FirstEnergy

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PO Box 16001
Reading, PA 19612-6001

September 5, 2014

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 2014 report on market prices and price trends in the PJM Interconnection LLC markets during 2013, 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 /cac

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

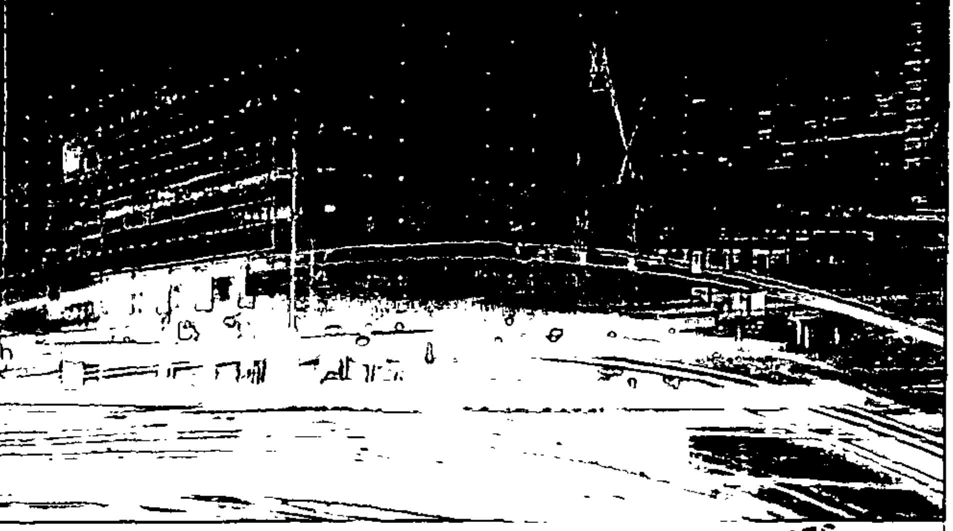
cc: Johnnie Simms, Bureau of Investigation and Enforcement
Tanya J. McCloskey, Office of Consumer Advocate
Steven Gray, Office of Small Business Advocate

# 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
Charles Russell


July 2014



THE Brattle GROUP

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

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## 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 annually for years 2011, 2012, 2013, 2014, and 2015 a report addressing wholesale market prices and price trends in PJM. This is the third of such five 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 2013. Total wholesale costs, in terms of dollars per megawatt-hour ("MWh") of total customer load, increased in all four zones relative to 2012. Wholesale costs in the Met-Ed, Penelec, APS, and Penn Power zones increased by 7.2%, 4.0%, 0.9%, and 14%, respectively.

Total wholesale cost is primarily composed of the costs of energy, capacity, and transmission service charges, but also includes the cost of ancillary services and other charges. Energy prices in 2013 increased relative to 2012 due primarily to higher natural gas prices in the region. In the day-ahead market, 2013 average zonal peak-hour locational marginal prices ("LMPs") increased relative to 2012 by 12-15% in the four Company zones. Similarly, off-peak LMPs increased by 11-15%. In the real-time market, average zonal peak-hour LMPs increased by 7-23%, and off-peak LMPs increased by 10-15%.

In 2013, the Penn Power zone had the highest load-weighted average energy price, primarily due to transmission congestion. The congestion component of Penn Power's LMP was particularly high in the real-time market and during peak hours. LMPs in Met-Ed also reflected transmission congestion in the zone, as in prior years.

Greater price separation in the capacity market led to higher capacity prices in the Mid-Atlantic Area Council ("MAAC") Locational Deliverability Area ("LDA"), which includes Penelec and Met-Ed, and lower capacity prices in the rest of the system (including APS and Penn Power). Under PJM's centralized capacity market, the Reliability Pricing Model ("RPM"), the two Base Residual Auctions ("BRA") held for the 2012/13 and 2013/14 capacity delivery years cleared at capacity prices of $133.37/MW-day and $226.15/MW-day, respectively, in MAAC, and $16.46/MW-day and $27.73/MW-day, respectively, in the rest of the system. Since the ATSI zone was integrated into PJM in 2011 and did not participate in the PJM forward capacity auction for the 2012/13 delivery year, ATSI capacity payments for the 2012/13 delivery year reflect transitional payments of \$20.46/MW-day. Four other capacity auctions were held in 2013, including the Base Residual Auction for the 2016/17 delivery year, and three incremental auctions for prior delivery years. Results from these auctions generally reflected lower capacity prices for incremental and future capacity. For the 2016/17 BRA results, PJM attributed the lower capacity prices generally to flat demand growth and an increase in supply.[1]

Transmission service charges did not change significantly in the Company zones relative to 2012. Transmission service charges in 2013 increased slightly in Penn Power, decreased slightly in Penelec and Met-Ed, and remained about the same in APS. Contribution to total wholesale cost in 2013 was \$2.49-2.99/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 2013 than in 2012, 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 February 2013 proposed rule changes that will give PJM more flexibility in procuring black start service were approved by PJM's Markets and Reliability Committee. In 2013, charges for black start service increased slightly relative to 2012, but contributed less than \$0.05/MWh to the total wholesale costs in the Companies' zones. Reactive power (voltage control) is also procured by PJM on a non-market basis. In 2013, charges for reactive power decreased relative to 2012, contributing \$0.02-0.48/MWh to total wholesale costs in the Companies' zones.

According to the assessment of PJM's Independent Market Monitor, the PJM wholesale market continued to operate in a competitive manner during 2013. All markets yielded competitive outcomes despite some concerns with market structure, participant behavior, and market design.

Going forward, there are important shifts in PJM market fundamentals that may have significant implications for the Companies. These include planned retirements of a large quantity of coal-fired generating capacity, planned renewable developments to meet state Renewable Portfolio Standards, and a growing need for natural gas supply during winter peak periods.

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1 (PJM 2013a).

# I. Introduction

## I.A. Purpose

This is the third 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 2013 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 expanded from 19 to 20 load zones in 2013,[2] seven 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.[3] 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.

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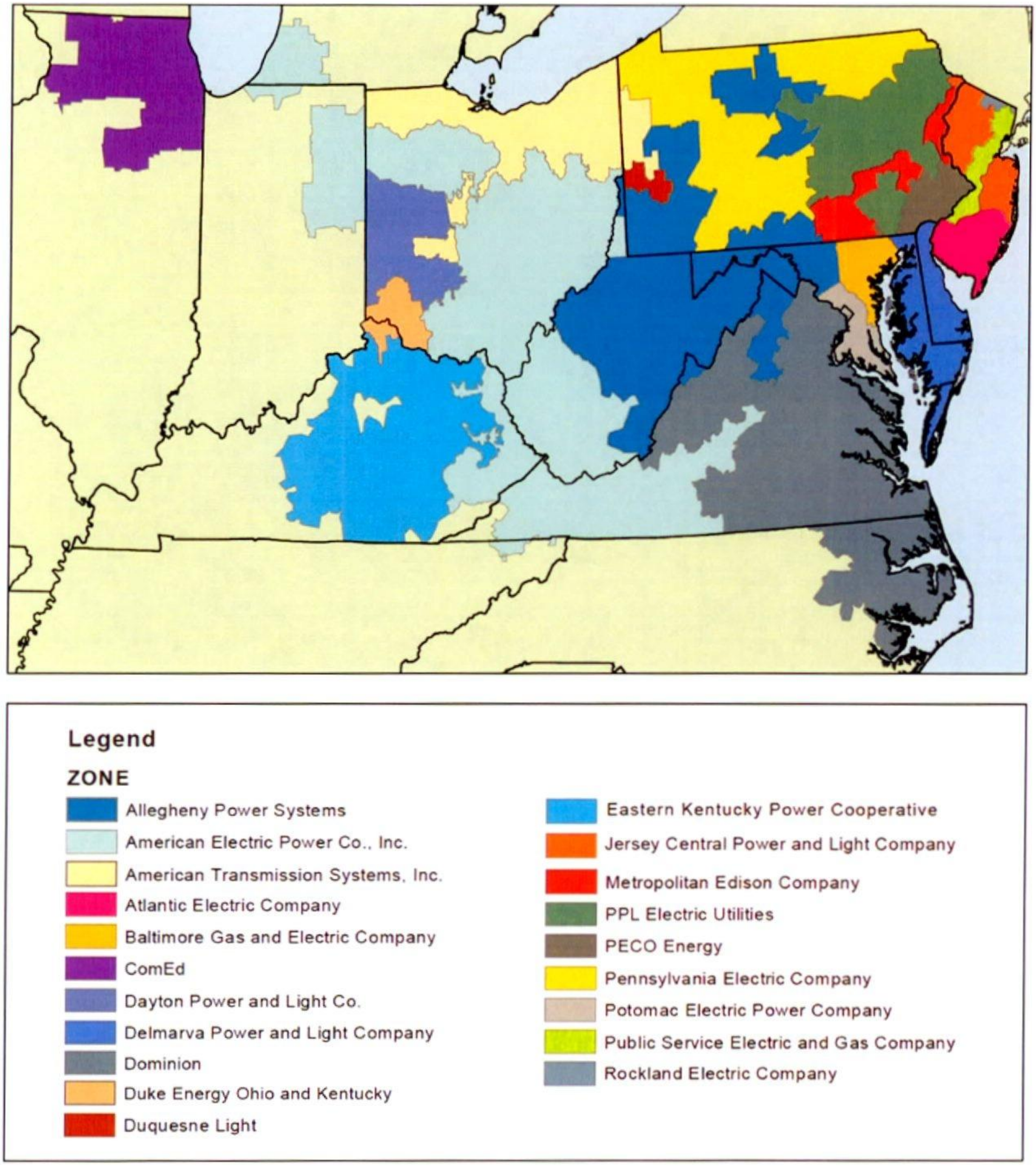
2 Effective June 1, 2013, PJM integrated the East Kentucky Power Cooperative load zone into its footprint.

3 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**[4]
**PJM's Footprint in 2013**




[4] (PJM No Date).

# 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/Reliability*First* Corporation ("NERC/RFC") charges; (14) RTO Startup and Expansion; (15) economic load response; (16) transmission facility charges; (17) non-synchronized reserves; (18) capacity (FRR); (19) emergency energy; and (20) emergency load response. Capacity (FRR), emergency energy, and emergency load response represent new line items reported by the market monitor in 2014. Due to the nature of the new products, they 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 2013.

**Table 1**
**Wholesale Costs of Electricity in 2013[5,6,7,8]**
*($/MWh)*

| | PJM | Penelec | Met-Ed | APS | Penn Power |
|---|---|---|---|---|---|
| Real-Time Load Wtd. LMP (Energy) | $38.66 | 38.71 | 39.72 | 37.70 | $41.03 |
| *Marginal Congestion Cost* | *$0.01* | *-$0.10* | *$0.34* | *-$0.57* | *$2.86* |
| *Marginal Transmission Losses* | *$0.02* | *$0.63* | *$0.75* | *-$0.11* | *-$0.20* |
| Capacity | $7.13 | $12.53 | $14.67 | $1.68 | $1.88 |
| Transmission Service Charges | $5.20 | $2.49 | $2.49 | $2.70 | $2.99 |
| Operating Reserves (Uplift) | $0.59 | $0.86 | $0.86 | $0.53 | $0.53 |
| Reactive | $0.80 | $0.02 | $0.07 | $0.48 | $0.05 |
| PJM Administrative Fees | $0.43 | $0.43 | $0.43 | $0.43 | $0.43 |
| Regulation | $0.24 | $0.24 | $0.24 | $0.24 | $0.24 |
| Transmission Enhancement Cost Recovery | $0.39 | $0.15 | $0.17 | $0.17 | $0.15 |
| Synchronized Reserves | $0.04 | $0.06 | $0.06 | $0.06 | $0.02 |
| Transmssion Owner (Schedule 1A) | $0.08 | $0.08 | $0.08 | - | $0.03 |
| Day Ahead Scheduling Reserve (DASR) | $0.06 | $0.06 | $0.06 | $0.06 | $0.06 |
| Black Start | $0.14 | $0.03 | $0.05 | $0.01 | $0.00 |
| NERC/RFC | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 |
| RTO Startup and Expansion | $0.01 | N/A | N/A | N/A | N/A |
| Economic Load Response | $0.01 | N/A | N/A | N/A | N/A |
| *Transmission Facility Charges* | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Non-Synchronized Reserves | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Capacity (FRR) | $0.11 | N/A | N/A | N/A | N/A |
| Emergency Energy | $0.00 | N/A | N/A | N/A | N/A |
| Emergency Load Response | $0.06 | N/A | N/A | N/A | N/A |
| Total | $53.97 | $55.68 | $58.92 | $44.09 | $47.43 |

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

5 *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.

6 For the Met-Ed, Penelec, and APS zones, the average synchronized reserve cost for the Mid-Atlantic Dominion Subzone is shown; however, portions of these two zones are located outside that synchronized reserve subzone, and consequently, consumers located in those areas incur a lower synchronized reserve cost.

7 Capacity (FRR), Emergency Energy, and Emergency Load Response are new itemized components of the wholesale cost of energy added by Monitoring Analytics in their 2013 State of the Market Report. The ATSI FRR Integration Auction Results for 2012/13 are included in the Capacity line item for Penn Power.

8 (Monitoring Analytics, LLC 2014) 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 91% of the total wholesale cost in 2013. Energy costs represent the largest single component for the Companies' zones, at an average of 77% of the total wholesale price in PJM, with even larger shares in the Companies' zones.[9] As shown in Table 1, energy costs vary by load zone, reflecting the regional variation in LMPs. The Penelec 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 and Penn Power zones, and lower than the PJM average in the APS zone, reflecting the fact that the Met-Ed and Penn Power are located in a more congested area of PJM, while APS 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, capacity auctions held for the calendar year 2013 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.

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[9] 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 2013**[10]
*(% of Total, by Component)*

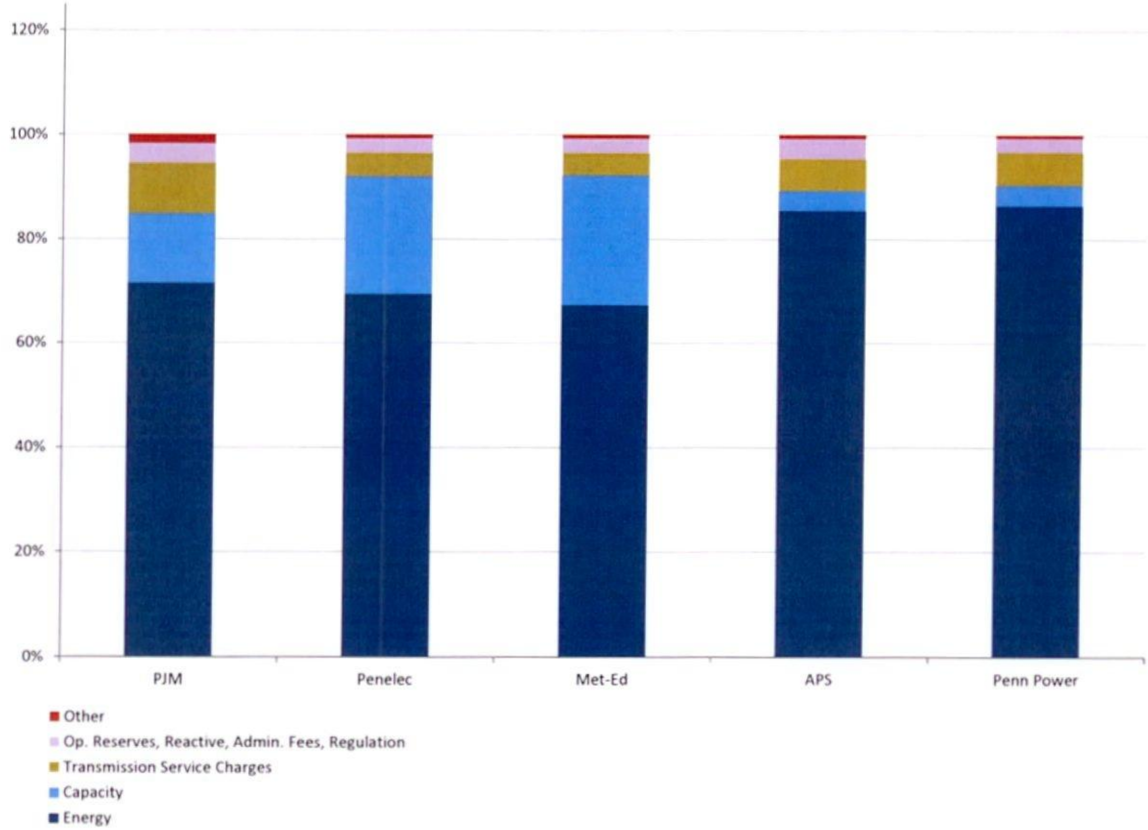


Table 2 shows the total wholesale cost of electricity by component for calendar years 2011 and 2012. Table 3 shows the percentage change in wholesale cost components from 2011 to 2013 and from 2012 to 2013. Between 2012 and 2013, the total cost of wholesale power increased by approximately 11%. Following a 22% drop in price from 2011 to 2012, the 2013 wholesale cost of power is still approximately 14% below the cost of power in 2011. Penn Power experienced a larger increase in total cost at 14.0% compared to 2012, while Penelec, Met-Ed and APS saw smaller increases in cost at 4.0%, 7.2%, and 0.9%, respectively. One of the primary factors that contributed to the rise in energy costs in 2013 was the notable increase in gas prices, of roughly $1/MMBtu. Capacity costs in the APS and Penn Power zones decreased the most when

[10] As show 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 and Penn Power, transmission congestion costs are approximately 1-7% 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 0.5% of the LMP.

compared to average capacity costs in 2011. Further discussion on capacity prices can be found in Section II.C.

**Table 2**
**Wholesale Costs of Electricity in 2011 and 2012**[11]
*($/MWh)*

| | 2011 | | | | | 2012 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | PJM | Penelec | Met-Ed | APS | Penn Power | PJM | Penelec | Met-Ed | APS | Penn Power |
| Real-Time Load Wtd. LMP (Energy) | $45.94 | $45.12 | $49.51 | $45.49 | $42.92 | $35.23 | $35.10 | $36.30 | $34.86 | $33.02 |
| *Congestion* | *$0.05* | *-$0.25* | *$2.87* | *$0.05* | *-$2.56* | *$0.04* | *-$0.12* | *$0.67* | *$0.04* | *-$0.87* |
| *Loss* | *$0.02* | *$0.38* | *$0.82* | *-$0.13* | *-$0.51* | *$0.01* | *$0.56* | *$0.53* | *-$0.09* | *-$0.21* |
| Capacity | $9.72 | $9.68 | $9.68 | $9.68 | $7.21 | $6.05 | $13.62 | $13.62 | $3.69 | $3.69 |
| Transmission Service Charges | $4.42 | $2.46 | $2.46 | $2.65 | $2.36 | $4.78 | $2.52 | $2.52 | $2.70 | $2.81 |
| Operating Reserves (Uplift) | $0.79 | $1.06 | $1.06 | $1.06 | $1.06 | $0.79 | $0.98 | $0.98 | $1.02 | $1.02 |
| Reactive | $0.42 | $0.19 | $0.51 | $0.46 | $0.39 | $0.43 | $0.28 | $0.52 | $0.50 | $0.23 |
| PJM Administrative Fees | $0.37 | $0.37 | $0.37 | $0.37 | $0.37 | $0.42 | $0.42 | $0.42 | $0.42 | $0.42 |
| Regulation | $0.32 | $0.32 | $0.32 | $0.32 | $0.32 | $0.26 | $0.26 | $0.26 | $0.26 | $0.26 |
| Transmission Enhancement Cost Recovery | $0.29 | $0.06 | $0.07 | $0.07 | N/A | $0.34 | $0.07 | $0.09 | $0.09 | $0.08 |
| Synchronized Reserves | $0.09 | $0.19 | $0.19 | $0.19 | $0.00 | $0.04 | $0.08 | $0.08 | $0.08 | $0.00 |
| Transmssion Owner (Schedule 1A) | $0.09 | $0.08 | $0.08 | N/A | $0.03 | $0.08 | $0.08 | $0.08 | N/A | $0.03 |
| Day Ahead Scheduling Reserve (DASR) | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 |
| Black Start | $0.02 | $0.02 | $0.03 | $0.00 | $0.00 | $0.03 | $0.03 | $0.03 | $0.00 | $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 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.01 | $0.03 | $0.01 | $0.02 | $0.00 |
| 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 | N/A | N/A | N/A | N/A | N/A | $0.00 | $0.01 | $0.01 | $0.01 | $0.01 |
| Total | $62.55 | $59.61 | $64.35 | $60.36 | $54.72 | $48.54 | $53.54 | $54.98 | $43.71 | $41.62 |

From 2011 to 2013 the total price of wholesale power fell by an average of approximately 14% for PJM as a whole. Penn Power saw a similar decrease of 13.3% while Penelec and Met-Ed experienced a 6.6% and 8.4% decrease, respectively. APS was the only region to record a larger decrease than PJM, with a 27.0% decrease in the cost of wholesale power from 2011 to 2013. Several components saw an increase in cost over the two years. For example, both Black Start and Day-Ahead Scheduling Reserve components saw significant increases in cost, although they have very little impact as a percentage of total wholesale cost.

11 (Monitoring Analytics, LLC 2012), (Monitoring Analytics, LLC 2013), (Monitoring Analytics, LLC 2014), and Brattle analysis.

**Table 3**
**Percent Change in Wholesale Cost Components[12]**

| | % Change (2013 vs. 2011) | | | | | % Change (2013 vs. 2012) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | PJM | Penelec | Met-Ed | APS | Penn Power | PJM | Penelec | Met-Ed | APS | Penn Power |
| Real-Time Load Wtd. LMP (Energy) | -15.8% | -14.2% | -19.8% | -17.1% | -4.4% | 9.7% | 10.3% | 9.4% | 8.1% | 24.3% |
| *Congestion* | -80.0% | -59.5% | -88.2% | -1159.7% | -212.0% | -72.7% | -13.9% | -49.2% | -1723.1% | -430.2% |
| *Loss* | -18.3% | 64.8% | -8.8% | -15.1% | -61.3% | 36.8% | 13.1% | 42.1% | 18.0% | -7.9% |
| Capacity | -26.6% | 29.5% | 51.6% | -82.6% | -74.0% | 17.9% | -8.0% | 7.7% | -54.3% | -49.1% |
| Transmission Service Charges | 17.6% | 1.2% | 1.2% | 1.8% | 26.8% | 8.8% | -1.2% | -1.2% | 0.0% | 6.5% |
| Operating Reserves (Uplift) | -25.3% | -19.1% | -19.1% | -49.4% | -49.4% | -25.3% | -12.7% | -12.7% | -47.8% | -47.8% |
| Reactive | 90.5% | -87.9% | -85.5% | 6.4% | -86.9% | 86.0% | -91.7% | -85.8% | -2.5% | -77.5% |
| PJM Administrative Fees | 16.2% | 16.2% | 16.2% | 16.2% | 16.2% | 2.4% | 2.4% | 2.4% | 2.4% | 2.4% |
| Regulation | -25.0% | -25.0% | -25.0% | -25.0% | -25.0% | -7.7% | -7.7% | -7.7% | -7.7% | -7.7% |
| Transmission Enhancement Cost Recovery | 34.5% | 172.2% | 134.2% | 133.7% | - | 14.7% | 101.8% | 89.2% | 94.7% | 89.1% |
| Synchronized Reserves | -55.6% | -68.3% | -68.3% | -68.3% | 658.3% | 0.0% | -20.9% | -20.9% | -20.9% | 294.8% |
| *Transmssion Owner (Schedule 1A)* | -11.1% | 0.0% | 0.0% | - | 10.9% | 0.0% | 0.0% | 0.0% | - | 4.4% |
| Day Ahead Scheduling Reserve (DASR) | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% |
| Black Start | 600.0% | 66.6% | 61.5% | 62.2% | 50.9% | 366.7% | 10.5% | 54.1% | 15.4% | 3.0% |
| NERC/RFC | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| RTO Startup and Expansion | 0.0% | - | - | - | - | 0.0% | - | - | - | - |
| Load Response | 268.4% | - | - | - | - | -14.7% | - | - | - | - |
| Transmission Facility Charges | - | - | - | - | - | - | - | - | - | - |
| Non-Synchronized Reserves | - | - | - | - | - | - | -81.2% | -81.2% | -81.2% | -99.7% |
| Capacity (FRR) | - | - | - | - | - | - | - | - | - | - |
| Emergency Energy | - | - | - | - | - | - | - | - | - | - |
| Emergency Load Response | - | - | - | - | - | - | - | - | - | - |
| Total | -13.7% | -6.6% | -8.4% | -27.0% | -13.3% | 11.2% | 4.0% | 7.2% | 0.9% | 14.0% |

## 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.

PJM's energy market did not change structurally in 2013, with the exception of some phase-in of PJM's scarcity pricing reforms implemented in late 2012. Specifically, PJM's energy price cap is scheduled to gradually increase to $2,700/MWh by June 1, 2015. Starting in October 2012 the price cap was $1,500/MWh. In May 2013 the price cap was increased to $1,800/MWh.

Table 4 and Table 5 summarize the zonal day-ahead and real-time simple average LMPs and their components for the calendar years 2011 through 2013. 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

12 (Monitoring Analytics, LLC 2012), (Monitoring Analytics, LLC 2013), (Monitoring Analytics, LLC 2014), and Brattle analysis.

increasing between 2012 and 2013 while decreasing from 2011 to 2013. Between 2011 and 2012 the Companies' zones experienced an 18% to 26% decrease in day-ahead prices, and 18% to 26% decrease in real-time prices. Between 2012 and 2013, they saw an average increase of 12% to 14% the day-ahead prices and a 9% to 18% increase in the real-time energy prices. In 2013, Met-Ed remained the zone with the highest simple average energy price, primarily due to transmission congestion.

**Table 4**
**Zonal Day-Ahead, Simple Average LMP Components**
**Calendar Years 2011 - 2013[13,14]**
*($/MWh)*

| | 2011 | | | | 2012 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Zone | LMP | Energy | Cong. | Loss | LMP | Energy | Cong. | Loss | LMP | Energy | Cong. | Loss |
| APS | 42.96 | 42.72 | 0.29 | -0.05 | 32.82 | 32.72 | 0.14 | -0.04 | 36.74 | 37.04 | -0.12 | -0.18 |
| Penn Power | 38.95 | 41.59 | -1.46 | -1.18 | 31.83 | 32.72 | -0.56 | -0.34 | 35.59 | 37.04 | -1.06 | -0.38 |
| Met-Ed | 45.82 | 42.72 | 2.37 | 0.72 | 33.68 | 32.72 | 0.37 | 0.59 | 38.27 | 37.04 | 0.69 | 0.55 |
| Penelec | 42.79 | 42.72 | -0.17 | 0.24 | 33.41 | 32.72 | 0.10 | 0.59 | 38.13 | 37.04 | 0.35 | 0.75 |

**Table 5**
**Zonal Real-Time, Simple Average LMP Components**
**Calendar Years 2011 - 2013[15]**
*($/MWh)*

| | 2011 | | | | 2012 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Zone | LMP | Energy | Cong. | Loss | LMP | Energy | Cong. | Loss | LMP | Energy | Cong. | Loss |
| APS | 42.91 | 42.77 | 0.23 | -0.09 | 33.08 | 33.06 | 0.09 | -0.07 | 36.00 | 36.52 | -0.40 | -0.11 |
| Penn Power | 38.66 | 41.19 | -1.88 | -0.66 | 31.69 | 33.06 | -0.81 | -0.56 | 37.27 | 36.52 | 1.53 | -0.78 |
| Met-Ed | 45.82 | 42.77 | 2.34 | 0.72 | 33.96 | 33.06 | 0.44 | 0.46 | 37.41 | 36.52 | 0.23 | 0.66 |
| Penelec | 42.95 | 42.77 | -0.19 | 0.37 | 33.50 | 33.06 | -0.10 | 0.54 | 37.01 | 36.52 | -0.09 | 0.58 |

Table 6 and Table 7 summarize the zonal day-ahead and real-time, load-weighted average LMPs by component for the calendar years 2011 through 2013. As prices tend to be higher in high-load hours, the load-weighted LMPs are typically higher than the simple average LMPs. This is demonstrated across years as well as across load zones.

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13 2011 values: (Monitoring Analytics, LLC 2012), p. 393, Table G-5 Zonal Day-ahead.
2012 values: (Monitoring Analytics, LLC 2013), p. 423
2013 values: simple annual averages of LMP data compiled by Ventyx, Inc., the Velocity Suite.

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

15 2011 values: (Monitoring Analytics, LLC 2012), p. 392, Table G-2 Zonal Real-Time
2012 values: (Monitoring Analytics, LLC 2013), p. 423.
2013 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 2011 - 2013[16][17]**
*($/MWh)*

| | 2011 | | | | 2012 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Zone | LMP | Energy | Cong. | Loss | LMP | Energy | Cong. | Loss | LMP | Energy | Cong. | Loss |
| APS | 47.66 | 47.96 | -0.16 | -0.15 | 34.29 | 34.26 | 0.09 | -0.06 | 38.23 | 38.62 | -0.21 | -0.18 |
| ATSI | 46.14 | 50.87 | -3.07 | -1.66 | 33.55 | 34.32 | -0.69 | -0.08 | 38.13 | 38.69 | -0.85 | 0.29 |
| Met-Ed | 52.37 | 48.08 | 3.28 | 1.01 | 35.44 | 34.29 | 0.50 | 0.65 | 40.04 | 38.62 | 0.83 | 0.59 |
| Penelec | 47.41 | 47.72 | -0.56 | 0.24 | 34.69 | 33.95 | 0.12 | 0.62 | 39.29 | 38.14 | 0.38 | 0.77 |

***Table 7***
**Zonal Real-Time, Load-Weighted Average LMP Components**
**Calendar Years 2011 - 2013[18,19]**
*($/MWh)*

| | 2011 | | | | 2012 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Zone | LMP | Energy | Cong. | Loss | LMP | Energy | Cong. | Loss | LMP | Energy | Cong. | Loss |
| APS | 48.57 | 48.99 | -0.22 | -0.20 | 34.86 | 34.91 | 0.04 | -0.09 | 37.70 | 38.39 | -0.57 | -0.11 |
| ATSI | 46.88 | 51.24 | -3.85 | -0.51 | 34.42 | 34.99 | -0.78 | 0.21 | 42.12 | 38.43 | 3.27 | 0.42 |
| Met-Ed | 53.64 | 49.22 | 3.42 | 1.00 | 36.30 | 35.11 | 0.67 | 0.53 | 39.72 | 38.63 | 0.34 | 0.75 |
| Penelec | 48.18 | 48.27 | -0.46 | 0.37 | 35.10 | 34.66 | -0.12 | 0.56 | 38.71 | 38.18 | -0.10 | 0.63 |

Table 8 contains the zonal peak and off-peak simple average LMPs for the day-ahead and real-time energy markets in 2013. In the day-ahead market, average zonal peak and off peak LMPs increased by 13% from 2012 to 2013. Average real-time, peak-hour LMPs increased by 11%, and off-peak LMPs increased by 12%. Of the Companies' zones, Met-Ed Zone continues to show the largest positive transmission congestion cost component for the day-ahead markets while Penn Power shows the largest positive transmission congestion cost for the real-time markets.

16 2011 values: (Monitoring Analytics, LLC 2012), p. 268, Table 10-4 Zonal and PJM day-ahead.
2012 values: (Monitoring Analytics, LLC 2013), p. 299.
2013 values: (Monitoring Analytics, LLC 2014), p. 359.

17 Due to a lack of granular data, and consistency across zones, values for ATSI are used in Table 6 and Table 7 as opposed to Penn Power.

18 2011 values: (Monitoring Analytics, LLC 2012), p. 268, Table 10-3 Zonal and PJM real-time.
2012 values: (Monitoring Analytics, LLC 2013), p. 299.
2013 values: (Monitoring Analytics, LLC 2014), p. 359.

19 Note that load-weighted average LMPs for 2011 and 2012 listed in Table 7 differ from average energy *costs reported in Table 2. The differences are due to the different methodology used by PJM's market* monitor to calculate load-weighted averages and differences in estimated and meter corrected hourly loads used to weight the hourly prices.

**Table 8**
**Zonal On- and Off-Peak Average Day-Ahead and Real-Time LMPs in 2013**
*($/MWh)*

| 2013 Day-Ahead Simple Average | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Zone | LMP | | Energy | | Congestion | | Loss | |
| | Peak | OffPeak | Peak | OffPeak | Peak | OffPeak | Peak | OffPeak |
| APS | 42.83 | 31.42 | 43.44 | 31.45 | -0.34 | 0.06 | -0.27 | -0.09 |
| Penn Power | 41.48 | 30.46 | 43.44 | 31.45 | -1.53 | -0.66 | -0.43 | -0.33 |
| Met-Ed | 45.08 | 32.34 | 43.44 | 31.45 | 0.98 | 0.44 | 0.66 | 0.45 |
| Penelec | 44.85 | 32.28 | 43.44 | 31.45 | 0.53 | 0.19 | 0.88 | 0.64 |
| PJM RTO | 43.63 | 31.50 | 43.44 | 31.45 | 0.19 | 0.04 | 0.00 | 0.00 |

| 2013 Real-Time Simple Average | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Zone | LMP | | Energy | | Congestion | | Loss | |
| | Peak | OffPeak | Peak | OffPeak | Peak | OffPeak | Peak | OffPeak |
| APS | 42.12 | 30.68 | 43.21 | 30.68 | -0.89 | 0.02 | -0.20 | -0.03 |
| Penn Power | 46.50 | 29.22 | 43.21 | 30.68 | 4.21 | -0.81 | -0.93 | -0.65 |
| Met-Ed | 44.08 | 31.60 | 43.21 | 30.68 | 0.06 | 0.38 | 0.80 | 0.53 |
| Penelec | 43.70 | 31.18 | 43.21 | 30.68 | -0.22 | 0.03 | 0.71 | 0.47 |
| PJM RTO | 43.24 | 30.72 | 43.21 | 30.68 | 0.00 | 0.02 | 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.[20] 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 net transmission congestion costs were $676.9 million in 2013, a 28% increase from 2012. Similarly, annual day-ahead congestion costs increased by over $200 million, increasing 30% from 2012. 2013 marks the first year since 2010 in which transmission congestion costs have not experienced a decline.

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

**Table 9**
**Transmission Congestion Costs from 2011 to 2013[21][22]**
*(Million $)*

**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 |

**Total Congestion Costs in 2011**

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

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 impact in PJM, contributed 32.2% (approximately $169 million)[23] to 2013 net PJM transmission

21 (Monitoring Analytics, LLC 2014), Table 11-8.

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

23 (Monitoring Analytics, LLC 2014), Section 11.

congestion cost, and it is the top constraint for the APS and ATSI Zones.[24] 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[25] 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 2013, PJM procured capacity in two BRAs: one for delivery year 2012/13 (BRA held in May 2009), and one for delivery year 2013/14 (BRA held in May 2010). For the 2012/13 delivery year, 1st, 2nd, and 3rd incremental auctions were held during the months of September 2010, July 2011, and February through March 2012, respectively. 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.[26]

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.[27]

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24 Top transmission constraints in 2013 for the Companies, which also appeared as top constraints in 2012, were *West Interface, Bedington-Black Oak Interface, Clover Transformer, 5004/5005 Interface,* and *AEP-DOM Interface.* Top constraints for the RTO in 2013 can be found at (Monitoring Analytics, LLC 2014), Section 11, Table 11-18.

25 Following the BRA, up to three incremental auctions are held for each delivery year – 20 months, 10 months, and 4 months before each delivery year – that can be used by market participants to adjust their commitments and by PJM to procure additional capacity.

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

27 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.

**Figure 3**[28]
**Locational Deliverability Areas in PJM**

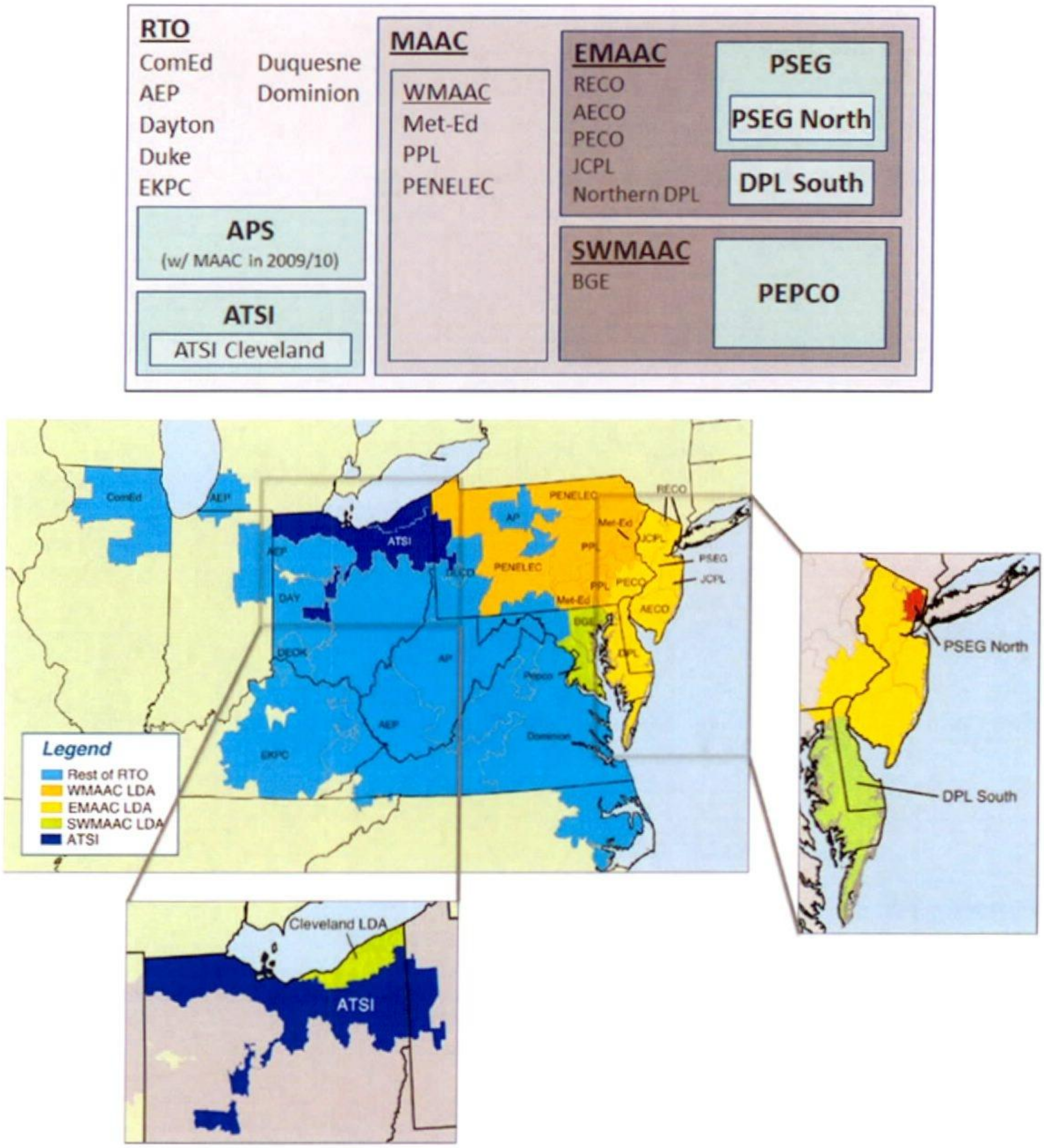



Table 10 summarizes RPM market-clearing prices in the Companies' zones for capacity delivered in the 2013 calendar year. Price separation occurred between MAAC and the rest of the RTO in the Base Residual Auctions held for the delivery years 2012/13 and 2013/14. MAAC prices cleared at $116.91/MW-day higher ($113.37/MW-day in MAAC versus $16.46/MW-day in RTO) for the 2012/13 delivery year, and $198.42/MW-day higher ($226.15/MW-day in MAAC versus $27.73/MW-day in RTO) for the 2013/14 delivery year. For the delivery year 2013/14 price

[28] (Monitoring Analytics, LLC 2014) Section 5: Capacity, Figure 5-1.

separation between MAAC and the rest of the RTO also occurred in the 2nd and 3rd incremental auctions. Since the ATSI Zone did not become part of PJM until 2011, it was not included in the BRAs held for the 2012/13 delivery year. Instead, transitional ATSI zone Fixed Resource Requirement ("FRR") integration auctions were held in March 2010, resulting in a capacity price of $20.46/MW-day.

Historically, incremental auctions have cleared at prices below BRA clearing prices. This trend continued in the 2012/13 and 2013/14 delivery years. Cleared volumes in incremental auctions are much lower than in the BRAs, and therefore their impact on overall capacity costs is relatively small.

**Table 10**
**Wholesale Capacity Prices in 2013**
*($/MW-day)*

| Delivery Year | Locational Delivery Area | Base Residual Auction | ATSI FRR Integration Auction | 1st Incremental Auction | 2nd Incremental Auction | 3rd Incremental Auction |
|---|---|---|---|---|---|---|
| 2012/13 | RTO | $16.46 | $20.46 | $16.46 | $13.01 | $2.51 |
| | MAAC | $133.37 | $20.46 | $16.46 | $13.01 | $2.51 |
| 2013/14 | RTO | $27.73 | N/A | $20.00 | $7.01 | $4.05 |
| | MAAC | $226.15 | N/A | $20.00 | $10.00 | $30.00 |

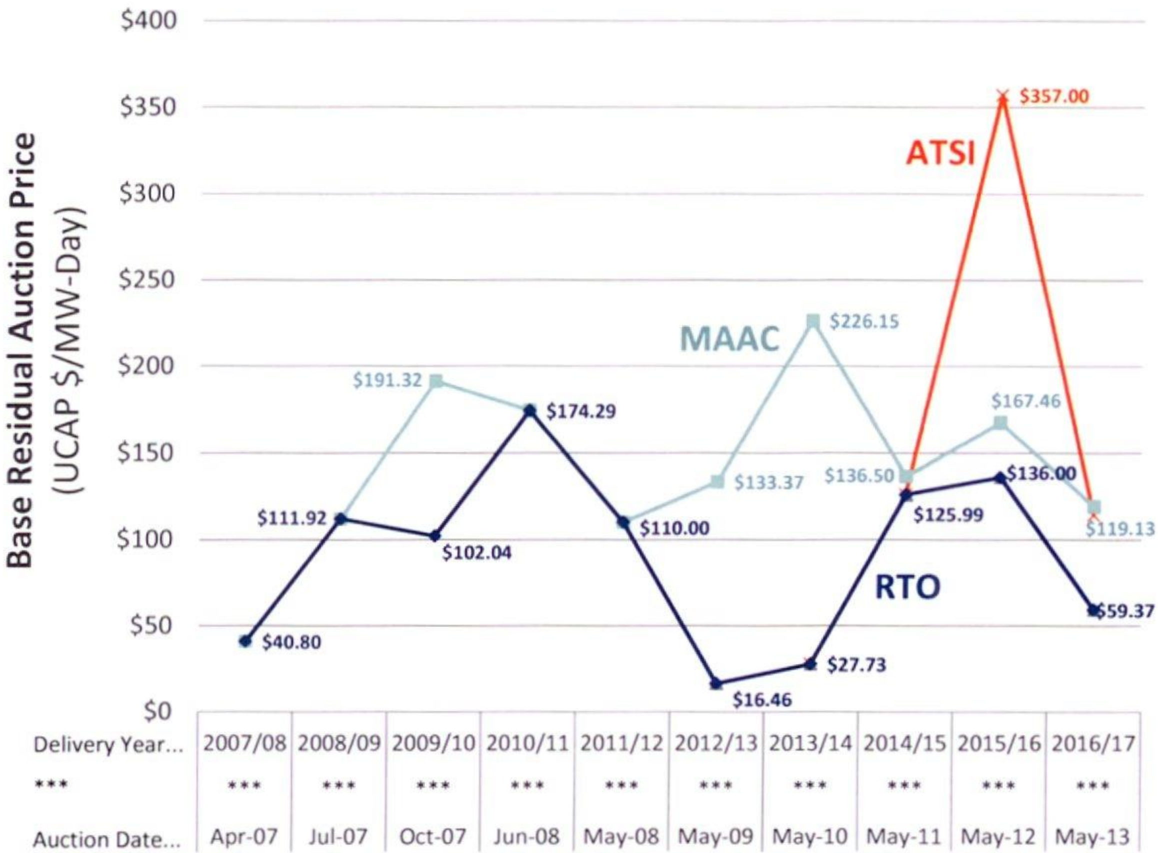
Figure 4 shows the BRA auction clearing prices for MAAC, ATSI, and the unconstrained part of PJM (rest of the RTO) from the first RPM delivery year 2007/08 through 2016/17. Although ATSI was included in the BRAs starting with the 2013/14 delivery year, 2015/16 was the first delivery year when ATSI was modeled as a separate LDA.[29] Capacity prices in MAAC (including Penelec and Met-Ed zones) remained around the long-term average[30] during 2013, while capacity prices in the unconstrained part of PJM (including APS and ATSI) fell significantly. For the 2015/16 delivery year, capacity prices in MAAC and the rest of the RTO almost converge, while the capacity price in ATSI rises to $357/MW-day. For the 2016/17 delivery year ATSI converged to the MAAC price, and prices in MAAC and the rest of RTO fell.

29 An LDA is modeled in the BRA and has a separate capacity demand (VRR) curve if: (1) its CETO/CETL 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.

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

**Figure 4**[31]

**Base Residual Auction Clearing Prices in MAAC and Unconstrained RTO**
**Through the 2016/17 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 3-6% of wholesale power cost.

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[31] (Monitoring Analytics, LLC 2014), Section 5: Capacity, Table 5-21. The figure shows capacity prices for annual capacity resources only.

The operating reserve (uplift) component is the average price per MWh of operating reserve charges. It is broken into three components: day-ahead, synchronous condensing, and balancing charges. The balancing portion is broken down further into generation and transactions, lost opportunity cost, canceled resources, and charges due to local transmission constraints. The generation and transactions category further separates into reliability charges, deviation charges, and lost opportunity costs and canceled resource charges. Of the hierarchy above, the only sub-categories that are zone-specific are the reliability charges and the deviation charges, which are broken down into the RTO, east, and west (for both real-time load and real-time exports). The remaining charges are allocated on a RTO-wide basis.

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.[32] For a more detailed discussion of PJM ancillary services markets in 2013, 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.

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32 (Monitoring Analytics, LLC 2014) Section 10: Ancillary Services, p. 318.

### RPM Demand Curve

The demand for capacity is based on an administratively-determined, downward-sloping demand curve. The demand curve is anchored at the net cost of new entry ("Net CONE") in such a manner that the capacity-clearing price equals Net CONE approximately at the target reserve level. Consequently, the RPM demand curve reflects a *lower* demand for reserves at relatively high capacity prices (i.e., above net CONE), assuming that at these price levels customers would be willing to increase the risk and cost of load interruption events in exchange for lower capacity costs. Conversely, the RPM demand curve reflects a *higher* demand for reserves at relatively low capacity prices (i.e., below net CONE), assuming that at these price levels customers would be willing to increase capacity costs in order to reduce the risk and cost of load interruption events.

### RPM Price Signals

The RPM capacity market interacts with and works in tandem with the PJM energy market to provide price and revenue signals to attract new, and retain existing, capacity. 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.[33] 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 ancillary services market prices on the one hand, and capacity prices on the other hand, is a relationship that would only be realized in the long-run over many years. More recently, both energy and capacity prices have been low relative to long-run sustainable levels.

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[33] In the PJM 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. Starting with the 2018/19 capacity delivery year, Gross CONE and E&AS values will be evaluated every fourth delivery year. Unless CONE values are revised for a given delivery year, the prior-year CONE value, escalated using the most recently published twelve-month change in Total Other Plant Production Plant Index shown in the Handy Whitman Index ("HWI") of Public Utility Construction Costs, is used. (PJM 2014d), Sections 3.3.1 and 3.3.2.

### RPM 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 2013

The basic features of the RPM design, discussed above, remained in place during 2013. In addition, five 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. As a consequence, ATSI capacity prices in the first half of the 2013 calendar year reflect results from the corresponding transitional integration auction, and ATSI capacity prices in the last half of the 2013 calendar year reflect results from the 2013/14 BRA. For consistency, starting with the 2013 State of the Market Report, the independent market monitor includes ATSI in reported PJM installed capacity and RPM reliability requirements as of June 1, 2013.

- Integration of East Kentucky Power Cooperative ("EKPC"): EKPC joined PJM in June 2013. EKPC participated in the May 2013 Base Residual Auction for the 2016/17 capacity delivery year. Although we have not analyzed this specifically, EKPC, as a zone with surplus supply,[34] should have the effect of relaxing rest of RTO market conditions and decreasing capacity prices.

- Revised (lowered) gross CONE values: On January 31, 2013 FERC approved updated gross Cost of New Entry values used to develop the demand curve for the 2016/17 Base Residual Auction held in May 2013. The updates lowered the gross CONE parameters by 0.5% in MAAC, 5.1% in ATSI, and 2.5% in RTO, compared to what would have been otherwise used in the 2016/17 BRA.[35]

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[34] For example, in the RPM Resource Model and planning period parameters for the 2017/18 BRA, EKPC has 2,746 MW of existing installed capacity and 2,340 MW of the Forecast Pool Requirement. See (PJM 2014b), (PJM 2014a).

[35] (PJM 2013a). Note that, although the updated gross CONE parameters are lower than what would have otherwise been used in the 2016/17 BRA, they are still slightly higher than what was used in the 2015/16 BRA.

- Additional changes to the Minimum Offer Price Rule (MOPR): The MOPR is used to mitigate the impact of new out-of-market capacity (e.g., capacity procured through long-term contracts by states) that would otherwise artificially depress the market price of capacity. The MOPR applies to sell offers of certain types of planned generation capacity, including planned upgrades of existing generators.

  Effective May 3, 2013, PJM made further changes to MOPR by clarifying and refining exemption rules.[36] Overall, exemptions were expanded, effectively relaxing constraints on new entrants participating in the market. Under the new MOPR rules, the Base Residual Auction held in May 2013 (for the 2016/17 capacity delivery year) resulted in the most cleared new generation capacity since RPM's inception.[37] However, PJM reports that the impact of the new MOPR rules was likely minimal, since "... less than half of all requested and approved MOPR exemptions were a part of the market clearing solution."[38] Some criticisms were raised after the auction regarding the MOPR unit-specific review process, but, in general, the independent market monitor found this process to be "capable of protecting the market from the exercise of market power and that it can produce consistent and reliable results."[39]

- Anticipated tightening of DR Plan rules: Although not in effect, anticipated changes in rules for Demand Resource Plans may have contributed to more conservative DR offers in the May 2013 Base Residual Auction (for the 2016/17 capacity delivery period).[40] Over 5,000 MW of DR dropped out in this auction compared to the prior BRA.[41]

## III.B. RESULTS OF PJM CAPACITY AUCTIONS IN 2013

Four RPM auctions were held during the 2013 calendar year:

- BRA for the 2016/17 delivery year;

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[36] FERC approved PJM's proposed revisions on February 4, 2013 in Docket No. ER13-529-000. FERC's order is available at http://www.pjm.com/~/media/documents/ferc/2013-orders/20130204-er13-529-000.ashx.

[37] Including uprates and new units. See (PJM 2013a) Table 2A.

[38] (PJM 2013a).

[39] PJM Interconnection, L.L.C., Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, filing before the Federal Energy Regulatory Commission, Docket No. ER13-535-001, April 19, 2013. Available at:

http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-535-001_20130419.pdf.

[40] (PJM 2013a).

[41] (PJM 2013a).

- 1st incremental auction for the 2015/16 delivery year;
- 2nd incremental auction for the 2014/15 delivery year; and
- 3rd incremental auction for the 2013/14 delivery year.

As shown previously in Figure 4, the BRA for 2016/17 cleared at an RTO price of $59.37/MW-day, a MAAC price of $119.13/MW-day, and the ATSI Zone price of $114.23/MW-day.[42] Compared to the 2015/16 BRA, capacity prices in all three LDAs were lower. The largest capacity price decrease occurred in the ATSI Zone, which cleared at $357.00/MW-day in the 2015/16 BRA. Capacity prices in MAAC and the rest of the RTO decreased by $48.33/MW-day and $76.63/MW-day, respectively.

PJM attributed the lower 2016/17 BRA capacity prices generally to flat demand growth and an increase in supply.[43] The committed RTO-wide 2016/17 reserve margin is projected to be 21.1%, which is 5.5% higher than the target reserve margin. There are likely a number of factors that contributed to these results.

Factors that likely contributed to *lower* prices in the 2016/17 BRA include:

- *Flat demand growth*, absent the addition of EKPC demand, contributed to a target reliability requirement only 749 MW (0.4%) higher than in the 2015/16 BRA.[44] The 2016/17 BRA preliminary zonal peak load forecast was 163,212 MW (excluding EKPC), versus 163,168 MW for the 2015/16 BRA.[45] The change in the target reliability requirement would have been even smaller if the target reserve level had not increased slightly (see below).
- *Significant new supply resources* entered the market, from new generating units (4,282 MW), incremental generation uprates (1,181 MW), increase in imports (3,558 MW), and incremental energy efficiency (195 MW).
- *EKPC surplus supply* may have contributed to downward price pressure, particularly in the unconstrained RTO area.
- *Expanded MOPR exemptions*, likely resulted in less mitigation of supply offers.

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42 These are resource clearing prices for annual resources.

43 (PJM 2013a).

44 (PJM 2012a), (PJM 2013b). The 749 MW figure is in unforced capacity terms and excludes the addition of EKPC demand in 2016/17.

45 (PJM 2012a), (PJM 2013b).

Offsetting factors that likely put *upward* pressure on 2016/17 BRA prices include:

- *Significant exit of demand response resources*, resulting in 5,449 MW less DR (unforced) capacity offered, and 2,425 MW less DR capacity cleared. DR exit was potentially influenced by anticipated changes to DR Plan rules.
- *Slightly higher target reserve level:* the Installed Reserve Margin (in installed capacity terms) was 15.6% in the 2016/17 BRA, versus 15.4% in the 2015/16 BRA. Likewise, the Forecast Pool Requirement (in unforced capacity terms) was 1.0902 in the 2016/17 BRA versus 1.0859 in the 2015/16 BRA.
- The *sloped demand curve* contributed to more surplus reserves compared to 2015/16. The projected 2016/17 reserve margin is 5.5% higher than the target, compared to 4.8% higher than the target in 2015/16.
- *Slightly higher net CONE parameters*, due to higher gross CONE parameters compared to 2015/16.
- *Coal plant retrofit costs,* to comply with environmental regulations (primarily the Mercury and Air Toxics Standard) likely increased supply offers. About 10,000 MW of coal-fired capacity did not clear in the 2016/17 auction, continuing the trend in recent years of coal retirements.

## 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.

### 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.[46] 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, new entrant nuclear plant in the AEP zone, new entrant solar installation in the PSEG zone, and new entrant wind in the ComEd and Penelec

[46] (Monitoring Analytics, LLC 2014) Section 7: Net Revenue.

zones. In the 2013 State of the Market Report, the market monitor also reports results for new entrant diesel plant for all zones. Net revenues are calculated using a hypothetical dispatch against historical day-ahead and real-time energy prices for each calendar year.

### 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 2011 through 2013.[47] 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.[48] Net revenues as a percentage of these levelized fixed costs are shown in the rightmost three columns of Table 11. During the period from 2011 through 2013, only new combined cycle plants would have earned sufficient net revenue to cover their total fixed costs, specifically in 2011 in all zones shown, and in 2013 in the Penelec zone. During the same period, coal and diesel plants were the least revenue adequate, followed by combustion turbines wind plants.[49] In 2013, the revenue adequacy of all types of plants in MAAC (including Met-Ed and Penelec zones) *increased* compared to 2012, driven by lower levelized fixed costs (with the exception of coal plants),higher capacity prices, and higher energy prices. In the rest of RTO (including APS zone), lower levelized fixed costs and higher energy prices were more than offset by lower capacity prices, leading to decreased revenue adequacy compared to 2012.

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47 The market monitor did not report net revenue estimates for the ATSI Zone.

48 In 2013, PJM's market monitor assumed a twenty-year levelized fixed cost of $110/kW-year for combustion turbines; $151/kW-year for combined cycle plants; $491/kW-year for coal plants, $153/kW-year for diesel plants; $801/kW-year for nuclear plants, $196/kW-year for wind installations, and $264/kW-year for solar installations. (Monitoring Analytics, LLC 2014) Section 7: Net Revenue, Table 7-21.

49 The PJM average total net revenues in 2013 covered only 22% of the levelized fixed costs of a new entrant coal plant, 24% of the levelized fixed costs of a new entrant diesel plant, and 60% 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 credits, which account for 41% of the 2013 net revenue of new wind installations in Penelec. (Monitoring Analytics, LLC 2014) Section 7: Net Revenue, Table 7-19. The total net revenues covered 83% of the levelized costs of new wind installations in Penelec. (Monitoring Analytics, LLC 2014) Section 7: Net Revenue, Table 7-27.

**Table 11**[50]
**Net Revenues Estimates for New Entrants**

| New Entrant Combustion Turbine | | | | | | |
|---|---|---|---|---|---|---|
| | Net Revenue ($/MWh-year) | | | % of 20-Year Levelized Fixed Costs | | |
| | 2011 | 2012 | 2013 | 2011 | 2012 | 2013 |
| APS | $82,483 | $40,648 | $26,129 | 75% | 36% | 24% |
| ATSI | N/A | N/A | N/A | N/A | N/A | N/A |
| Met-Ed | $90,325 | $68,164 | $84,811 | 82% | 60% | 77% |
| PENELEC | $81,614 | $65,189 | $86,068 | 74% | 58% | 78% |
| PJM avg. | $85,647 | $54,485 | $53,958 | 78% | 52% | 60% |

| New Entrant Combined Cycle | | | | | | |
|---|---|---|---|---|---|---|
| | Net Revenue ($/MWh-year) | | | % of 20-Year Levelized Fixed Costs | | |
| | 2011 | 2012 | 2013 | 2011 | 2012 | 2013 |
| APS | $160,460 | $120,834 | $88,873 | 104% | 78% | 59% |
| ATSI | N/A | N/A | N/A | N/A | N/A | N/A |
| Met-Ed | $158,551 | $139,501 | $146,902 | 103% | 90% | 98% |
| PENELEC | $155,947 | $149,678 | $167,866 | 101% | 96% | 111% |
| PJM avg. | $153,536 | $129,221 | $114,939 | 100% | 87% | 85% |

| New Entrant Coal Plant | | | | | | |
|---|---|---|---|---|---|---|
| | Net Revenue ($/MWh-year) | | | % of 20-Year Levelized Fixed Costs | | |
| | 2011 | 2012 | 2013 | 2011 | 2012 | 2013 |
| APS | $146,086 | $74,196 | $102,069 | 31% | 15% | 21% |
| ATSI | N/A | N/A | N/A | N/A | N/A | N/A |
| Met-Ed | $108,848 | $81,612 | $107,399 | 23% | 17% | 22% |
| PENELEC | $142,324 | $95,700 | $171,249 | 30% | 20% | 35% |
| PJM avg. | $120,431 | $66,034 | $100,059 | 26% | 14% | 22% |

| New Entrant Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Net Revenue ($/MWh-year) | | | % of 20-Year Levelized Fixed Costs | | |
| | 2011 | 2012 | 2013 | 2011 | 2012 | 2013 |
| APS | $47,957 | $19,816 | $9,284 | 31% | 13% | 6% |
| ATSI | N/A | N/A | N/A | N/A | N/A | N/A |
| Met-Ed | $51,031 | $43,744 | $64,315 | 33% | 29% | 42% |
| PENELEC | $48,609 | $44,003 | $64,135 | 32% | 29% | 42% |
| PJM avg. | $50,348 | $31,932 | $36,026 | 33% | 21% | 24% |

| New Entrant Wind | | | | | | |
|---|---|---|---|---|---|---|
| | Net Revenue ($/MWh-year) | | | % of 20-Year Levelized Fixed Costs | | |
| | 2011 | 2012 | 2013 | 2011 | 2012 | 2013 |
| PENELEC | N/A | $132,802 | $162,479 | N/A | 68% | 83% |

50 (Monitoring Analytics, LLC 2014) Section 7: Net Revenue, Tables 7-5 through 7-28.

## 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, with the exception of coal and oil or gas steam units.[51] The market monitor also found that 14,597 MW of capacity (mostly coal) is at-risk for retirement. Due to lack of data, the market monitor's analysis excludes nuclear units.[52]

## 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 over 58,000 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.

**Table 12[53]**
**Impact of RPM on Capacity Availability to Date**
***Through the 2016/17 Base Residual Auction Results***
*(MW)*

| Change in Capacity Availability | Installed Capacity (MW) |
|---|---|
| New Generation | 20,451 |
| Generation Upgrades (excluding reactiviations) | 7,168 |
| Generator Reactivations | 560 |
| Demand Resources and Energy Efficiency | 15,483 |
| Withdrawn and Canceled Retirements | 4,640 |
| Net Imports | 9,809 |
| Total | 58,111 |

51 (Monitoring Analytics, LLC 2014) Section 7: Net Revenue, pp. 230-233.

52 (Monitoring Analytics, LLC 2014) Section 7: Net Revenue, p. 233.

53 (PJM 2013a) Table 10.

# 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.[54]

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 to minute-by-minute changes in load. PJM operates a single market for regulation and the market clearing price is the uniform price paid for regulation across the RTO footprint. Regulation is procured from either generators with quick response capabilities or demand response resources. In 2012, significant changes were made to the regulation market. On October 1, 2012, PJM implemented performance-based regulation to comply with FERC Order No. 755.[55] The main objective of the order was to ensure that flexible resources are properly compensated for providing regulation service. Traditionally, regulation was priced based solely on capability (measured in terms of MW per minute), which disadvantaged flexible resources that were more often dispatched for regulation than other less flexible resources.

Under the new pay-for-performance construct, regulation offers consist of two parts: a regulation capability cost component, and a regulation performance cost component. In addition, PJM introduced two distinct types of frequency response: (1) RegA (traditional and slower oscillation signal) and (2) RegD (faster oscillation signal). A study commissioned by PJM found that newer and faster response technologies could be used, in combination with traditional resources, to reduce the need for regulation. The study also showed that RegD response is a substitute, up to a point and at a diminishing rate, for RegA response. RegA and RegD resources are cleared in a single regulation market with a uniform price; and therefore, the offers of the two types of resources are converted into comparable units. This is accomplished by adjusting the capability offer component of each resource by the unit-specific benefits factor and historic performance score. The benefits factor translates a specific flexible resource's MW capability into a traditional MW capability to estimate its effective regulation capability.[56] Performance scores measure each resource's response to PJM control signals by tracking delays, correlation, and precision.

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

[55] (FERC 2011).

[56] The benefit factor provides a sliding scale that makes dynamic resources more desirable until the optimal resource mix of dynamic and traditional resources is reached.

On November 16, 2012, FERC issued an order[57] that only partially accepted the regulation market design implemented on October 1, 2012. In particular, it fixed the marginal benefits factor for RegD resources at a value of 1.0 for purposes of payment, which created a dichotomy in the PJM regulation market with the marginal value of RegD resources in the dispatch.

The implementation of performance-based regulation allowed PJM to lower the regulation requirement. Previously, requirements were calculated at 1% of forecasted daily peak load for on-peak hours, and 1% of forecasted minimum daily load for off-peak hours. Following October 1, 2012, PJM lowered the regulation requirement to 0.78%, which was lowered to 0.7% by the end of 2012.[58]

On October 2, 2013, FERC directed PJM to remove the use of the marginal benefits factor from settlement calculations and to replace it with RegD and RegA mileage ratio in the performance credit paid to RegD resources. From October 1, 2012 through October 31, 2013, PJM had followed the FERC order that had required the marginal benefits factor be fixed at one for settlement calculations. As shown in the 2013 State of the Market Report,[59] the actual marginal benefits factor was always higher than one, causing resources following the RegD signal to be underpaid. The market monitors conclude that while the new design of the Regulation Market was improved with the changes implemented in 2012, issues remain. The failure to correctly use the marginal benefit factor has lead MW's from RegD resources to be paid disproportionately to effective MW's provided by RegA resources.[60]

Daily average prices and regulation requirements in 2013 are shown in Figure 5.

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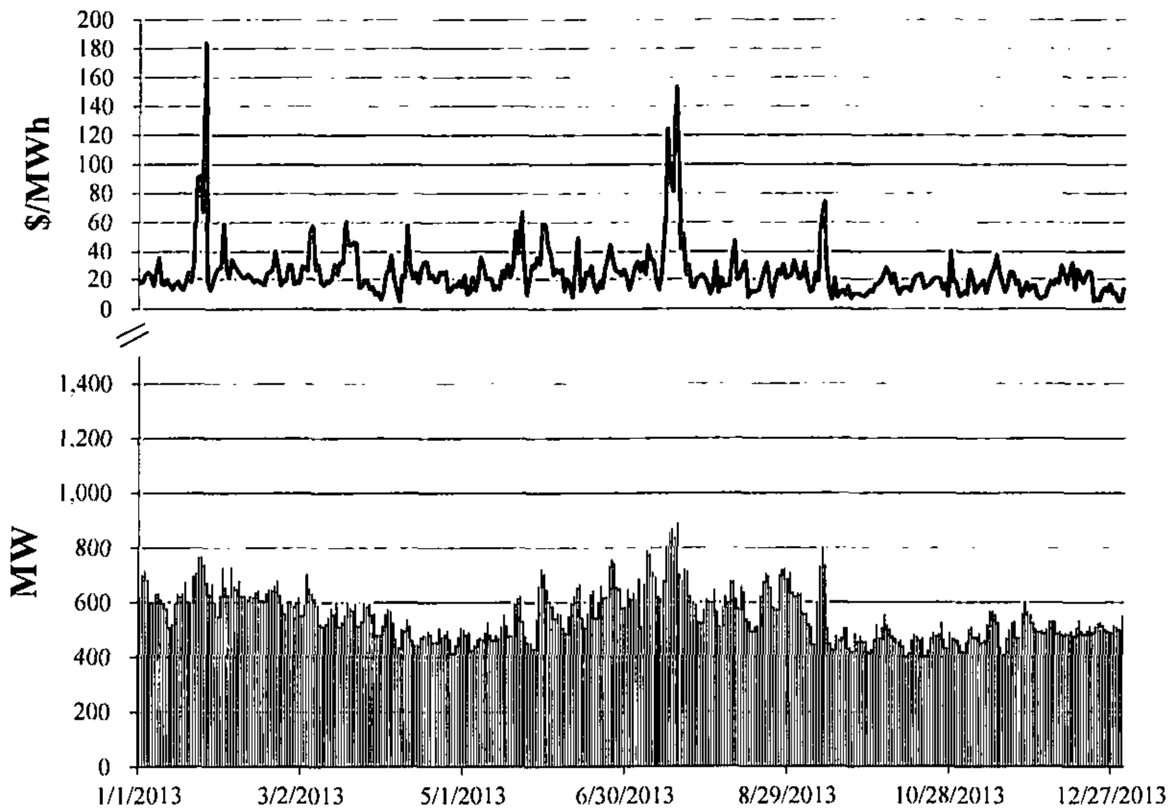
[57] (FERC 2012).

[58] (Monitoring Analytics, LLC 2013), p. 275.

[59] (Monitoring Analytics, LLC 2014), p.295.

[60] *Ibid.*, p. 293.

**Figure 5**
**Daily Average Regulation Purchases (MW) and Market Clearing Prices ($/MWh) in 2013**[61]




## IV.B. Synchronized Reserve

PJM satisfies its contingency reserve requirements defined under the NERC Performance Standard BAL-002-0 (Disturbance Control Performance)[62] 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.[63] At least 1,375 MW of the requirement must be

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[61] PJM Regulation Market Capability Clearing Prices ("RMCCP") are provided from January through December 2013.

[62] Available at http://www.nerc.com/files/BAL-002-0.pdf.

[63] (Monitoring Analytics, LLC 2014) p. 306.

met by synchronized reserve, and at least 1,300 MW of that synchronized reserve must be located in the Mid-Atlantic Dominion subzone.[64]

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.[65]

Tier 2 reserves are procured in the synchronized market only if there are not sufficient Tier 1 resources available. Tier 1 resources are paid only when they respond to a reserve event, while Tier 2 resources are compensated for the synchronized reserve capability that clears in the market. Thus, there is a market clearing price only for Tier 2 reserves when the synchronized market is needed and cleared. In late 2013 PJM implemented reforms to how Tier 1 available supply is estimated. The changes resulted in a more conservative estimation of Tier 1 supply, and increased the number of hours when a synchronized market was needed in cleared. Prior to the changes (during the period of January through September, 2013) the RTO Synchronized Reserve Market cleared in 3% of hours. After the changes (October through December, 2013), the RTO Synchronized Reserve Market cleared in 49.6% of hours.[66]

Figure 6 illustrates daily average Tier 2 reserve procured and market clearing prices in the Mid-Atlantic Dominion Subzone. Consistent with the changes in estimating Tier 1 supply, the volume of Tier 2 procured increased in late 2013. In 2013, the average amount of Tier 2 reserves cleared in the Mid-Atlantic Dominion Subzone was 153.8 MW.[67] The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $6.98 per MW in 2012, which was $1.04/MW lower than in 2012. The corresponding average cost of synchronized reserves in 2013 was $13.07/MW, a $0.38/MW increase from 2012.[68] On an annual average basis this widening gap of price and cost indicates lower efficiency in the market. However, the market monitor found that this cap decreased significantly in late 2013 when reforms to the market were implemented, decreasing to almost zero by December.[69]

Contribution of demand resources to the supply of synchronized reserves remained significant in 2013. Demand resources represented 38% of all cleared Tier 2 synchronized reserves, compared

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64 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 2013 the zone was defined east of the Bedington–Black Oak interface constraint. (Monitoring Analytics, LLC 2014) p.306.

65 (PJM 2014c) Section 4.

66 (Monitoring Analytics, LLC 2014) p. 308.

67 (Monitoring Analytics, LLC 2014) p. 308.

68 (Monitoring Analytics, LLC 2014) p. 311, Table 10-24.

69 (Monitoring Analytics, LLC 2014) p. 312, Table 10-15.

to 36% in 2012.[70] Demand resources continue to exert a significant impact on the Tier 2 market clearing price. In the hours when all cleared MW were demand resources, the weighted average synchronized reserve price was $1.21, while the average synchronized reserve price across all hours was $6.98.[71]

During times of reserve shortage, PJM applies a penalty factor to energy prices to reflect the very 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. As of October 1, 2012, the Synchronized Reserve Penalty Factor and the Non-Synchronized Reserve Penalty Factor were both equal to $250/MWh. Starting June 1, 2013, the penalty factors were increased to $400/MWh.[72] No reserve shortage occurred in 2013;[73] therefore, the reserve penalty factors did not affect the pricing of ancillary services.

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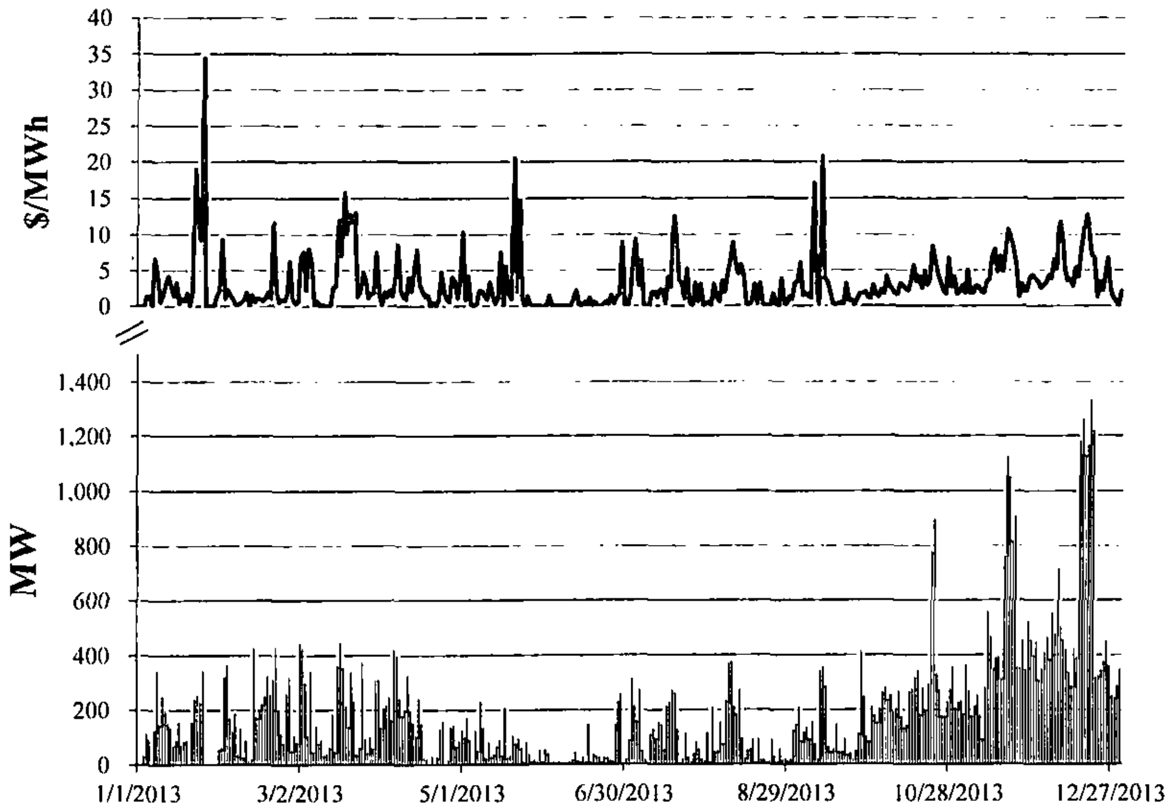
70 (Monitoring Analytics, LLC 2014) p. 310.

71 (Monitoring Analytics, LLC 2014) p. 311.

72 (PJM 2012b) Slide 154.

73 (Monitoring Analytics, LLC 2014) p. 308.

**Figure 6**
**Daily Average Mid-Atlantic Dominion Subzone Synchronized Reserve Purchases (MW) and Market Clearing Prices ($/MWh) in 2013**




PJM's market monitor concluded that in 2013, the synchronized reserve market was highly concentrated and, therefore, not structurally competitive. At the same time, the conduct of market participants was consistent with competition; and the market outcomes in the synchronized reserve markets were competitive.[74]

### IV.C. 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,[75] with some restrictions. At least 1,375 MW of the requirement must be met by synchronized reserve, and at least 1,300 MW of that synchronized

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[74] (Monitoring Analytics, LLC 2014) p. 289.

[75] (Monitoring Analytics, LLC 2014) p. 306.

reserve must be located in the Mid-Atlantic Dominion subzone.[76] The remaining primary reserve requirement can be met by non-synchronized reserve.

Non-synchronized reserve must be capable of responding to PJM dispatch within ten minutes, and capable of maintaining output for at least thirty minutes. Examples of such resources include shutdown run-of-river hydro, shutdown pumped hydro, and offline industrial combustion turbines. The market monitor found that almost all non-synchronized reserve resources are combustion turbines, and some are diesels.[77] 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 2013, the non-synchronized reserve price was greater than zero in 73 hours in the RTO reserve zone, and 228 hours in the Mid-Atlantic Dominion subzone. Between October and December 2012, the non-synchronized reserve price in the RTO Zone was greater than zero in only three hours. In the Mid-Atlantic Dominion Subzone, non-synchronized reserve prices were above zero in 159 hours, or about 7% of the time.[78]

### IV.D. Day-Ahead Scheduling Reserve

Day-Ahead Scheduling Reserve 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 RFC and Dominion regions separately. The RFC DASR requirement is based on the region's historical load under-forecast and generator outage rates.[79] In 2013, the DASR requirement was 6.91% of forecasted peak load, down from 7.03% in 2012.[80]

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76 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 2013 the zone was defined east of the Bedington–Black Oak interface constraint. (Monitoring Analytics, LLC 2014) p.306.

77 (Monitoring Analytics, LLC 2014) p. 315.

78 (Monitoring Analytics, LLC 2014) p. 315.

79 (Monitoring Analytics, LLC 2014) p. 316.

80 *Ibid.*

*In 2013, 82% of the hours cleared at a price of $0.00.*[81] *There were, however, extremely high* DASR prices during the months of July and September, with a maximum clearing price of $230.10/MWh. 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 weighted DASR clearing price in 2013 was $0.70 per MW, up from $0.57 per MW in 2012.[82] 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, 12% of all units offered DASR at or above $5 per MW.[83]

## IV.E. Black Start Service

Black start service is procured to ensure reliable restoration following a blackout. PJM works in conjunction with transmission owners to locate capable resources in the appropriate locations. Restoration plans identify critical resources and PJM defines a minimum critical black start level for each transmission zone, while providing incentives to the transmission owners to provide such service.[84]

As mentioned previously, there is no organized market for black start service. PJM may accept proposals to provide service from any willing party in a given location. Generators are compensated for black start service based on (a) a revenue requirement formula specified in Section 18 of Schedule 6A of PJM's Open Access Transmission Tariff, plus (b) payments for scheduling in the DASR market or committing in the real-time market.[85] The cost is then allocated to transmission customers proportionally based on load ratios.[86] The 2013 black start charges totaled $108 million, composed of $21 million in revenue requirement charges and $87 million in operating reserve charges.[87]

In 2011 the PJM's market monitor pointed out that the separate planning for each transmission zone significantly constrains the flexibility to consider how to restart the grid.[88] This concern was reiterated by the market monitor in 2012, stating that there is a "disconnect" between the service required, the approach to procure the service, and the need to secure voluntary

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81 *Ibid* p. 317, Table 10-28.

82 *Ibid.*

83 *Ibid.*

84 (Monitoring Analytics, LLC 2014) p. 318.

85 (Monitoring Analytics, LLC 2014) p. 318. Note that the revenue requirement includes NERC Critical Infrastructure Protection capital costs for black start units in Met-Ed and Penelec.

86 *Ibid.*

87 (Monitoring Analytics, LLC 2014) p. 319, Table 10-30.

88 (Monitoring Analytics, LLC 2011) p. 259.

participation.[89] One of the barriers to a competitive process is that proposal requests cannot be accepted at reasonable rates, as the market is "characterized by inelastic demand and substantial local market power."[90] One of the recommendations from the market monitor in 2011 was to re-evaluate how black start service is procured to ensure rates are solicited in a cost-efficient manner for the entire PJM market. Following a stakeholder process in 2012, the PJM and market monitor proposal was accepted in February 2013. The proposed changes allow cross-zonal coordination between transmission zones; revise the time requirement for black start from ninety minutes to three hours; and create a process to reevaluate black start plans every five years to ensure restoration needs are met.[91]

### IV.F. Reactive Power

Reactive power is a requirement for a generator or other resource in PJM to maintain transmission voltages within acceptable limits. Reactive supply and voltage control from generation is provided by PJM, which customers must purchase. Each network and point-to-point customer is charged a rate for reactive services that is based on the suppliers' reactive revenue requirements.[92] Reactive power services were developed in response to a need for an accurate portrayal of voltage and reactive resources and capability. Similar to black start service, charges are allocated to customers based on percentage of load. The wholesale cost component in Table 1 is calculated using the zonal revenue requirements and the corresponding zonal load.

## V. Conclusion

Overall, PJM markets are governed by market fundamentals and market performance. In 2013, market dynamics were driven by higher natural gas prices and constrained capacity supply in MAAC. Market performance was mostly competitive, with a few exceptions discussed below.

### V.A. Market Performance in 2013

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

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89 (Monitoring Analytics, LLC 2013) p. 291.

90 (Monitoring Analytics, LLC 2011) p. 259.

91 (Monitoring Analytics, LLC 2013) p. 291.

92 (Monitoring Analytics, LLC 2014) p. 319.

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 2013. With the exception of the regulation and synchronized reserve markets, 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**[93]
**Market Monitor's Assessment of PJM Markets in 2013**

| Market | Market Structure | | Participant Behavior | Market Design | Market Performance |
|---|---|---|---|---|---|
| | Aggregate | Local | | | |
| 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

93 (Monitoring Analytics, LLC 2014) Section 1.

competitive. In the Day-Ahead Scheduling Reserve market, participant behavior was mixed because 12% of offers reflected economic withholding.[94]

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 April 1, 2014, the percentage of residential customers served by an alternative supplier in the Companies' territories ranged from 31.2% in the West Penn service territory to 37.1% in the Penn Power service territory, representing 33.2% and 38.4% of the retail load, respectively.[95] The percentage of commercial load served by an alternative supplier ranged from 60.7% in the West Penn territory to 69.9% in the Met-Ed territory. The percentage of industrial load served by an alternative supplier ranged from 88.5% in the West Penn territory to 97.7% in the Met-Ed territory.

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94 (Monitoring Analytics, LLC 2014) p. 289.

95 (Pennsylvania Office of Consumer Advocate 2014).

## 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 |
| EKPC | East Kentucky Power Cooperative |
| FRR | Fixed Resource Requirement |
| GROSS CONE | Gross Cost of New Entry (gross investment cost) |
| HHI | Herfindahl-Hirschman Index |
| HWI | Handy Whitman 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 |
| MOPR | Minimum Offer Price Rule |
| 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) |
| 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 |
| RPM | Reliability Pricing Model |
| RTO | Regional Transmission Organization |
| WEST PENN | West Penn Power Company |

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# Appendix A

## APS Control Zone
## Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2013

| | | | | 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 | -16.00 | -72.90 | 3.00 | 59.90 | 2.50 | 5.00 | -4.40 | -6.80 | 53.10 | 12,660 | 2,276 |
| 2 | Bedington - Black Oak | Interface | 500 | -1.00 | -9.20 | -1.10 | 7.10 | 0.40 | 0.40 | 0.50 | 0.50 | 7.60 | 4,296 | 328 |
| 3 | Bedington | Transformer | AP | 1.60 | -3.10 | -0.30 | 4.40 | -0.10 | 0.40 | 0.30 | -0.20 | 4.20 | 1,224 | 80 |
| 4 | West | Interface | 500 | -9.40 | -13.40 | -1.90 | 2.10 | -0.10 | 0.20 | 0.60 | 0.30 | 2.40 | 3,690 | 190 |
| 5 | Readington - Roseland | Line | PSEG | -2.30 | -0.70 | -1.10 | -2.70 | -0.10 | 0.20 | 0.90 | 0.60 | -2.10 | 8,354 | 1,634 |
| 6 | Dickerson - Pleasant View | Line | Pepco | 0.60 | -1.00 | 0.40 | 2.00 | 0.10 | 0.00 | -0.40 | -0.20 | 1.70 | 1,384 | 200 |
| 7 | ATSI | Interface | ATSI | 0.00 | 0.00 | 0.00 | 0.00 | -1.30 | 0.50 | 0.00 | -1.70 | -1.70 | 0 | 36 |
| 8 | 5004/5005 Interface | Interface | 500 | -3.10 | -4.80 | -0.20 | 1.50 | 0.20 | 0.20 | 0.10 | 0.10 | 1.60 | 1,124 | 392 |
| 9 | Stephenson - Stonewall | Line | AP | 1.30 | -0.20 | 0.30 | 1.70 | 0.00 | 0.00 | -0.10 | -0.10 | 1.60 | 1,200 | 46 |
| 10 | South Canton | Transformer | AEP | 0.40 | -1.10 | 0.00 | 1.50 | 0.00 | 0.00 | 0.10 | 0.10 | 1.60 | 1,030 | 30 |
| 11 | Brambleton - Loudoun | Line | Dominion | 0.70 | -0.70 | -0.10 | 1.30 | 0.00 | 0.00 | 0.00 | 0.00 | 1.30 | 686 | 0 |
| 12 | Mt. Storm | Other | Dominion | -0.30 | -1.90 | 0.20 | 1.70 | 0.10 | 0.30 | -0.30 | -0.40 | 1.30 | 834 | 284 |
| 13 | Butler - Karns City | Line | AP | 1.50 | 0.20 | -0.10 | 1.20 | -0.10 | 0.00 | 0.00 | -0.10 | 1.10 | 1,962 | 110 |
| 14 | Riversville - Wove | Line | AP | 0.60 | -0.30 | 0.00 | 0.90 | 0.00 | 0.00 | 0.00 | 0.10 | 1.00 | 692 | 84 |
| 15 | Doubs | Transformer | AP | -0.10 | -0.90 | -0.20 | 0.50 | 0.40 | 0.10 | 0.10 | 0.40 | 1.00 | 994 | 76 |
| 17 | Collinsf - Osage | Line | AP | 0.60 | -0.40 | -0.10 | 0.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.90 | 852 | 0 |
| 18 | Halfway - Marlowe | Line | AP | 0.20 | -0.80 | 0.00 | 0.90 | 0.00 | 0.00 | -0.10 | -0.10 | 0.90 | 1,366 | 16 |
| 20 | Bedington - Marlowe | Line | AP | 0.10 | -0.70 | -0.10 | 0.60 | 0.00 | 0.10 | 0.10 | 0.00 | 0.60 | 256 | 48 |
| 26 | Marlowe | Transformer | AP | 0.30 | 0.00 | 0.20 | 0.50 | 0.00 | 0.00 | 0.00 | 0.00 | 0.50 | 3,914 | 0 |
| 30 | All Dam - Kittanning | Line | AP | 0.00 | -0.40 | 0.00 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.40 | 486 | 54 |

## ATSI Control Zone
## Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2013

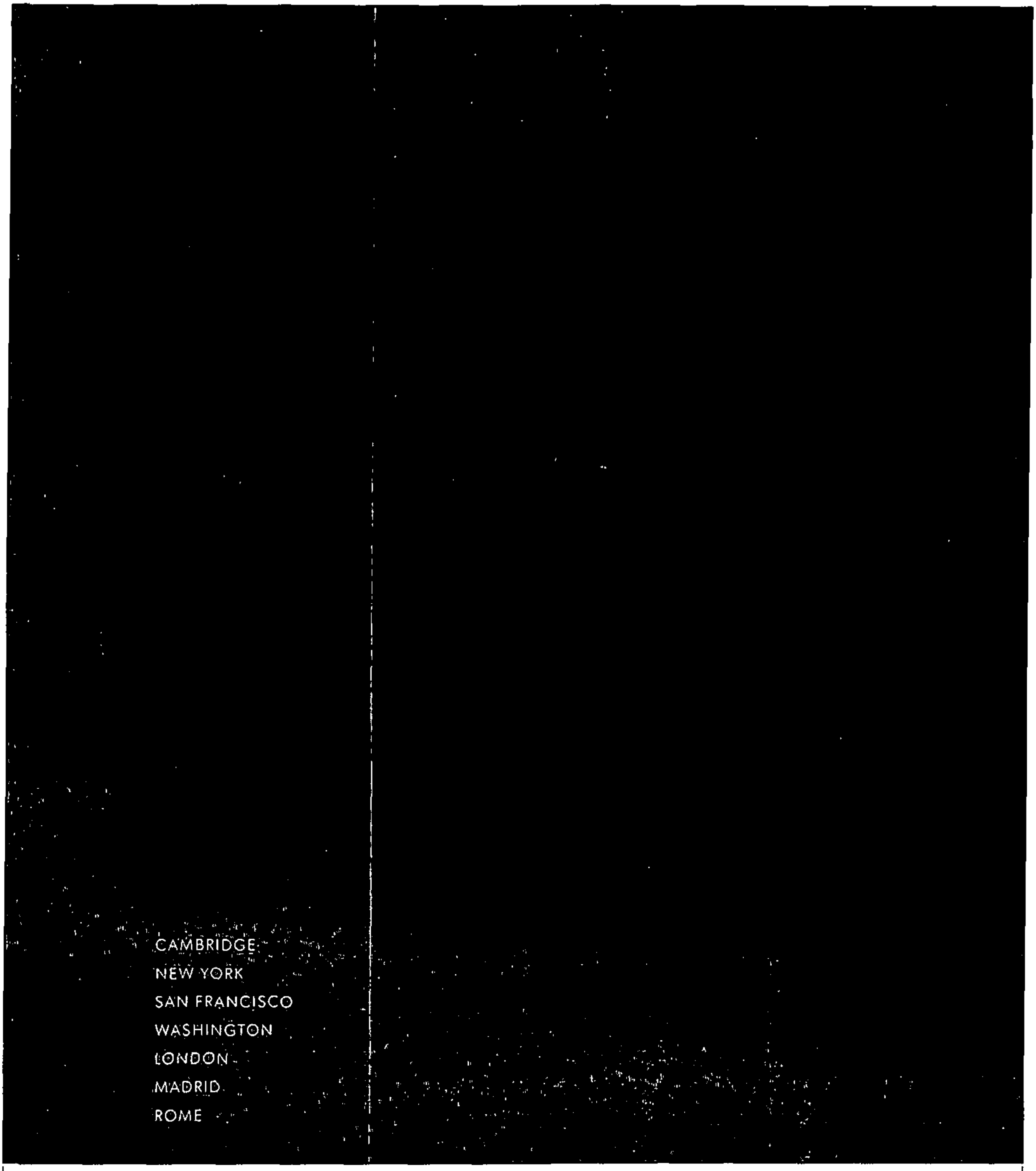
| | | | | Day Ahead | | | | Balancing | | | | | Event Hours | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Constraint | Type | Location | Load Payments | Generation Credits | Explicit | Total | Load Payments | Generation Credits | Explicit | Total | Grand Total | Day Ahead | Real Time |
| 1 | ATSI | Interface | ATSI | 0.00 | 0.00 | 0.00 | 0.00 | 12.90 | 10.60 | -29.00 | -26.70 | -26.70 | 0 | 36 |
| 2 | AP South | Interface | 500 | -57.50 | -50.50 | -1.60 | -8.60 | 0.50 | 3.10 | 1.30 | -1.30 | -9.90 | 12,660 | 2,276 |
| 3 | Lakeview - Greenfield | Line | ATSI | 2.50 | -1.90 | 0.80 | 5.30 | -0.20 | 0.20 | -0.30 | -0.80 | 4.40 | 2,280 | 202 |
| 4 | South Canton | Transformer | AEP | 8.60 | 6.10 | 0.50 | 2.90 | 0.20 | 0.20 | -0.10 | -0.20 | 2.70 | 1,030 | 30 |
| 5 | Ottowa - West Fremont | Line | ATSI | -0.50 | -2.90 | 0.20 | 2.60 | 0.00 | 0.00 | 0.00 | 0.00 | 2.60 | 526 | 46 |
| 6 | West | Interface | 500 | -13.90 | -12.00 | -0.40 | -2.20 | 0.10 | 0.20 | 0.10 | 0.00 | -2.20 | 3,690 | 190 |
| 7 | Brookside - Troy | Line | ATSI | 4.70 | 2.30 | 0.50 | 3.00 | -0.40 | 0.20 | -0.50 | -1.00 | 2.00 | 1,420 | 54 |
| 8 | Readington - Roseland | Line | PSEG | 7.00 | 5.30 | 0.10 | 1.90 | -0.20 | -0.50 | -0.30 | 0.00 | 1.80 | 8,354 | 1,634 |
| 9 | East Akron - Knox | Line | ATSI | 1.40 | -0.20 | 0.20 | 1.80 | 0.00 | 0.00 | 0.00 | 0.00 | 1.80 | 880 | 0 |
| 10 | Benton Harbor - Palisades | Flowgate | MISO | 6.50 | 5.00 | 0.80 | 2.30 | 0.00 | 0.00 | -1.00 | -1.00 | 1.20 | 4,990 | 228 |
| 11 | Inland - Pofok Tie | Line | ATSI | 0.80 | 0.20 | 0.60 | 1.20 | 0.00 | 0.00 | 0.00 | 0.00 | 1.20 | 2,234 | 0 |
| 12 | Bedington - Black Oak | Interface | 500 | -7.80 | -6.70 | -0.30 | -1.40 | 0.10 | 0.10 | 0.20 | 0.20 | -1.10 | 4,296 | 328 |
| 13 | 5004/5005 Interface | Interface | 500 | -5.30 | -4.80 | -0.10 | -0.60 | 0.10 | 0.50 | 0.10 | -0.20 | -0.90 | 1,124 | 392 |
| 14 | Michigan City - Laporte | Flowgate | MISO | 2.80 | 2.40 | 0.50 | 0.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.90 | 6,764 | 0 |
| 15 | New Castle - Hoytdale | Line | ATSI | 1.10 | 0.40 | 0.00 | 0.80 | 0.00 | 0.00 | 0.00 | 0.00 | 0.80 | 66 | 0 |
| 21 | Avon Lake | Transformer | ATSI | 0.00 | -0.80 | 0.00 | 0.80 | 0.00 | 0.00 | 0.00 | 0.00 | 0.80 | 206 | 48 |
| 23 | Longview - ARMCO | Line | ATSI | 0.80 | 0.40 | 0.20 | 0.60 | 0.30 | 0.00 | -0.30 | -0.10 | 0.60 | 404 | 60 |
| 36 | Bayshore | Transformer | ATSI | 0.00 | 0.00 | 0.00 | 0.00 | 0.60 | 0.00 | -0.10 | 0.50 | 0.50 | 4 | 38 |
| 45 | Bluebell - Knox | Line | ATSI | 0.40 | 0.00 | 0.00 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.40 | 216 | 2 |
| 60 | Babb - Evans | Line | ATSI | 0.40 | 0.10 | 0.10 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 72 | 0 |

## METED Control Zone
## Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2013

| | | | | 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 | 6.60 | 9.30 | 0.60 | -2.10 | 0.10 | 0.00 | -0.20 | -0.10 | -2.30 | 3,690 | 190 |
| 2 | Readington-Roseland | Line | PSEG | -8.40 | -10.50 | -0.40 | 1.70 | -0.10 | 0.10 | 0.30 | 0.00 | 1.70 | 8,354 | 1,634 |
| 3 | Bridgewater-Middlesex | Line | PSEG | 0.30 | -0.70 | 0.00 | 1.10 | 0.00 | 0.10 | 0.20 | 0.10 | 1.10 | 6,092 | 514 |
| 4 | Bagley-Graceton | Line | BGE | -4.00 | -5.00 | -0.50 | 0.50 | 0.00 | 0.10 | 0.50 | 0.40 | 0.90 | 4,174 | 880 |
| 5 | Wescosville | Transformer | PPL | 0.90 | 0.00 | 0.00 | 0.90 | 0.10 | 0.00 | -0.20 | 0.00 | 0.90 | 3,258 | 272 |
| 6 | Jackson-Three Mile Island | Line | Met-Ed | 0.50 | -0.30 | 0.00 | 0.80 | 0.00 | 0.00 | 0.00 | 0.00 | 0.80 | 138 | 4 |
| 7 | Middletown Junction | Transformer | Met-Ed | 0.70 | 0.00 | 0.00 | 0.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.70 | 62 | 0 |
| 8 | Middletown Jct. - Middletwon Jctn. | Other | Met-Ed | 0.60 | -0.10 | 0.00 | 0.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.70 | 236 | 16 |
| 9 | Conemaugh - Hunterstown | Line | 500 | 0.60 | 1.10 | 0.20 | -0.30 | 0.00 | 0.00 | -0.40 | -0.40 | -0.70 | 306 | 136 |
| 10 | Gardners - Texas East | Line | Met-Ed | 0.30 | -0.30 | 0.10 | 0.60 | 0.00 | 0.00 | 0.00 | -0.10 | 0.60 | 678 | 34 |
| 11 | Martins Creek - Siegfried | Line | PPL | 0.60 | 0.20 | 0.10 | 0.40 | 0.00 | -0.10 | 0.00 | 0.10 | 0.50 | 2,426 | 182 |
| 12 | 5004/5005 Interface | Interface | 500 | 2.50 | 2.90 | -0.20 | -0.60 | 0.10 | 0.10 | 0.10 | 0.10 | -0.50 | 1,124 | 392 |
| 13 | Brunner Island - Yorkana | Line | Met-Ed | 0.10 | -0.20 | 0.00 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.40 | 322 | 0 |
| 14 | Northwood | Transformer | Met-Ed | 0.90 | 0.50 | 0.10 | 0.50 | 0.10 | 0.00 | -0.20 | -0.10 | 0.40 | 760 | 162 |
| 15 | Clover | Transformer | Dominion | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | -0.40 | -0.40 | -0.40 | 60 | 414 |
| 20 | Hunterstown | Transformer | Met-Ed | 0.20 | 0.00 | 0.10 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 612 | 32 |
| 22 | Middletown Jct | Transformer | Met-Ed | 0.20 | 0.00 | 0.10 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 584 | 0 |
| 23 | Berks - S Lebanon | Line | Met-Ed | 0.00 | -0.30 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 140 | 72 |
| 24 | Middletwon Jct - Yorkhaven | Line | Met-Ed | 0.10 | 0.00 | 0.30 | 0.40 | 0.00 | 0.00 | -0.10 | -0.10 | 0.20 | 4,094 | 16 |
| 29 | Fox Hill - Shawnee | Line | Met-Ed | 0.00 | 0.00 | 0.00 | 0.00 | 0.20 | 0.10 | 0.10 | 0.20 | 0.20 | 0 | 100 |

## Penelec Control Zone
## Top Transmission Congestion Cost Impacts (By Facility) ($Millions): Calendar Year 2013

| | | | | 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 | -27.50 | -40.30 | 1.00 | 13.90 | 0.50 | 0.00 | 0.00 | 0.40 | 14.30 | 12,660 | 2,276 |
| 2 | West | Interface | 500 | -5.60 | -15.60 | -1.00 | 9.00 | 0.00 | 0.40 | 0.10 | -0.30 | 8.70 | 3,690 | 190 |
| 3 | 5004/5005 Interface | Interface | 500 | -2.40 | -6.80 | -0.50 | 3.90 | 0.10 | 0.50 | 0.60 | 0.20 | 4.10 | 1,124 | 392 |
| 4 | Readington - Roseland | Line | PSEG | 10.40 | 5.40 | -1.10 | 4.00 | -0.20 | 0.50 | -0.40 | -1.20 | 2.80 | 8,354 | 1,634 |
| 5 | Butler - Karns City | Line | AP | 8.20 | 6.50 | 0.70 | 2.40 | 0.10 | 0.10 | -0.10 | -0.10 | 2.20 | 1,962 | 110 |
| 6 | Bedington - Black Oak | Interface | 500 | -3.80 | -5.90 | 0.10 | 2.10 | 0.00 | 0.00 | 0.00 | 0.00 | 2.10 | 4,296 | 328 |
| 7 | Bagley - Graceton | Line | BGE | -3.80 | -5.80 | 0.30 | 2.30 | 0.00 | 0.10 | -0.40 | -0.40 | 1.80 | 4,174 | 880 |
| 8 | Corrcy East - Warren | Line | PENELEC | 0.20 | 0.20 | 0.00 | 0.00 | -1.10 | 0.50 | -0.10 | -1.70 | -1.70 | 94 | 352 |
| 9 | BCPEP | Interface | Pepco | -2.10 | -3.00 | 0.80 | 1.70 | 0.00 | 0.00 | -0.20 | -0.20 | 1.50 | 2,590 | 90 |
| 10 | Conemaugh - Hunterstown | Line | 500 | -1.10 | -2.70 | -0.20 | 1.40 | 0.00 | 0.30 | 0.20 | -0.10 | 1.30 | 306 | 136 |
| 11 | Bridgewater - Middlesex | Line | PSEG | -0.90 | -2.20 | -0.10 | 1.20 | 0.00 | 0.10 | 0.20 | 0.10 | 1.30 | 6,092 | 514 |
| 12 | Wescosville | Transformer | PPL | -0.20 | -1.10 | -0.10 | 0.90 | 0.00 | 0.00 | 0.20 | 0.20 | 1.10 | 3,258 | 272 |
| 13 | Conastone - Graceton | Line | BGE | -1.60 | -2.60 | 0.00 | 1.00 | 0.00 | 0.00 | 0.00 | 0.10 | 1.10 | 1,750 | 116 |
| 14 | Bedington - Black Oak | Transformer | AP | -1.30 | -1.90 | 0.00 | 0.60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.60 | 1,224 | 80 |
| 15 | Seward | Transformer | PENELEC | 2.30 | 1.50 | 0.30 | 1.10 | 0.10 | 0.30 | -0.30 | -0.50 | 0.60 | 96 | 72 |
| 21 | Hooversville | Transformer | PENELEC | 1.50 | 1.10 | 0.20 | 0.60 | 0.00 | 0.10 | -0.10 | -0.10 | 0.50 | 274 | 12 |
| 25 | Cambria Slope - Summit | Line | PENELEC | 0.40 | -0.10 | 0.00 | 0.50 | 0.00 | 0.00 | 0.00 | -0.10 | 0.40 | 76 | 0 |
| 34 | Farmers Valley - Lewis Run | Line | PENELEC | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | -0.20 | -0.40 | -0.30 | 76 | 114 |
| 35 | Edgewood - Shelocta | Line | PENELEC | 1.00 | 0.60 | 0.10 | 0.40 | 0.00 | 0.00 | -0.10 | -0.10 | 0.30 | 254 | 56 |
| 39 | Falconer - Warren | Line | PENELEC | 1.50 | 0.90 | 0.00 | 0.70 | -0.70 | 0.20 | -0.10 | -1.00 | -0.30 | 696 | 164 |

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