3.60	22.00	1.10	1.10	1.70	1.70	23.70	5,592	646
4	Cloverdale	Transformer	AEP	11.40	5.30	4.30	10.40	0.00	-0.10	-0.50	-0.40	9.90	8,246	334
5	Wolf Creek	Transformer	AEP	7.80	11.10	3.60	0.20	0.80	-0.90	-10.40	-8.70	-8.50	10,204	262
6	USAP - Woodville	Line	DLCO	8.70	1.80	0.90	7.70	0.30	0.00	-0.90	-0.60	7.10	1,490	244
7	Brambleton - Loudoun	Line	Dominion	3.50	-1.60	1.00	6.10	0.10	0.00	-0.20	-0.10	6.00	194	28
8	Rivesville - Wove	Line	AP	3.60	-1.50	-0.10	4.90	0.30	0.20	0.00	0.10	5.00	794	340
9	Benton Harbor - Palisades	Flowgate	MISO	7.50	4.10	1.10	4.50	0.00	0.00	-0.20	-0.20	4.30	6,050	274
10	Grafton - Pruntytown	Line	AP	3.30	-0.80	0.10	4.10	0.10	0.10	0.10	0.10	4.20	680	94
11	Bagley - Graceton	Line	BGE	13.20	10.50	-0.80	2.00	0.30	-0.10	0.90	1.30	3.20	9,168	3,768
12	Readington - Roseland	Line	PSEG	-2.60	-0.60	-1.90	-4.00	0.00	0.10	1.20	1.10	-2.90	2,338	378
13	Kingwood - Pruntytown	Line	AP	1.70	-0.60	0.50	2.80	0.00	0.00	0.00	0.00	2.80	1,738	0
14	5004/5005 Interface	Interface	500	-4.80	-6.50	-1.00	0.60	0.10	0.30	2.10	1.80	2.40	1,108	672
15	Dravosburg - West Mifflin	Line	DLCO	2.90	0.70	1.10	3.30	0.10	0.10	-1.00	-0.90	2.30	578	202
19	Lakelynn - Westrun	Line	AP	0.60	-0.90	0.00	1.50	0.00	0.00	0.00	0.00	1.50	546	0
21	Enon - Gilboa	Line	AP	3.90	3.40	0.90	1.40	0.00	0.00	0.00	0.00	1.40	576	0
24	Butler - Karns City	Line	AP	0.90	-0.40	0.00	1.30	-0.20	0.10	0.20	-0.10	1.20	1,538	120
25	All Dam - Kittanning	Line	AP	-0.30	-1.80	-0.10	1.40	-0.10	0.10	0.10	-0.20	1.20	1,406	0
27	Doubs - Mt. Storm	Line	AP	-0.10	-1.20	0.00	1.10	0.00	0.00	0.00	0.00	1.10	104	0

ATSI Control Zone
Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2014

				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	AP South	Interface	500	-181.30	-167.60	-8.50	-22.20	-0.50	7.30	7.60	-0.30	-22.50	10,180	1,962
2	West	Interface	500	-122.10	-114.90	-4.70	-11.90	0.30	3.50	1.10	-2.10	-13.90	3,068	830
3	Benton Harbor - Palisades	Flowgate	MISO	39.50	27.40	0.00	12.10	-0.40	-0.10	-1.10	-1.50	10.70	6,050	274
4	SENECA	Interface	500	0.00	0.00	-8.30	-8.30	0.00	0.00	0.00	0.00	-8.30	7,124	0
5	Cook - Palisades	Flowgate	MISO	26.60	15.40	1.10	12.30	-0.80	-0.10	-4.20	-4.90	7.50	1,632	616
6	South Canton - Star	Line	AEP	7.40	3.40	1.20	5.20	-0.10	-0.20	-0.30	-0.30	4.90	1,186	10
7	Bedington - Black Oak	Interface	500	-28.70	-25.40	-0.30	-3.50	0.30	0.70	0.50	0.10	-3.50	5,592	646
8	Ottowa - West Fremont	Line	ATSI	-1.40	-4.40	0.20	3.20	0.00	0.00	-0.10	-0.10	3.10	552	66
9	Cloverdale	Transformer	AEP	-10.50	-6.80	1.20	-2.50	-0.10	0.00	-0.10	-0.10	-2.60	8,246	334
10	East Lima - New Liberty	Line	AEP	4.00	2.10	0.60	2.40	0.00	0.00	0.00	0.00	2.40	1,838	0
11	Wolf Creek	Transformer	AEP	-2.00	-0.40	0.20	-1.50	-0.10	0.10	-0.70	-0.90	-2.30	10,204	262
12	Beaver Valley - Hanna	Line	DLCO	1.40	-0.60	0.20	2.30	0.00	0.00	0.00	0.00	2.30	242	0
13	Highland - Salt Springs	Line	ATSI	2.00	0.20	0.30	2.10	0.00	0.00	0.00	0.00	2.10	436	0
14	AEP - DOM	Interface	500	-5.90	-4.60	0.00	-1.30	0.00	0.40	-0.30	-0.80	-2.10	5,022	132
15	Inland - Pofok Tie	Line	ATSI	1.50	0.30	0.70	1.90	0.00	0.00	0.00	0.00	1.90	2,856	0
17	Lakeview - Greenfield	Line	ATSI	11.10	-1.10	4.90	17.10	1.10	9.30	-7.00	-15.20	1.90	1,828	312
19	Longview - ARMCO	Line	ATSI	2.70	1.50	0.80	2.00	0.60	0.30	-0.60	-0.30	1.70	676	148
22	Juniper - Northfield	Line	ATSI	1.60	0.20	0.20	1.50	1.20	0.20	-1.00	0.00	1.50	378	44
23	Brookside - Troy	Line	ATSI	1.90	1.00	0.40	1.40	0.00	0.00	0.00	0.00	1.40	1,208	0
24	West Akron - Brush	Line	ATSI	1.80	0.60	0.20	1.40	0.00	0.00	0.00	0.00	1.40	534	0

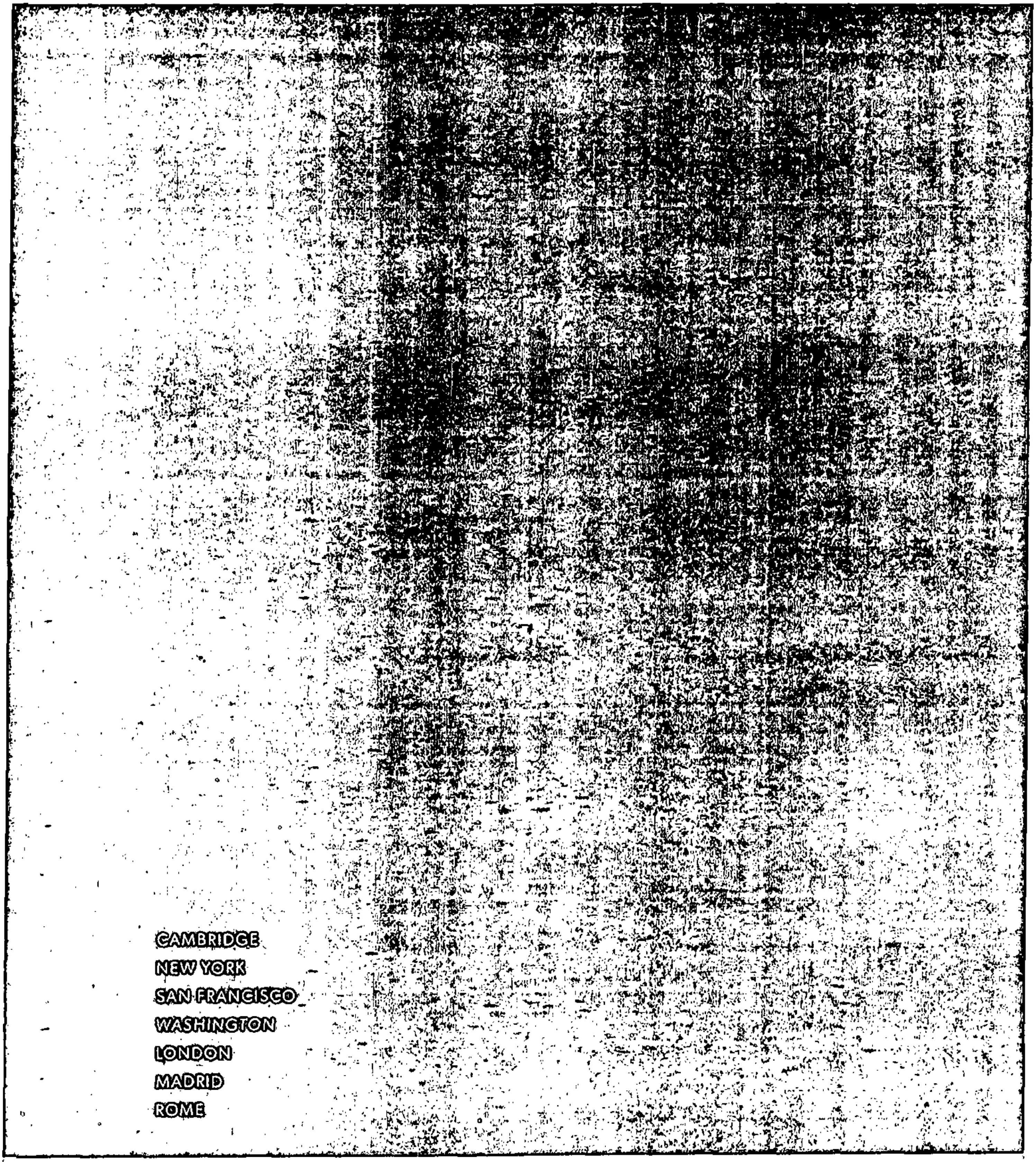
[101] (Monitoring Analytics, LLC 2015), Appendix G.

METED Control Zone
Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2014

				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*	*-28.60*	*-42.60*	*-2.00*	*11.90*	*0.60*	*1.00*	*2.00*	*1.60*	*13.50*	*9,168*	*3,768*
2	West	Interface	500	65.90	76.60	0.30	-10.50	1.00	3.60	-0.50	-3.00	-13.50	3,068	830
3	Wescosville	Transformer	PPL	1.50	-0.10	0.20	1.80	0.00	0.00	0.00	0.00	1.80	2,390	8
4	Graceton - Safe Harbor	Line	BGE	-3.80	-5.10	-0.30	1.00	0.10	0.50	0.80	0.40	1.30	3,562	802
5	5004/5005 Interface	Interface	500	4.10	4.40	0.00	-0.40	0.60	1.30	0.00	-0.70	-1.00	1,108	672
6	Readington - Roseland	Line	PSEG	-5.80	-6.90	-0.10	1.00	0.00	0.00	0.10	0.00	1.00	2,338	378
7	Cloverdale	Transformer	AEP	4.10	5.10	0.10	-0.90	0.00	0.00	0.00	0.00	-0.90	8,246	334
8	Cook - Palisades	Flowgate	MISO	3.00	3.90	0.00	-0.90	0.00	0.00	-0.10	0.00	-0.90	4,632	616
9	Brunner Island - Yorkanna	Line	Met-Ed	0.10	-0.70	0.00	0.80	0.00	0.00	0.00	0.00	0.80	216	0
10	AP South	Interface	500	5.80	6.50	0.50	-0.30	0.30	0.30	-0.50	-0.50	-0.80	10,180	1,962
11	Benton Harbor - Palisades	Flowgate	MISO	4.80	5.60	0.10	-0.70	0.00	0.00	0.00	0.00	-0.70	6,050	274
12	Northwood	Transformer	Met-Ed	0.90	0.30	0.00	0.60	0.00	0.00	-0.10	-0.10	0.60	578	76
13	Brambleton - Loudoun	Line	Dominion	3.60	4.10	0.00	-0.50	0.00	0.10	0.00	-0.10	-0.60	194	28
14	Wolf Creek	Transformer	AEP	0.90	1.20	0.00	-0.30	0.10	0.30	0.00	-0.30	-0.60	10,204	262
15	Conastone - Northwest	Line	BGE	-1.10	-1.50	-0.10	0.30	0.00	0.00	0.20	0.20	0.50	206	216
21	Jackson - Three Mile Island	Line	Met-Ed	0.10	-0.20	0.00	0.30	0.00	0.00	0.00	0.00	0.30	156	4
23	Hunterstown	Transformer	Met-Ed	0.30	0.00	0.20	0.50	0.00	0.00	-0.10	-0.10	0.30	950	10
39	Middletown Jct - Yorkhaven	Line	Met-Ed	0.00	0.00	0.10	0.10	0.00	0.00	0.00	0.00	0.10	2,084	0
42	*Gardners - Texas East*	*Line*	*Met-Ed*	*0.10*	*0.00*	*0.00*	*0.20*	*0.00*	*0.00*	*0.00*	*0.00*	*0.10*	*178*	*0*
48	Ironwood - South Lebanon	Line	Met-Ed	0.00	-0.10	0.00	0.10	0.00	0.00	0.00	0.00	0.10	142	0

Penelec Control Zone
Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2014

				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	West	Interface	500	-42.00	-119.30	-8.60	68.80	0.80	6.80	2.10	-3.90	64.80	3,068	830
2	AP South	Interface	500	-89.00	-129.00	-1.40	38.60	2.40	8.40	1.90	-4.10	34.50	10,180	1,962
3	Bagley - Graceton	Line	BGE	-30.20	-44.10	-0.80	13.10	0.90	1.60	1.30	0.60	13.70	9,168	3,768
4	Seneca	Interface	PENELEC	0.00	0.00	0.00	0.00	-3.00	1.20	-8.00	-12.20	-12.20	0	6,454
5	Bedington - Black Oak	Interface	500	-16.60	-24.30	0.30	8.00	0.20	0.30	-0.40	-0.50	7.40	5,592	646
6	5004/5005 Interface	Interface	500	-4.20	-11.70	-0.80	6.70	0.40	2.30	2.00	0.10	6.80	1,108	672
7	*Corry East - Warren*	*Line*	*PENELEC*	*1.90*	*1.20*	*0.00*	*0.70*	*-5.40*	*0.80*	*-0.30*	*-6.50*	*-5.80*	*846*	*1,074*
8	Benton Harbor - Palisades	Flowgate	MISO	17.20	21.40	-0.80	-5.00	0.00	0.00	0.20	0.20	-4.80	6,050	274
9	Homer City - Shelocta	Line	PENELEC	-14.30	-17.70	-0.20	3.10	0.10	0.40	0.60	0.30	3.40	1,054	76
10	Cook - Palisades	Flowgate	MISO	10.70	13.90	-0.80	-4.00	0.10	0.10	0.80	0.80	-3.20	4,632	616
11	USAP - Woodville	Line	DLCO	2.90	5.40	0.10	-2.40	0.00	0.00	-0.20	-0.20	-2.60	1,490	244
12	Cloverdale	Transfomer	AEP	4.60	7.80	0.90	-2.20	0.00	0.00	-0.20	-0.30	-2.50	8,246	334
13	Central	Interface	500	-0.50	-3.40	-0.40	2.50	0.00	0.10	0.00	-0.10	2.40	668	20
14	Readington - Roseland	Line	PSEG	6.20	2.90	-2.40	1.00	0.00	0.00	1.30	1.20	2.20	2,338	378
15	East	Interface	500	-3.10	-5.80	-0.60	2.10	0.00	0.10	0.10	0.00	2.10	3,468	34
16	Tumblin - Trade City	Line	PENELEC	-2.10	-5.90	-0.10	3.70	-0.60	1.60	0.50	-1.80	1.90	1,082	398
20	Goudey - Laurel Lake	Line	PENELEC	3.00	1.20	0.10	1.90	0.00	-0.10	-0.30	-0.20	1.70	788	52
28	*Glade - Forest*	*Line*	*PENELEC*	*3.90*	*0.50*	*-0.50*	*2.90*	*-1.50*	*0.90*	*-1.50*	*-3.80*	*-1.00*	*1,196*	*266*
36	Seneca	Transfomer	PENELEC	-0.10	0.10	0.90	0.80	0.00	0.00	0.00	0.00	0.80	3,848	80
42	Morgan Street - Venango Jct	Line	PENELEC	-0.10	-0.80	0.00	0.70	0.00	0.10	-0.10	-0.10	0.60	350	26



CAMBRIDGE
NEW YORK
SAN FRANCISCO
WASHINGTON
LONDON
MADRID
ROME

THE Brattle GROUP

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

PRESORTED FIRST CLASS

U.S. POSTAGE PITNEY BOWES

ZIP 19605 $ 002.79
02 4W
0000333319 DEC 16 2015

Ms. Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Bldg.
2nd FL., Room -N201
400 North Street
Harrisburg, PA 17120

AUTO PRESORTED FIRST-CLASS
170 171 17107S N1
407915121 7-100621
1
17120