2013 State of the Market Report for PJM

March 13, 2014

Washington, DC

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Monitoring Analytics

Market Monitoring Unit

- Monitoring Analytics, LLC
  - Independent company
  - Formed August 1, 2008
- Independent Market Monitor for PJM
  - Independent from Market Participants
  - Independent from RTO management
  - Independent from RTO board of directors
- MMU Accountability
  - To FERC (per FERC MMU Orders and MM Plan)
  - To PJM markets
  - To PJM Board for administration of the contract

Role of Market Monitoring

- Market monitoring is required by FERC Orders
- Role of competition under FERC regulation
  - Mechanism to regulate prices
  - Competitive outcome = just and reasonable
- FERC has enforcement authority
- Relevant model of competition is not laissez faire
- Competitive outcomes are not automatic
- Detailed rules required
- Detailed monitoring required:
  - Of participants
  - Of RTO
  - Of rules

Role of Market Monitoring

- Market monitoring is primarily analytical
  - Adequacy of market rules
  - Compliance with market rules
  - Exercise of market power
- Market monitoring provides inputs to prospective mitigation
- Market monitoring provides retrospective mitigation
- Market monitoring provides information
  - To FERC
  - To state regulators
  - To market participants
  - To RTO

Market Monitoring Plan

- **Monitor compliance with rules.**
- **Monitor actual or potential design flaws in rules.**
- **Monitor structural problems in the PJM market.**
- **Monitor the potential of market participants to exercise market power.**

Figure 1-1 PJM's footprint and its 18 control zones

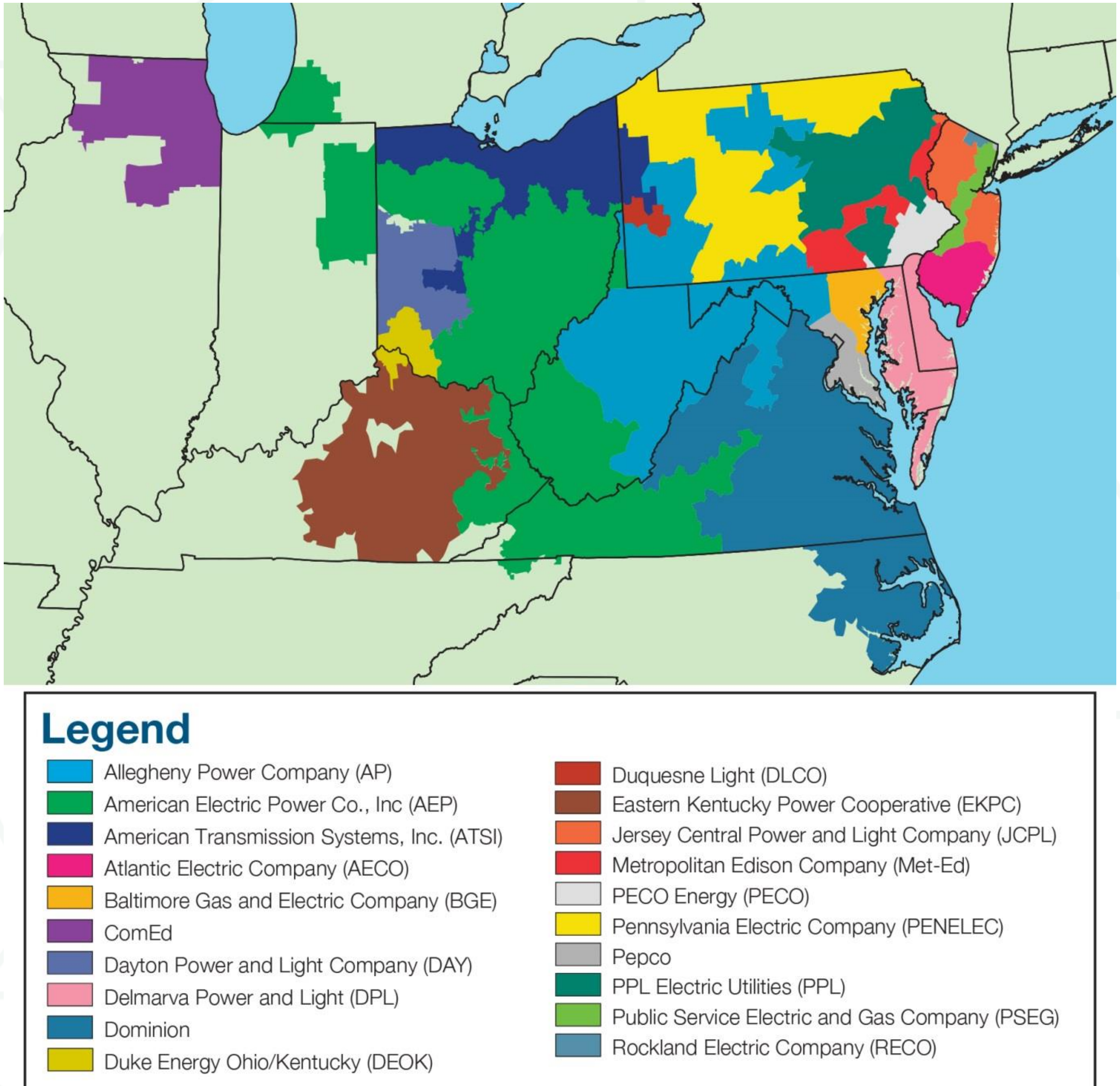

Table 1-2 The Energy Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

State of the Market Report Recommendations

- **Energy market**
  - **Eliminate FMU/AU adders.**
  - **PJM should not create closed loop interfaces to address shortcomings of demand resources**
  - **Interchange optimisation improvements**

Table 1-9 Total price per MWh by category: 2012 and 2013

Category	2012 $/MWh	2013 $/MWh	Percent Change Totals	2012 Percent of Total	2013 Percent of Total
Load Weighted Energy	$35.23	$38.66	9.7%	71.8%	71.7%
Capacity	$6.05	$7.13	17.8%	12.3%	13.2%
Transmission Service Charges	$4.78	$5.20	8.7%	9.7%	9.6%
Reactive	$0.43	$0.80	87.6%	0.9%	1.5%
Energy Uplift (Operating Reserves)	$0.79	$0.59	(25.5%)	1.6%	1.1%
PJM Administrative Fees	$0.44	$0.43	(2.0%)	0.9%	0.8%
Transmission Enhancement Cost Recovery	$0.34	$0.39	15.5%	0.7%	0.7%
Regulation	$0.26	$0.24	(5.3%)	0.5%	0.5%
Black Start	$0.03	$0.14	437.7%	0.1%	0.3%
Capacity (FRR)	$0.52	$0.11	(79.4%)	1.1%	0.2%
Transmission Owner (Schedule 1A)	$0.08	$0.08	(0.3%)	0.2%	0.2%
Emergency Load Response	$0.02	$0.06	209.0%	0.0%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.06	21.9%	0.1%	0.1%
Synchronized Reserves	$0.04	$0.04	3.1%	0.1%	0.1%
NERC/RFC	$0.02	$0.02	(1.2%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(1.4%)	0.0%	0.0%
Economic Load Response	$0.01	$0.01	41.6%	0.0%	0.0%
Non-Synchronized Reserves	$0.00	$0.00	127.3%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	17.2%	0.0%	0.0%
Emergency Energy	$0.00	$0.00	(100.0%)	0.0%	0.0%
Total	**$49.07**	**$53.92**	**9.9%**	**100.0%**	**100.0%**

Figure 3-2 Average PJM aggregate real-time generation supply curves: Summer of 2012 and 2013

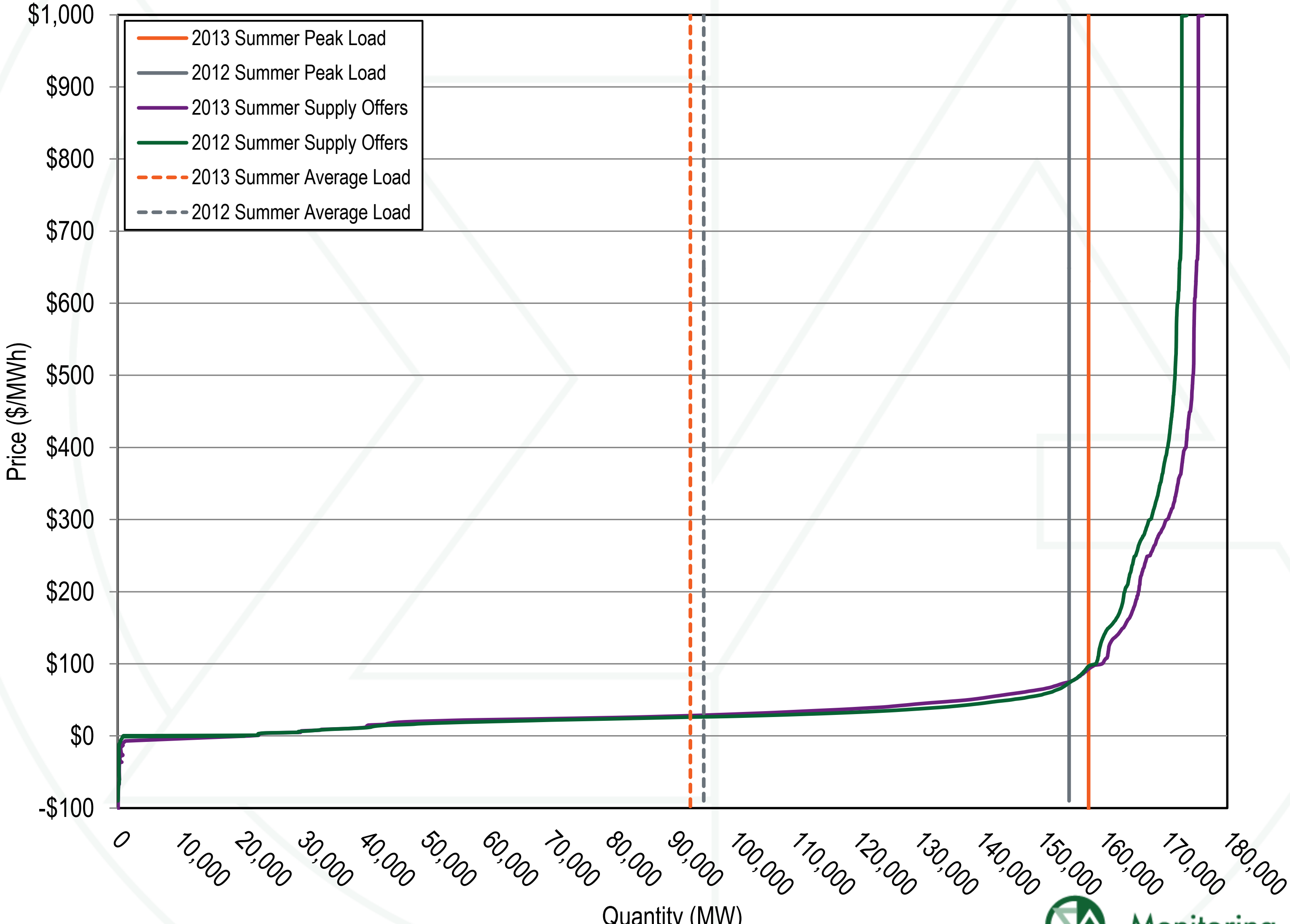

Figure 3-10 PJM footprint calendar year peak loads: 1999 to 2013

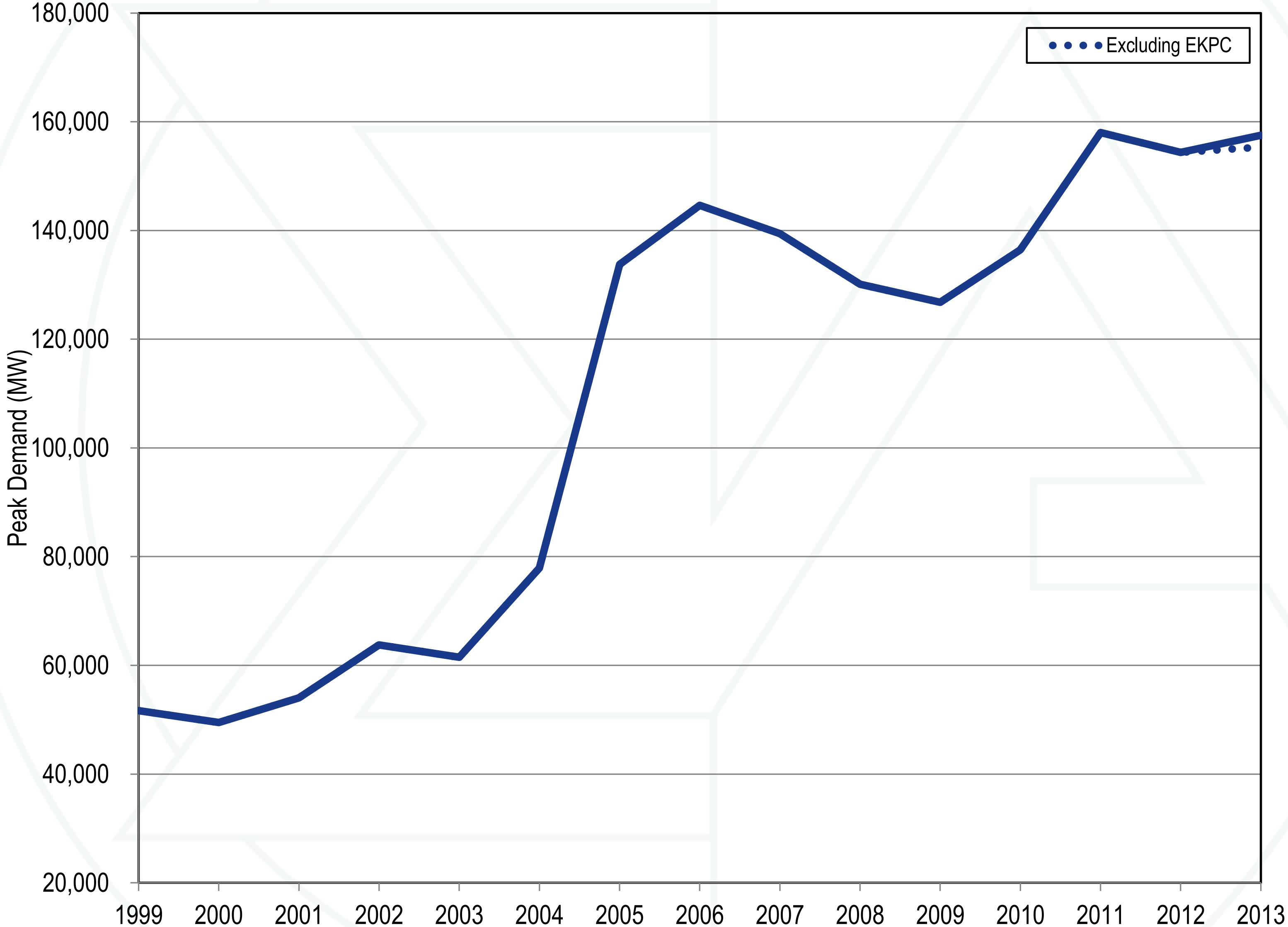

Table 3-14 Actual PJM footprint peak loads: 1999 to 2013

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, July 06	14	51,689	NA	NA
2000	Wed, August 09	17	49,469	(2,220)	(4.3%)
2001	Thu, August 09	15	54,015	4,546	9.2%
2002	Wed, August 14	16	63,762	9,747	18.0%
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Tue, August 03	17	77,887	16,387	26.6%
2005	Tue, July 26	16	133,761	55,875	71.7%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013 (with EKPC)	Thu, July 18	17	157,508	3,165	2.1%
2013 (without EKPC)	Thu, July 18	17	155,333	990	0.6%

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2013

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Year	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,578	5,511	NA	NA	NA	NA	NA	NA
1999	29,641	5,955	NA	NA	3.7%	8.1%	NA	NA
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	NA	NA
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)

Figure 3-13 PJM real-time monthly average hourly load: January 2012 through December 2013

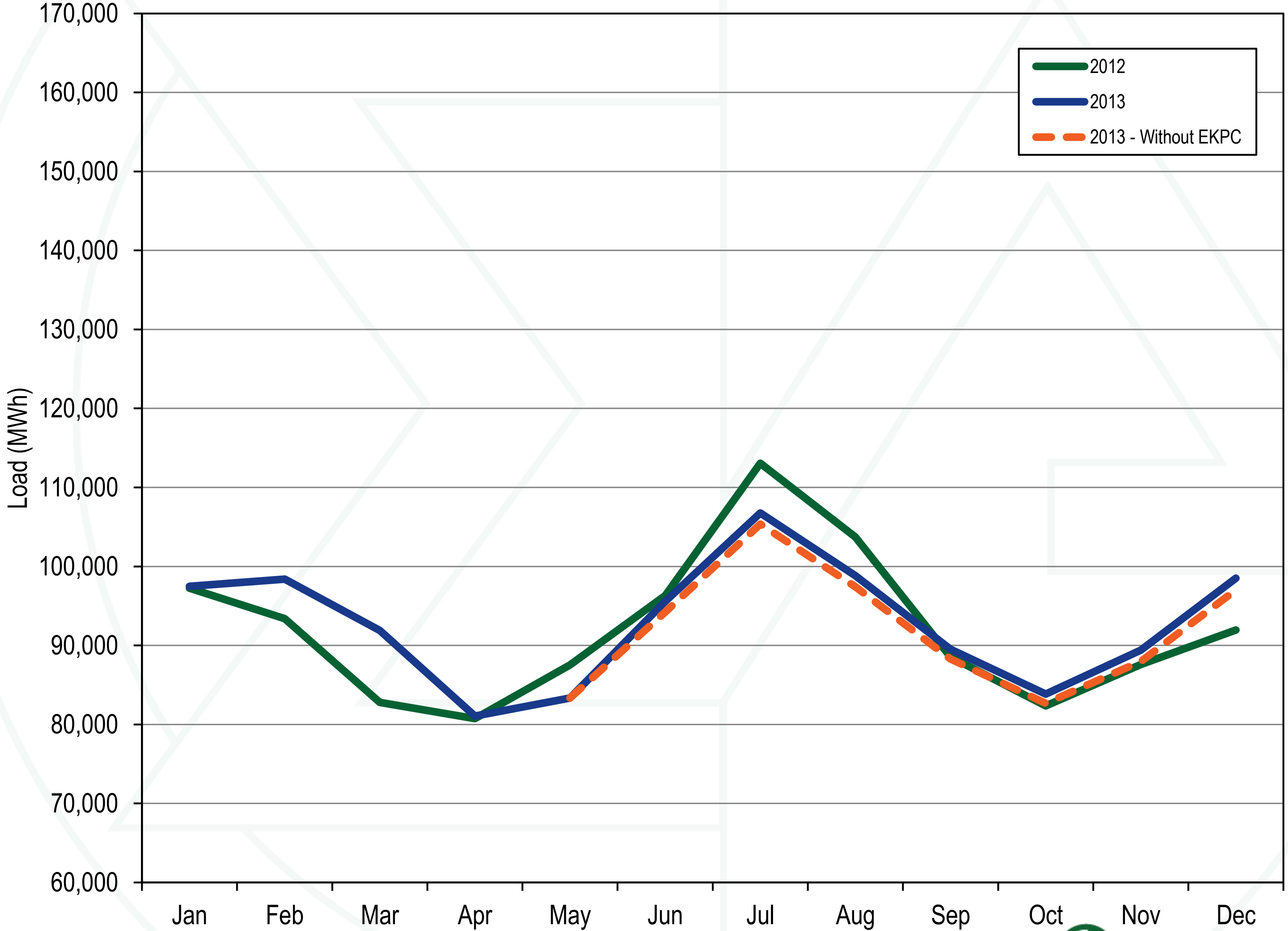

Table 3-60 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2013

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%

Figure 3-25 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2013

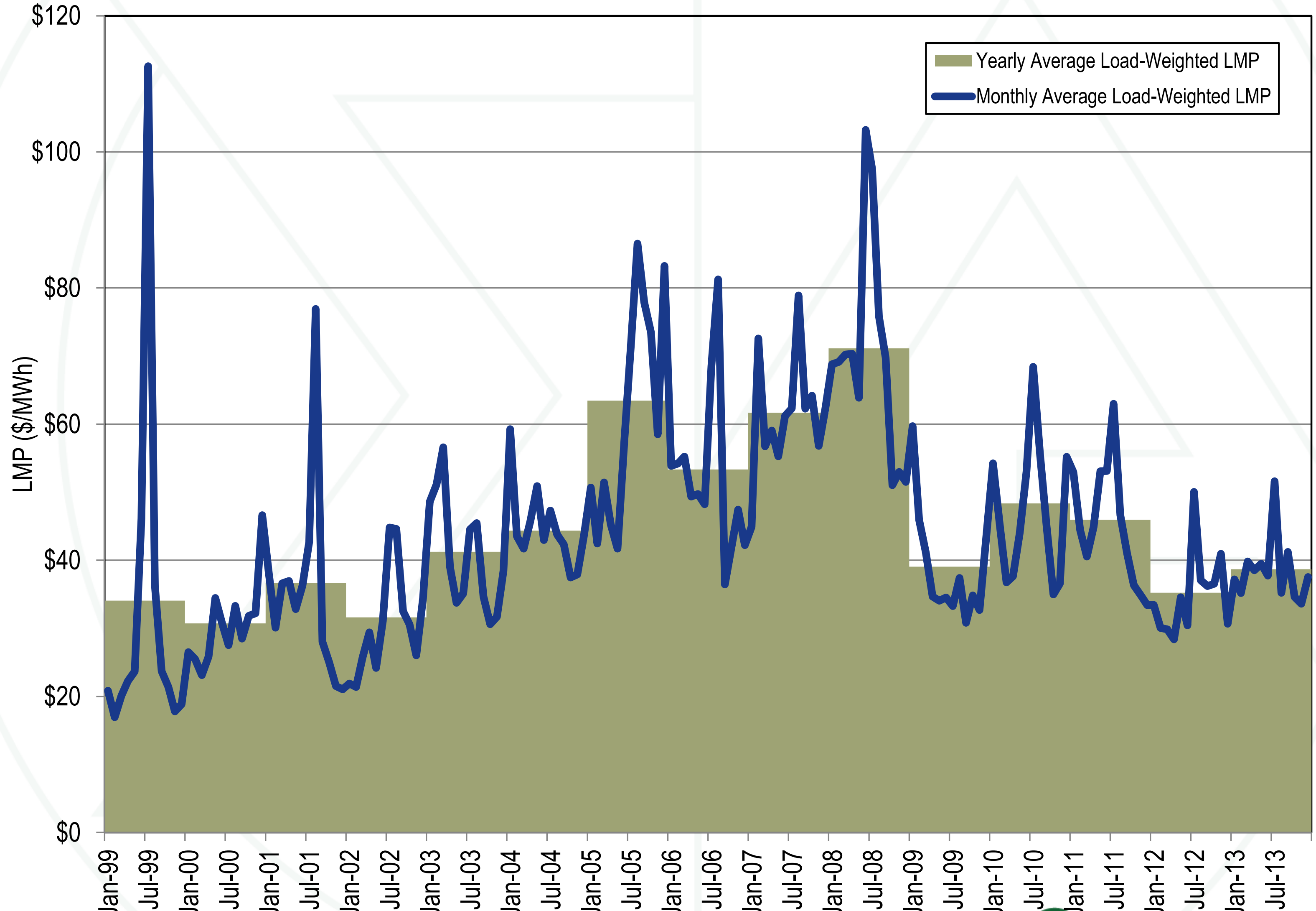

Figure 3-26 Spot average fuel price comparison with fuel delivery charges: 2012 through 2013 ($/MMBtu)

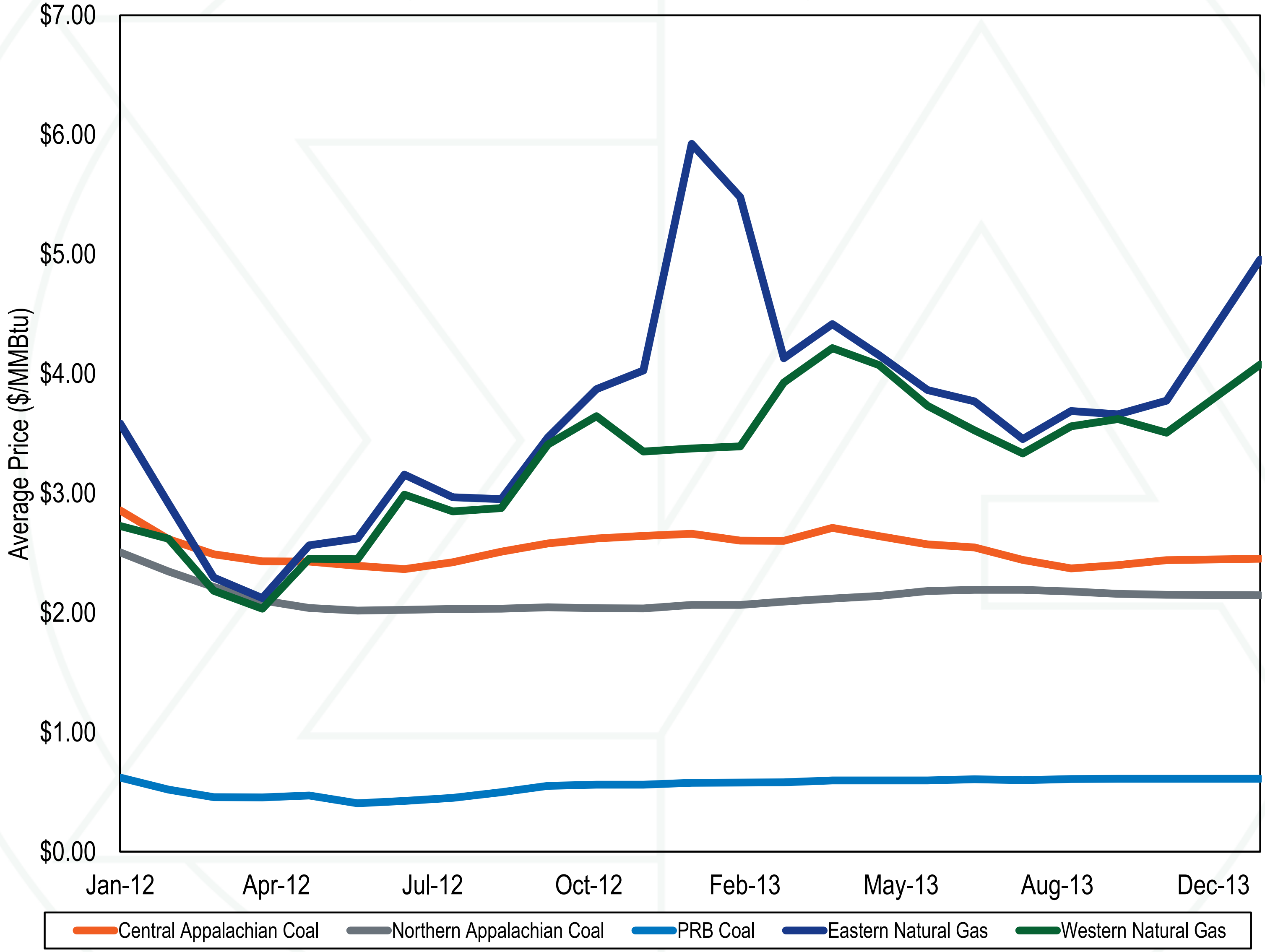

Figure 7-2 Average zonal operating costs: 2009 through 2013

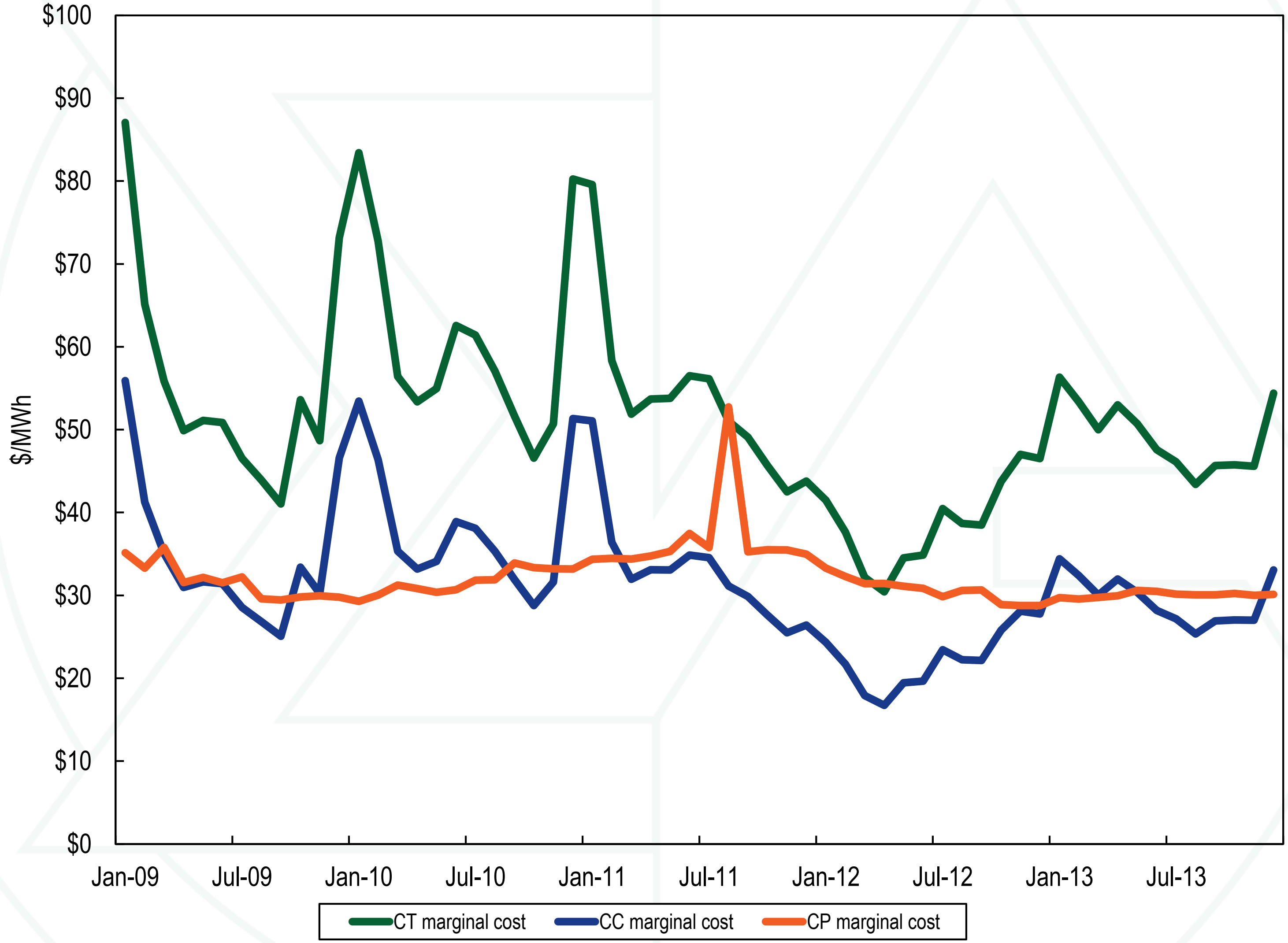

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Table 3-61 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2013 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$38.66	$34.46	(10.9%)
	2012 Load-Weighted LMP	**2013 Fuel-Cost-Adjusted, Load-Weighted LMP**	**Change**
Average	$35.23	$34.46	(2.2%)
	2012 Load-Weighted LMP	**2013 Load-Weighted LMP**	**Change**
Average	$35.23	$38.66	9.7%

Table 3-8 PJM generation (By fuel source (GWh)): 2012 and 2013

	2012 GWh	Percent	2013 GWh	Percent	Change in Output
Coal	332,762.0	42.1%	353,463.5	44.3%	6.2%
Standard Coal	323,043.5	40.9%	343,957.5	43.2%	6.3%
Waste Coal	9,718.5	1.2%	9,506.1	1.2%	(0.1%)
Nuclear	273,372.2	34.6%	277,277.8	34.8%	1.4%
Gas	148,230.4	18.8%	130,102.3	16.3%	(12.2%)
Natural Gas	146,007.5	18.5%	127,726.8	16.0%	(12.5%)
Landfill Gas	2,222.3	0.3%	2,321.0	0.3%	4.4%
Biomass Gas	0.5	0.0%	54.5	0.0%	10,323.4%
Hydroelectric	12,649.7	1.6%	14,085.0	1.8%	11.3%
Pumped Storage	6,521.9	0.8%	6,690.4	0.8%	2.6%
Run of River	6,127.8	0.8%	7,394.5	0.9%	20.7%
Wind	12,633.6	1.6%	14,826.9	1.9%	17.4%
Waste	5,177.6	0.7%	5,040.1	0.6%	(2.7%)
Solid Waste	4,200.3	0.5%	4,185.0	0.5%	(0.4%)
Miscellaneous	977.3	0.1%	855.1	0.1%	(12.5%)
Oil	5,030.9	0.6%	1,948.3	0.2%	(61.3%)
Heavy Oil	4,796.9	0.6%	1,730.7	0.2%	(63.9%)
Light Oil	218.9	0.0%	187.2	0.0%	(14.5%)
Diesel	9.9	0.0%	14.6	0.0%	47.5%
Kerosene	5.1	0.0%	15.7	0.0%	204.6%
Jet Oil	0.0	0.0%	0.1	0.0%	219.4%
Solar	233.5	0.0%	355.0	0.0%	52.0%
Battery	0.3	0.0%	0.7	0.0%	122.3%
Total	790,090.3	100.0%	797,099.6	100.0%	0.9%

Table 3-20 Offer-capping statistics – Energy only: 2009 to 2013

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.6%	0.2%	0.0%	0.0%
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%

Table 3-21 Offer-capping statistics for energy and reliability: 2009 to 2013

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.7%	0.2%	0.0%	0.0%
2012	1.7%	1.0%	0.9%	0.5%
2013	2.9%	2.4%	3.2%	2.1%

Table 3-64 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: 2013 and 2012

Element	2012 Contribution to LMP	2012 Percent	2013 Contribution to LMP	2013 Percent	Change Percent
Coal	$19.06	54.1%	$18.35	47.5%	(6.7%)
Gas	$8.39	23.8%	$10.69	27.6%	3.8%
VOM	$2.53	7.2%	$2.27	5.9%	(1.3%)
Ten Percent Adder	$1.50	4.3%	$1.87	4.8%	0.6%
NA	$1.16	3.3%	$1.61	4.2%	0.9%
FMU Adder	$0.10	0.3%	$1.32	3.4%	3.1%
Oil	$1.69	4.8%	$1.28	3.3%	(1.5%)
Markup	$0.44	1.2%	$0.77	2.0%	0.7%
LPA Rounding Difference	$0.35	1.0%	$0.22	0.6%	(0.4%)
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.17	0.4%	0.4%
Emergency Demand Response Adder	$0.00	0.0%	$0.17	0.4%	0.4%
CO2 Cost	$0.09	0.3%	$0.13	0.3%	0.1%
NOx Cost	$0.10	0.3%	$0.10	0.3%	(0.0%)
Increase Generation Adder	$0.12	0.3%	$0.04	0.1%	(0.2%)
SO2 Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.04)	(0.1%)	$0.00	0.0%	0.1%
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
Market-to-Market Adder	$0.02	0.1%	($0.00)	(0.0%)	(0.1%)
Decrease Generation Adder	($0.22)	(0.6%)	($0.13)	(0.3%)	0.3%
LPA-SCED Differential	($0.10)	(0.3%)	($0.21)	(0.6%)	(0.3%)
Total	$35.23	100.0%	$38.66	100.0%	

Table 3-63 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: 2013 and 2012

	2012		2013		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Coal	$18.90	53.6%	$18.04	46.6%	(7.0%)
Gas	$8.39	23.8%	$10.69	27.6%	3.8%
Ten Percent Adder	$3.48	9.9%	$3.51	9.1%	(0.8%)
VOM	$2.52	7.2%	$2.24	5.8%	(1.4%)
NA	$1.16	3.3%	$1.61	4.2%	0.9%
FMU Adder	$0.10	0.3%	$1.55	4.0%	3.7%
Oil	$1.69	4.8%	$1.28	3.3%	(1.5%)
LPA Rounding Difference	$0.35	1.0%	$0.22	0.6%	(0.4%)
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.17	0.4%	0.4%
Emergency DR Adder	$0.00	0.0%	$0.17	0.4%	0.4%
CO2 Cost	$0.09	0.3%	$0.13	0.3%	0.1%
NOx Cost	$0.10	0.3%	$0.10	0.2%	(0.0%)
Increase Generation Adder	$0.12	0.3%	$0.04	0.1%	(0.2%)
SO2 Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.04)	(0.1%)	$0.00	0.0%	0.1%
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
Market-to-Market Adder	$0.02	0.1%	($0.00)	(0.0%)	(0.1%)
Decrease Generation Adder	($0.22)	(0.6%)	($0.13)	(0.3%)	0.3%
LPA-SCED Differential	($0.10)	(0.3%)	($0.21)	(0.6%)	(0.3%)
Markup	($1.37)	(3.9%)	($0.76)	(2.0%)	1.9%
Total	$35.23	100.0%	$38.66	100.0%	

Table 3-26 Average, real-time marginal unit markup index (By price category): 2012 and 2013

	2012			2013		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.25)	31.3%	(0.01)	($3.27)	17.8%
$25 to $50	(0.05)	($2.67)	56.5%	(0.01)	($1.23)	65.3%
$50 to $75	0.05	$1.23	4.8%	(0.01)	($3.90)	8.4%
$75 to $100	0.28	$24.24	0.7%	0.04	($1.50)	1.5%
$100 to $125	0.23	$23.67	0.5%	0.10	$9.85	0.7%
$125 to $150	0.20	$27.69	0.2%	0.04	$4.98	1.7%
>= $150	0.04	$9.40	5.9%	0.03	$7.21	4.5%

Table 11-6 Total PJM congestion (Dollars (Millions)): 2008 to 2013

Congestion Costs (Millions)				
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,051.8	NA	$34,306	6.0%
2009	$719.0	(65.0%)	$26,550	2.7%
2010	$1,423.3	98.0%	$34,771	4.1%
2011	$999.0	(29.8%)	$35,887	2.8%
2012	$529.0	(47.0%)	$29,181	1.8%
2013	$676.9	28.0%	$33,862	2.0%

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 to 2013

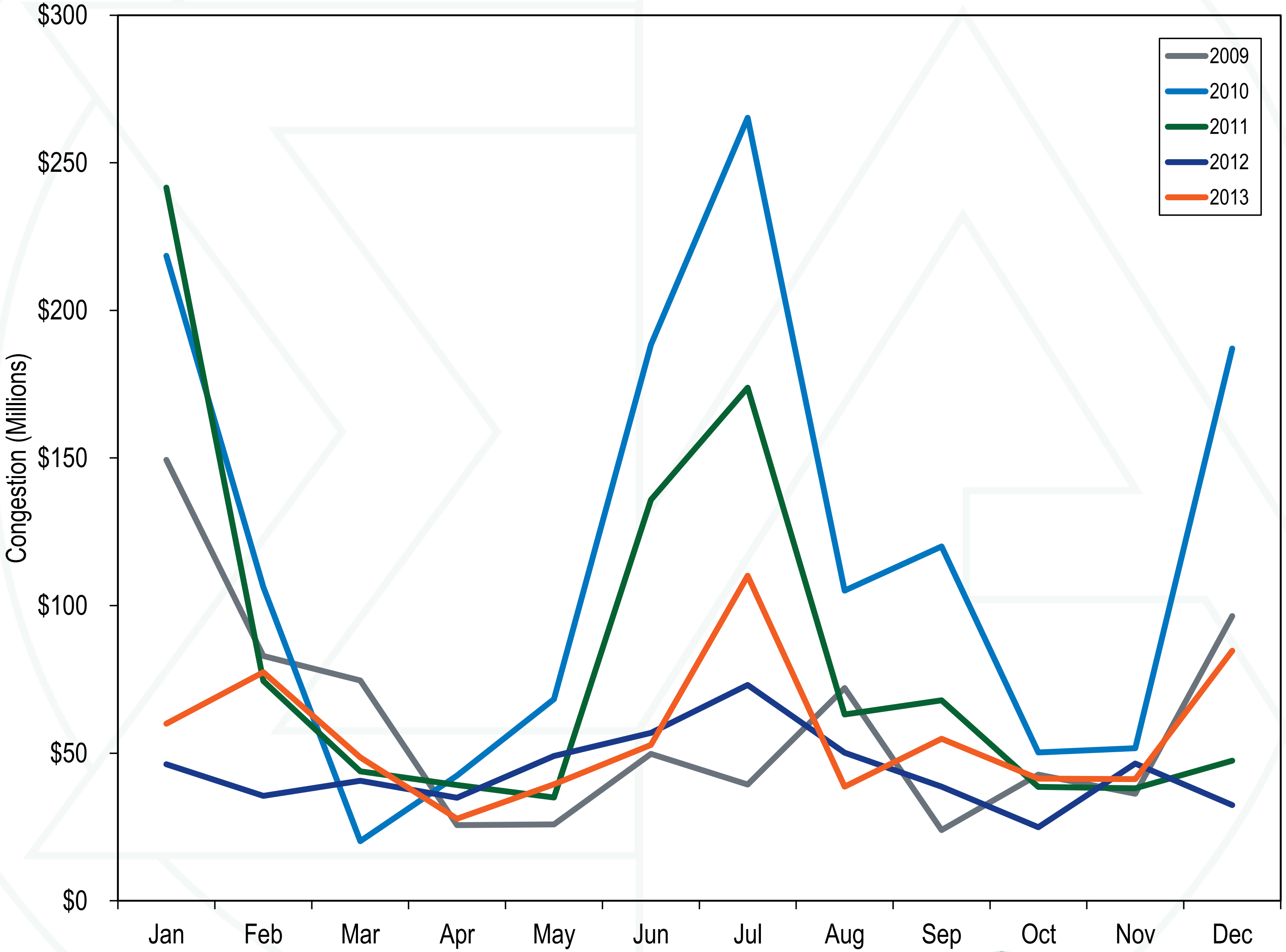


Table 11-7 Total PJM congestion costs by accounting category (Dollars (Millions)): 2008 to 2013

	Congestion Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$1,034.4	($1,053.9)	($36.5)	$0.0	$2,051.8
2009	$253.3	($515.1)	($49.4)	$0.0	$719.0
2010	$338.9	($1,167.0)	($82.6)	($0.0)	$1,423.3
2011	$454.0	($668.1)	($123.1)	$0.0	$999.0
2012	$115.1	($467.4)	($53.5)	$0.0	$529.0
2013	$287.1	($461.3)	($71.5)	$0.0	$676.9

Table 1-3 The Capacity Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

State of the Market Report Recommendations

- Capacity market
  - Consistent definition of capacity for all sources
    - Physical at auction
    - Physical in delivery year
    - All sources full substitutes
  - All imports should be full substitutes
    - Pseudo ties should be required
  - All demand resources should be full substitutes
    - Eliminate limited and summer unlimited products.
  - Eliminate 2.5 percent demand reduction.
  - Improve performance incentives.
    - Eliminate OMC outages.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2013

	1-Jan-13		31-May-13		1-Jun-13		31-Dec-13	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,989.2	41.7%	76,055.6	41.8%	77,981.5	42.0%	75,559.6	41.3%
Gas	52,003.2	28.6%	52,106.1	28.6%	53,420.2	28.8%	53,380.0	29.2%
Hydroelectric	7,879.8	4.3%	7,880.4	4.3%	8,091.4	4.4%	8,106.7	4.4%
Nuclear	33,024.0	18.1%	33,024.0	18.1%	33,072.8	17.8%	33,076.7	18.1%
Oil	11,531.2	6.3%	11,361.2	6.2%	11,339.5	6.1%	11,314.2	6.2%
Solar	47.0	0.0%	47.0	0.0%	80.7	0.0%	84.2	0.0%
Solid waste	757.1	0.4%	756.4	0.4%	709.4	0.4%	701.4	0.4%
Wind	779.6	0.4%	805.6	0.4%	872.4	0.5%	872.4	0.5%
Total	182,011.1	100.0%	182,036.3	100.0%	185,567.9	100.0%	183,095.2	100.0%

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2013

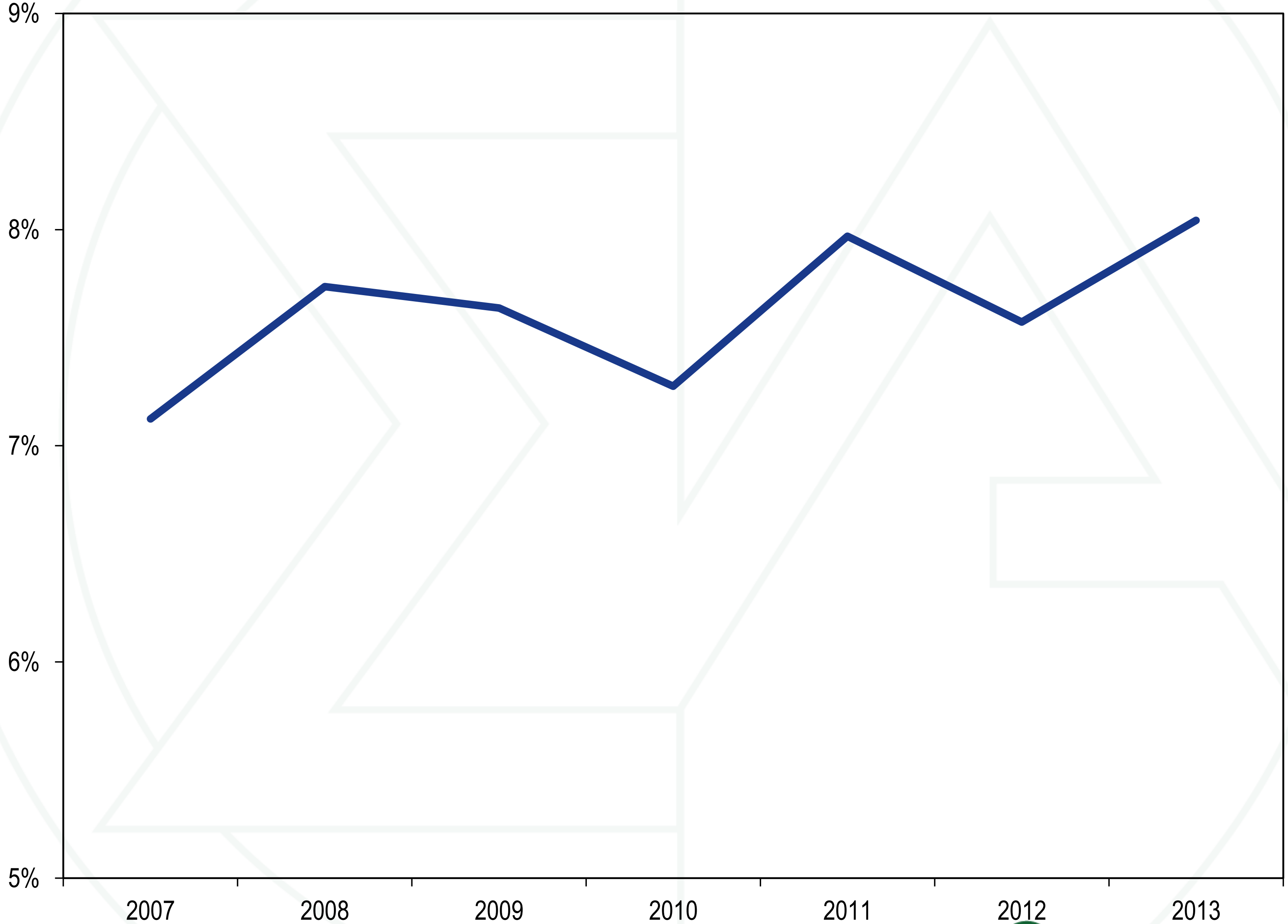


Table 5-34 PJM EFORd, XEFORd and EFORp data by unit type: 2013

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.3%	3.0%	1.8%	0.3%	1.5%
Combustion Turbine	10.8%	6.7%	3.6%	4.0%	7.1%
Diesel	6.3%	5.8%	3.2%	0.5%	3.1%
Hydroelectric	3.2%	1.2%	1.4%	2.1%	1.8%
Nuclear	1.2%	1.0%	0.7%	0.2%	0.4%
Steam	11.6%	10.3%	7.3%	1.3%	4.3%
Total	8.0%	6.6%	4.5%	1.4%	3.6%

Figure 5-9 PJM distribution of EFORd data by unit type: 2013

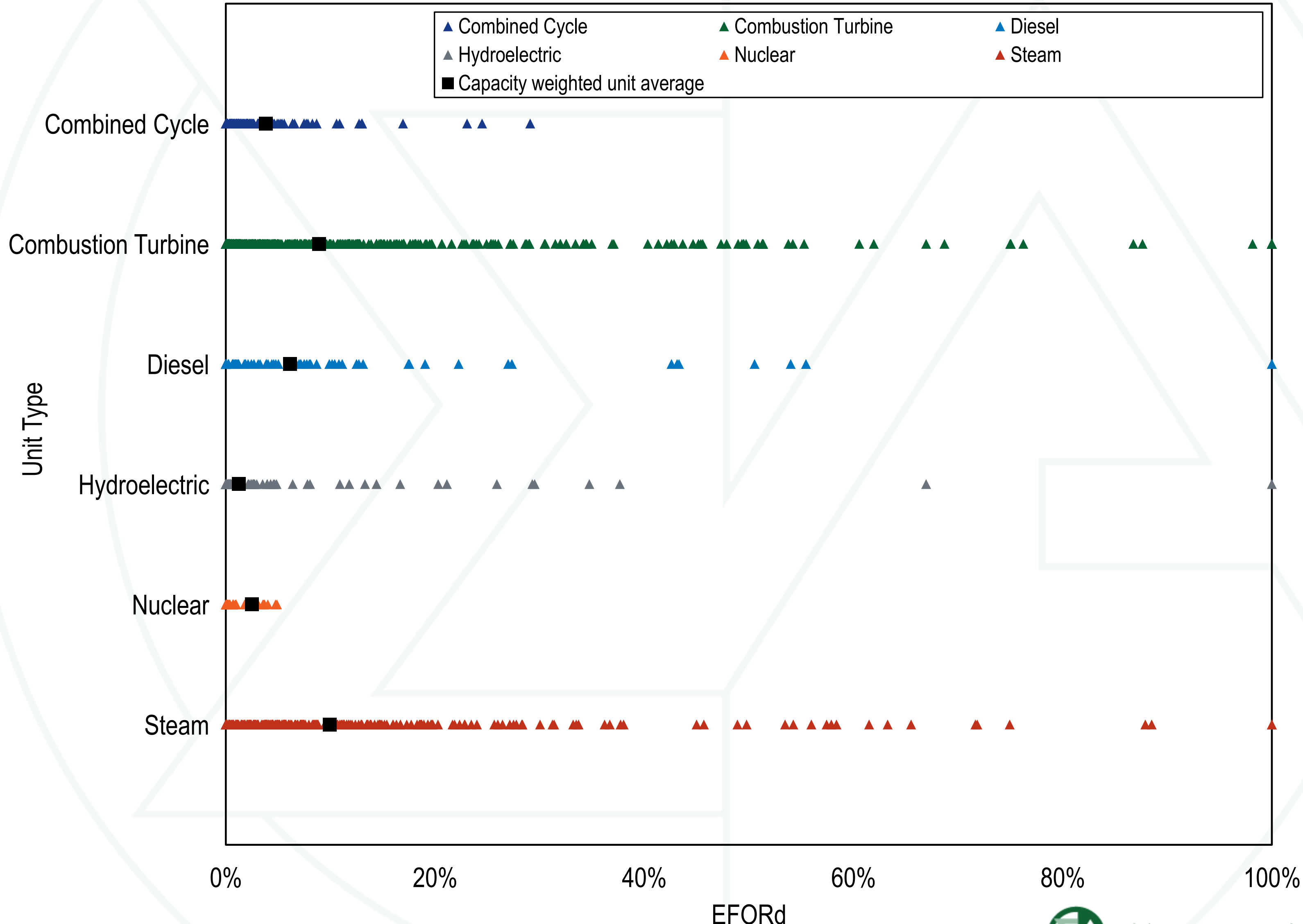


Figure 5-4 History of PJM capacity prices: 1999/2000 through 2016/2017

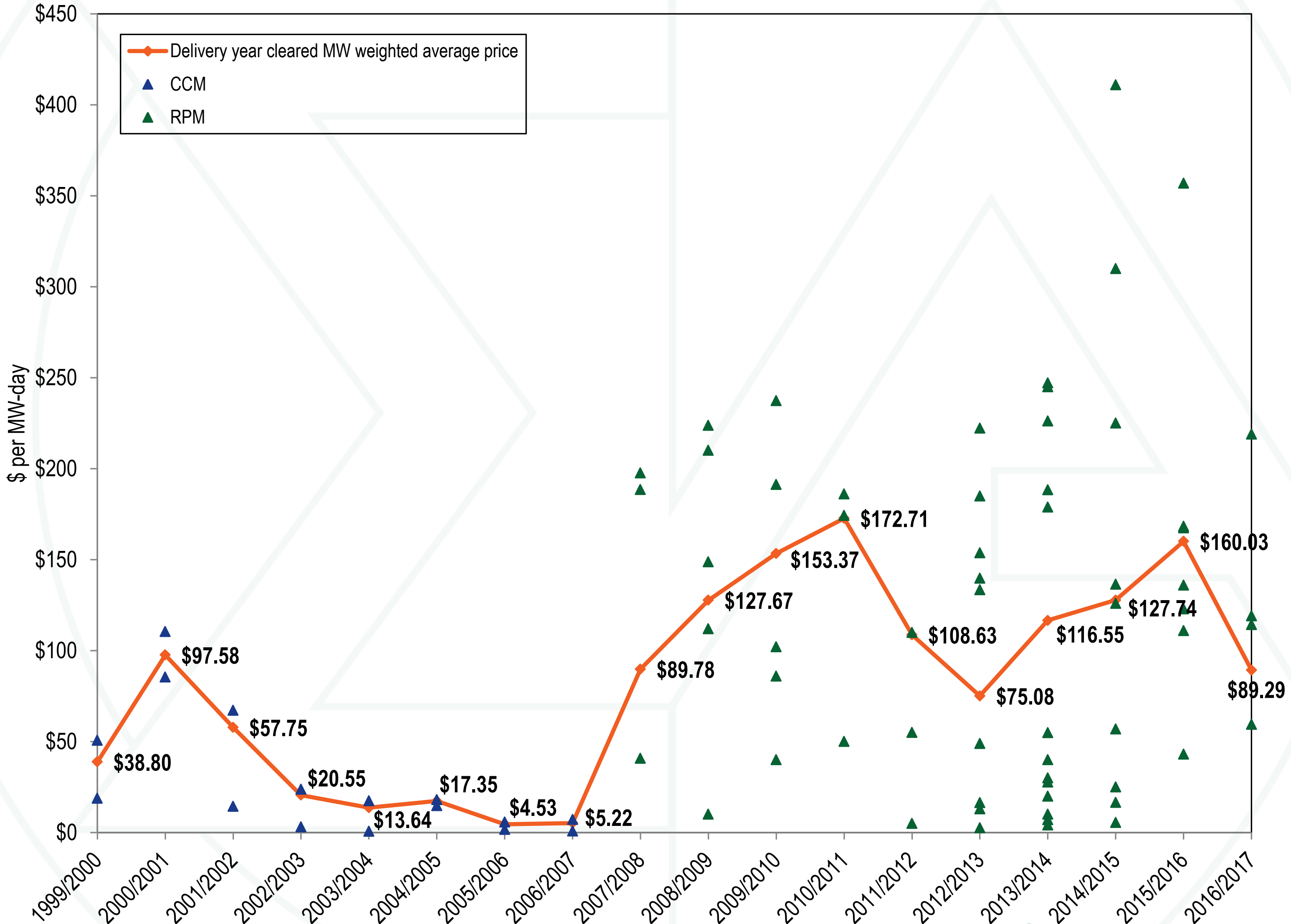


Figure 7-4 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013

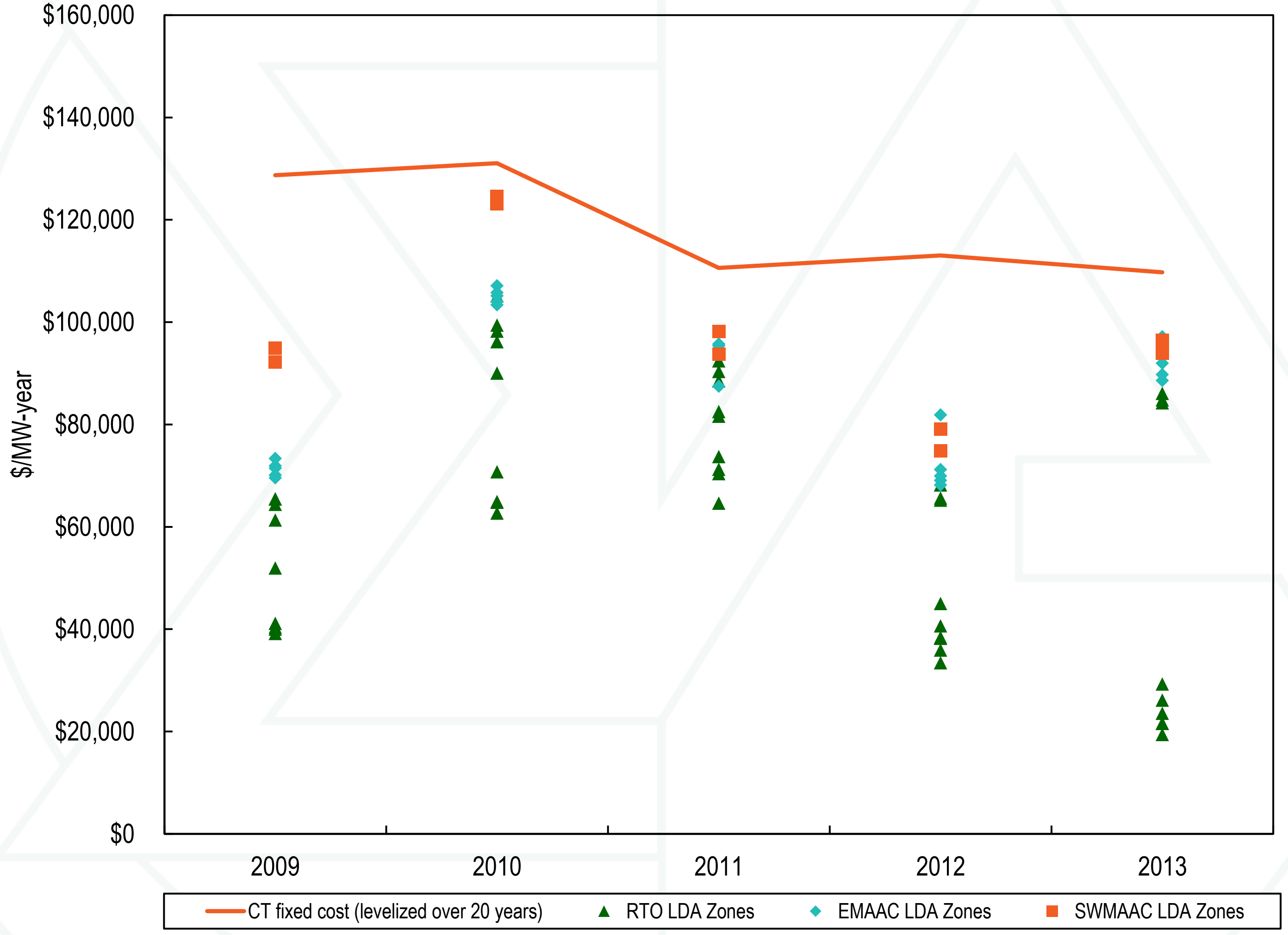


Figure 7-6 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013

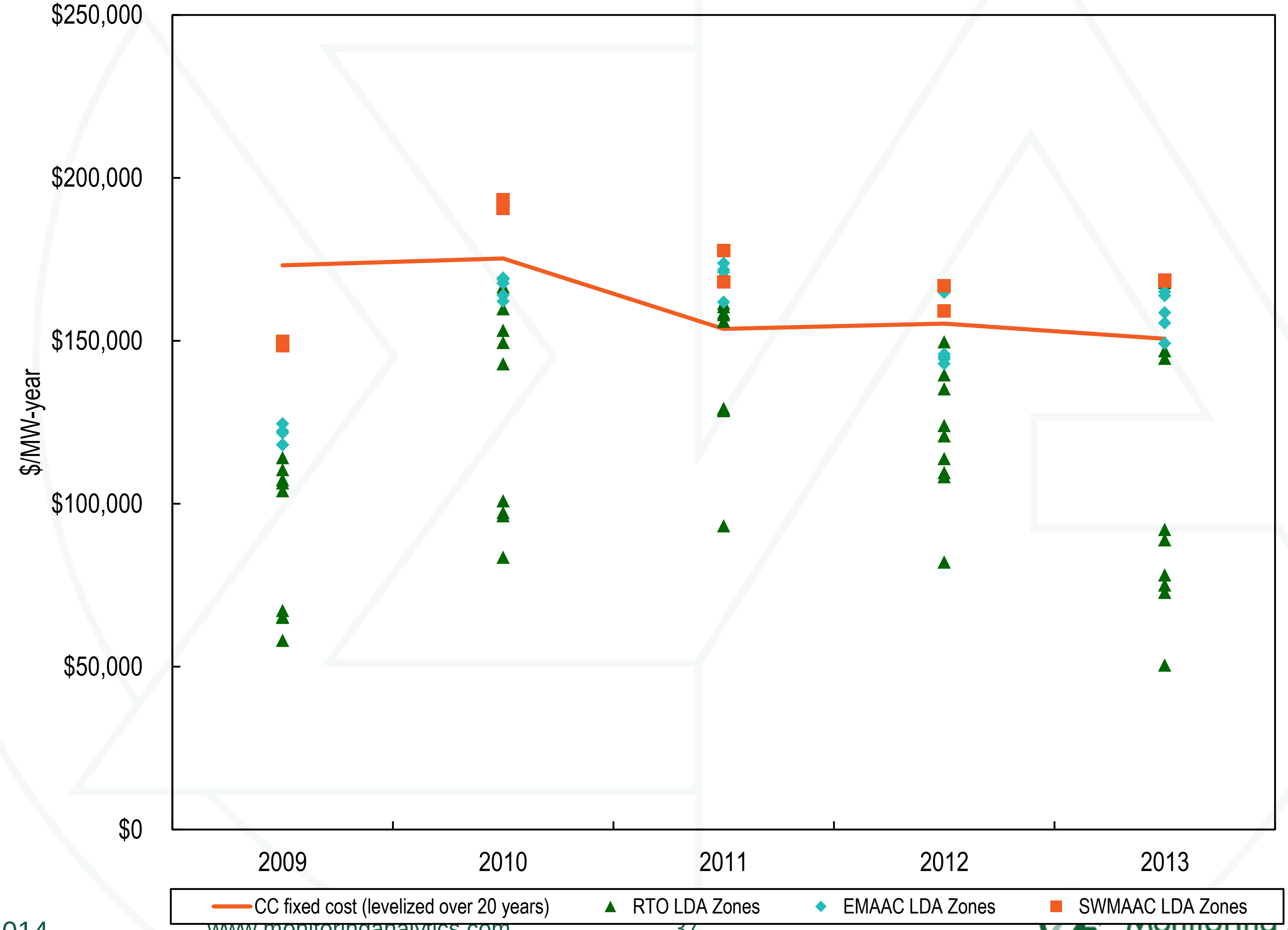


Figure 7-8 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013

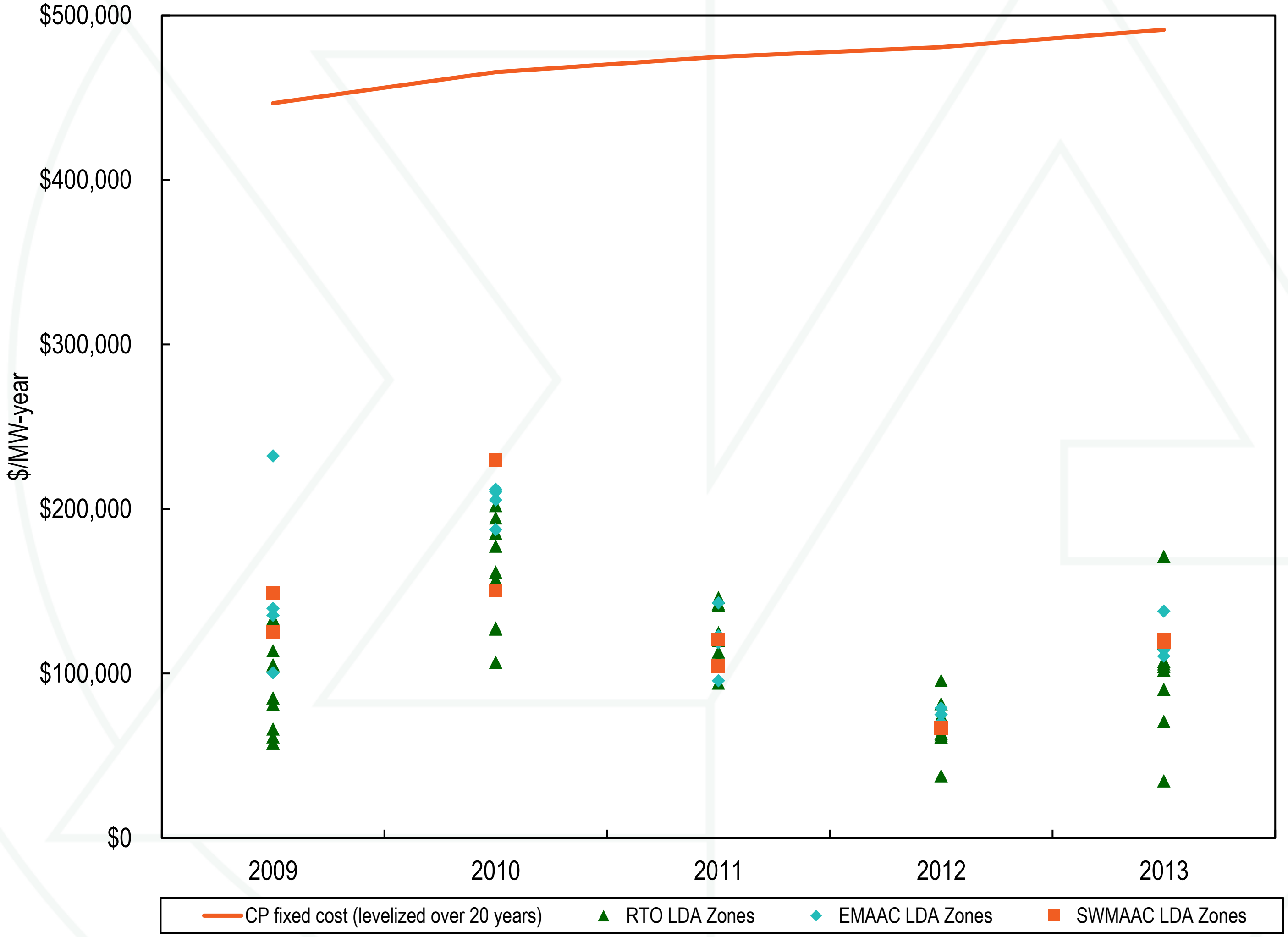


Table 7-15 PJM-wide net revenue for a nuclear plant by market (Dollars per installed MW-year): 2012 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$218,504	$35,789	$0	$0	$0	$254,293
2010	$261,098	$48,898	$0	$0	$0	$309,996
2011	$270,022	$45,938	$0	$0	$0	$315,960
2012	$201,658	$18,730	$0	$0	$0	$220,387
2013	$233,502	$7,743	$0	$0	$0	$241,244

Table 7-25 Percent of 20-year levelized fixed costs recovered by nuclear energy and capacity net revenue

Zone	2009	2010	2011	2012	2013
AEP	32%	39%	39%	28%	30%

Table 7-18 ComEd net revenue for a wind installation by market (Dollars per installed MW-year): 2012 through 2013

ComEd	Energy	Credits	Capacity	Total	Change (%)
2012	$67,294	$57,709	$2,435	$127,438	NA
2013	$82,934	$62,837	$1,007	$146,777	15.2%

Table 7-19 PENELEC net revenue for a wind installation by market (Dollars per installed MW-year): 2012 through 2013

PENELEC	Energy	Credits	Capacity	Total	Change (%)
2012	$68,913	$58,450	$5,439	$132,802	NA
2013	$87,404	$66,885	$8,189	$162,479	22.3%

Table 7-27 Percent of 20-year levelized fixed costs recovered by wind energy and capacity net revenue and wind credits

Zone	2012	2013
ComEd	65%	75%
PENELEC	68%	83%

Table 7-20 PSEG net revenue for a solar installation by market (Dollars per installed MW-year): 2012 through 2013

	Energy	Credits	Capacity	Total	Change (%)
2012	$50,363	$314,530	$17,565	$382,458	NA
2013	$81,813	$428,449	$26,516	$536,778	40.3%

Table 7-28 Percent of 20-year levelized fixed costs recovered by solar energy and capacity net revenue and solar credits

Zone	2012	2013
PSEG	97%	203%

Table 7-39 Proportion of units recovering avoidable costs from energy and ancillary markets : 2009 to 2013

Technology	Units with full recovery from energy and ancillary services markets 2009	2010	2011	2012	2013
CC - NUG Cogeneration Frame B or E Technology	64%	77%	60%	65%	61%
CC - Two on Three on One Frame F Technology	71%	73%	70%	64%	54%
CT - First & Second Generation Aero (P&W FT 4)	44%	35%	25%	15%	20%
CT - First & Second Generation Frame B	32%	32%	31%	23%	15%
CT - Second Generation Frame E	63%	54%	72%	67%	48%
CT - Third Generation Aero	50%	53%	77%	78%	52%
CT - Third Generation Frame F	45%	64%	72%	81%	75%
Diesel	77%	77%	72%	57%	53%
Hydro and Pumped Storage	98%	98%	95%	98%	97%
Nuclear	0%	0%	0%	0%	0%
Oil or Gas Steam	44%	52%	48%	41%	44%
Sub-Critical Coal	80%	81%	59%	40%	51%
Super Critical Coal	87%	87%	74%	48%	53%

Table 7-40 Proportion of units recovering avoidable costs from all markets: 2009 to 2013

	Units with full recovery from all markets				
Technology	2009	2010	2011	2012	2013
CC - NUG Cogeneration Frame B or E Technology	95%	95%	96%	90%	100%
CC - Two on Three on One Frame F Technology	100%	95%	98%	92%	85%
CT - First & Second Generation Aero (P&W FT 4)	95%	90%	90%	90%	86%
CT - First & Second Generation Frame B	99%	99%	95%	94%	91%
CT - Second Generation Frame E	100%	100%	100%	100%	100%
CT - Third Generation Aero	99%	99%	99%	97%	89%
CT - Third Generation Frame F	100%	100%	100%	94%	96%
Diesel	97%	98%	91%	85%	73%
Hydro and Pumped Storage	100%	100%	100%	100%	100%
Nuclear	0%	0%	0%	0%	0%
Oil or Gas Steam	97%	95%	85%	75%	81%
Sub-Critical Coal	93%	95%	88%	55%	69%
Super Critical Coal	100%	100%	91%	68%	89%

Table 7-41 Profile of units that did not recover avoidable costs from total market revenues or did not clear the 15/16 BRA or 16/17 BRA but cleared in previous auctions

Technology	No. Units	ICAP (MW)	Avg. 2013 Run Hrs	Avg. Heat Rate	Avg. Unit Age (Yrs)
CT	30	1,195	393	13,454	31
Coal	22	8,650	6,808	10,577	45
Diesel	16	161	1,641	11,288	24
Oil or Gas Steam	11	2,542	2,076	11,502	33
Other	8	2,049	5,600	5,954	35
Total	87	14,597	3,197	11,391	34

Table 12-7 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,196.5
Retirements 2012	6,961.9
Retirements 2013	2,862.6
Retirements 2014	50.0
Planned Retirements 2014	1,870.0
Planned Retirements 2015	9,975.0
Planned Retirements Post-2015	2,016.5
Total	24,932.5

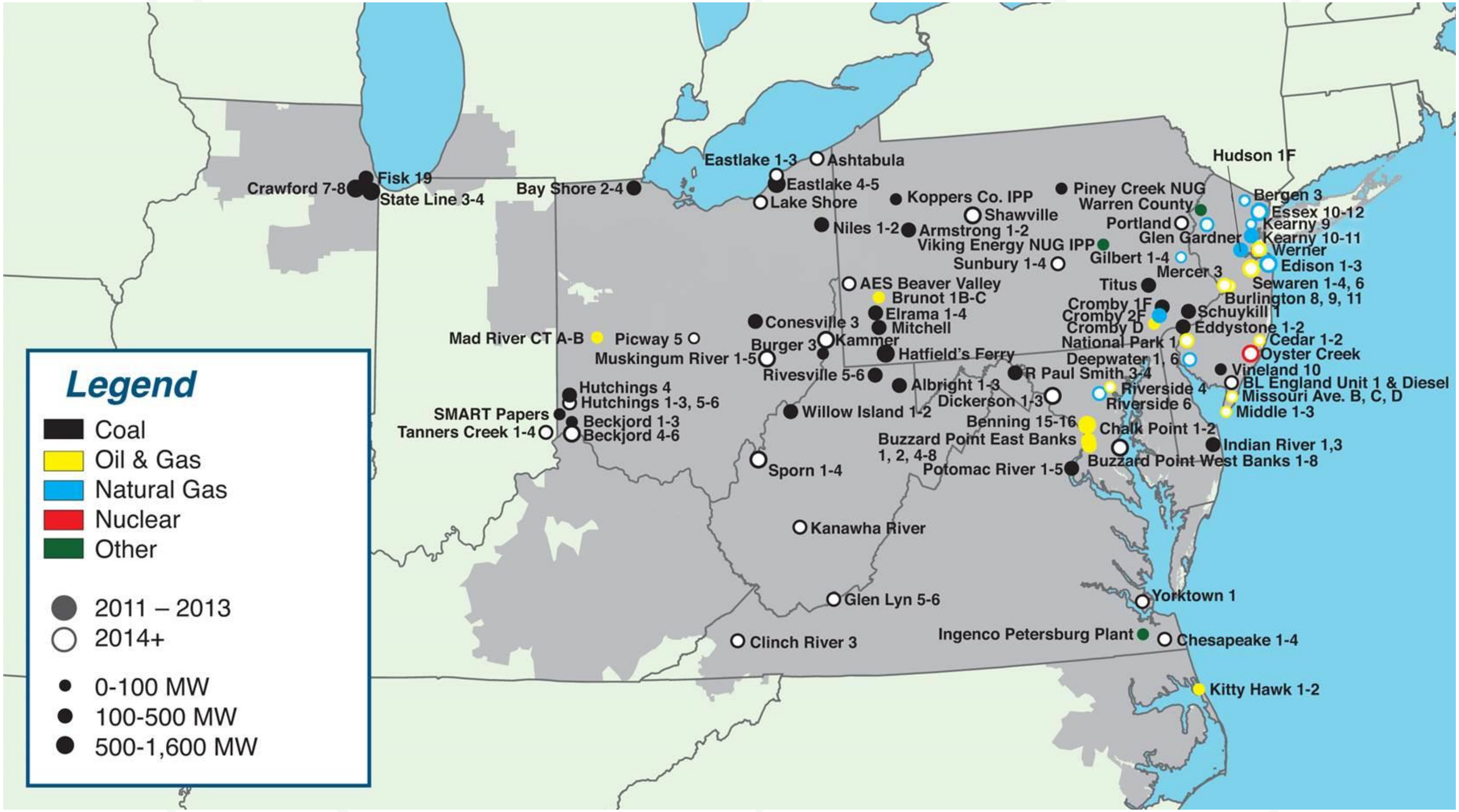
Table 12-10 Unit deactivations between January 1, 2013 and January 15, 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Exelon Corporation	Schuylkill 1	166.0	Heavy Oil	PECO	54	01-Jan-13
Exelon Corporation	Schuylkill Diesel	3.0	Diesel	PECO	45	01-Jan-13
Marina Energy	Warren County Landfill	10.8	Landfill Gas	JCPL	07	09-Jan-13
First Energy	Piney Creek NUG	31.0	Waste Coal	PENELEC	20	12-Apr-13
Ingenco Wholesale Power, LLC	Ingenco Petersburg	2.9	Landfill Gas	Dominion	22	31-May-13
The AES Corporation	Hutchings 4	61.9	Coal	DAY	62	01-Jun-13
NRG Energy	Titus 1	81.0	Coal	Met-Ed	60	01-Sep-13
NRG Energy	Titus 2	81.0	Coal	Met-Ed	24	01-Sep-13
NRG Energy	Titus 3	81.0	Coal	Met-Ed	60	01-Sep-13
NextEra Energy	Koppers Co. IPP	08.0	Wood waste	PPL	59	30-Sep-13
Duke Energy	Walter C Beckjord 2	94.0	Coal	DEOK	44	01-Oct-13
Duke Energy	Walter C Beckjord 3	128.0	Coal	DEOK	43	01-Oct-13
First Energy	Hatfield's Ferry 1	530.0	Coal	APS	42	09-Oct-13
First Energy	Hatfield's Ferry 2	530.0	Coal	APS	65	09-Oct-13
First Energy	Hatfield's Ferry 3	530.0	Coal	APS	50	09-Oct-13
First Energy	Mitchell 2	82.0	Coal	APS	08	09-Oct-13
First Energy	Mitchell 3	277.0	Coal	APS	21	09-Oct-13
Delmarva Power	Indian River 3	165.0	Coal	DPL	44	31-Dec-13
First Energy	Mad River CTs A	25.0	Diesel	ATSI	41	09-Jan-14
First Energy	Mad River CTs B	25.0	Diesel	ATSI	41	09-Jan-14
Total		2,912.6				

Table 12-8 Planned deactivations of PJM units, as of December 31, 2013

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
BL England 1	AECO	113.0	Coal	Steam	01-May-14
Deepwater 1, 6	AECO	158.0	Natural gas	Steam	01-Jun-14
Burlington 9	PSEG	184.0	Kerosene	Combustion Turbine	01-Jun-14
Portland	Met-Ed	401.0	Coal	Steam	01-Jun-14
Riverside 6	BGE	115.0	Natural gas	Combustion Turbine	31-Dec-14
Chesapeake 1-4	Dominion	576.0	Coal	Steam	31-Dec-14
Yorktown 1-2	Dominion	323.0	Coal	Steam	01-Apr-15
Walter C Beckjord 4-6	DEOK	802.0	Coal	Steam	16-Apr-15
Shawville 1-7	PENELEC	603.0	Coal	Steam	01-May-15
Gilbert 1-4	JCPL	98.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner 1-8	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	31-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	31-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	01-Jun-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Clinch River 3	AEP	230.0	Coal	Steam	01-Jun-15
Eastlake 1-3	ATSI	327.0	Coal	Steam	01-Jun-15
Edison 1-3	PSEG	504.0	Natural gas	Combustion Turbine	01-Jun-15
Essex 10-11	PSEG	352.0	Natural gas	Combustion Turbine	01-Jun-15
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Kammer 1-3	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River 1-2	AEP	400.0	Coal	Steam	01-Jun-15
Lake Shore	ATSI	190.0	Coal	Steam	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
Muskingum River 1-5	AEP	1,355.0	Coal	Steam	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Sewaren 1-4,6	PSEG	558.0	Kerosene	Combustion Turbine	01-Jun-15
Sporn 1-4	AEP	580.0	Coal	Steam	01-Jun-15
Sunbury 1-4	PPL	347.0	Coal	Steam	01-Jun-15
Tanners Creek 1-4	AEP	982.0	Coal	Steam	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Riverside 6	BGE	74.0	Natural gas	Combustion Turbine	01-Jun-16
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-17
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-17
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Jun-17
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		13,861.5			

Figure 12-1 Map of PJM unit retirements: 2011 through 2019



Monitoring Analytics

State of the Market Report Recommendations

- Energy Uplift (Operating reserves)
  - Improve process of identifying reasons for paying credits and allocating charges.
  - All uplift payments should be public information
  - Fix lost opportunity cost flaws
    - Use operating schedule to calculate energy LOC
    - Treat no load and startup as costs
    - Use entire curve to calculate LOC
  - Require up to congestion transactions to pay uplift charges like other virtuals.
  - Net DASR and regulation revenues from uplift
  - Transparency in creation of closed loop interfaces

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:	Charges Category:	Charges Paid By:	
	Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Balancing			
Generation Resources	Balancing Operating Reserve Generator	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
		Balancing Operating Reserve for Deviations	Deviations	in RTO, Eastern or Western Region
		Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC			
Real-Time Import Transactions	Balancing Operating Reserve Transaction			
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator			
Economic Load Response Resources	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-6 Total energy uplift charges: 1999 through 2013

	Total Energy Uplift Charges	Annual Change	Annual Percentage Change	Energy Uplift as a Percent of Total PJM Billing
1999	$133,897,428	NA	NA	7.5%
2000	$216,985,147	$83,087,719	62.1%	9.6%
2001	$284,046,709	$67,061,562	30.9%	8.5%
2002	$273,718,553	($10,328,156)	(3.6%)	5.8%
2003	$376,491,514	$102,772,961	37.5%	5.4%
2004	$537,587,821	$161,096,307	42.8%	6.1%
2005	$712,601,789	$175,013,968	32.6%	3.1%
2006	$365,572,034	($347,029,755)	(48.7%)	1.7%
2007	$503,279,869	$137,707,835	37.7%	1.6%
2008	$474,268,500	($29,011,369)	(5.8%)	1.4%
2009	$322,729,996	($151,538,504)	(32.0%)	1.2%
2010	$622,843,365	$300,113,369	93.0%	1.8%
2011	$605,017,353	($17,826,013)	(2.9%)	1.7%
2012	$650,777,886	$45,760,533	7.6%	2.2%
2013	$882,219,896	$231,442,009	35.6%	2.6%

Table 4-11 Additional energy uplift charges: 2012 and 2013

Type	2012	2013	Change	2012 Share	2013 Share
Reactive Services Charges	$76,010,175	$339,482,039	$263,471,864	89.9%	79.6%
Synchronous Condensing Charges	$148,250	$396,377	$248,127	0.2%	0.1%
Black Start Services Charges	$8,384,651	$86,593,749	$78,209,098	9.9%	20.3%
Total	$84,543,077	$426,472,166	$341,929,089	100.0%	100.0%

Figure 4-8 Allocation changes of energy uplift charges associated with units needed for black start and reactive support

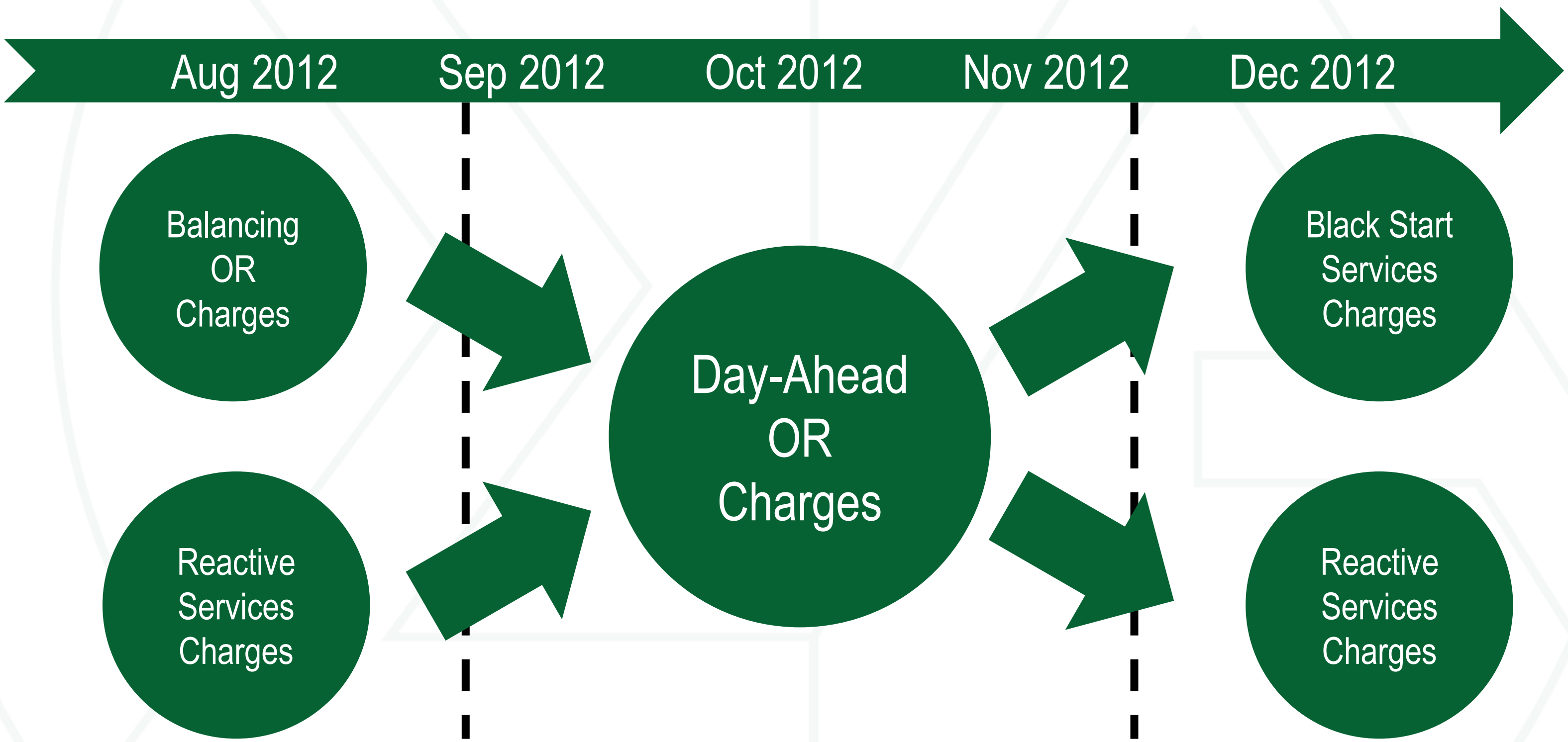


Figure 4-7 Energy uplift charges change from 2012 to 2013 by category

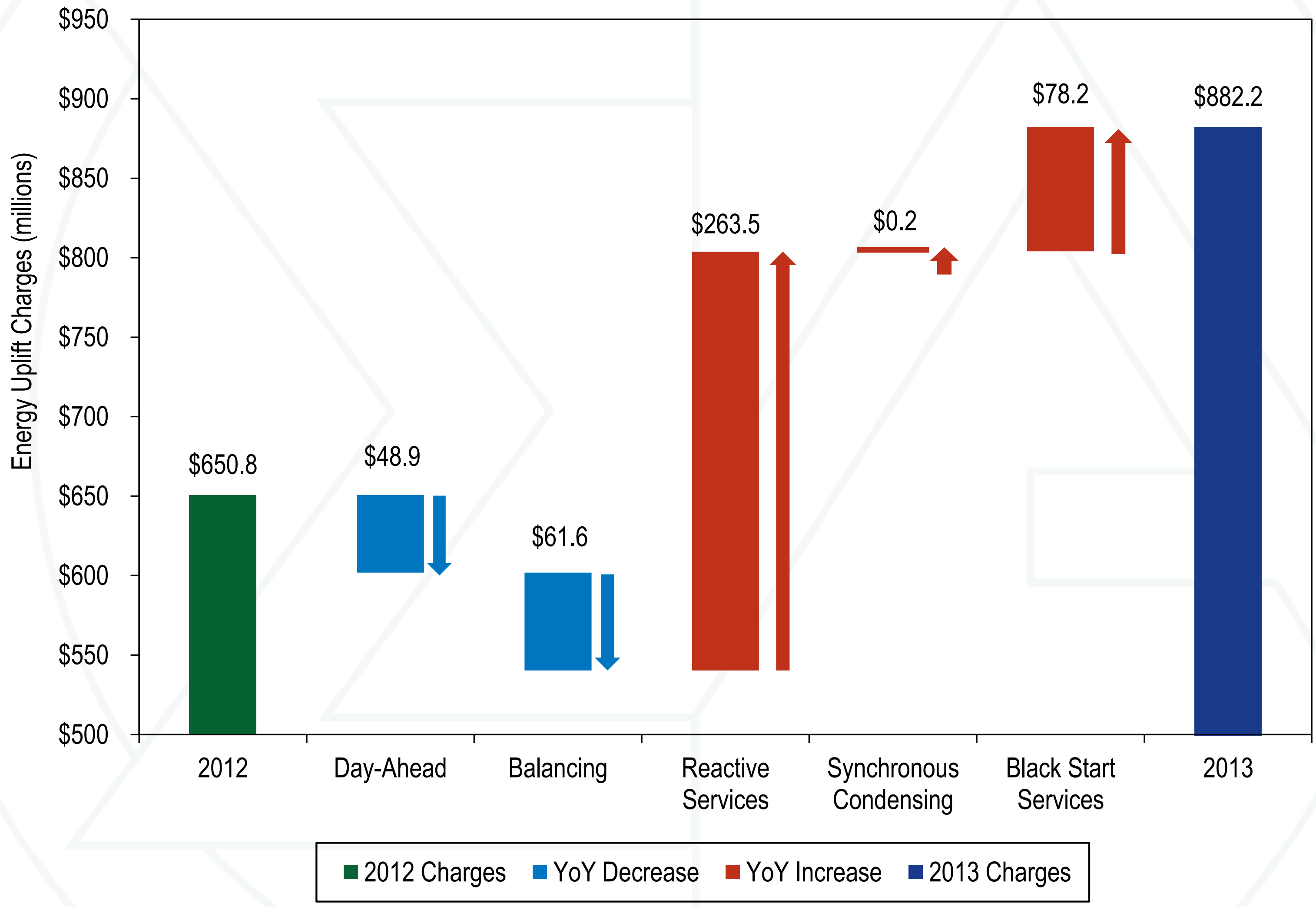


Figure 4-9 Energy uplift charges change from 2012 to 2013 by issue

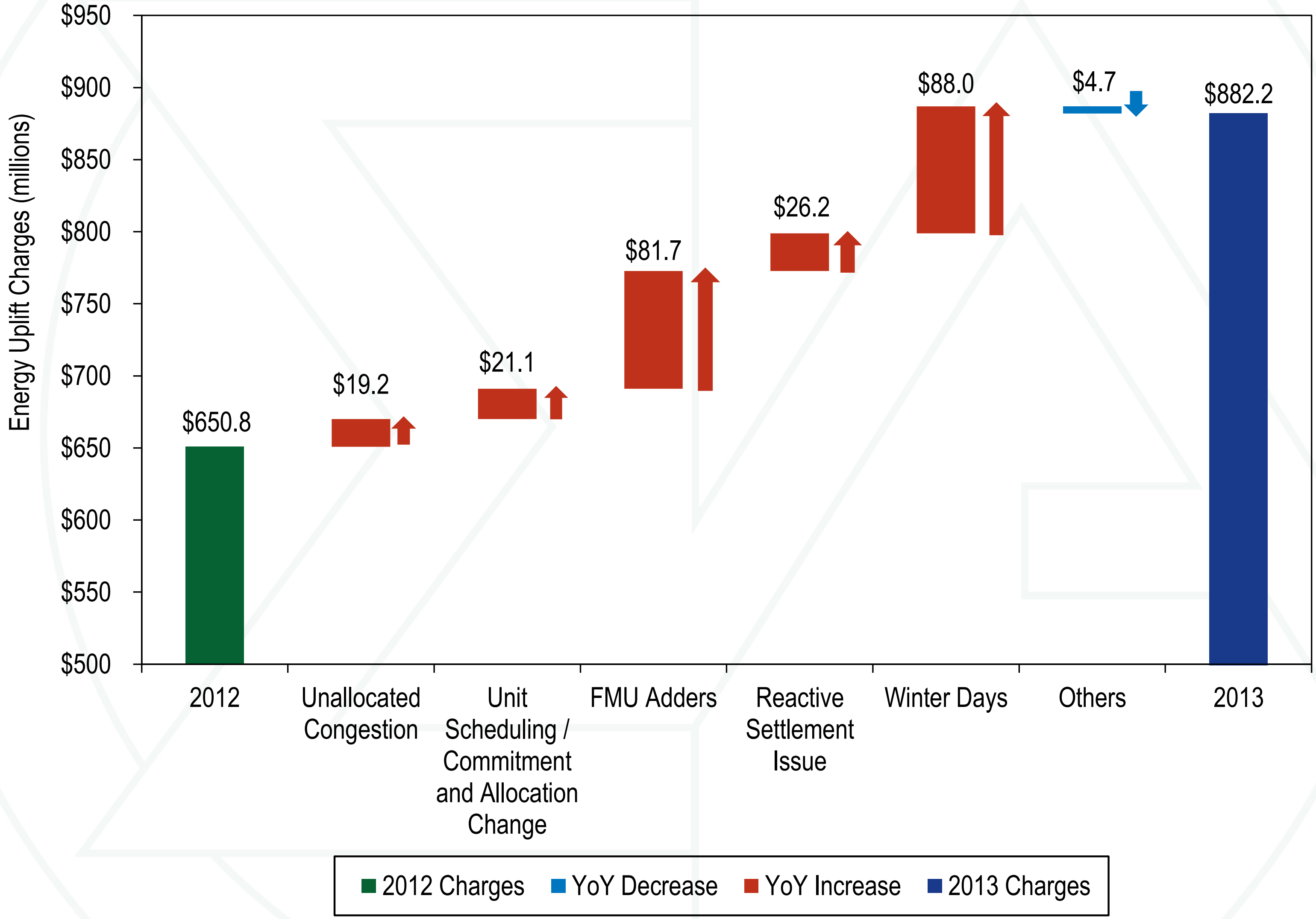


Table 4-27 Top 10 energy uplift credits units (By percent of total system): 2001 through 2013

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%
2011	28.1%	0.8%
2012	22.7%	0.7%
2013	38.0%	0.7%

Table 4-37 Impact on energy market lost opportunity cost credits of rule changes: 2013

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$23,240,998	$63,394,565	$86,635,563
Impact 1: Committed Schedule	$1,186,428	$18,944,558	$20,130,986
Impact 2: Eliminating DA LMP	NA	($453,018)	($453,018)
Impact 3: Using Offer Curve	($1,198,276)	$7,553,265	$6,354,989
Impact 4: Including No Load Cost	NA	($37,440,979)	($37,440,979)
Impact 5: Including Startup Cost	NA	($11,353,697)	($11,353,697)
Net Impact	($11,848)	($22,749,871)	($22,761,719)
Credits After Changes	$23,229,150	$40,644,694	$63,873,844

Table 4-39 Current and proposed average operating reserve rate by transaction: 2013

	Transaction	Current Rates ($/MWh)	Proposed Rates ($/MWh)	Change ($/MWh)	Change (%)
East	INC	3.198	0.176	(3.022)	(94.5%)
	DEC	3.301	0.202	(3.099)	(93.9%)
	DA Load	0.103	0.026	(0.077)	(74.6%)
	RT Load	0.073	0.057	(0.016)	(22.5%)
	Deviation	3.198	0.176	(3.022)	(94.5%)
West	INC	1.561	0.125	(1.436)	(92.0%)
	DEC	1.664	0.151	(1.513)	(90.9%)
	DA Load	0.103	0.026	(0.077)	(74.6%)
	RT Load	0.053	0.036	(0.016)	(31.4%)
	Deviation	1.561	0.125	(1.436)	(92.0%)
UTC	East to East	NA	0.377		
	West to West	NA	0.276		
	East to/from West	NA	0.327		

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2012 and 2013

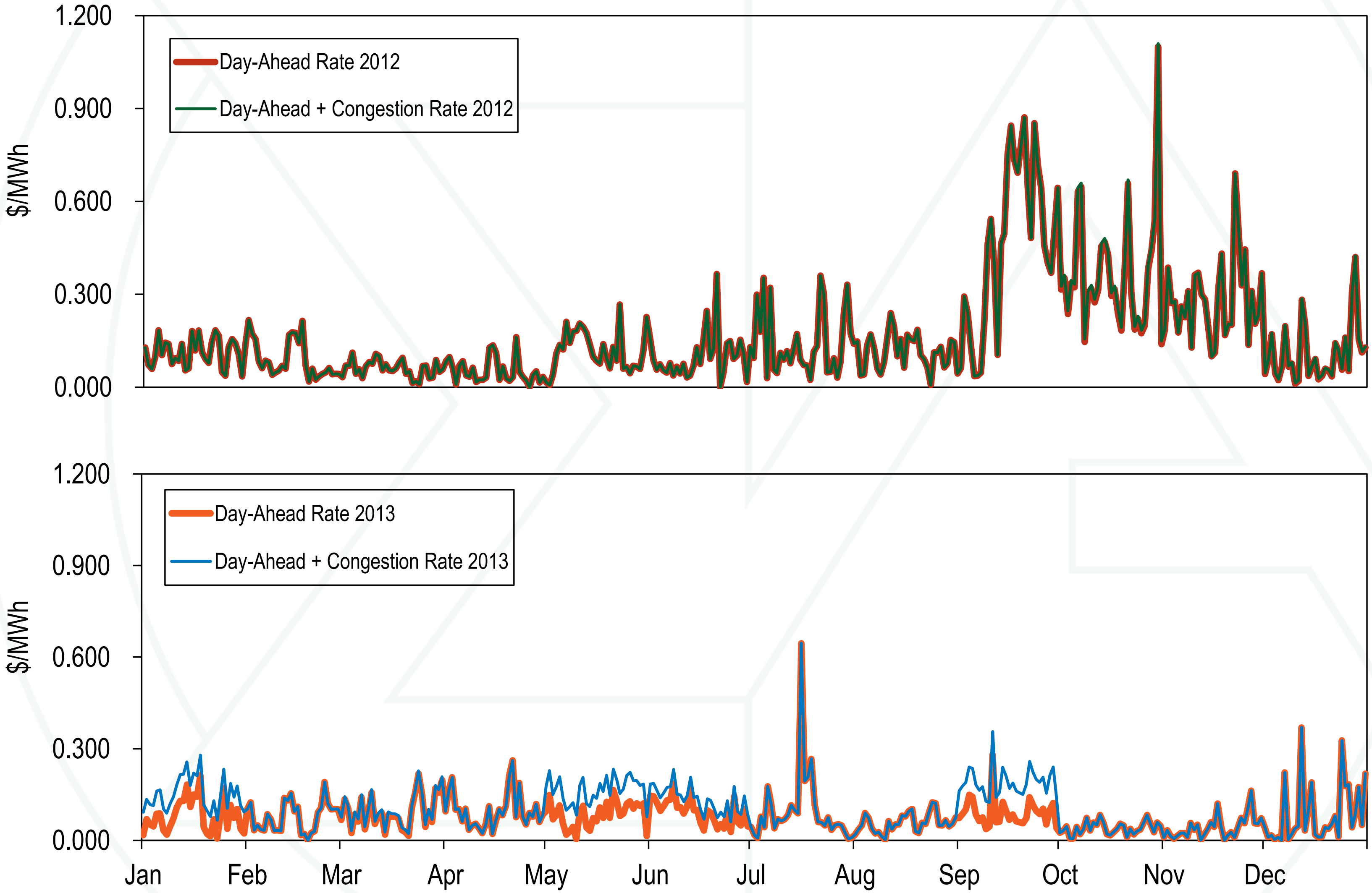


Table 4-14 Operating reserve rates ($/MWh): 2012 and 2013

Rate	2012 ($/MWh)	2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.161	0.079	(0.082)	(51.1%)
Day-Ahead with Unallocated Congestion	0.162	0.103	(0.059)	(36.5%)
RTO Reliability	0.025	0.051	0.026	107.2%
East Reliability	0.022	0.030	0.008	35.9%
West Reliability	0.115	0.004	(0.111)	(96.2%)
RTO Deviation	0.820	0.863	0.043	5.2%
East Deviation	0.333	1.868	1.535	460.8%
West Deviation	0.127	0.122	(0.006)	(4.6%)
Lost Opportunity Cost	1.329	0.705	(0.623)	(46.9%)
Canceled Resources	0.024	0.003	(0.021)	(87.8%)

Table 4-15 Operating reserve rates ($/MWh): 2013

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	33.024	3.198	0.024	5.028
	DEC	33.056	3.301	0.147	5.029
	DA Load	0.646	0.103	0.000	0.076
	RT Load	3.610	0.073	0.000	0.226
	Deviation	33.024	3.198	0.024	5.028
West	INC	16.429	1.561	0.024	1.804
	DEC	16.785	1.664	0.116	1.825
	DA Load	0.646	0.103	0.000	0.076
	RT Load	0.802	0.053	0.000	0.087
	Deviation	16.429	1.561	0.024	1.804

State of the Market Report Recommendations

- **Demand response**
  - **All demand resources should be full substitutes for generation capacity resources**
    - **Eliminate limited and summer unlimited products.**
  - **DR should be classified as economic and not emergency program.**
  - **Daily must offer in energy market**
  - **Uniform offer cap for all resources**
  - **Nodal location and dispatch**
  - **Shorter lead times**
  - **Improve measurement and verification**
  - **Compliance should include both increases and decreases**

Table 6-1 Overview of demand response programs

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment.

Figure 6-2 Economic program credits by month: 2009 through 2013

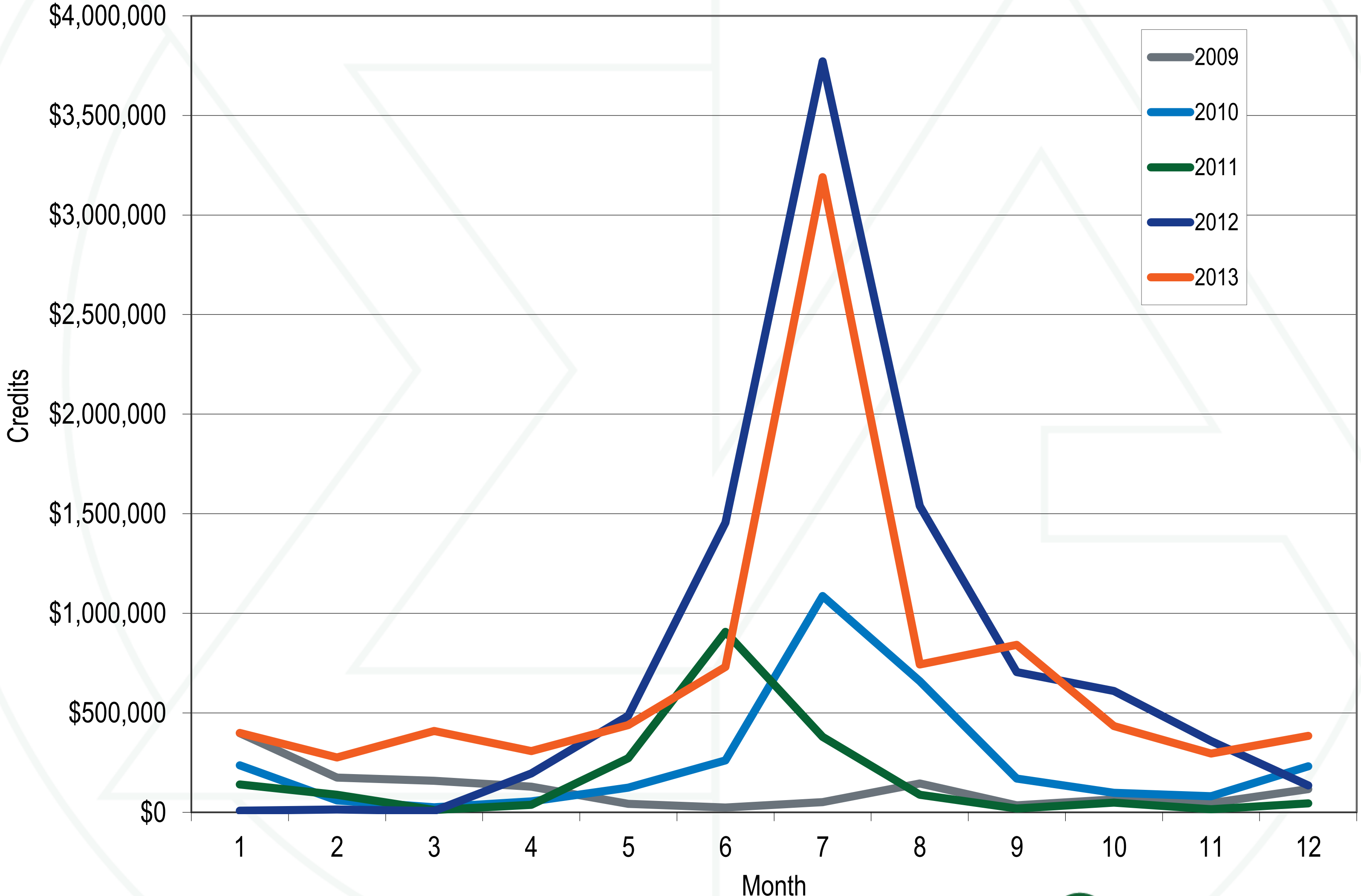


Figure 6-1 Demand response revenue by market: 2002 through 2013

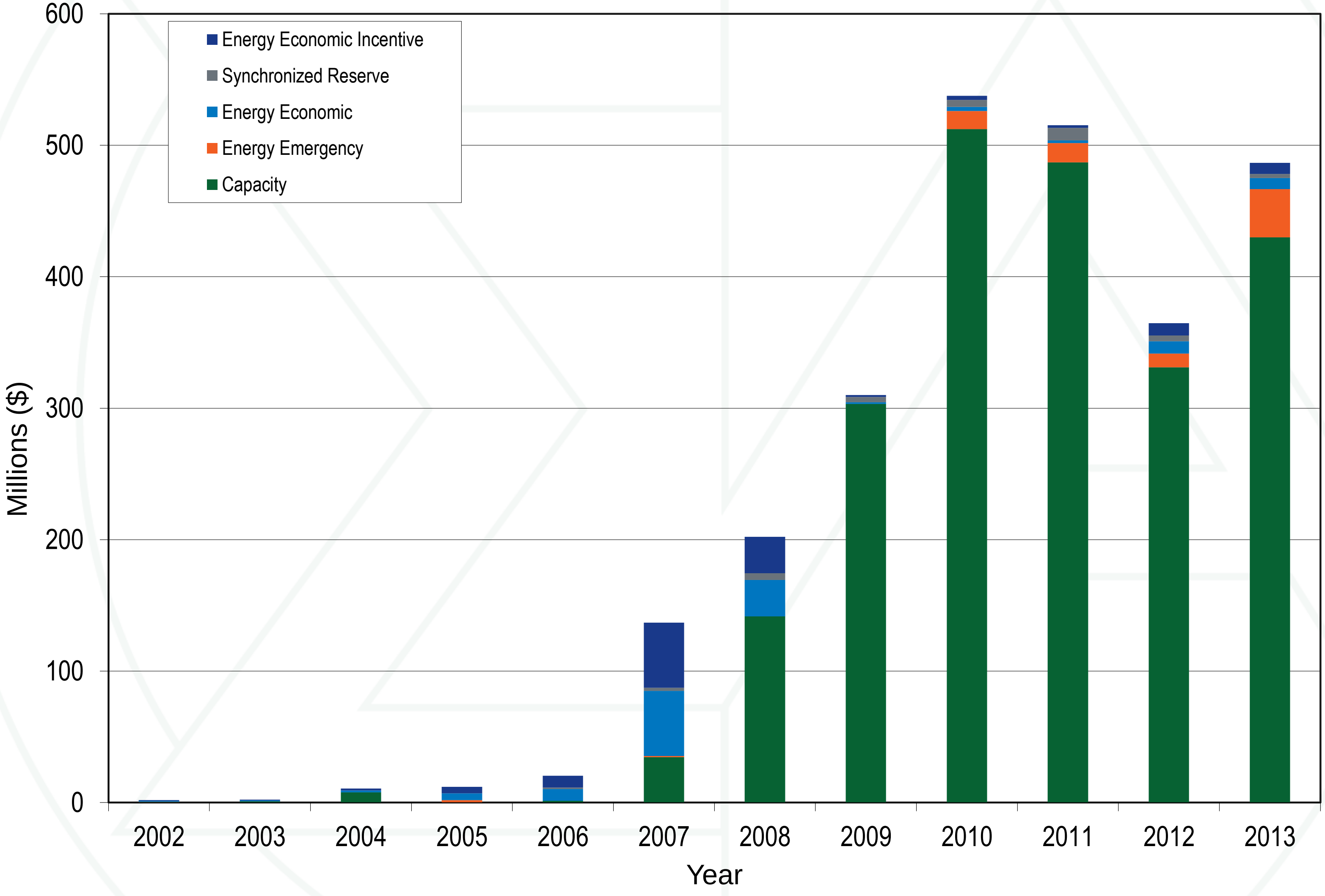


Table 6-21 Load management event performance: 2013 Aggregated

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	114.7	102.5	91.8	86.4	5.4	89.6%	84.3%
AEP	1,576.0	830.2	1,243.0	1,131.3	111.7	149.7%	136.3%
ATSI	797.4	690.0	625.8	514.7	111.1	90.7%	74.6%
BGE	787.7	627.2	690.3	672.7	17.6	110.1%	107.3%
DLCO	91.7	69.2	54.3	49.4	4.8	78.4%	71.4%
Dominion	863.1	751.7	683.0	621.4	61.6	90.9%	82.7%
DPL	250.7	220.3	221.8	208.2	13.7	100.7%	94.5%
JCPL	191.0	156.7	145.3	83.4	61.9	92.7%	53.2%
Met-Ed	231.2	173.6	180.0	167.5	12.5	103.7%	96.5%
PECO	571.8	410.3	353.4	304.0	49.4	86.1%	74.1%
PENELEC	322.3	265.0	259.6	236.1	23.5	97.9%	89.1%
Pepco	700.2	371.9	304.9	294.9	10.0	82.0%	79.3%
PPL	770.8	621.5	592.5	555.8	36.7	95.3%	89.4%
PSEG	377.9	350.6	203.3	152.4	50.8	58.0%	43.5%
RECO	6.4	4.0	4.8	3.8	1.0	118.1%	93.5%
Weighted Total	7,652.9	5,644.7	5,488.5	4,807.8	571.7	97.2%	85.2%

Table 6-22 Distribution of participant event days and nominated MW across ranges of performance levels across the event in the 2013/2014 Delivery Year compliance period

Ranges of performance as a percentage of nominated ICAP MW	Number of participant event days	Proportion of participant event days	Nominated MW	Proportion of Nominated MW
0%, load increase, or no reporting	2,974	20%	1,102	9%
0% - 10%	1,342	9%	790	6%
10% - 20%	1,036	7%	909	7%
20% - 30%	844	6%	435	4%
30% - 40%	777	5%	376	3%
40% - 50%	649	4%	323	3%
50% - 60%	641	4%	331	3%
60% - 70%	579	4%	523	4%
70% - 80%	608	4%	332	3%
80% - 90%	622	4%	479	4%
90% - 100%	1,868	12%	875	7%
100% - 110%	1,236	8%	3,411	28%
110% - 125%	608	4%	1,194	10%
125% - 150%	535	4%	631	5%
150% - 175%	252	2%	243	2%
175% - 200%	157	1%	155	1%
200% - 300%	267	2%	138	1%
> 300%	217	1%	136	1%
Total	15,212	100%	12,383	100%

Table 6-15 PJM declared load management events: 2013

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	Geographical Area
15-Jul-13	15:50-18:22	16:00-18:00	32	Long Lead	ATSI
16-Jul-13	13:30-16:30	14:00-16:00	60	Long Lead	ATSI
18-Jul-13	14:40-18:00	15:00-18:00	20	Long Lead	ATSI
	14:40-17:00	15:00-17:00	20	Long Lead	PECO, PPL
	15:00-18:00	15:00-18:00	0	Long Lead	AEP Canton Subzone
10-Sep-13	15:50-21:30	16:00-20:00	100	Long Lead	ATSI
	16:45-21:30	17:00-20:00	115	Long Lead	AEP Canton Subzone
11-Sep-13	13:30-19:30	14:00-19:00	60	Long Lead	AEP
	14:00-20:00	14:00-20:00	0	Long Lead	ATSI
	14:00-17:15	14:00-17:00	15	Short Lead	AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC Pepco, PPL, PSEG, RECO
	14:30-18:30	15:00-18:00	60	Long Lead	Dominion
	15:00-17:00	15:00-17:00	0	Long Lead	AECO, JCPL, PSEG, RECO
	15:00-17:30	15:00-17:30	30	Long Lead	Met-Ed, PECO, PPL
	15:00-18:00	15:00-18:00	0	Long Lead	BGE, DPL, Pepco
	15:00-18:30	15:00-18:00	30	Long Lead	PENELEC, DLCO

Table 6-16 Load management event performance: July 15, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	795.7	690.0	670.8	535.3	135.5	97.2%	77.6%
Total	795.7	690.0	670.8	535.3	135.5	97.2%	77.6%

Table 6-17 Load management event performance: July 16, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	795.7	690.0	637.9	519.7	118.2	92.5%	75.3%
Total	795.7	690.0	637.9	519.7	118.2	92.5%	75.3%

Table 6-18 Load management event performance: July 18, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	796.2	690.0	607.3	519.5	87.8	88.0%	75.3%
PECO	580.0	410.1	378.2	331.3	46.9	92.2%	80.8%
PPL	751.5	578.8	573.4	546.1	27.3	99.1%	94.3%
Total	2,127.7	1,678.9	1,558.8	1,396.9	161.9	92.8%	83.2%

Table 6-19 Load management event performance: September 10, 2013

Zone	Nominated ICAP (MW)	Committed MW	Reduction Reported	Reduction Observed	Difference	Compliance Reported	Complianc Observe
ATSI	799.4	690.0	642.5	532.0	110.5	93.1%	77.1%
Total	799.4	690.0	642.5	532.0	110.5	93.1%	77.1%

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Table 6-20 Load management event performance: September 11, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	114.7	102.5	91.8	86.4	5.4	89.6%	84.3%
AEP	1,576.0	830.2	1,243.0	1,131.3	111.7	149.7%	136.3%
ATSI	800.0	690.0	601.4	467.2	134.2	87.2%	67.7%
BGE	787.7	627.2	690.3	672.7	17.6	110.1%	107.3%
BGE Long Lead	715.3	565.6	617.9	600.4	17.6	109.2%	106.1%
BGE Short Lead	72.4	61.6	72.4	72.4	0.0	117.5%	117.5%
DLCO	91.7	69.2	54.3	49.4	4.8	78.4%	71.4%
Dominion	863.1	751.7	683.0	621.4	61.6	90.9%	82.7%
DPL	250.7	220.3	221.8	208.2	13.7	100.7%	94.5%
DPL Long Lead	178.7	154.4	119.2	105.5	13.7	77.2%	68.3%
DPL Short Lead	72.0	65.9	102.7	102.7	0.0	155.8%	155.8%
JCPL	191.0	156.7	145.3	83.4	61.9	92.7%	53.2%
JCPL Lead Lead	171.1	136.8	120.3	58.4	61.9	87.9%	42.7%
JCPL Short Lead	19.9	19.9	25.0	25.0	0.0	125.6%	125.6%
Met-Ed	231.2	173.6	180.0	167.5	12.5	103.7%	96.5%
PECO	563.7	410.3	328.6	276.7	52.0	80.1%	67.4%
PENELEC	322.3	265.0	259.6	236.1	23.5	97.9%	89.1%
Pepco	700.2	371.9	304.9	294.9	10.0	82.0%	79.3%
Pepco Long Lead	203.9	200.3	160.8	150.8	10.0	80.3%	75.3%
Pepco Short Lead	496.3	171.7	144.1	144.1	0.0	83.9%	83.9%
PPL	790.2	621.5	611.7	565.6	46.1	98.4%	91.0%
PPL Long Lead	742.9	578.8	548.0	501.8	46.1	94.7%	86.7%
PPL Short Lead	47.2	42.6	63.8	63.8	0.0	149.6%	149.6%
PSEG	377.9	350.6	203.3	152.4	50.8	58.0%	43.5%
PSEG Long Lead	364.6	346.1	198.4	157.7	40.7	57.3%	45.6%
PSEG Short Lead	13.3	4.4	4.9	(5.3)	10.2	110.8%	(119.8%)
RECO	6.4	4.0	4.8	3.8	1.0	118.1%	93.5%
Total	7,666.7	5,644.7	5,623.7	5,017.0	606.7	99.6%	88.9%

State of the Market Report Recommendations

- **Transactions**
  - **Eliminate the IESO pricing point**
  - **Implement validation rules to prevent sham scheduling.**
  - **Align interface pricing definitions with MISO**
- **Planning**
  - **Enhance competition between transmission and generation**
  - **Create competition to finance transmission projects**
  - **Define property rights status of capacity injection rights**
  - **Improve queue management**

Figure 9-3 PJM's footprint and its external interfaces

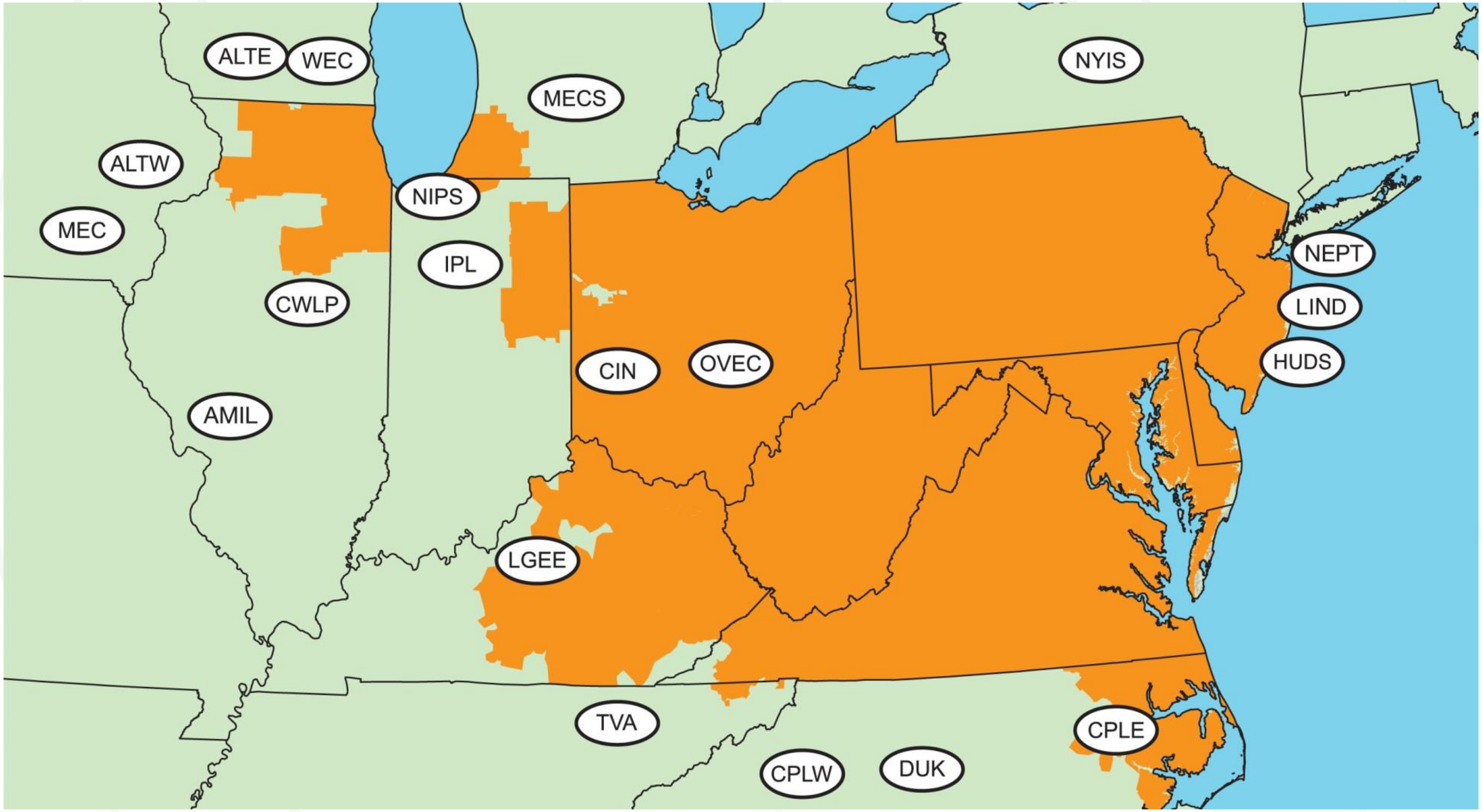


Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through 2013

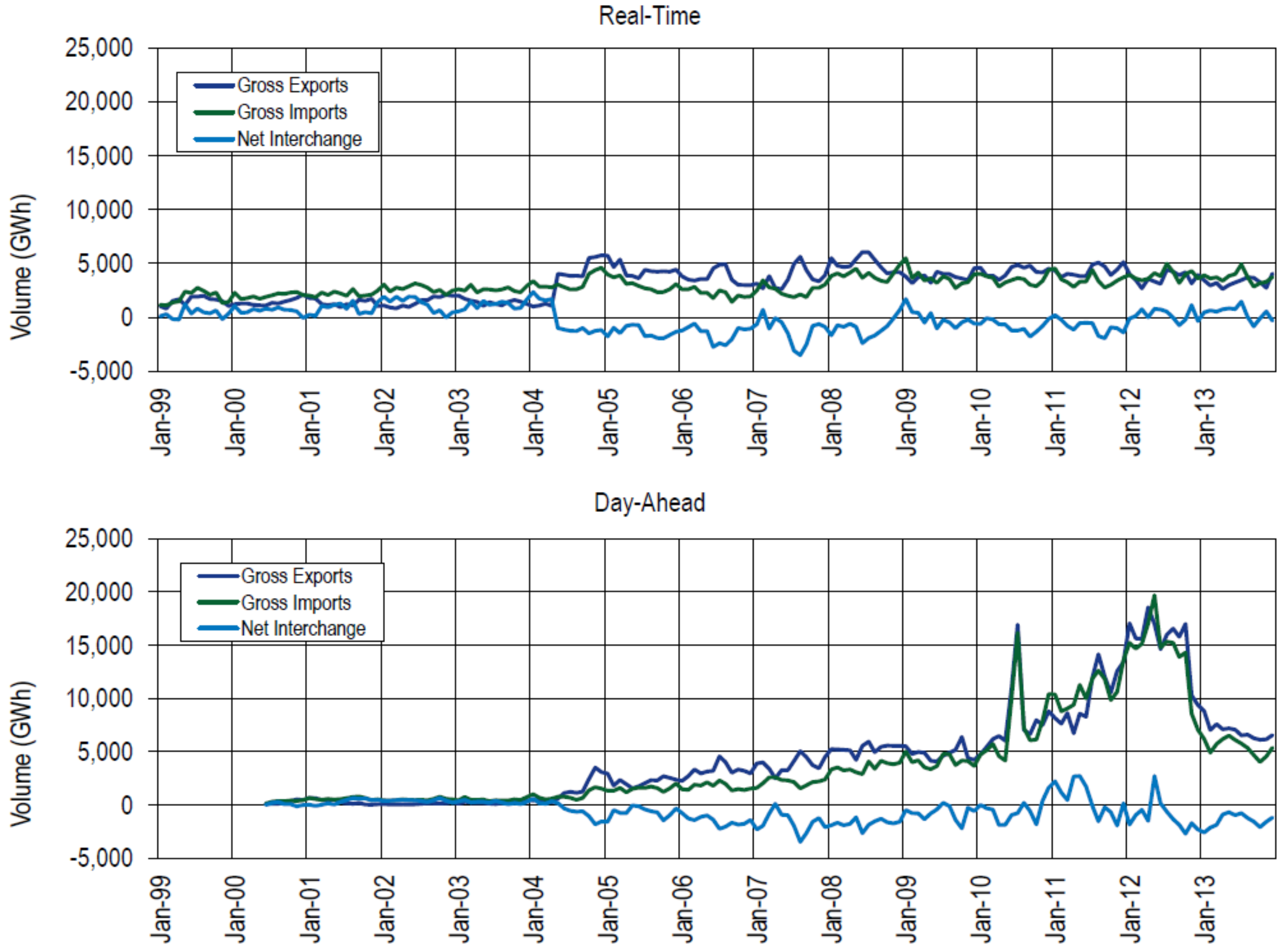
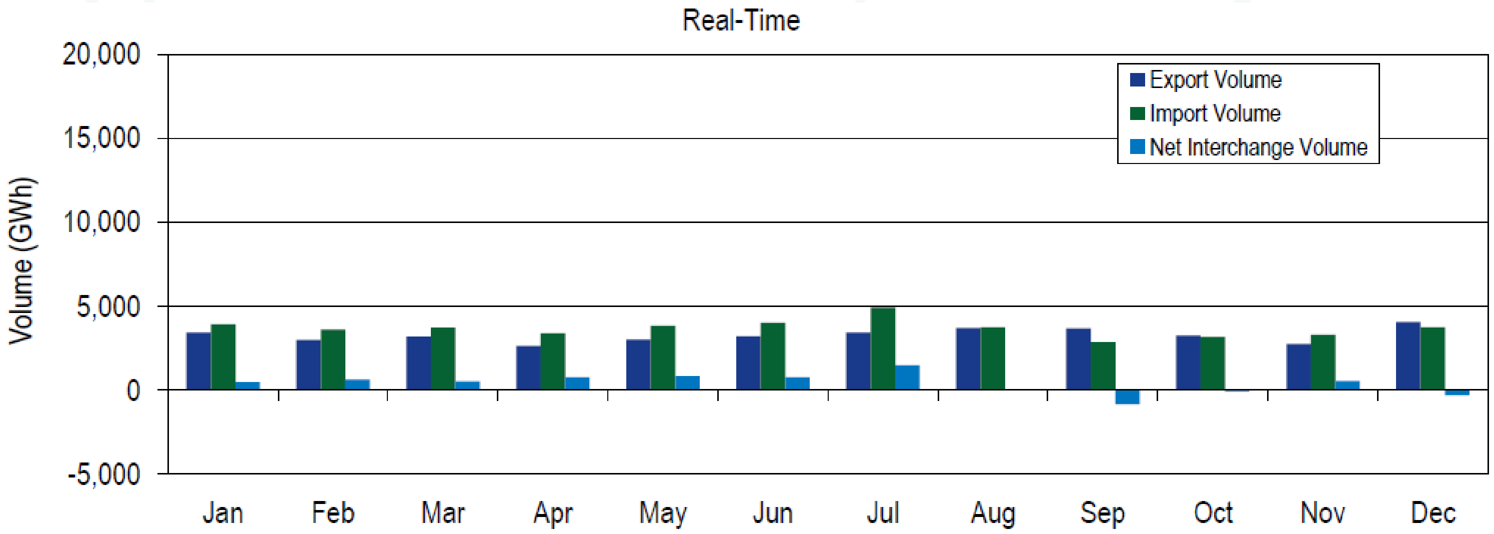


Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: 2013



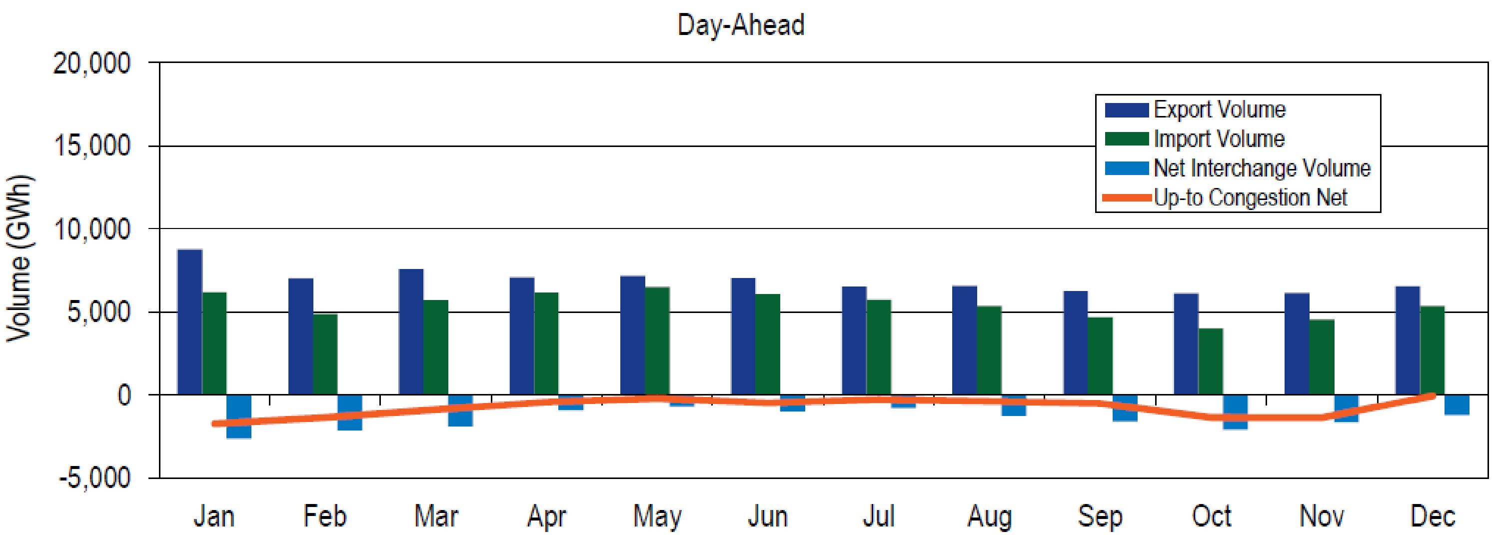


Figure 9-6 PJM, NYISO and MISO real-time and day-ahead border price averages: 2013

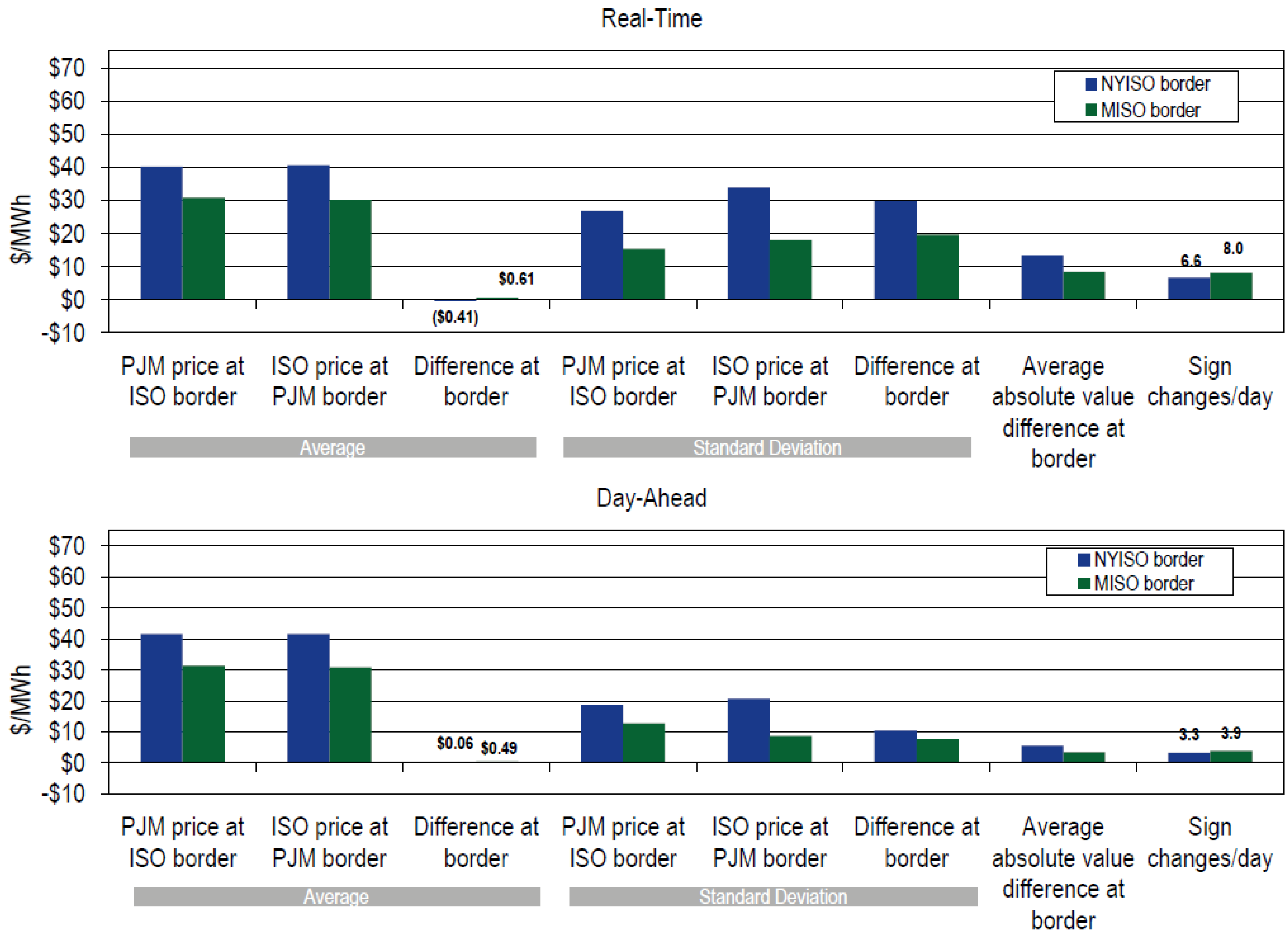


Table 1-4 The Regulation Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Flawed**

Table 1-5 The Synchronized Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

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Table 1-6 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	**Competitive**	**Mixed**

State of the Market Report Recommendations

- **Ancillary**
  - **Implement consistent treatment of marginal benefit factor in the Regulation Market.**
  - **Eliminate rule which pays Tier 1 synchronized reserves full Tier 2 price when non synchronized reserves have a price above zero.**
  - **Use operating schedule to calculate LOC.**
  - **Consider replacing day ahead DASR with real time DASR**
  - **Implement explicit rules about Tier 1 biasing**

Figure 10-8 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2013

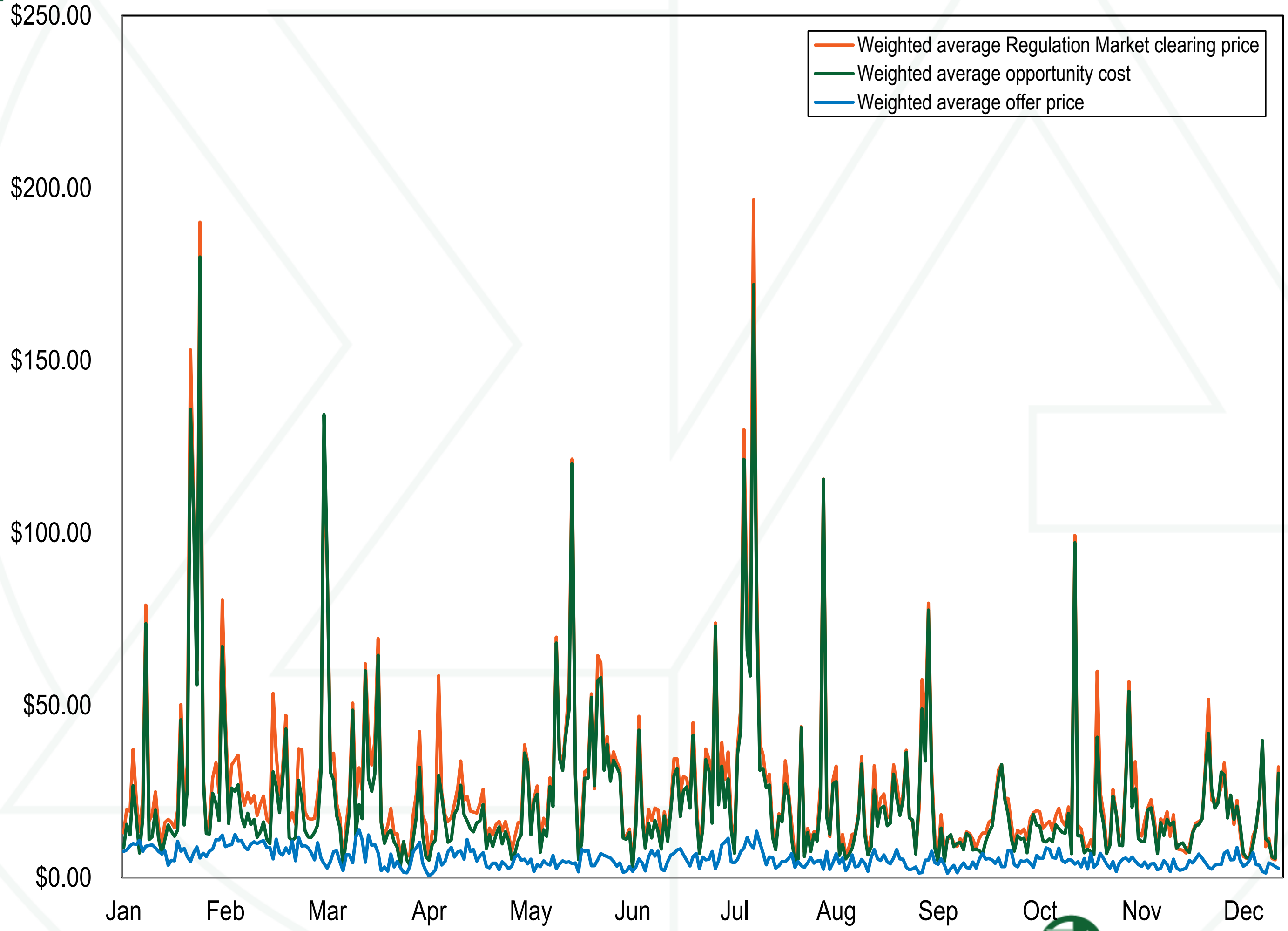

Table 10-19 Comparison of average price and cost for PJM Regulation, 2007 through 2013

Period	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$16.21	$29.28	55%
2012	$20.35	$26.41	77%
2013	$30.14	$34.57	87%

Table 10-24 Comparison of yearly weighted average price and cost for PJM Tier 2 Synchronized Reserve, 2005 through 2013

Year	Weighted Average Tier 2 Synchronized Reserve Market Price	Weighted Average Tier 2 Synchronized Reserve Cost	Weighted Average Tier 2 Synchronized Reserve Price as Percent of Cost
2005	$13.29	$17.59	76%
2006	$14.57	$21.65	67%
2007	$11.22	$16.26	69%
2008	$10.65	$16.43	65%
2009	$7.75	$9.77	79%
2010	$10.55	$14.41	73%
2011	$11.81	$15.48	76%
2012	$8.02	$12.71	63%
2013	$6.98	$13.07	53%

Table 10-22 Mid-Atlantic Dominion Subzone weighted synchronized reserve market clearing prices, credits, and MWs: 2013

Year	Month	Weighted Tier 2 Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Credits	Tier 1 Credits When NSR Prices are Above $0	PJM Tier 2 and DSR Scheduled Synchronized Reserve (MW)	Flexible Tier 2 Synchronized Reserve Added by SCED (MW)	Self Scheduled Tier 2 Synchronized Reserve MW
2013	Jan	$8.34	$1,241,545	$1,201,252	66,682	15,270	102
2013	Feb	$3.96	$1,237,024	$264,087	86,561	41,251	598
2013	Mar	$7.34	$2,303,326	$2,408,969	124,913	14,727	0
2013	Apr	$3.55	$981,153	$1,208,482	103,897	3,362	165
2013	May	$8.63	$783,952	$696,039	45,746	5,815	140
2013	Jun	$6.06	$354,786	$293,787	22,207	3,432	0
2013	Jul	$10.59	$1,798,168	$2,523,518	70,652	7,029	0
2013	Aug	$6.15	$817,829	$1,213,299	61,389	4,649	291
2013	Sep	$9.81	$1,444,831	$2,071,443	79,412	13,660	892
2013	Oct	$5.03	$1,683,055	$136,521	150,382	26,727	14,478
2013	Nov	$6.90	$2,570,725	$6,459	165,272	15,816	100,888
2013	Dec	$8.92	$2,781,599	$112,207	156,749	5,355	158,239
Total		$6.98	$17,997,993	$12,136,062	1,133,862	157,093	275,793

Table 1-7 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

State of the Market Report Recommendations

- ARRs/FTRs
  - Eliminate portfolio netting to eliminate cross subsidies
  - Ensure symmetric treatment of counter flow FTRs for payout
  - Eliminate geographic subsidies
  - Improve transmission outage modeling
  - Eliminate over allocation of ARRs
  - Apply FTR forfeiture rule to up to congestion transactions

Figure 13-19 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2013

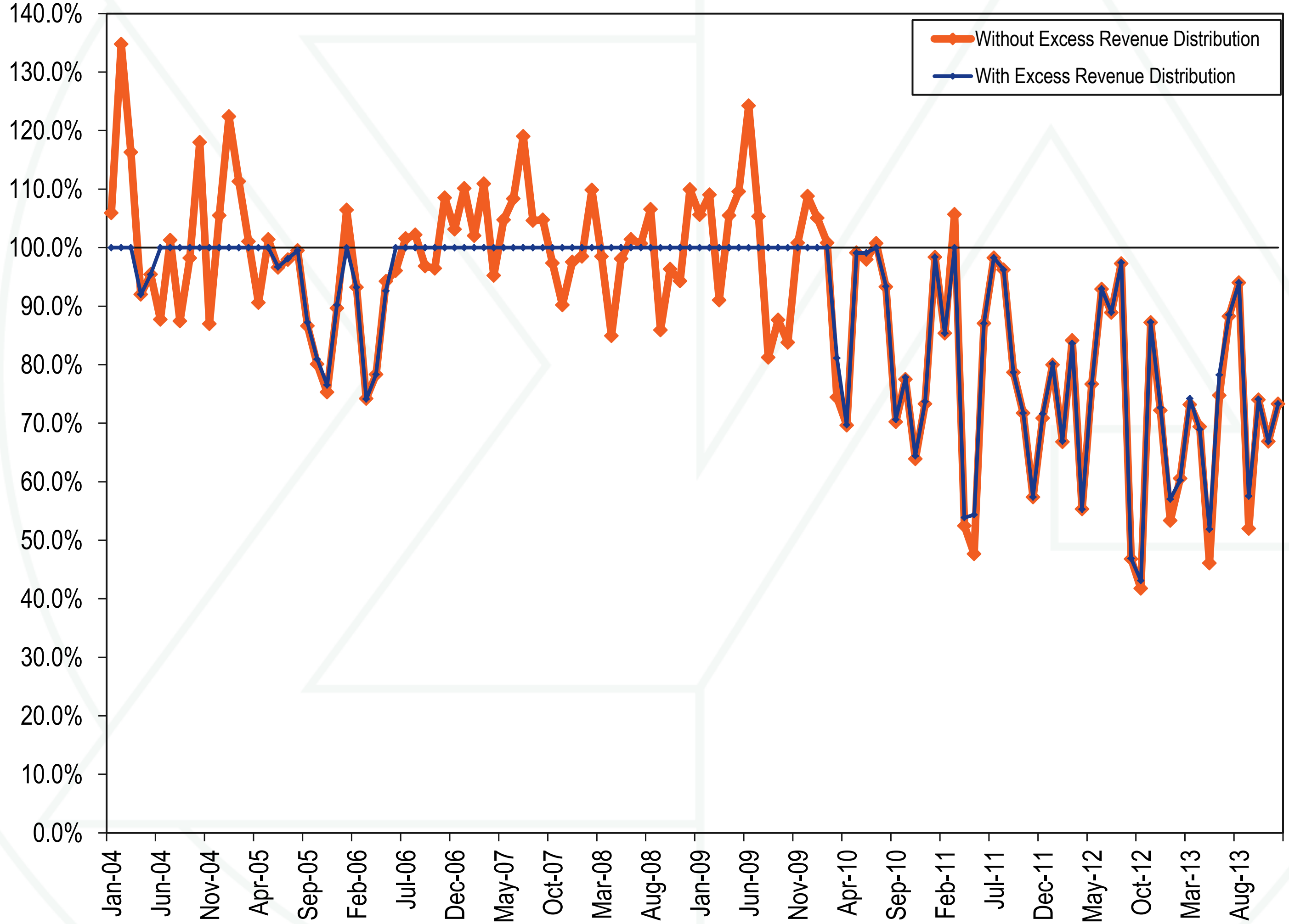

Figure 13-5 Annual FTR Auction volume: Planning period 2009 to 2010 to 2013 to 2014

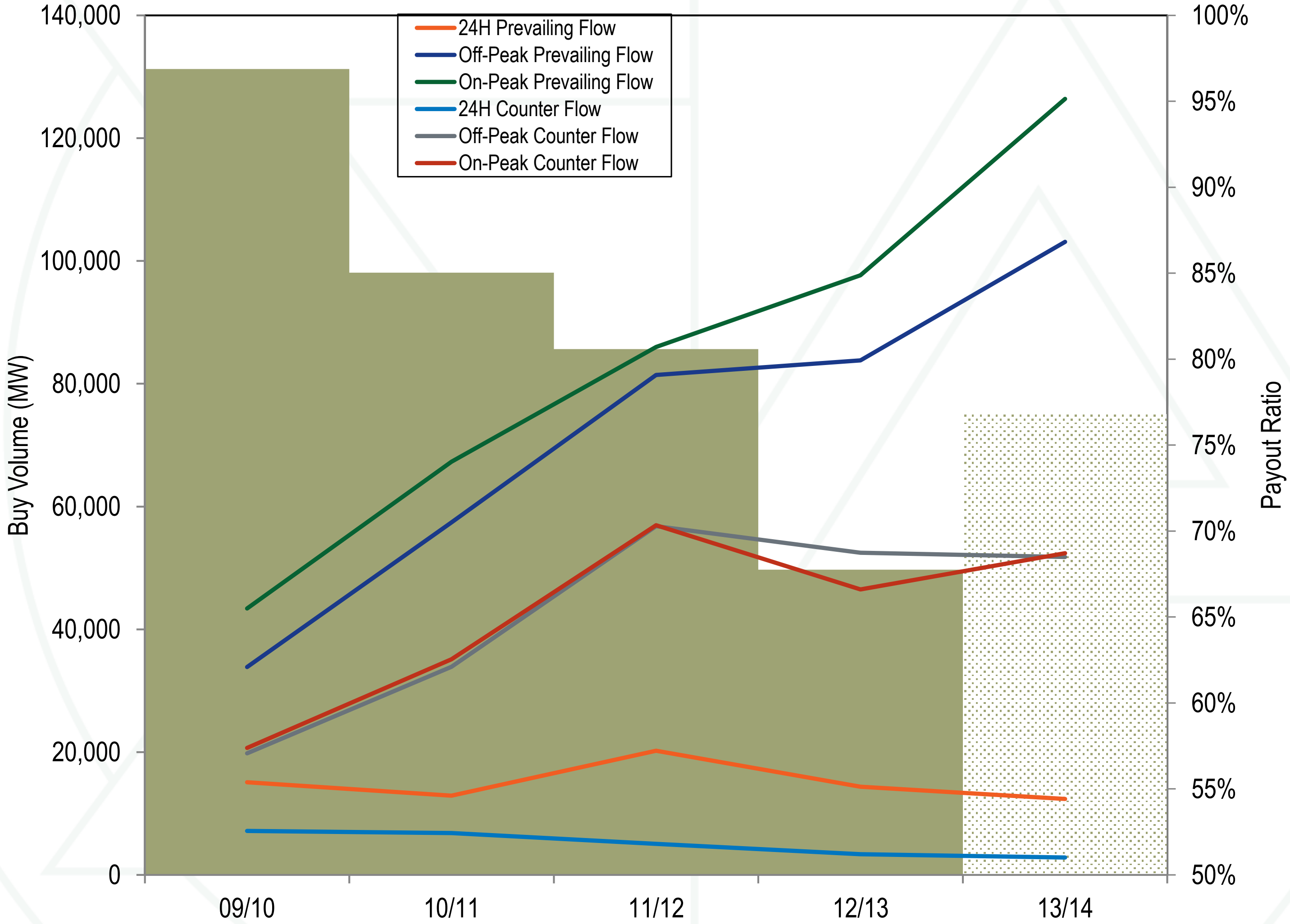

Figure 13-9 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009 to 2010 through December 31, 2013

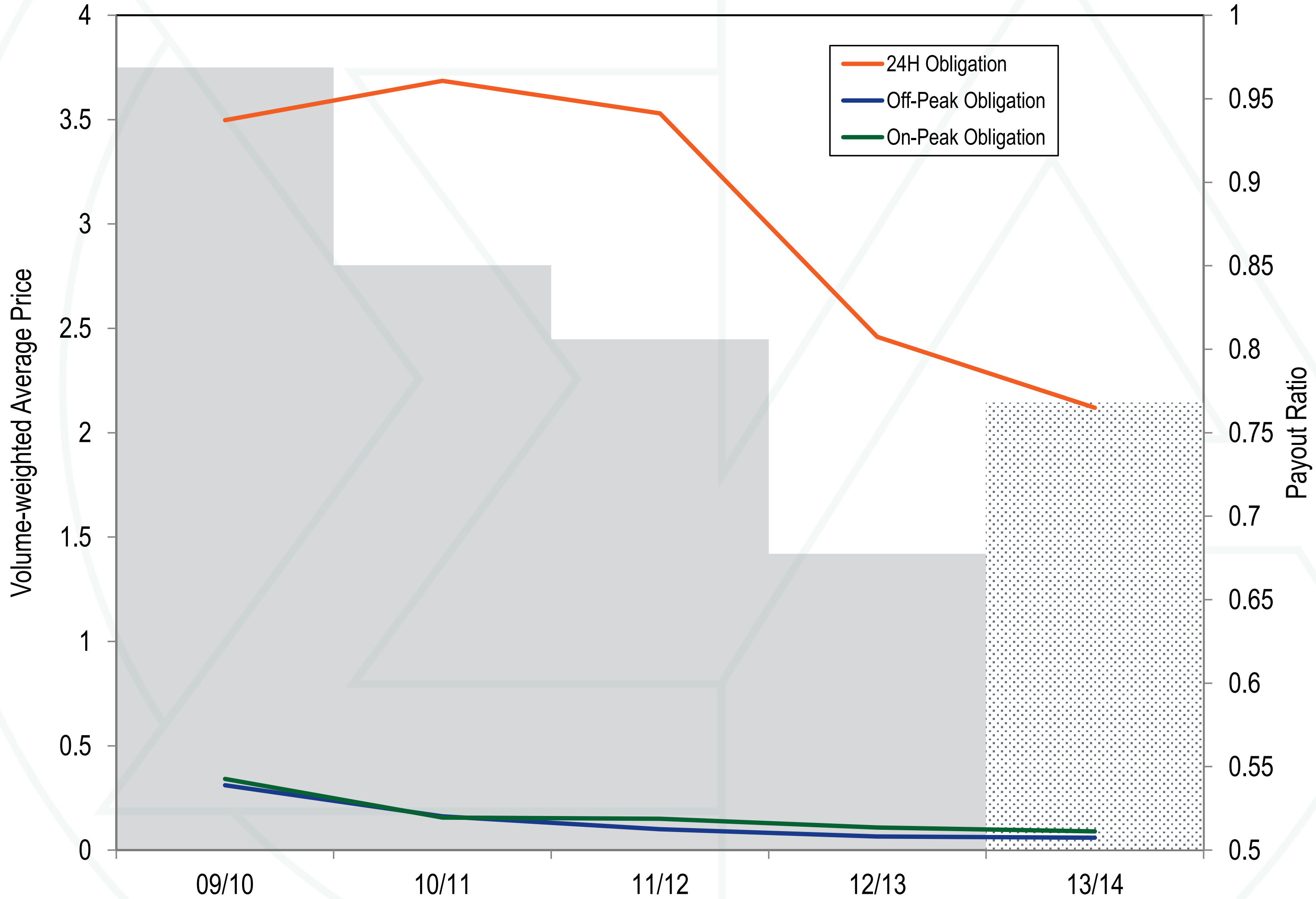

Figure 13-4 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through December 2013

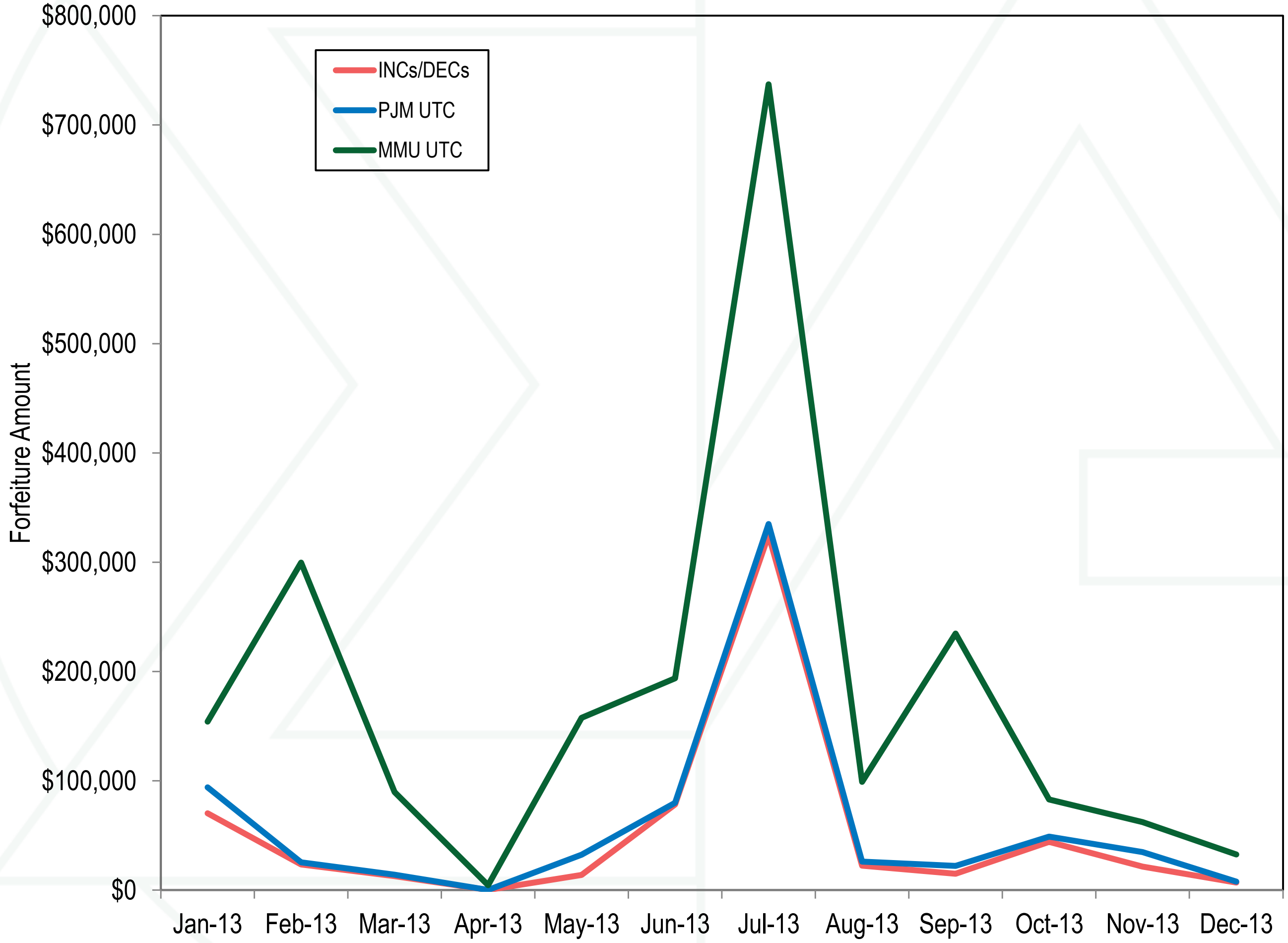

Table 13-43 ARR and FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through December 31, 2013

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$4.1	$2.9	$4.9	$2.1	$4.2	($2.1)	49.5%
AEP	$83.5	$67.7	$103.3	$47.9	$76.4	($28.5)	62.7%
APS	$66.4	$23.7	$32.8	$57.2	$48.8	$8.4	>100%
ATSI	$5.9	$22.2	$0.9	$27.1	($18.7)	$45.8	>100%
BGE	$30.5	$26.1	$32.2	$24.4	$26.4	($2.0)	92.5%
ComEd	$84.1	$60.4	$56.7	$87.9	$106.5	($18.7)	82.5%
DAY	$4.0	$4.0	$3.9	$4.1	$2.5	$1.6	>100%
DEOK	$4.4	$4.1	$4.6	$3.9	($2.9)	$6.8	>100%
DLCO	$2.1	$1.2	$0.6	$2.7	$1.9	$0.8	>100%
Dominion	$94.9	$73.7	$134.5	$34.1	$49.0	($15.0)	69.5%
DPL	$19.3	$23.7	$15.1	$28.0	$18.0	$10.0	>100%
EKPC	$2.1	$0.4	$2.8	($0.3)	($1.9)	$1.6	0.0%
External	$2.8	$1.3	$1.9	$2.2	$3.4	($1.1)	66.0%
JCPL	$6.6	$19.8	$5.8	$20.5	$17.2	$3.3	>100%
MetEd	$6.9	$8.3	$7.8	$7.5	$2.6	$4.8	>100%
PECO	$22.4	$4.2	$18.5	$8.2	($9.7)	$17.9	>100%
PENELEC	$12.0	$27.1	$43.1	($4.0)	$19.7	($23.7)	0.0%
Pepco	$19.6	$47.8	$75.0	($7.6)	$44.9	($52.6)	0.0%
PPL	$10.1	$10.3	$0.3	$20.2	$4.3	$15.9	>100%
PSEG	$38.1	$39.4	$49.1	$28.3	$29.1	($0.8)	97.2%
RECO	$0.1	($0.4)	($1.0)	$0.7	$2.2	($1.5)	30.1%
Total	$519.9	$467.9	$592.9	$394.9	$423.9	($29.0)	93.2%

Table 13-29 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2012 to 2013 and 2013 to 2014

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jan-13	$129,096,732	($8,682,957)	$233,783,161	($113,347,680)	$68,617,681	57.0%	77.8%
Feb-13	$135,702,271	($7,613,234)	$259,657,461	($131,557,526)	$77,154,565	60.3%	80.4%
Mar-13	$74,421,312	($3,760,700)	$146,552,085	($75,878,638)	$52,428,118	74.2%	87.6%
Apr-13	$50,520,958	($3,090,289)	$108,760,047	($61,325,460)	$32,698,909	68.9%	86.5%
May-13	$95,352,565	($4,678,790)	$190,798,195	($100,110,478)	$47,015,169	51.9%	77.1%
Jun-13	$86,723,727	($4,836,912)	$164,066,220	($82,101,063)	$64,060,468	78.3%	89.1%
Jul-13	$134,302,957	($6,017,378)	$255,724,128	($127,113,708)	$113,548,567	88.8%	94.1%
Aug-13	$51,545,380	($5,741,003)	$104,601,365	($58,796,985)	$43,059,687	94.1%	97.4%
Sep-13	$126,168,822	($10,172,695)	$279,972,757	($163,977,565)	$66,719,631	57.5%	82.4%
Oct-13	$69,748,034	($5,779,197)	$158,354,017	($94,365,761)	$47,353,545	74.1%	89.5%
Nov-13	$71,460,441	($4,566,566)	$156,649,135	($89,755,253)	$44,748,426	66.9%	85.9%
Dec-13	$123,125,598	($7,182,127)	$256,139,289	($140,195,812)	$84,974,997	73.3%	87.9%
2012/2013 Total	$992,878,752	($86,061,137)	$1,897,830,880	($990,471,801)	$614,014,377	67.7%	84.5%
2013/2014 Total	$663,074,957	($44,295,877)	$1,375,506,911	($674,205,083)	$464,465,322	75.1%	82.8%

Table 13-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2013 to 2014

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	9.2%	0.2%	7.0%
		No	36.1%	17.5%	31.5%
		Total	45.3%	17.8%	38.5%
	Financial	No	54.7%	82.2%	61.5%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		20.7%	19.0%	20.2%
	Financial		79.3%	81.0%	79.8%
	Total		100.0%	100.0%	100.0%

Table 13-10 Comparison of self-scheduled FTRs: Planning periods from 2009 to 2010 through 2013 to 2014

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%
2011/2012	46,017	103,735	44.4%
2012/2013	41,716	99,115	42.1%
2013/2014	29,341	94,061	31.2%

Figure 3-23 PJM cleared up-to congestion transactions by type (MW): January 2005 through December of 2013

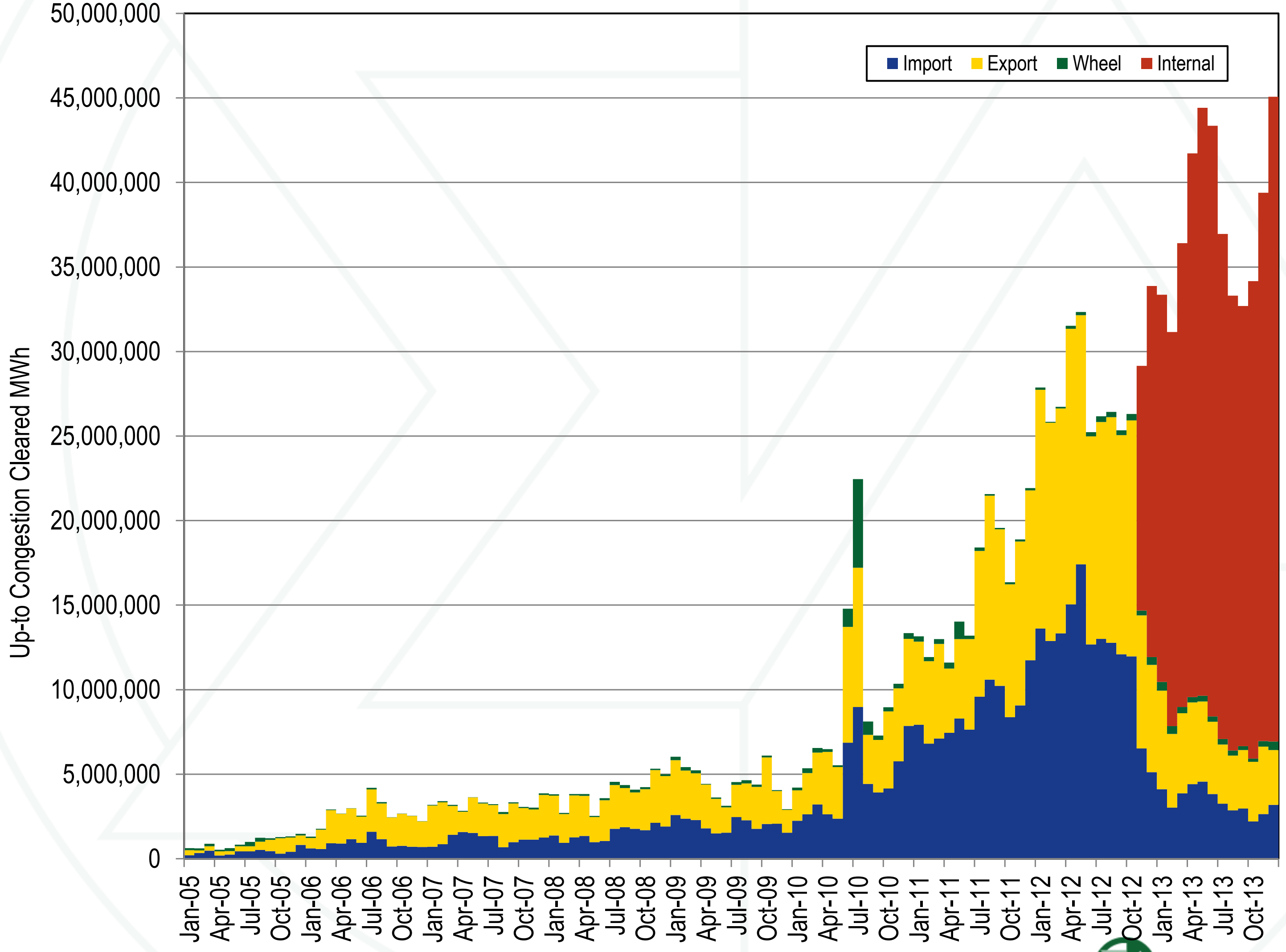

Table 3-36 PJM up-to congestion transactions by type of parent organization (MW): 2012 and 2013

	2012		2013	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	318,217,668	94.7%	432,126,914	95.6%
Physical	17,660,315	5.3%	19,875,032	4.4%
Total	335,877,984	100.0%	452,001,946	100.0%

Table 3-44 PJM cleared up-to congestion transactions by type (MW): 2012 and 2013

	2012				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	27,203,428	23,416,981	1,932,987	1,732,647	32,704,386
PJM total (MW)	146,428,449	150,988,394	2,974,891	35,486,249	335,877,984
Top ten total as percent of PJM total	18.6%	15.5%	65.0%	4.9%	9.7%
PJM total as percent of all up-to congestion transactions	43.6%	45.0%	0.9%	10.6%	100.0%
	2013				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	7,553,718	628,674	3,119,740	28,923,614	29,738,595
PJM total (MW)	40,902,161	49,738,703	4,177,320	357,183,762	452,001,946
Top ten total as percent of PJM total	18.5%	1.3%	74.7%	8.1%	6.6%
PJM total as percent of all up-to congestion transactions	9.0%	11.0%	0.9%	79.0%	100.0%

Market Monitoring Unit

- **The State of the Market Report is the work of the entire Market Monitoring Unit.**

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